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CHRISTENSEN ASSOCIATES ENERGY CONSULTING

2018 Load Impact Evaluation of Pacific Gas and Electric Company’s Residential Time-of-Use Rates

Ex-Post and *Ex-Ante* Report

CALMAC Study ID PGE0430

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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 2018. 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[1] customers in 2018, and 2) *ex-ante* forecasts of load impacts for 2019 through 2029 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 2018, PG&E offered three options rates 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-C became available in 2018. In addition, E-6 is a legacy TOU rate that is closed to new enrollment and scheduled to be terminated at the end of 2020.

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 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[2], 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.

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. Customers not selected to be defaulted onto E-TOU-C had the option to voluntarily join it beginning in April 2018.

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-C is 4 p.m. to 9 p.m. on all days. E-TOU-A and E-TOU-C 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

[1] E-TOU-C3 is hereafter abbreviated E-TOU-C.

[2] A sample of 160,525 customers were 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.

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-TOU-B, or E-TOU-C; 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 2016 to September 2017. 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 2017 to September 2018. In addition, we extended the *ex-post* evaluations conducted as part of the prior year evaluation[3] 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 2017 through September 2018, with each row representing the month's average weekday. Non-NEM enrollment reached approximately 70,000 during the program year. Percentage load impacts ranged from 2.6 percent in July to [redacted] percent in October. Note that the regression sample is smallest in these early months, as the models include only customers enrolled on or after October 1, 2017. (Enrollments reflect total non-NEM enrollment rather than the regression sample size.) The results get more robust as the program year proceeds.

[3] "2017 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates," CALMAC Study ID PGE0412.01.

Table ES.1: E-1 to E-TOU-A Peak Load Reductions – *Average Weekday by Month*[4]

		Aggregate		Per-Customer			
Month	Enrolled	Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Oct 2017	[redacted]						72.1
Nov 2017	45,482	39.8	1.5	0.88	0.032	3.6% [1.1% - 6.2%]	59.0
Dec 2017	46,188	48.3	3.8	1.05	0.081	7.8% [6.2% - 9.4%]	53.9
Jan 2018	55,187	49.8	3.0	0.90	0.054	5.9% [4.6% - 7.3%]	55.4
Feb 2018	49,237	39.7	2.5	0.81	0.051	6.3% [5.0% - 7.6%]	56.8
Mar 2018	59,230	42.1	1.8	0.71	0.031	4.4% [3.3% - 5.5%]	60.5
Apr 2018	62,880	41.4	1.7	0.66	0.027	4.1% [3.0% - 5.2%]	64.9
May 2018	67,900	46.1	1.3	0.68	0.019	2.8% [1.7% - 4.0%]	70.1
Jun 2018	64,083	54.4	2.4	0.85	0.037	4.4% [3.3% - 5.5%]	80.7
Jul 2018	70,672	75.0	1.9	1.06	0.027	2.6% [1.7% - 3.5%]	87.8
Aug 2018	69,245	63.6	2.6	0.92	0.037	4.0% [3.1% - 5.0%]	82.3
Sep 2018	67,184	54.1	3.1	0.81	0.046	5.7% [4.7% - 6.7%]	78.5

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 47,000 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.

[4] 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 2017	[redacted]						62.3
Nov 2017	31,031	60.4	6.0	1.95	0.193	9.9% [7.9% - 11.9%]	57.1
Dec 2017	30,747	64.4	5.2	2.10	0.170	8.1% [6.9% - 9.3%]	51.8
Jan 2018	37,333	70.0	5.4	1.87	0.144	7.7% [6.6% - 8.7%]	54.3
Feb 2018	33,349	59.8	4.0	1.79	0.120	6.7% [5.7% - 7.7%]	54.6
Mar 2018	39,840	65.9	2.8	1.65	0.071	4.3% [3.5% - 5.1%]	59.2
Apr 2018	42,696	67.8	5.5	1.59	0.130	8.2% [7.4% - 8.9%]	63.3
May 2018	45,789	76.4	5.3	1.67	0.116	6.9% [6.2% - 7.7%]	68.3
Jun 2018	42,537	91.6	8.3	2.15	0.195	9.0% [8.3% - 9.7%]	78.5
Jul 2018	47,241	124.7	8.2	2.64	0.173	6.5% [6.0% - 7.1%]	85.1
Aug 2018	46,373	105.4	7.6	2.27	0.165	7.3% [6.7% - 7.8%]	79.8
Sep 2018	44,845	90.5	6.2	2.02	0.137	6.8% [6.1% - 7.5%]	76.2

Table ES.3 shows the monthly peak-period load impacts for defaulted customers who continued with the transition to E-TOU-C. Load impacts ranged from 0.029 to 0.045 kWh/hour/customer, or 3 to 4 percent of reference loads.

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)		
Jun 2018	108,945	105.2	3.1	0.97	0.029	3.0% [2.8% - 3.1%]	80.7
Jul 2018	107,571	139.9	4.8	1.30	0.045	3.5% [3.4% - 3.6%]	87.8
Aug 2018	106,443	114.0	3.7	1.07	0.035	3.3% [3.2% - 3.4%]	82.5
Sep 2018	105,225	95.0	3.8	0.90	0.036	4.0% [3.9% - 4.2%]	77.8

Table ES.4 shows the peak-period load impacts for the customers who were not selected for the Transition, but made the choice to switch from E-1 to E-TOU-C. Non-NEM enrollment reached approximately 1,700 customers by the end of the summer. Notice that reference loads and load impacts for these customers were substantially higher than those of the Default E-TOU-C customers. The fact that the monthly temperatures are comparable to or lower than those of the Default E-TOU-C customers indicates that the load impact difference are not simply due to voluntary customers being more concentrated in hot weather regions.

Table ES.4: E-1 to Voluntary 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)		
Jun 2018	866	1.3	0.1	1.46	0.163	11.1% [9.2% - 13.0%]	78.1
Jul 2018	1,237	2.3	0.3	1.87	0.205	10.9% [9.5% - 12.4%]	84.5
Aug 2018	1,554	2.4	0.2	1.55	0.139	8.9% [7.6% - 10.3%]	79.6
Sep 2018	1,733	2.3	0.1	1.35	0.086	6.4% [4.9% - 7.9%]	75.9

ES.4 Ex-Ante Load Impacts

For the TOU rates, *ex-ante* load impacts were developed separately for three TOU rates: E-TOU-A, E-TOU-B, and E-TOU-C; and for six categories of TOU customers, as follows:

- *E-TOU-A, B, and C incremental*. These are customers who are assumed to newly enroll in the E-TOU-A, E-TOU-B, and E-TOU-C rates in future years.
- *E-TOU-A, B, and C embedded*. These are customers who have enrolled in E-TOU-A and B as of the current year, and are assumed to remain on the rate in the future. The E-TOU-C customers represent both the participants in PG&E's Default Transition Phase I and those who chose to enroll in the rate in 2018.

Figures ES.1A and B show the yearly enrollments forecast for the month of August[5], for each customer group. The forecast assumes that E-TOU-A will be terminated at the end of 2020, with the assumption that the majority of its customers will transition to E-TOU-C. Enrollments for the E-TOU-B and E-TOU-C incremental groups increase throughout the forecast period, while the corresponding embedded customer enrollments decline (representing attrition among the currently enrolled customers). Note that the E-TOU-C embedded customers primarily reflect those enrolled in the rate via the Default Transition Phase I.

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

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

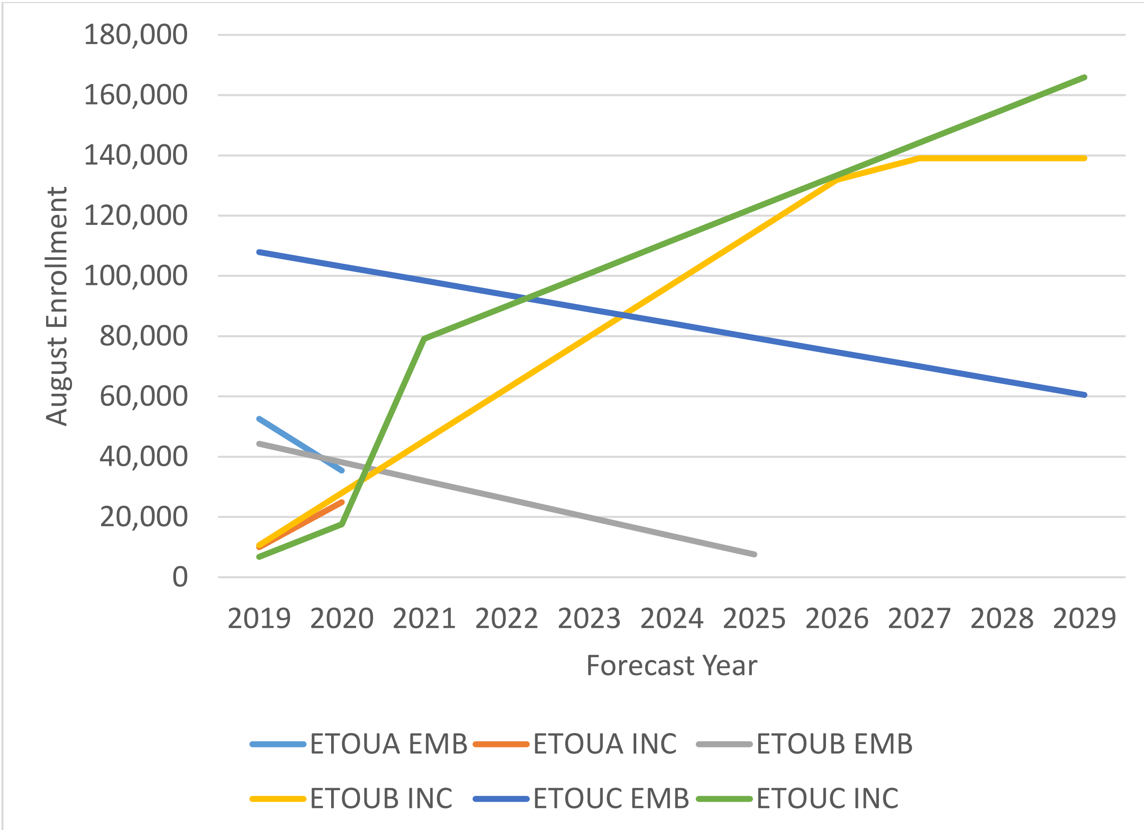


Figure ES.1B: Forecast August Enrollments by Year and Customer Group - Distribution

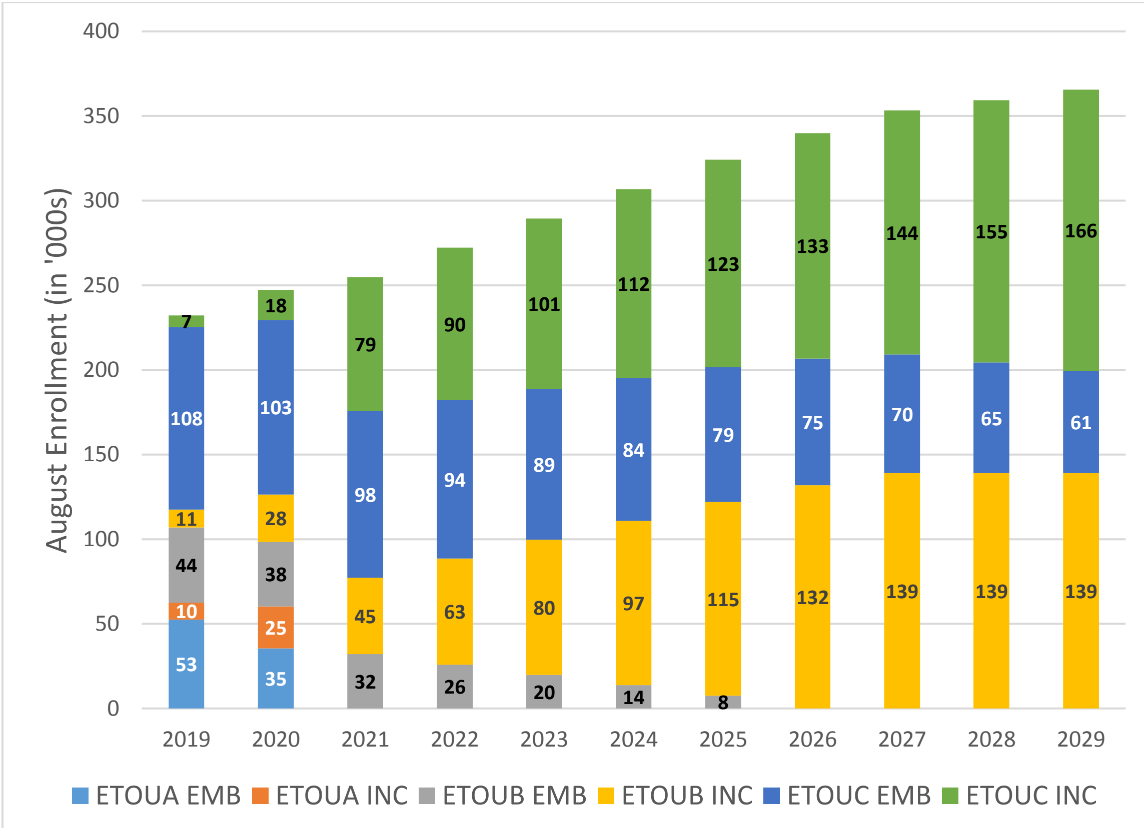
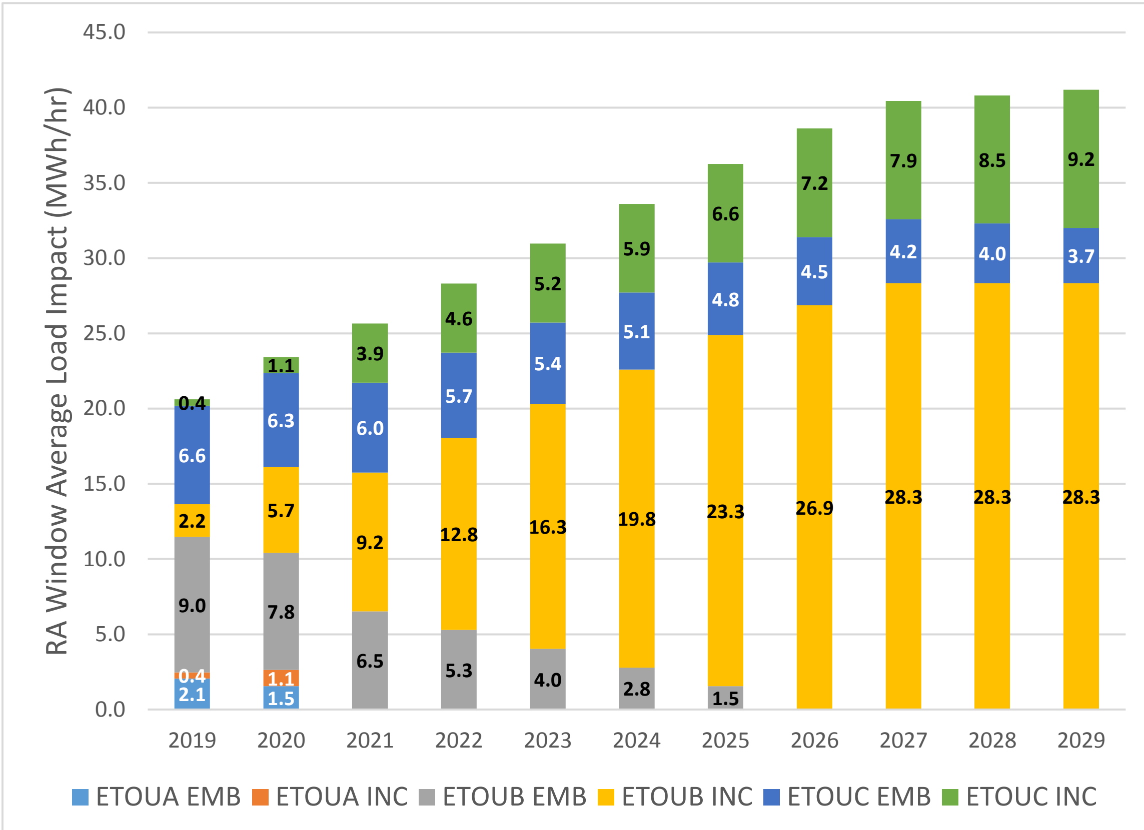


Figure ES.2 summarizes the forecast load impacts for the month of August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 weather conditions. For additional details on assumptions and methodology, refer to Section 3.2. The load impact pattern across years closely resembles the corresponding enrollment pattern, as shown in Figure ES.1B.

