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2020 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates

Ex-Post and *Ex-Ante* Report

CALMAC Study ID PGE0458

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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 2020. The report addresses the two primary objectives of providing: 1) estimates of *ex-post* load impacts for E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, and EV2-A customers in 2020, and 2) *ex-ante* forecasts of load impacts for 2021 through 2031 that are based on PG&E's enrollment forecasts and the *ex-post* load impact estimates produced in this study and prior studies.

ES.1 Resources Covered

During the 2020 program year, PG&E was in the process of modifying its portfolio of residential TOU rates. E-TOU-A, E-TOU-B, and EV-A were phased out, leaving E-TOU-C, E-TOU-D, EV-B, and EV2-A as the available options going forward. E-TOU-C became available in 2018 and will serve as the default TOU rate in the coming years. E-TOU-A was closed to new enrollment at the end of 2019 and is scheduled for termination in September 2020. E-TOU-B was closed to new enrollment at the end of April 2020 and is scheduled for termination in October 2025. E-TOU-D opened for enrollment May 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 was limited to a subset of the total eligible population, with the objective of understanding the operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU.

All rates except EV2-A have two pricing periods: Peak and Off-Peak. (EV2-A adds a Partial Peak period.) 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-D is 5 p.m. to 8 p.m. on non-holiday weekdays. 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 and E-TOU-D are likely to appeal to higher-use customers due to the absence of the tiered structure. EV2-A does not contain the tiered structure and is only available to customers who charge an electric vehicle.

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, E-TOU-C, E-TOU-D, or EV2-A. NEM and non-NEM customers were separately analyzed for E-TOU-B and E-TOU-C. (Only non-NEM customers were analyzed for the other rates due to small sample sizes of NEM customers.) To select the control-group, customers were matched on pre-enrollment load data from October 2018 to September 2019. 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 2019 to September 2020.

ES.3 Ex-Post Load Impacts

Table ES.1 shows the estimated Peak-period load impacts for the average weekday in February 2020, by rate. Note that there is no estimate for E-TOU-D because it was not yet available for enrollment. All rates except the E-TOU-B non-NEM customers have an estimated reduction in Peak-period usage, though the 80 percent confidence interval is often quite wide. The per-customer reference loads reflect the expected self-selection into the rates, with E-TOU-A customers having the lowest usage, E-TOU-B customers having the highest usage, and E-TOU-C falling in between the two.

Table ES.1: Peak-period Load Impacts by Rate, February Average Weekday[1]

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-A	No	4,287	2.66	0.36	0.620	0.083	13.5% [9.0 – 17.9%]	61.9
E-TOU-B	No	6,492	10.62	-0.15	1.637	-0.022	-1.4% [-3.8 – 1.1%]	60.1
E-TOU-C	No	9,261	7.74	0.60	0.836	0.065	7.8% [5.0 – 10.6%]	60.0
EV2-A	No	3,956	4.02	0.46	1.016	0.117	11.5% [7.6 – 15.5%]	60.2
E-TOU-B	Yes	556	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
E-TOU-C	Yes	389	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table ES.2 shows the estimated Peak-period load impacts for the average weekday in August 2020, by rate. E-TOU-D non-NEM customers are now included in the results and, as expected, they have the highest reference loads of the available options. (E-TOU-B and E-TOU-D will tend to appeal to high-use customers because of the absence of the baseline credit.) Note the reduction in the E-TOU-C non-NEM customer load impact, from 7.8 percent in February to 0.3 percent in August. As we will discuss in more depth

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

in Section 4.2, this appears to be due to a COVID-based self-selection effect. That is, the results point to the possibility that customers who expected to have the largest increases in usage relative to pre-COVID times were more likely to voluntarily adopt a TOU rate. This leads to a "shift" in the hourly load impact profile, with many estimated increases in hourly usage on