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



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 2018, 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 (hereafter abbreviated E-TOU-C).[6]

This is the first evaluation of E-TOU-C, which was made available to customers in April 2018 and currently consists of customers who were selected for TOU Transition Phase I and continued with the Transition in April 2018; and residential customers who opted into the rate. The evaluation separately studies the load impacts for transitioned and opt-in E-TOU-C customers.

The primary goals of the evaluation are the following:

1. Estimate *ex-post* load impacts for each rate for program year 2018, and
2. Develop *ex-ante* load impact forecasts for the rates for 2019 through 2029.

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 PY2017 *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 2018, PG&E offered three options rates 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-C became available in 2018. In addition, E-6 is a legacy TOU rate that is closed to new enrollment and scheduled to be terminated at the end of 2020.

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[7], with the objective of understanding the

[6] Previous evaluations included E-6 and E-7. E-7 is terminated and E-6 is closed to new enrollment.

[7] A sample of 160,525 customers were 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.

operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU.

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. At the end of 2018, approximately 2.6 percent of those who transitioned had switched back to a tiered rate or another TOU rate, while 8 percent were stopped or closed as service accounts. Customers not selected to be defaulted onto E-TOU-C had the option to voluntarily join it beginning in April 2018.

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-C is 4 p.m. to 9 p.m. on all days. E-TOU-A and E-TOU-C 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 moved to E-TOU-A, E-TOU-B, or E-TOU-C during the 2018 program year (October 2017 through September 2018). In addition, we estimated some extensions of the analysis in the PY2017 load impact evaluation, which estimate the persistence of the load impacts for customers who migrated from E-1 to E-TOU-A or E-TOU-B.

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 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 the 2017 program year, 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 four groups of customers, defined as those who changed rates from E-1 to E-TOU-A, E-TOU-B, and E-TOU-C with the latter group further divided into customers who voluntarily joined the rate and 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 and E-TOU-B load impacts from the 2017 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-

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

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.

Control group selection

For the newly enrolled former E-1 customers in E-TOU-A, E-TOU-B, and E-TOU-C, 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 2016 through September 2017 for the TOU and potential control group customers. We then apply propensity score matching using pre-treatment monthly billing data summary variables 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 request pre-processed interval load data, collapsed to pre-defined 24-hour profiles[10], for all TOU customers and the preliminary matched E-1 customers.[11] 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 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 A.

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.[12]

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[9] Specifically, we estimate propensity score models by LCA and CARE status with a TOU enrollment indicator as the dependent variable and summer and winter use per day as the independent variables. We then select the six 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 cooling and heating degree days calculated from participant-weighted temperature data (*i.e.*, temperatures across PG&E's weather stations were combined into a single profile weighted according to the number of TOU customers associated with each station). 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.

[11] PG&E produced the average load shape data to reduce the need for transferring large amounts of hourly interval data.

[12] Some customers were screened out of the study due to large changes in usage across years. Our initial estimates were not credible and an examination of the data revealed that some treatment and control customers had large changes in load across years, well beyond what one would expect from price-based demand response. Causes could have included installing solar panels (but not yet being classified as NEM),

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. Separate models are estimated by hour, month, CARE status, and LCA, where the customer-level fixed-effects models are of the following form:[13]

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

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

adding square footage to the home, or a change in the number of people living at home. After screening "big changers" out of the dataset, the regression results reflected much more plausible TOU demand response.

[13] 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.

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 averaged across "cells" (*e.g*., for the average 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. We attempted to incorporate the relationship between load impacts and weather by interacting the load impact variable with cooling degree days (CDD) and heating degree days (HDD), but found the estimated to be unreliable. Instead, 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.

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 2018 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* forecast of E-TOU-C customers is complicated by two factors: we only have summer *ex-post* load impacts upon which to base the forecast (because the rate was not available during the winter months of PY2018); and the voluntary enrollment in the rate was quite low relative to forecast levels. For the *embedded* E-TOU-C customers (who were defaulted onto the rate as part of TOU Transition Phase I), we base the summer *ex-ante* forecast on the *ex-post* analysis of those same customers. The winter *ex-ante* forecast is based on the E-TOU-A percentage load impacts (because we are not yet able to estimate E-TOU-C winter load impacts) applied to reference loads from voluntary E-TOU-C customers, adjusting the difference in average usage between the two groups.[14] For the *incremental* E-TOU-C customers, we based the *ex-ante* forecast on the per-customer *ex-post* impacts for the E-TOU-A customers. There are several reasons for this modeling choice: we have full-year load impact estimates for E-TOU-A but not E-TOU-C; many of the incremental E-TOU-C customers in the enrollment forecast are assumed to have migrated from E-TOU-A after it closes in 2020; and E-TOU-A and E-TOU-C are similar in structure as they both include the tiered rate structure (which E-TOU-B does not), and thus may be expected to attract similar customers.

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-C. 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.

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 2017 through September 2018, with each row representing the month's average weekday. Non-NEM enrollment reached approximately 70,000 during the program year. Percentage load impacts ranged from 2.6 percent in July to [redacted] percent in October. Note that the regression sample is smallest in these early months, as the models include only customers enrolled on or after October 1, 2017. (Enrollments reflect total non-NEM enrollment rather than the regression sample size.) The results get more robust as the program year proceeds.

[14] Voluntary E-TOU-C customers had substantially higher usage than the default E-TOU-C customers during summer 2018. We estimated LCA-specific adjustment factors to adjust the reference loads, which ranged from 0.44 to 0.76.

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

		Aggregate		Per-Customer			
Month	Enrolled	Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Oct 2017	[redacted]						72.1
Nov 2017	45,482	39.8	1.5	0.88	0.032	3.6% [1.1% - 6.2%]	59.0
Dec 2017	46,188	48.3	3.8	1.05	0.081	7.8% [6.2% - 9.4%]	53.9
Jan 2018	55,187	49.8	3.0	0.90	0.054	5.9% [4.6% - 7.3%]	55.4
Feb 2018	49,237	39.7	2.5	0.81	0.051	6.3% [5.0% - 7.6%]	56.8
Mar 2018	59,230	42.1	1.8	0.71	0.031	4.4% [3.3% - 5.5%]	60.5
Apr 2018	62,880	41.4	1.7	0.66	0.027	4.1% [3.0% - 5.2%]	64.9
May 2018	67,900	46.1	1.3	0.68	0.019	2.8% [1.7% - 4.0%]	70.1
Jun 2018	64,083	54.4	2.4	0.85	0.037	4.4% [3.3% - 5.5%]	80.7
Jul 2018	70,672	75.0	1.9	1.06	0.027	2.6% [1.7% - 3.5%]	87.8
Aug 2018	69,245	63.6	2.6	0.92	0.037	4.0% [3.1% - 5.0%]	82.3
Sep 2018	67,184	54.1	3.1	0.81	0.046	5.7% [4.7% - 6.7%]	78.5

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 47,000 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.

[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 2017	[redacted]						62.3
Nov 2017	31,031	60.4	6.0	1.95	0.193	9.9% [7.9% - 11.9%]	57.1
Dec 2017	30,747	64.4	5.2	2.10	0.170	8.1% [6.9% - 9.3%]	51.8
Jan 2018	37,333	70.0	5.4	1.87	0.144	7.7% [6.6% - 8.7%]	54.3
Feb 2018	33,349	59.8	4.0	1.79	0.120	6.7% [5.7% - 7.7%]	54.6
Mar 2018	39,840	65.9	2.8	1.65	0.071	4.3% [3.5% - 5.1%]	59.2
Apr 2018	42,696	67.8	5.5	1.59	0.130	8.2% [7.4% - 8.9%]	63.3
May 2018	45,789	76.4	5.3	1.67	0.116	6.9% [6.2% - 7.7%]	68.3
Jun 2018	42,537	91.6	8.3	2.15	0.195	9.0% [8.3% - 9.7%]	78.5
Jul 2018	47,241	124.7	8.2	2.64	0.173	6.5% [6.0% - 7.1%]	85.1
Aug 2018	46,373	105.4	7.6	2.27	0.165	7.3% [6.7% - 7.8%]	79.8
Sep 2018	44,845	90.5	6.2	2.02	0.137	6.8% [6.1% - 7.5%]	76.2

Table 4.3 shows the monthly peak-period load impacts for the defaulted E-TOU-C customers. Load impacts ranged from 0.029 to 0.045 kWh/hour/customer, or 3 to 4 percent of reference loads.[16]

[16] Note that the Default E-TOU-C load impacts reported here do not match those reported in a December 2018 memorandum of prelimimary summer 2018 load impacts. The key differences are: preliminary memorandum employed a Random Encouragement Design (RED) analysis that incorporated the impacts of defaulted customers who declined E-TOU-C or selected a different voluntary TOU rate (E-TOU-A or B), whereas this study focuses only on the load impacts of customers served on E-TOU-C; this study excludes NEM customers while the preliminary memorandum included them; and this study reports load impacts by LCA while the preliminary memorandum reported load impacts by research segment (broadly, by climate region and CARE status).

Table 4.3: 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)		
Jun 2018	108,945	105.2	3.1	0.97	0.029	3.0% [2.8% - 3.1%]	80.7
Jul 2018	107,571	139.9	4.8	1.30	0.045	3.5% [3.4% - 3.6%]	87.8
Aug 2018	106,443	114.0	3.7	1.07	0.035	3.3% [3.2% - 3.4%]	82.5
Sep 2018	105,225	95.0	3.8	0.90	0.036	4.0% [3.9% - 4.2%]	77.8

Table 4.4 shows the peak-period load impacts for the customers who voluntarily switched from E-1 to E-TOU-C. Non-NEM enrollment reached approximately 1,700 customers by the end of the summer. Notice that reference loads and load impacts for these customers were substantially higher than those of the Default E-TOU-C customers. The fact that the monthly temperatures are comparable to or lower than those of the Default E-TOU-C customers indicates that the load impact difference are not simply due to voluntary customers being more concentrated in hot weather regions.

Table 4.4: E-1 to Voluntary 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)		
Jun 2018	866	1.3	0.1	1.46	0.163	11.1% [9.2% - 13.0%]	78.1
Jul 2018	1,237	2.3	0.3	1.87	0.205	10.9% [9.5% - 12.4%]	84.5
Aug 2018	1,554	2.4	0.2	1.55	0.139	8.9% [7.6% - 10.3%]	79.6
Sep 2018	1,733	2.3	0.1	1.35	0.086	6.4% [4.9% - 7.9%]	75.9

4.2 Seasonal peak load impacts by LCA and Climate Region

Tables 4.5 and 4.6 show E-TOU-A peak-period load impacts for the average summer weekday, by LCA and climate region, respectively.[17] Percentage peak load impacts vary considerably across LCAs, averaging 4 percent. Kern has the highest percentage load impact while customers not located in an LCA have the lowest. The results by climate region (in Table 4.6) reflect the expected relationship between climate region and average customer usage, with the highest-use customers in the hot region. Customers in the hot and moderate regions have similar percentage load impacts, while the customers in the cool region have lower load impacts in level and percentage terms.

Table 4.5: E-1 to E-TOU-A 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	37,547	20.1	0.9	0.54	0.024	4.4% [3.4% - 5.4%]	72.7
Greater Fresno	[redacted]						94.0
Humboldt							69.5
Kern							96.2
Northern Coast	7,836	7.2	0.1	0.92	0.019	2.1% [-0.2% - 4.4%]	76.3
Other	9,007	11.6	0.2	1.29	0.023	1.8% [-0.8% - 4.3%]	87.4
Sierra	4,785	7.4	0.4	1.54	0.089	5.8% [2.8% - 8.8%]	88.3
Stockton	[redacted]						88.0
All	**67,796**	**61.8**	**2.5**	**0.91**	**0.037**	**4.0% [3.1% - 5.0%]**	**82.3**

[17] 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.

Table 4.6: E-1 to E-TOU-A Peak Load Reductions by Climate Region – Average *Summer* Weekday

Climate Region	Enrolled	Aggregate: Peak Ref. Load (MW)	Aggregate: Peak Load Impact (MW)	Per-Customer: Peak Ref. Load (kW)	Per-Customer: Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Hot	17,387	29.4	1.2	1.69	0.068	4.0% [2.5% - 5.6%]	89.7
Moderate	32,309	21.7	1.1	0.67	0.034	5.1% [3.8% - 6.4%]	76.5
Cool	18,101	8.0	0.1	0.44	0.003	0.8% [-0.4% - 2.0%]	66.1

Tables 4.7 and 4.8 show comparable results for the E-1 to E-TOU-B group. For this group, percentage load impacts average 7.3 percent, with the highest responsiveness in Humboldt and the lowest in Kern. As Table 4.8 shows, the E-TOU-B customers in the cool region are somewhat responsive, though still less responsive (in both level and percentage terms) than the customers in the moderate and hot climate regions.

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

LCA	Enrolled	Aggregate: Peak Ref. Load (MW)	Aggregate: Peak Load Impact (MW)	Per-Customer: Peak Ref. Load (kW)	Per-Customer: Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Greater Bay Area	21,611	37.8	2.3	1.75	0.104	6.0% [5.3% - 6.6%]	71.8
Greater Fresno	3,263	12.2	1.0	3.75	0.302	8.0% [6.3% - 9.8%]	93.3
Humboldt	[redacted]						67.2
Kern	[redacted]						94.6
Northern Coast	5,046	8.8	0.3	1.74	0.061	3.5% [1.9% - 5.1%]	74.6
Other	7,314	19.4	2.0	2.65	0.277	10.4% [8.3% - 12.5%]	84.0
Sierra	4,153	13.3	0.8	3.21	0.202	6.3% [4.5% - 8.0%]	85.2
Stockton	[redacted]						85.4
All	**45,249**	**103.0**	**7.6**	**2.28**	**0.167**	**7.3% [6.7% - 8.0%]**	**79.9**

Table 4.8: E-1 to E-TOU-B 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	14,961	49.3	4.1	3.29	0.276	8.4% [7.5% - 9.3%]	87.2
Moderate	18,800	37.9	2.4	2.02	0.127	6.3% [5.6% - 7.0%]	74.8
Cool	11,488	15.1	0.9	1.31	0.077	5.9% [4.8% - 6.9%]	64.3

Table 4.9 shows Default E-TOU-C load impacts by LCA. Per-customer load impacts were lowest in Kern and highest in Sierra (in level terms). The pilot design of TOU Transition Phase I segmented customers by climate region and CARE status, excluding CARE customers in the hot climate region.[18] Our preliminary evaluation of the summer 2018 load impacts found the highest estimated load impacts for non-CARE customers in the hot climate region. Within the moderate and cool climate regions, non-CARE customers had higher load impacts than CARE customers (in both level and percentage terms).

[18] There were also two segments that included all customers in two CCAs and a single segment that included all NEM customers.

Table 4.9: E-1 to Default E-TOU-C 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	13,463	10.3	0.5	0.76	0.035	4.7% [4.3% - 5.0%]	74.0
Greater Fresno	6,727	12.3	0.5	1.84	0.067	3.6% [3.3% - 4.0%]	94.0
Humboldt	316	0.2	0.0	0.70	0.060	8.6% [6.1%-11.1%]	64.7
Kern	2,076	4.6	0.0	2.22	0.019	0.9% [0.3% - 1.4%]	95.8
Northern Coast	22,807	18.5	0.6	0.81	0.028	3.5% [3.2% - 3.8%]	76.2
Other	45,934	44.2	1.2	0.96	0.025	2.6% [2.4% - 2.8%]	79.8
Sierra	9,383	15.9	0.9	1.70	0.092	5.4% [5.1% - 5.8%]	86.2
Stockton	6,341	7.5	0.2	1.18	0.035	2.9% [2.4% - 3.5%]	87.0
All	**107,046**	**113.5**	**3.9**	**1.06**	**0.036**	**3.4% [3.3% - 3.5%]**	**82.2**

Tables 4.10 and 4.11 show results by LCA and climate region for the customers who voluntarily adopted E-TOU-C. Load impacts were rather high overall, but highest in Greater Fresno and Stockton. Table 4.11 shows the expected relationship between temperatures, reference loads, and load impacts.

Table 4.10: E-1 to Voluntary E-TOU-C 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	728	0.8	0.0	1.14	0.042	3.7% [1.6% - 5.7%]	71.5
Greater Fresno	[redacted]						92.5
Humboldt							65.6
Kern							94.9
Northern Coast							74.0
Other							85.8
Sierra							84.2
Stockton							85.2
All	**1,348**	**2.1**	**0.2**	**1.55**	**0.141**	**9.1% [7.6% - 10.6%]**	**79.5**

Table 4.11: E-1 to Voluntary E-TOU-C 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	417	1.0	0.1	2.45	0.277	11.3% [9.2% - 13.4%]	88.5
Moderate	574	0.7	0.0	1.30	0.068	5.2% [2.8% - 7.7%]	74.5
Cool	357	0.3	0.0	0.88	0.033	3.7% [0.8% - 6.7%]	64.4

4.3 Peak load impacts by CARE status

Tables 4.12 through 4.14 show average summer peak-period load reductions by CARE status for the E-TOU-A, E-TOU-B, and voluntary E-TOU-C customers, respectively. In each case, CARE customers have higher reference loads and load impacts, though this is likely explained by where CARE customers tend to live compared to non-CARE customers, as reflected in the significantly higher average peak temperatures for the CARE customers.

Table 4.12: 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	58,950	52.31	1.952	0.89	0.033	3.7% [2.6%-4.8%]	82
	CARE	8,846	9.48	0.545	1.07	0.062	5.7% [4.3%-7.2%]	86

Table 4.13: 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	38,047	86.43	6.260	2.27	0.165	7.2% [6.5%-8.0%]	79
	CARE	7,202	16.61	1.300	2.31	0.181	7.8% [7.1%-8.6%]	84

Table 4.14: Peak Load Reductions by CARE Status – *E-1 to Voluntary E-TOU-C*

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	990	1.49	0.122	1.50	0.123	8.2% [6.2%-10.2%]	78
	CARE	358	0.60	0.068	1.68	0.191	11.4% [9.7%-13.1%]	85

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 2018. 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 2018 and January 2018, respectively. Figures 4.3 and 4.4 show the same information for the E-TOU-B customers.

Figures 4.5 and 4.6 show the August load impacts for the voluntary and default E-TOU-C customers, respectively. 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 2018*)

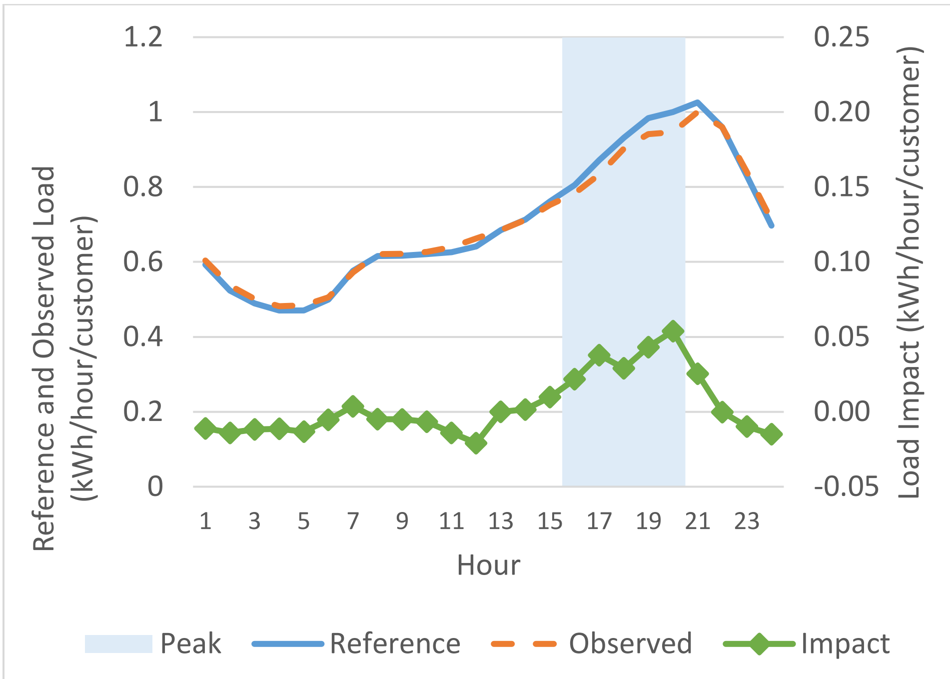


Figure 4.2: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-A (*Average Weekday, January 2018*)

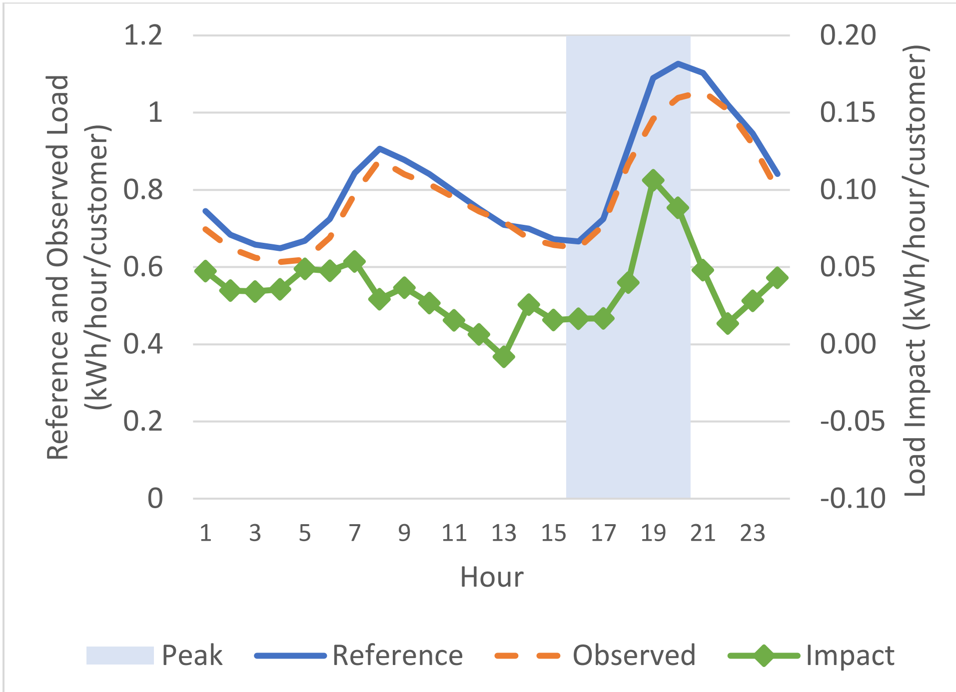


Figure 4.3: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-B (*Average Weekday, August 2018*)

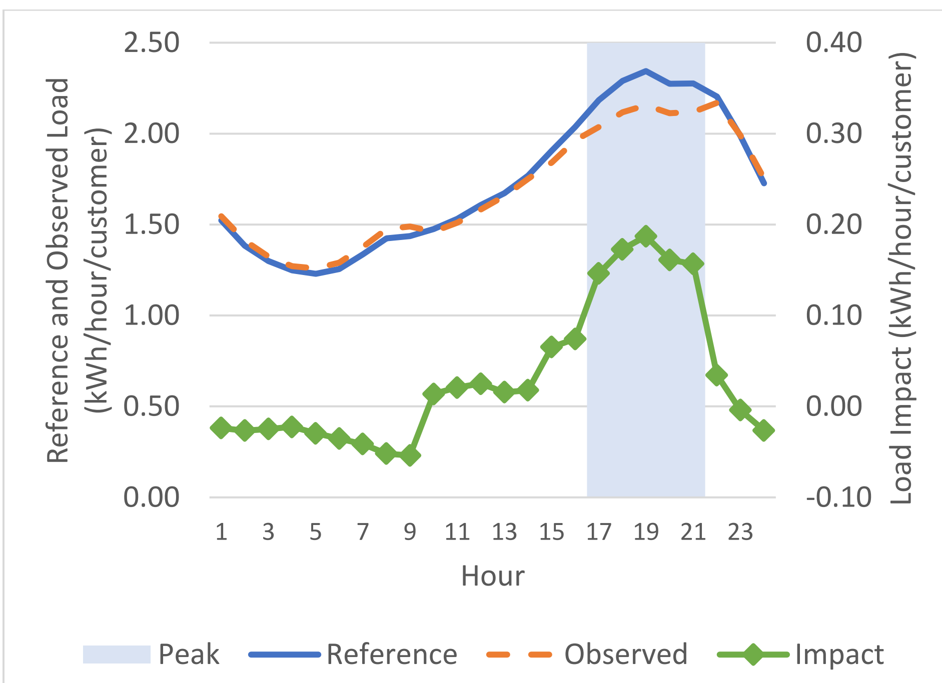


Figure 4.4: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-B (*Average Weekday, January 2018*)

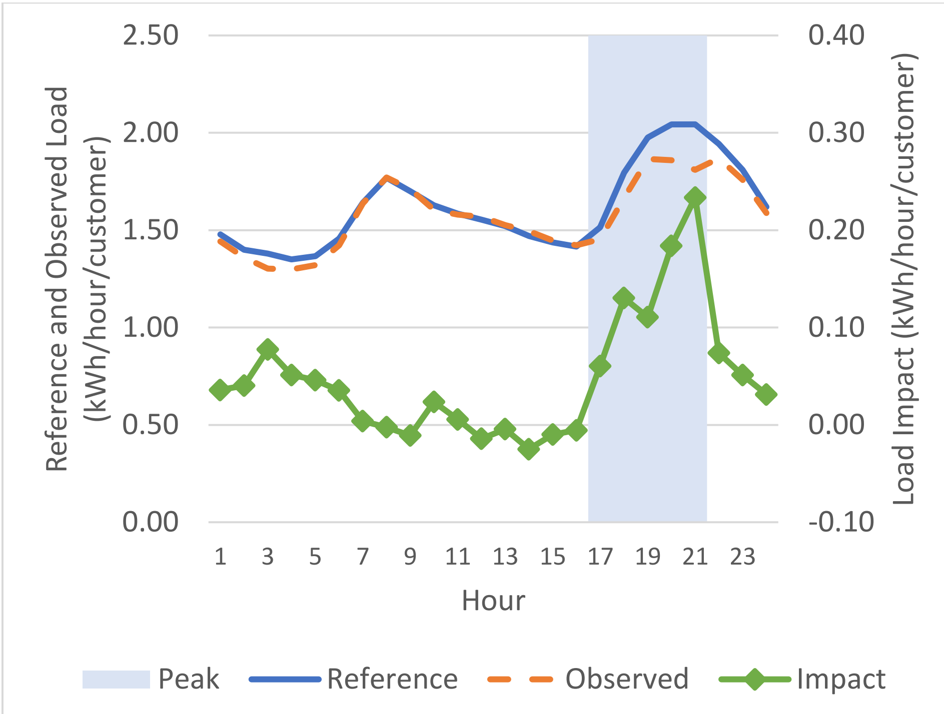


Figure 4.5: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to Voluntary E-TOU-C (*Average Weekday, August 2018*)

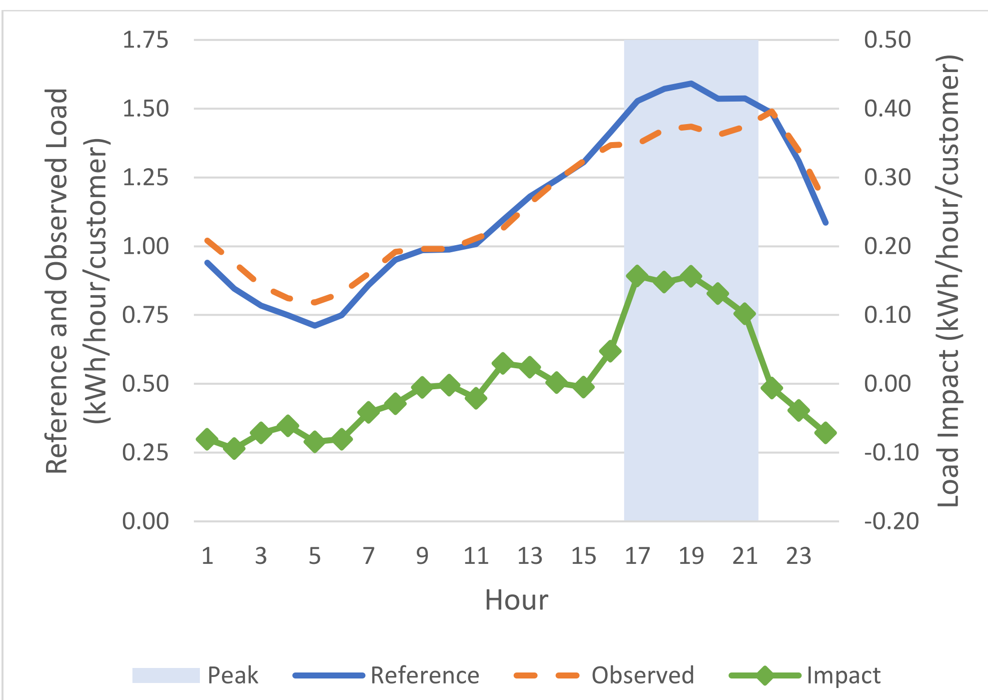
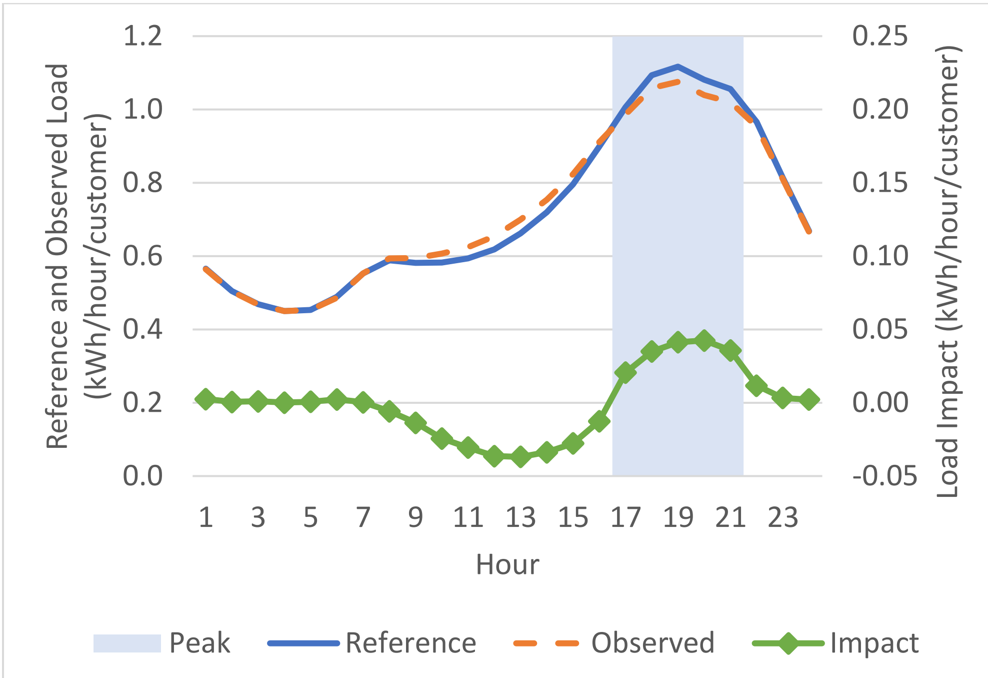


Figure 4.6: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to Default E-TOU-C (*Average Weekday, August 2018*)



4.5 Load Impacts for Structural Benefiters

PG&E provided a variable indicating whether each E-TOU-A, E-TOU-B, and E-TOU-C 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.[19]

The share of structural benefiters was quite different by rate, with 64 percent of E-TOU-A customers, 77 percent of E-TOU-B customers, 44 percent of E-TOU-C voluntary customers, 37 percent of E-TOU-C default customers obtaining that status. 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-C but not E-TOU-B). This theory is supported by the fact that E-TOU-B benefiters use 40

[19] 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.

percent more energy during summer months than E-TOU-B non-benefiters. Conversely, E-TOU-A benefiters use 50 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 models by benefiter status.

Table 4.15 summarizes the reference loads and estimated load impacts by rate and season 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-C. As described above, this is attributable to the absence of the tiered rate structure in E-TOU-B.
- The level of load impacts (in kWh/hour/customer) tends to be higher for non-benefiters, with the exception of E-TOU-B during the summer months.
- Percentage load impacts tend to be higher for non-benefiters as well.
- The generally lower load impacts for benefiters may reflect the motivations for joining the rate. That is, benefiters may join to realize the "instant" bill benefit, whereas non-benefiters hope to save money by altering their usage patterns in response to the TOU prices.

Table 4.15: Average Event-Hour and Daily Load Impacts by Structural Benefiter Status (kWh/hour/customer)

Rate	Season	Hours	Reference Load (kWh/hr/cust)		Load Impact (kWh/hr/cust)		% Load Impact	
			Non-benefiter	Benefiter	Non-benefiter	Benefiter	Non-benefiter	Benefiter
ETOUA	Winter	All	0.79	0.67	0.04	0.01	5.6%	1.3%
		Peak	0.89	0.73	0.06	0.03	6.9%	4.5%
	Summer	All	0.94	0.51	0.00	0.00	0.2%	-0.3%
		Peak	1.31	0.56	0.05	0.00	3.6%	0.5%
ETOUB	Winter	All	1.62	1.68	0.17	0.09	10.7%	5.2%
		Peak	1.74	1.91	0.29	0.17	16.5%	9.1%
	Summer	All	1.30	1.86	0.09	0.10	7.3%	5.6%
		Peak	1.79	2.33	0.12	0.24	6.9%	10.3%
ETOUC Voluntary	Summer	All	1.26	1.04	0.06	0.02	4.9%	1.8%
		Peak	1.78	1.26	0.17	0.10	9.4%	8.1%
ETOUC Default	Summer	All	1.00	0.85	0.04	0.01	3.9%	1.1%
		Peak	1.58	1.10	0.12	0.02	7.6%	1.7%

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

The previous (PY2017) load impact study examined residential customers who enrolled in a TOU rate during the 2017 program year (between October 1, 2016 and September 30, 2017).

In this study, we explore the persistence of the load impacts for the customers included in the PY2017 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 PY2017 load impact, while the "TOU year 2 load impact" is the PY2018 load impact. Note that the participants in PY2017 load impacts shown in Table 5.1 do not match the participants reported in the PY2017 study because we restricted the sample to customers who continued to be enrolled in the TOU rate during PY2018, maintained non-NEM status, and still had a valid matched control-group customer.[20]

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

Result	E-TOU-A	E-TOU-B
TOU year 1 load impact	0.078 (8.9%)	0.154 (6.0%)
TOU year 2 load impact	0.043 (5.0%)	0.035 (1.5%)
Yr 1 = Yr 2 p-value	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. However, it's possible that weather played a role in the differences across years, as 2017 was somewhat hotter than 2018. For example, for E-TOU-A customers the average Mean17 value was 68.3°F in 2017 and 66.5°F in 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-C, and for six categories of TOU customers, as follows:

- *E-TOU-A, B, and C incremental*. These are customers who are assumed to newly enroll in the E-TOU-A, B, and C rates in future years.

[20] The average load impact from June through September in the PY2017 evaluation was 0.106 kWh/hour/customer for E-TOU-A and 0.171 kWh/hour/customer for E-TOU-B.

- *E-TOU-A, B, and C embedded*. These are customers who were enrolled in E-TOU-A, B, and C 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.

Figures 6.1A and 6.1B show the yearly enrollments forecast for the month of August[21], for each customer group. The forecast assumes that E-TOU-A will be terminated at the end of 2020, with the assumption that the majority of its customers will transition to E-TOU-C. Enrollments for the E-TOU-B and E-TOU-C incremental groups increase throughout the forecast period, while the corresponding embedded customer enrollments decline (representing attrition among the currently enrolled customers). Note that the E-TOU-C embedded customers reflect those enrolled in the rate via the Default Transition Phase I and those who chose to enroll in the rate in 2018.

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

Figure 6.1A: Forecast August Enrollments by Year and Customer Group

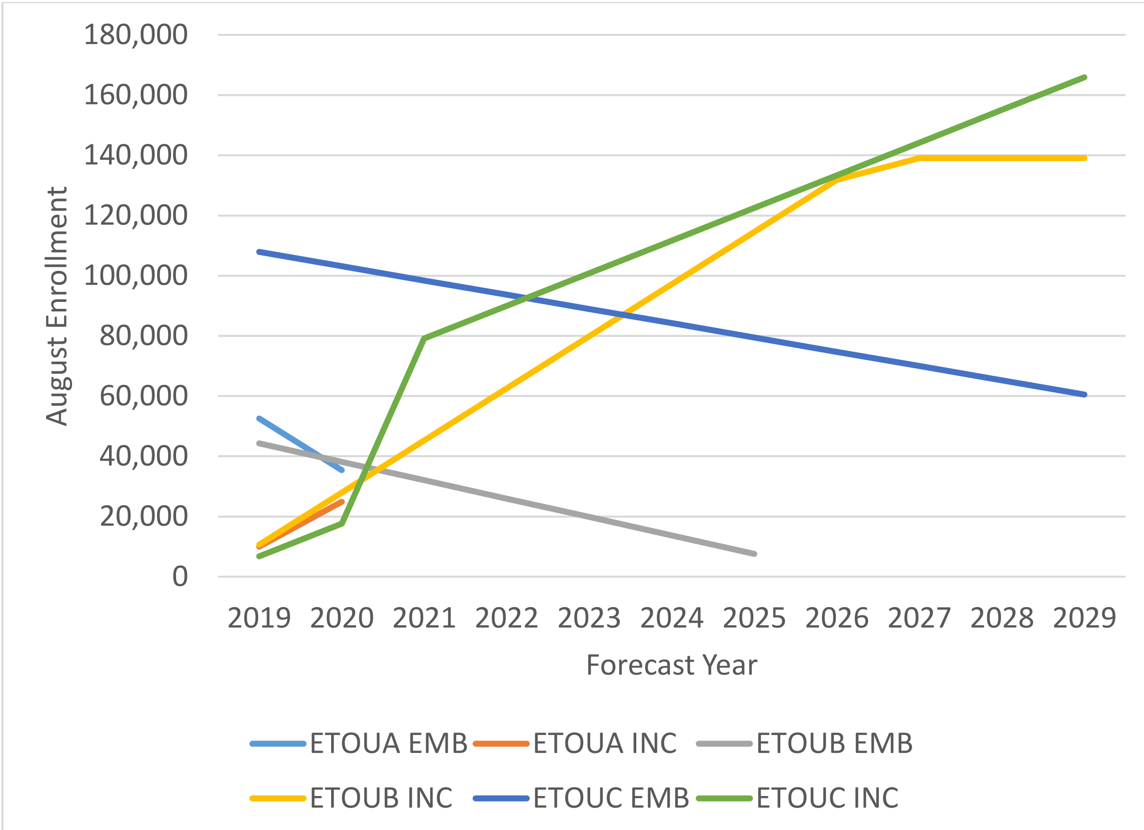
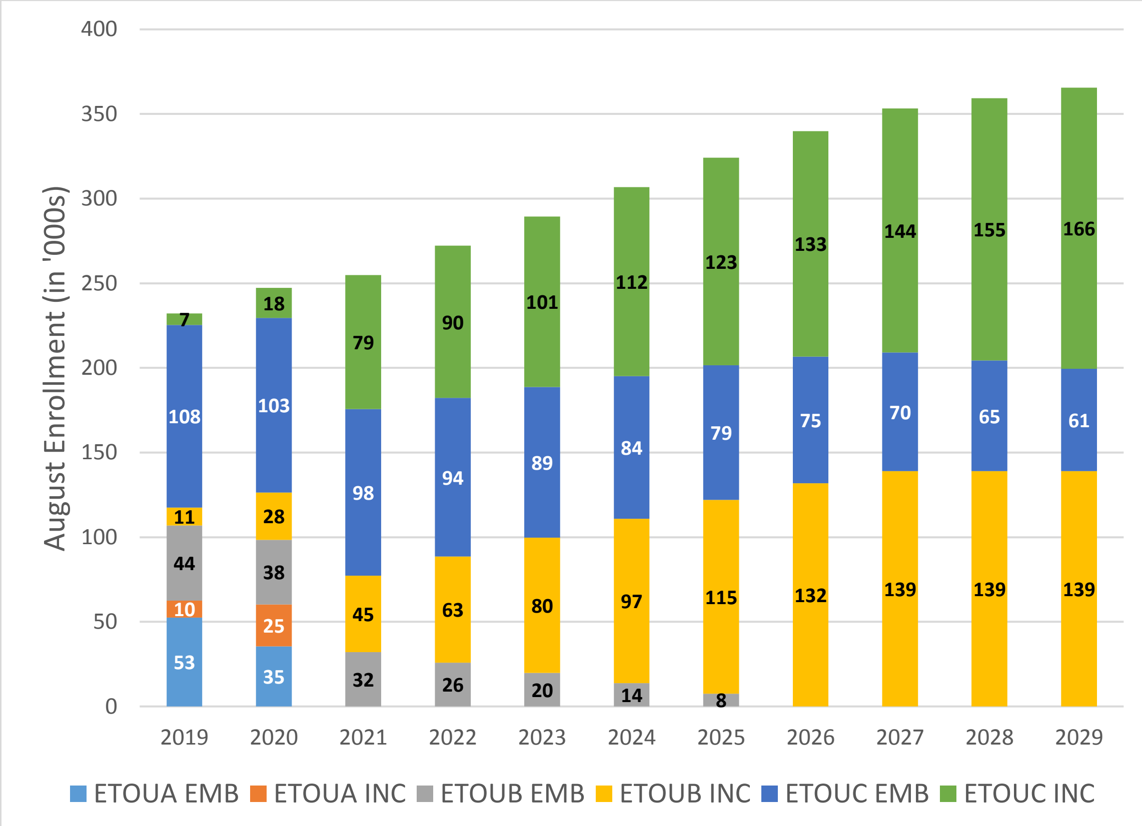


Figure 6.1B: Forecast August Enrollments by Year and Customer Group - Distribution



6.2 Ex-Ante Load Impact Results

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

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

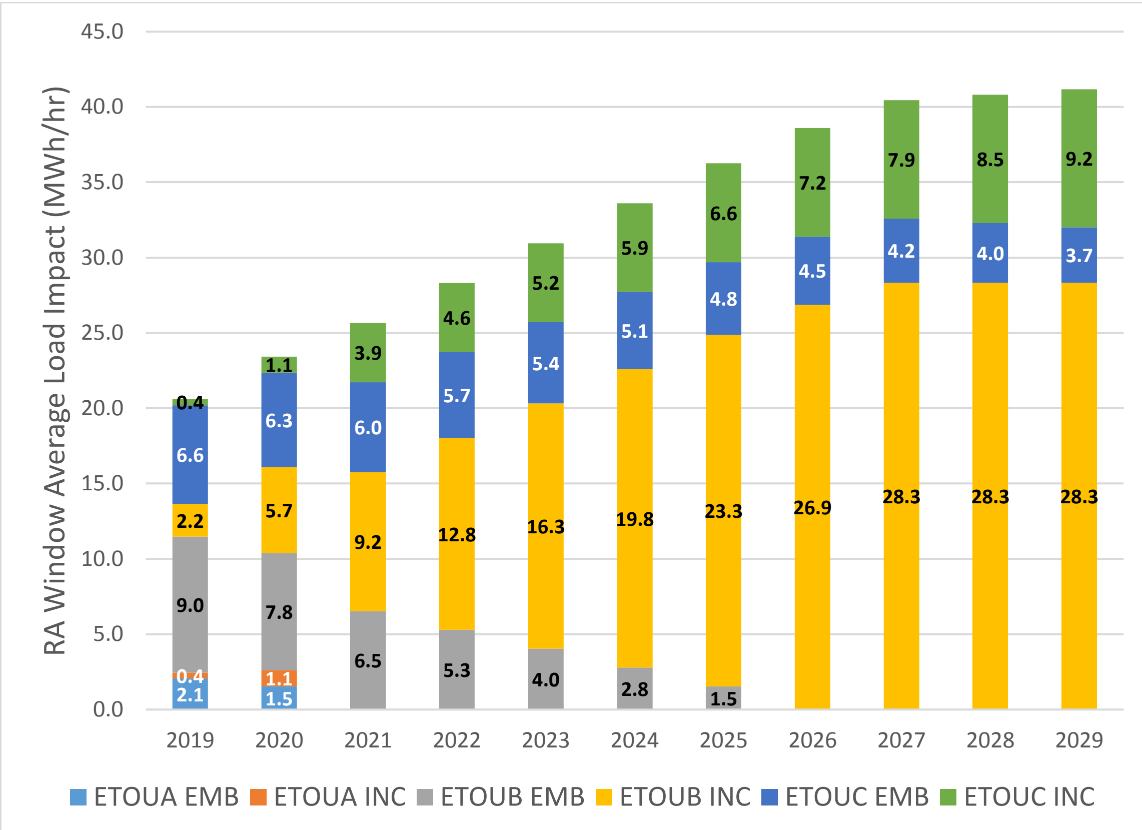
The following sub-sections present the *ex-ante* forecasts for each of these groups. For E-TOU-A and E-TOU-B, the incremental and embedded forecasts are combined into one sub-section.[22]

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

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

(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 6.1B.

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



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

Tables 6.1 and 6.2 show the E-TOU-A embedded and incremental load impacts (respectively), averaged during the Resource Adequacy window. The tables show monthly load impacts in 2019 associated with each of the four weather scenarios. Embedded enrollment declines somewhat across the twelve months shown, from approximately 66,000 to 46,000 customers. In contrast, incremental enrollment increases from approximately 1,200 to 15,000 customers. On a per-customer basis, winter (October through May) load impacts are slightly higher than summer load impacts (*e.g.*, 0.039 kWh/hour/customer in summer and 0.045 kWh/hour/customer in winter for the PG&E 1-in-2 weather year). This is a reflection of the seasonal pattern in the *ex-post* impacts.

Table 6.1: E-TOU-A Embedded *Ex-Ante* Load Impacts, 2019 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	3.6	3.4	3.6	3.5
February	3.0	3.0	3.2	3.1
March	2.3	2.7	2.6	2.7
April	2.0	2.0	2.0	2.0
May	2.8	2.5	3.3	2.6
June	2.1	2.1	2.4	2.2
July	2.3	2.0	2.4	2.1
August	2.1	1.9	2.3	2.1
September	1.8	1.7	2.0	1.9
October	2.4	2.1	2.6	2.1
November	1.7	1.8	1.9	2.0
December	2.4	2.2	2.5	2.4

Table 6.2: E-TOU-A Incremental *Ex-Ante* Load Impacts, 2019 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	0.1	0.1	0.1	0.1
March	0.1	0.2	0.2	0.2
April	0.2	0.2	0.2	0.2
May	0.3	0.3	0.4	0.3
June	0.3	0.3	0.3	0.3
July	0.4	0.3	0.4	0.3
August	0.4	0.4	0.4	0.4
September	0.4	0.4	0.4	0.4
October	0.6	0.5	0.7	0.5
November	0.5	0.5	0.5	0.6
December	0.8	0.7	0.8	0.8

Figures 6.3 and 6.4 show the hourly loads and load impacts associated with two of the cells in Tables 6.1 and 6.2: the August and January PG&E 1-in-2 scenarios. The figures don't differ because the embedded and incremental forecasts have the same per-customer basis.

Figure 6.3: E-TOU-A Embedded *Ex-Ante* Load Impacts, 2019 August PG&E 1-in-2 Peak Day

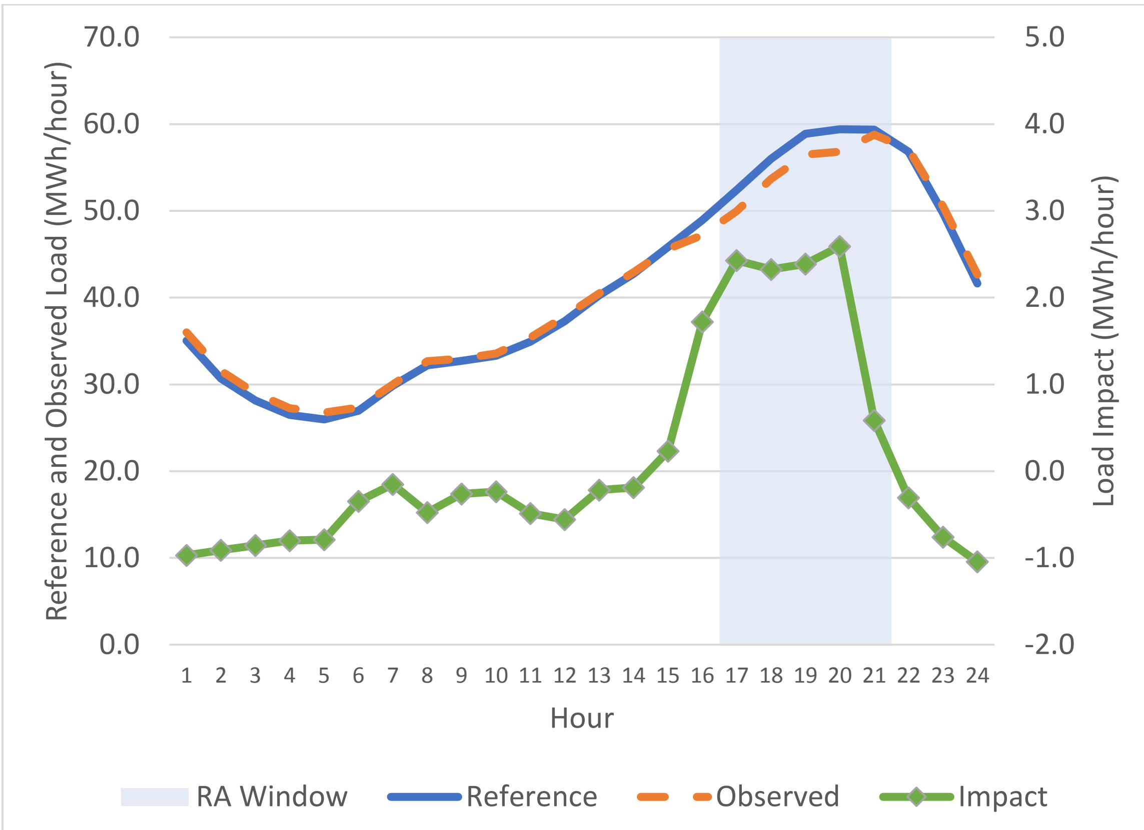
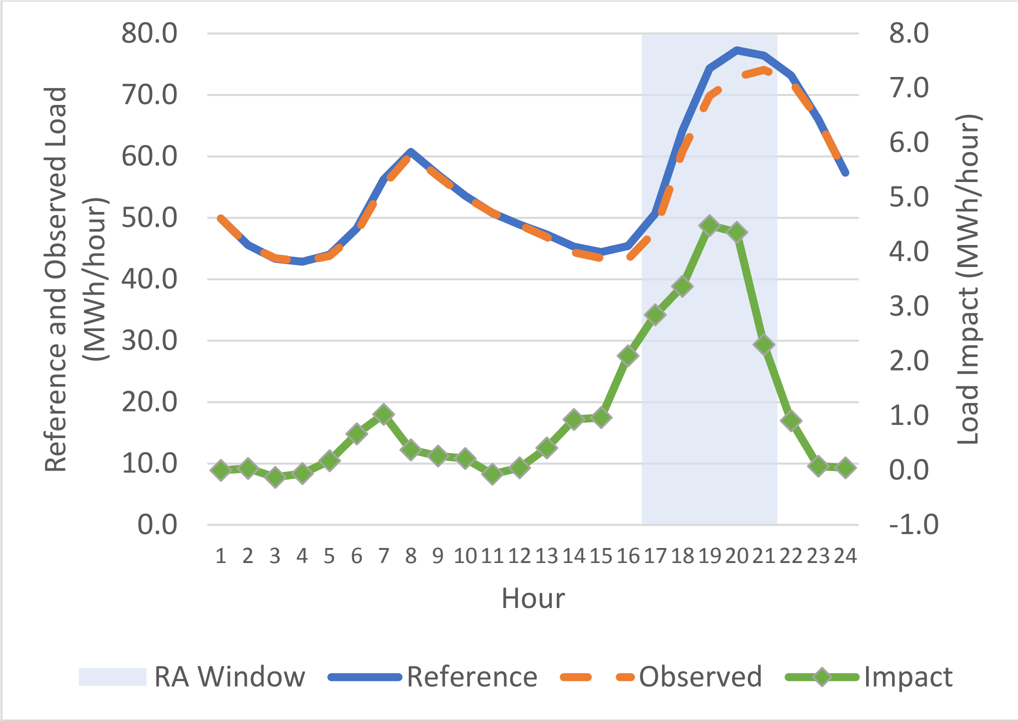


Figure 6.4: E-TOU-A Embedded *Ex-Ante* Load Impacts, 2019 January PG&E 1-in-2 Peak Day



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

Tables 6.3 and 6.4 show the E-TOU-B embedded and incremental load impacts (respectively), averaged during the Resource Adequacy window. The tables show monthly load impacts in 2019 associated with each of the four weather scenarios. Embedded enrollment declines somewhat across the twelve months shown, from approximately 48,000 to 42,000 customers. In contrast, incremental enrollment increases from approximately 500 to 16,500 customers. On a per-customer basis, winter (October through May) load impacts are lower than summer load impacts (*e.g.*, 0.202 kWh/hour/customer in summer and 0.154 kWh/hour/customer in winter for the PG&E 1-in-2 weather year).

Table 6.3: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2019 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	8.1	7.8	8.2	7.9
February	7.2	7.3	7.5	7.3
March	6.0	6.7	6.6	6.9
April	5.8	5.7	5.9	5.7
May	8.8	7.6	10.3	7.9
June	9.1	9.1	10.2	9.2
July	10.0	8.8	10.5	9.3
August	9.3	8.1	9.9	9.0
September	8.1	7.6	8.9	8.5
October	7.9	7.1	8.7	6.9
November	5.4	5.5	5.7	6.1
December	7.1	6.7	7.4	7.0

Table 6.4: E-TOU-B Incremental *Ex-Ante* Load Impacts, 2019 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	0.3	0.3	0.3	0.3
March	0.4	0.5	0.5	0.5
April	0.6	0.6	0.6	0.6
May	1.2	1.1	1.4	1.1
June	1.5	1.6	1.7	1.6
July	2.1	1.8	2.2	1.9
August	2.2	1.9	2.4	2.2
September	2.2	2.1	2.5	2.3
October	2.5	2.2	2.7	2.2
November	1.9	1.9	2.0	2.1
December	2.8	2.6	2.9	2.7

Figures 6.5 and 6.6 show the hourly loads and load impacts associated with two of the cells in Tables 6.3 and 6.4: the August and January PG&E 1-in-2 scenarios. The figures don't differ because the embedded and incremental forecasts have the same per-customer basis.

Figure 6.5: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2019 August PG&E 1-in-2 Peak Day

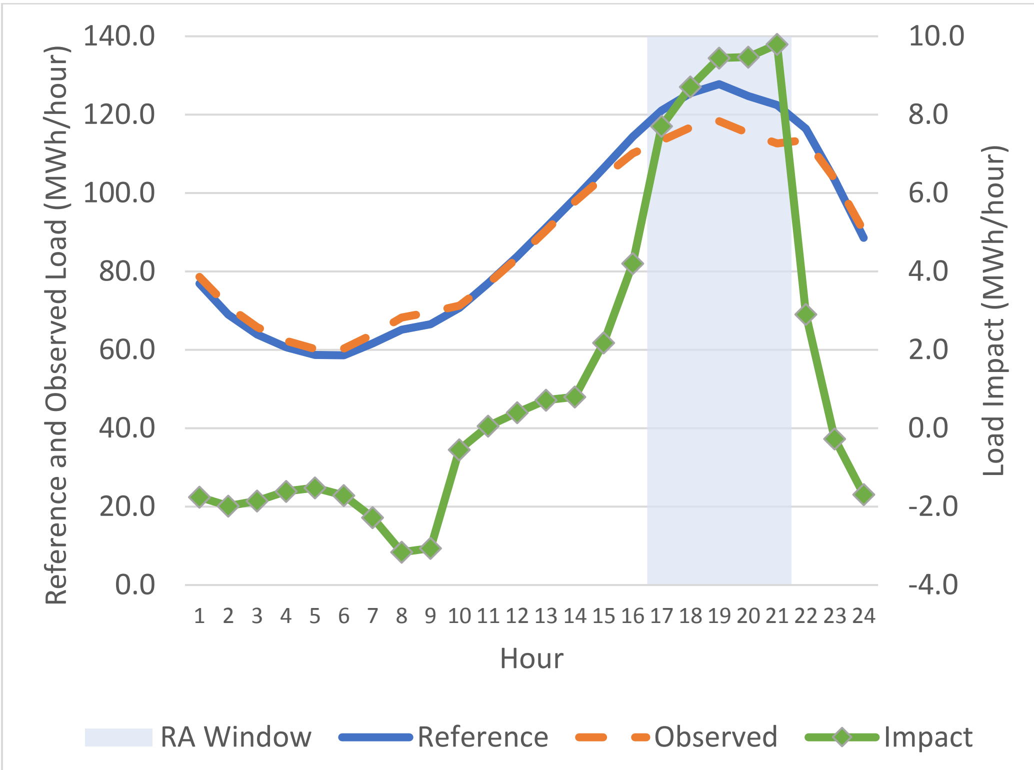


Figure 6.6: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2019 January PG&E 1-in-2 Peak Day

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

Tables 6.5 and 6.6 show the E-TOU-C embedded and incremental load impacts (respectively), averaged during the Resource Adequacy window. The tables show monthly load impacts in 2019 associated with each of the four weather scenarios. Embedded enrollment declines slightly across the twelve months shown, from approximately 110,000 to 106,000 customers. In contrast, incremental enrollment increases from approximately 500 to 10,000 customers. On a per-customer basis, winter (October through May) load impacts are lower than summer load impacts for embedded customers (*e.g.*, 0.060 kWh/hour/customer in summer and 0.035 kWh/hour/customer in winter for the PG&E 1-in-2 weather year), while the seasons are closer in magnitude for incremental customers (*e.g.*, 0.060 kWh/hour/customer in summer and 0.055 kWh/hour/customer in winter for the PG&E 1-in-2 weather year).

Table 6.5: E-TOU-C Embedded *Ex-Ante* Load Impacts, 2019 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	4.8	4.7	4.9	4.8
February	4.3	4.3	4.5	4.4
March	3.6	4.0	4.0	4.1
April	3.3	3.3	3.3	3.3
May	5.1	2.6	7.2	2.9
June	7.1	6.2	9.0	6.0
July	8.4	6.1	9.5	6.9
August	7.4	5.6	8.5	6.6
September	6.4	4.9	7.1	6.3
October	5.0	3.4	6.5	2.6
November	3.4	3.5	3.6	3.9
December	4.6	4.3	4.8	4.5

Table 6.6: E-TOU-C Incremental *Ex-Ante* Load Impacts, 2019 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	0.0	0.0	0.0	0.0
February	0.1	0.1	0.1	0.1
March	0.1	0.1	0.1	0.1
April	0.1	0.1	0.1	0.1
May	0.3	0.2	0.3	0.2
June	0.3	0.3	0.3	0.3
July	0.4	0.3	0.4	0.4
August	0.4	0.4	0.4	0.4
September	0.4	0.4	0.5	0.4
October	0.6	0.5	0.6	0.5
November	0.4	0.4	0.4	0.5
December	0.7	0.6	0.7	0.6

Figures 6.7 and 6.8 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. Figures 6.9 and 6.10 correspond to the same cell in Table 6.6. In this case, separate figures are provided for the incremental and embedded customers because they have a different basis (though the winter percentage load impacts are both based on those of E-TOU-A customers).

Figure 6.7: E-TOU-C Embedded *Ex-Ante* Load Impacts, 2019 August PG&E 1-in-2 Peak Day

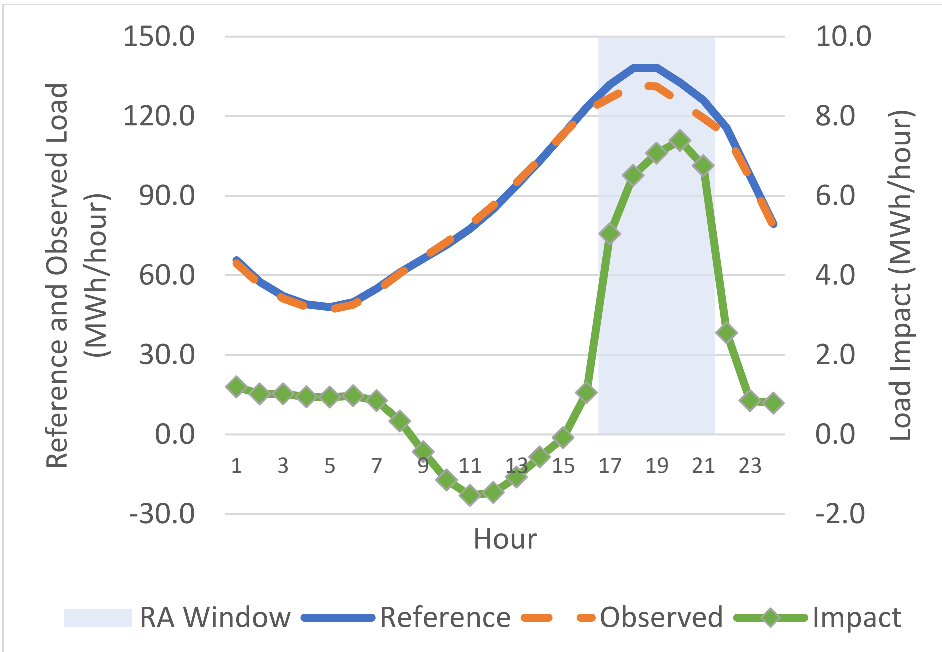


Figure 6.8: E-TOU-C Embedded *Ex-Ante* Load Impacts, 2019 January PG&E 1-in-2 Peak Day

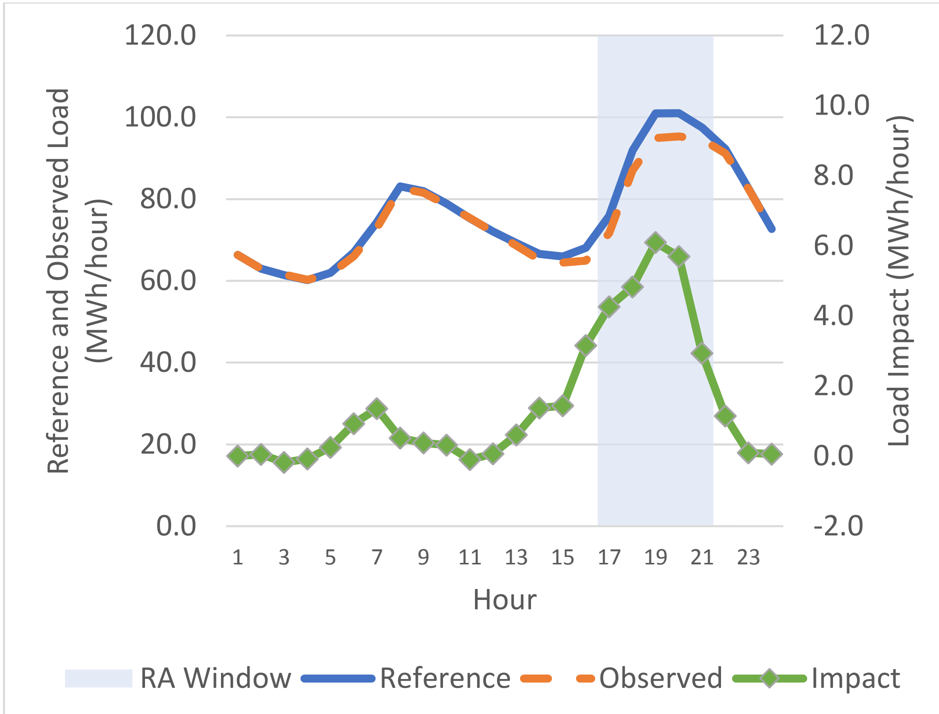


Figure 6.9: E-TOU-C Incremental *Ex-Ante* Load Impacts, 2019 August PG&E 1-in-2 Peak Day

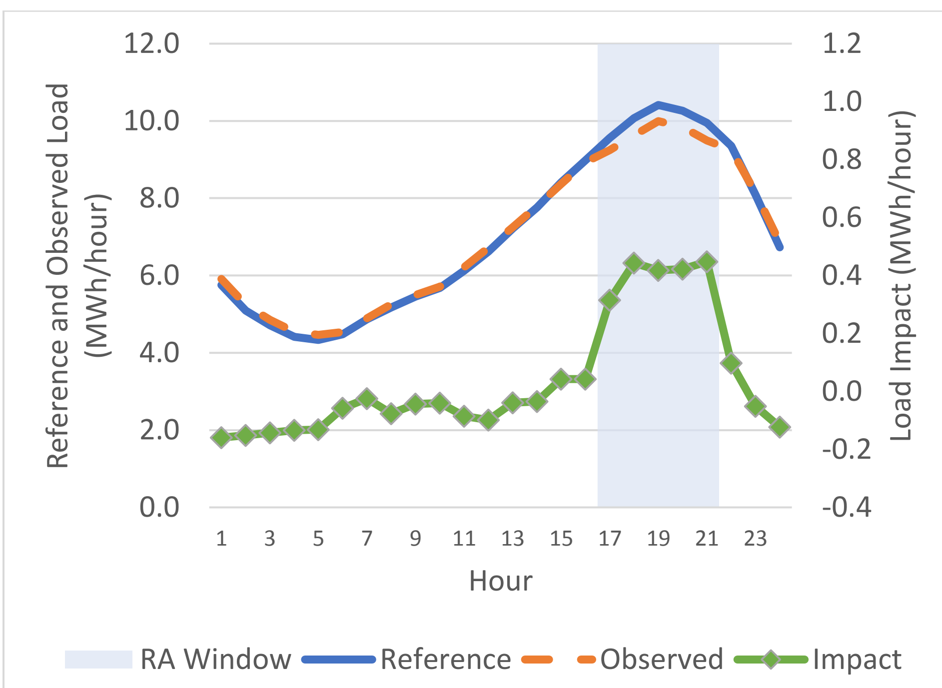
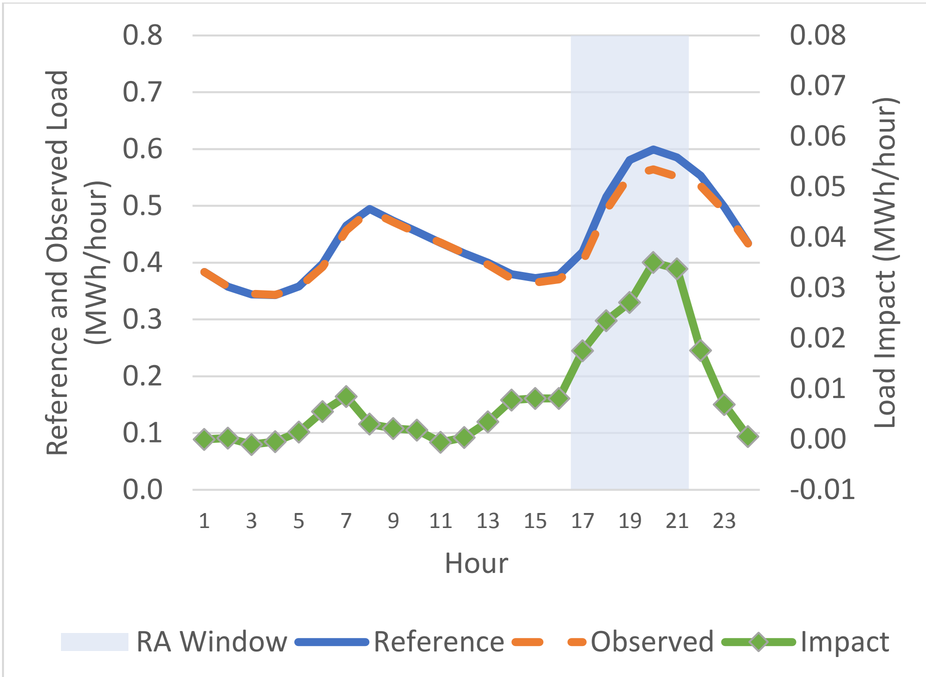


Figure 6.10: E-TOU-C Incremental *Ex-Ante* Load Impacts, 2019 January PG&E 1-in-2 Peak Day



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 for the E-TOU-A, E-TOU-B, and E-TOU-C rates, 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 PY2018. The term "previous" refers to findings in reports for PY2017. In the final comparison above, we illustrate the linkage between the PY2018 *ex-post* load impacts and the *ex-ante* forecast (of the 1-in-2 August peak day) for 2019. The E-TOU-A and E-TOU-B comparisons focus on the *incremental* load impacts forecast while the E-TOU-C comparison focuses on the *embedded* load impact forecast. Note that E-TOU-C did not exist prior to this program year, which limits the comparisons presented.

7.1 Residential E-TOU-A Incremental Load Impacts

7.1.1 Previous versus current *ex-post*

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. 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 significantly lower in the current evaluation.[23] This could reflect differences in temperatures across years, as August 2018 was substantially cooler than August 2017. 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 PY2017 and PY2018, E-TOU-A

Level	Outcome	PY2017	PY2018
Total	# SAIDs	42,807	69,245
	Reference (MW)	48.5	63.6
	Load Impact (MW)	4.2	2.6
	Avg. Temp.	85.9	82.3
Per SAID	Reference (kW)	1.13	0.92
	Load Impact (kW)	0.10	0.04
	% Load Impact	8.6%	4.0%

7.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2017 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study").

Table 7.2 reports the incremental load impact forecast for the August 2019 average weekday under PG&E 1-in-2 peak weather conditions. The enrollment level is higher in the current evaluation, but the per-customer load impacts are lower. This is consistent with the *ex-post* impact differences shown in Table 7.1 that serve as the basis for each forecast.

[23] Note that while the PY2018 estimated load impacts are lower than those of PY2017, they are consistent with the estimates from PY2016, which were 0.041 kWh/hour/customer during the average summer weekday.

Table 7.2: Comparison of Average August 2019 Weekday Peak-period *Ex-Ante* Impacts in PY2017 and PY2018 Studies, E-TOU-A

Level	Outcome	Previous Study	Current Study
Total	# SAIDs	37,327	52,568
	Reference (MW)	38.7	44.6
	Load Impact (MW)	3.7	1.9
	Avg. Temp.	81.7	81.2
Per SAID	Reference (kW)	1.04	0.85
	Load Impact (kW)	0.10	0.04
	% Load Impact	9.7%	4.2%

7.1.3 Previous *ex-ante* versus current *ex-post*

Table 7.3 provides a comparison of the *ex-ante* forecast of August 2018 average weekday load impacts prepared following PY2017 and the *ex-post* PY2018 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. As above, the per-customer load impact differences stand out, reflecting differences in the *ex-post* estimates across evaluations.

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

Level	Outcome	*Ex-Ante* for Aug. 2018 Avg. Weekday from PY2017 Study	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study
Total	# SAIDs	42,523	69,245
	Reference (MW)	44.0	63.6
	Load Impact (MW)	4.3	2.6
	Avg. Temp.	81.7	82.3
Per SAID	Reference (kW)	1.04	0.92
	Load Impact (kW)	0.10	0.04
	% Load Impact	9.7%	4.0%

7.1.4 Current *ex-post* versus current *ex-ante*

Table 7.4 compares the PY2018 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2019 produced in this study. The per-customer load impacts are similar by design, as the *ex-ante* forecast is derived from the *ex-post* impacts.

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

Level	Outcome	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study	*Ex-Ante* for Aug. 2019 Avg. Weekday from PY2018 Study
Total	# SAIDs	69,245	52,568
	Reference (MW)	63.6	44.6
	Load Impact (MW)	2.6	1.9
	Avg. Temp.	82.3	81.2
Per SAID	Reference (kW)	0.92	0.85
	Load Impact (kW)	0.04	0.04
	% Load Impact	4.0%	4.2%

Table 7.5 reviews the potential sources of differences between PY2018 *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	82.3 degrees Fahrenheit during the peak period window of the August 2018 average weekday.	81.2 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, but the effect on the percentage load impact is small.
Enrollment	69,245 SAIDs during the August 2018 average weekday.	52,568 SAIDs in August 2019.	The enrollment level directly scales the per-customer *ex-ante* load impacts.
Methodology	LCA-specific difference-in-differences estimates using a matched control group.	Estimated using season-specific models that assume a constant percentage load impact across LCAs and months.	The *ex-ante* simulations produce very similar per-customer load impacts to *ex-post*.

7.2 Residential E-TOU-B Incremental Load Impacts

7.2.1 Previous versus current *ex-post*

Table 7.6 shows the average peak-hour reference loads and load impacts for the August average weekday during the current and previous program years. Enrollment is substantially higher in the current evaluation, which affects the overall scale of the load impact proportionately. The per-customer load impact is quite similar in level terms, but slightly higher in percentage terms in the current evaluation. The lower per-customer reference load may be partly due to the cooler weather in PY2018.

Table 7.6: Comparison of Average August Weekday Peak-period *Ex-Post* Impacts in PY2017 and PY2018, E-TOU-B

Level	Outcome	PY2017	PY2018
Total	# SAIDs	28,739	46,373
	Reference (MW)	83.8	105.4
	Load Impact (MW)	4.2	7.6
	Avg. Temp.	82.8	79.8
Per SAID	Reference (kW)	2.92	2.27
	Load Impact (kW)	0.15	0.16
	% Load Impact	5.0%	7.3%

7.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2017 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study").

Table 7.7 reports the incremental load impact forecast for the August 2019 average weekday under PG&E 1-in-2 peak weather conditions. The enrollment level is higher in the current evaluation, which directly affects the scale of the reference loads and load impacts. The per-customer results are more mixed. The average customer reference load has decreased significantly while the load impact has declined by a smaller amount, resulting in an increase in the percentage load impact. The comparability of temperatures across years indicates that weather is likely to be a smaller factor than a change in the composition of customers.

Table 7.7: Comparison of Average August 2019 Weekday Peak-period *Ex-Ante* Impacts in PY2017 and PY2018 Studies, E-TOU-B

Level	Outcome	Previous Study	Current Study
Total	# SAIDs	29,736	44,298
	Reference (MW)	82.3	99.8
	Load Impact (MW)	5.6	7.3
	Avg. Temp.	78.8	79.9
Per SAID	Reference (kW)	2.77	2.25
	Load Impact (kW)	0.19	0.16
	% Load Impact	6.9%	7.3%

7.2.3 Previous *ex-ante* versus current *ex-post*

Table 7.8 provides a comparison of the *ex-ante* forecast of August 2018 average weekday load impacts prepared following PY2017, and the *ex-post* PY2018 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. As above, the enrollments and per-customer reference loads are the most significant difference between the sets of results. In contrast, the per-customer load impact is more comparable across years (in level and percentage terms).

Table 7.8 Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts, E-TOU-B

Level	Outcome	*Ex-Ante* for Aug. 2018 Avg. Weekday from PY2017 Study	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study
Total	# SAIDs	30,960	46,373
	Reference (MW)	85.6	105.4
	Load Impact (MW)	5.9	7.6
	Avg. Temp.	78.8	79.8
Per SAID	Reference (kW)	2.77	2.27
	Load Impact (kW)	0.19	0.16
	% Load Impact	6.9%	7.3%

7.2.4 Current *ex-post* versus current *ex-ante*

Table 7.9 compares the PY2018 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2019 produced in this study. The per-customer reference loads and load impacts are similar by design, as the *ex-ante* forecast is derived from the *ex-post* impacts.

Table 7.9 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, E-TOU-B

Level	Outcome	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study	*Ex-Ante* for Aug. 2019 Avg. Weekday from PY2018 Study
Total	# SAIDs	46,373	44,298
	Reference (MW)	105.4	99.8
	Load Impact (MW)	7.6	7.3
	Avg. Temp.	79.8	79.9
Per SAID	Reference (kW)	2.27	2.25
	Load Impact (kW)	0.16	0.16
	% Load Impact	7.3%	7.3%

Table 7.10 reviews the potential sources of differences between PY2017 *ex-post* August average weekday load impacts and the corresponding *ex-ante* load impacts. The two are linked quite closely, with the total load impact declining by approximately 5 percent.

Table 7.10: E-TOU-B Incremental *Ex-Post* versus *Ex-Ante* Factors

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Weather	79.8 degrees Fahrenheit during the peak period window of the August 2018 average weekday.	79.9 degrees Fahrenheit during the peak period on utility-specific 1-in-2 August average weekday.	No discernible effect due to the similarity of temperatures.
Enrollment	46,373 SAIDs during the August 2018 average weekday.	44,298 SAIDs in August 2019.	The enrollment level directly scales the per-customer *ex-ante* load impacts. Slightly lower *ex-ante* enrollments reduce the overall load impact commensurately.
Methodology	LCA-specific difference-in-differences estimates using a matched control group.	Estimated using season-specific models that assume a constant percentage load impact across LCAs and months.	The *ex-ante* simulations produce very similar per-customer load impacts to *ex-post*.

7.3 Residential E-TOU-C Incremental and Embedded Load Impacts

Current *ex-post* versus current *ex-ante*

Table 7.11 compares the PY2018 Default E-TOU-C *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2019 produced in this study. Forecast enrollment is slightly higher than historical enrollment (1.4 percent), but per-customer reference loads and load impacts are lower (by 8 and 6 percent, respectively), leading to a slight decline in the total load impact.

Table 7.11 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, Default E-TOU-C

Level	Outcome	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study	*Ex-Ante* for Aug. 2019 Avg. Weekday from PY2018 Study
Total	# SAIDs	106,443	107,911
	Reference (MW)	114.0	106.3
	Load Impact (MW)	3.7	3.5
	Avg. Temp.	82.5	79.3
Per SAID	Reference (kW)	1.07	0.98
	Load Impact (kW)	0.04	0.03
	% Load Impact	3.3%	3.3%

Table 7.12 compares the voluntary E-TOU-C PY2018 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2019 produced in this study. Forecast enrollment is significantly higher than historical enrollment, which affects the scale of the total reference load and load impact. The per-customer load impact is substantially lower in the forecast, as it is based on the E-TOU-A *ex-post* impacts.

Table 7.12 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, Voluntary E-TOU-C

Level	Outcome	*Ex-Post* for Aug. 2018 Avg. Weekday from PY2018 Study	*Ex-Ante* for Aug. 2019 Avg. Weekday from PY2018 Study
Total	# SAIDs	1,554	6,772
	Reference (MW)	2.4	8.0
	Load Impact (MW)	0.2	0.3
	Avg. Temp.	79.6	82.4
Per SAID	Reference (kW)	1.55	1.19
	Load Impact (kW)	0.14	0.05
	% Load Impact	8.9%	4.0%

Table 7.13 reviews the potential sources of differences between PY2018 *ex-post* August average weekday load impacts and the corresponding *ex-ante* load impacts for Default E-TOU-C customers. The total load impact is approximately 5 percent lower in the *ex-ante* forecast, driven primarily by a reduction in the per-customer load impact.

Table 7.13: Default E-TOU-C Embedded *Ex-Post* versus *Ex-Ante* Factors

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Weather	82.5 degrees Fahrenheit during the peak period window of the August 2018 average weekday.	79.3 degrees Fahrenheit during the peak period on utility-specific 1-in-2 August average weekday.	Hotter *ex-post* weather increases the reference load and load impact slightly, but the effect on the percentage load impact is small.
Enrollment	106,443 SAIDs during the August 2018 average weekday.	107,911 SAIDs in August 2019.	The enrollment level directly scales the per-customer *ex-ante* load impacts. The *ex-ante* enrollment is 1.4 percent higher than the *ex-post* enrollment.
Methodology	LCA-specific difference-in-differences estimates using a matched control group.	Estimated using season-specific models with the load impact interacted with weather variables (CDD in summer, CDD and HDD in winter).	The simulations produce slightly lower per-customer load impacts in level terms, but equivalent percentage load impacts. The *ex-ante* reference loads are somewhat lower, which could be due to the cooler weather conditions.

Table 7.14: Voluntary E-TOU-C Embedded *Ex-Post* versus *Ex-Ante* Factors

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Weather	79.9 degrees Fahrenheit during the peak period window of the August 2018 average weekday.	82.4 degrees Fahrenheit during the peak period on utility-specific 1-in-2 August average weekday.	Hotter *ex-ante* weather increases the forecast reference load and load impact slightly, but the effect on the percentage load impact is small, particulary compared with the effect of basing the forecast on the E-TOU-A analysis (see below).
Enrollment	1,554 SAIDs during the August 2018 average weekday.	6,772 SAIDs in August 2019.	The enrollment level directly scales the per-customer *ex-ante* load impacts. The *ex-ante* enrollment is 4.4 times the *ex-post* enrollment.
Methodology	LCA-specific difference-in-differences estimates using a matched control group.	Based on the E-TOU-A *ex-ante* forecast, which was estimated using season-specific models with the load impact interacted with weather variables (CDD in summer, CDD and HDD in winter).	Forecast per-customer load impacts are lower than those estimated for PY2018.

Appendices

Appendix A	*Ex-Post* Analysis Match Quality
Appendix B	E-1 to E-TOU-A *Ex-Post* Load Impact Tables
Appendix C	E-1 to E-TOU-B *Ex-Post* Load Impact Tables
Appendix D	E-1 to E-TOU-C (Voluntary) *Ex-Post* Load Impact Tables
Appendix E	E-TOU-C Default *Ex-Post* Load Impact Tables
Appendix F	E-TOU-A Incremental *Ex-Ante* Load Impact Tables
Appendix G	E-TOU-B Incremental *Ex-Ante* Load Impact Tables
Appendix H	E-TOU-C Incremental *Ex-Ante* Load Impact Tables
Appendix I	E-TOU-A Embedded *Ex-Ante* Load Impact Tables
Appendix J	E-TOU-B Embedded *Ex-Ante* Load Impact Tables
Appendix K	E-TOU-C Embedded *Ex-Ante* Load Impact Tables

Appendix A. Match Quality

This appendix presents the summaries of our control-group matching process. Figures A.1 through A.5 illustrate the seasonal matches for E-TOU-A, E-TOU-B, and E-TOU-C 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 A.1 through A.5.

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

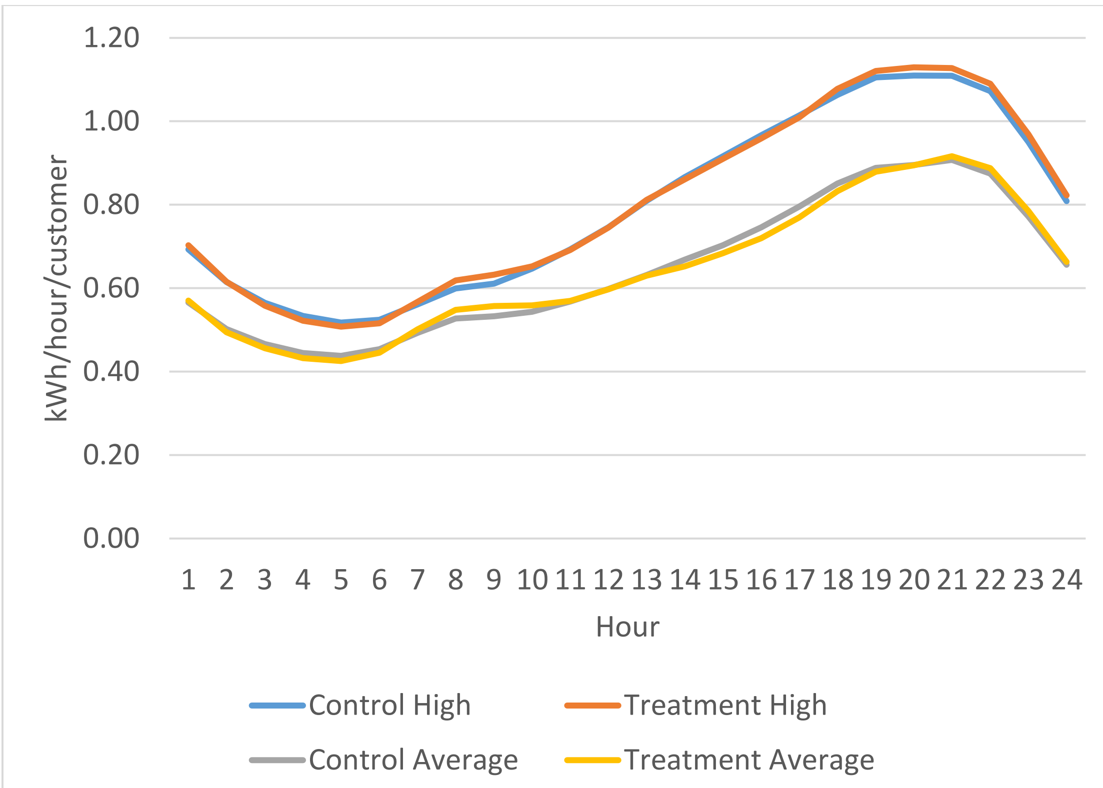


Figure A.2: E-TOU-A Winter Match Quality

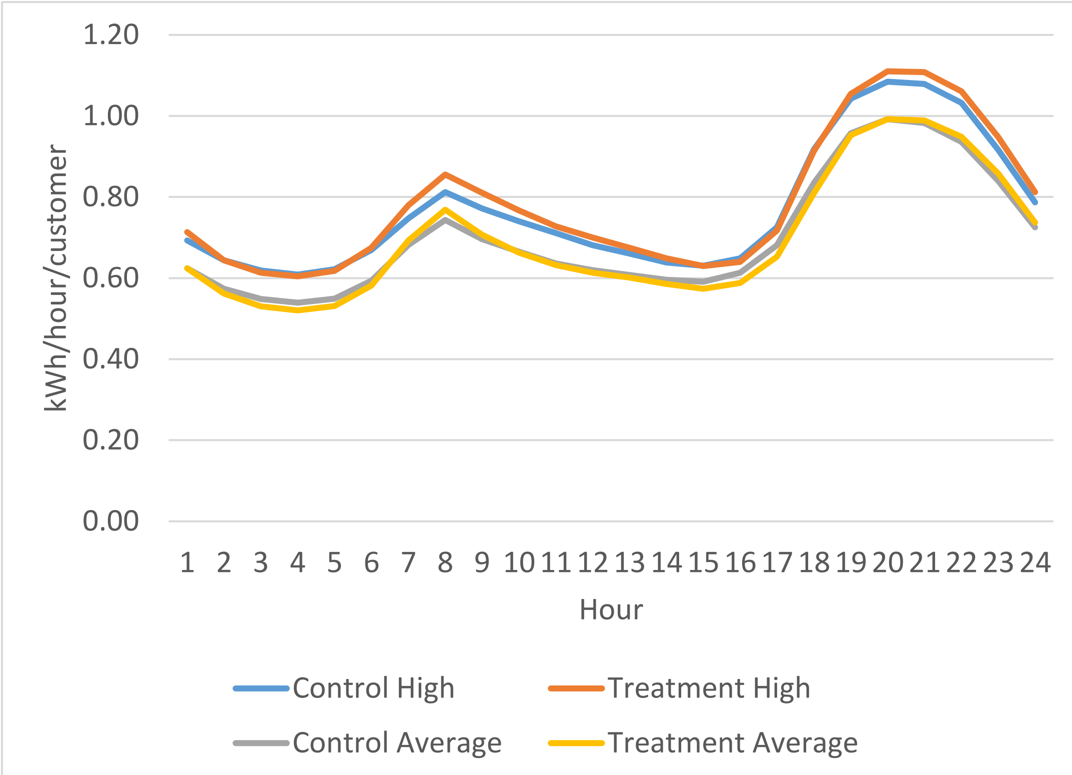


Figure A.3: E-TOU-B Summer Match Quality

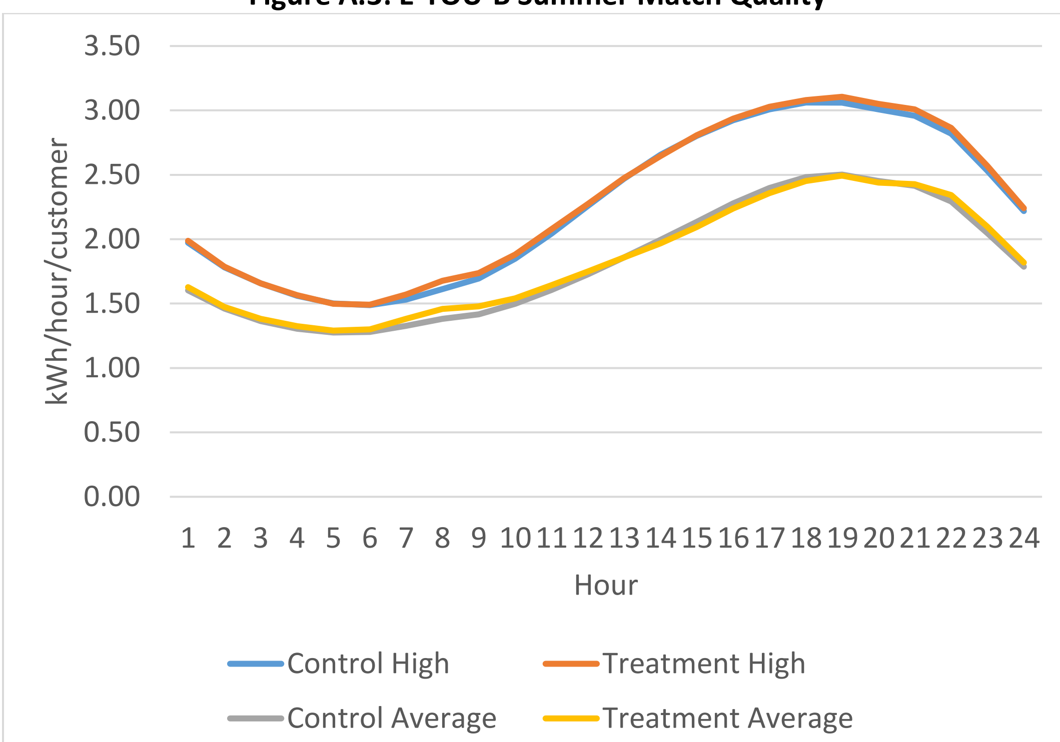


Figure A.4: E-TOU-B Winter Match Quality

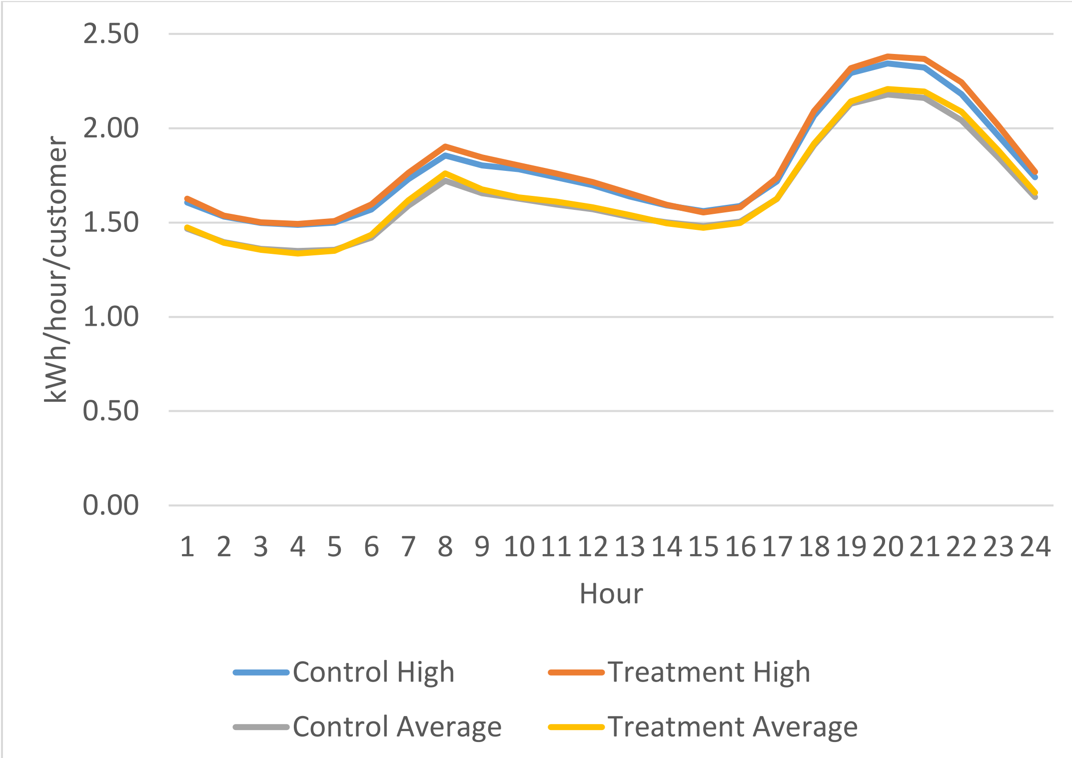
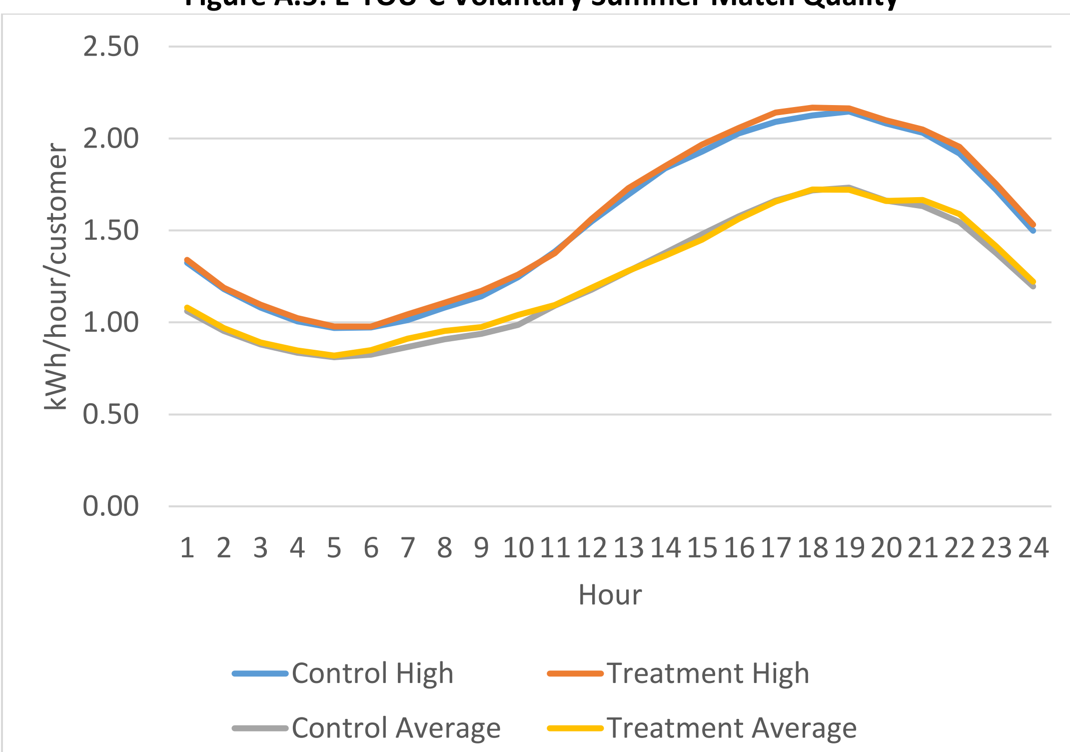


Figure A.5: E-TOU-C Voluntary Summer Match Quality



Tables A.1 through A.5 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 A.1: Summer Match Quality, E-TOU-A

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	0.1%	1.9%	2,272	0.1%	1.9%	586
Greater Fresno	-2.2%	3.7%	73	-0.7%	2.1%	61
Humboldt	4.5%	6.3%	45	7.2%	10.1%	26
Kern	6.6%	18.6%	6	-3.3%	4.8%	13
Northern Coast	0.0%	3.0%	282	0.4%	2.5%	80
Other	-0.3%	2.6%	176	1.6%	3.3%	125
Sierra	-1.7%	3.4%	111	0.5%	3.0%	66
Stockton	-1.1%	5.1%	32	-0.4%	3.2%	38

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

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	0.2%	2.0%	2,249	0.1%	2.9%	583
Greater Fresno	-1.4%	4.0%	66	-1.3%	3.3%	60
Humboldt	-1.4%	7.0%	29	-8.3%	10.7%	20
Kern	19.2%	30.2%	6	-1.0%	6.9%	13
Northern Coast	-1.7%	3.4%	225	0.8%	4.4%	71
Other	-0.8%	3.4%	149	-0.8%	2.8%	123
Sierra	-0.1%	2.9%	105	-0.2%	2.5%	65
Stockton	-4.6%	6.2%	31	-0.4%	3.9%	37

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

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.1%	1.4%	2,414	-1.3%	1.6%	617
Greater Fresno	-0.3%	1.4%	83	-1.1%	1.5%	201
Humboldt	-0.6%	3.8%	96	-0.4%	5.3%	28
Kern	-5.1%	7.2%	15	0.4%	2.5%	65
Northern Coast	-0.7%	1.8%	394	-1.2%	3.1%	134
Other	0.1%	2.7%	140	-0.6%	2.0%	233
Sierra	-1.6%	2.4%	184	-1.0%	2.6%	163
Stockton	-3.5%	5.5%	34	-2.1%	3.4%	68

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

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-0.7%	0.9%	2,409	-0.8%	1.3%	615
Greater Fresno	-1.1%	3.8%	81	-2.1%	2.4%	201
Humboldt	-1.9%	3.0%	93	-4.3%	6.1%	27
Kern	-1.6%	5.8%	15	-1.1%	2.9%	65
Northern Coast	-0.6%	1.4%	380	-1.4%	3.1%	129
Other	-0.7%	1.9%	136	-0.8%	2.2%	233
Sierra	-0.7%	2.0%	184	-1.7%	2.5%	163
Stockton	-0.2%	5.5%	33	0.6%	2.8%	68

Table A.5: Summer Match Quality, E-TOU-C Voluntary

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.2%	1.7%	342	-1.6%	2.7%	147
Greater Fresno	0.1%	3.7%	22	1.5%	3.4%	46
Humboldt	-2.0%	8.9%	8	2.5%	9.5%	11
Kern	-1.0%	6.8%	6	2.0%	4.6%	13
Northern Coast	-2.3%	4.2%	51	-0.1%	3.7%	30
Other	-4.7%	6.0%	20	-1.8%	3.4%	60
Sierra	-3.3%	4.2%	24	-3.0%	4.4%	36
Stockton	-1.4%	6.6%	4	-0.5%	5.8%	14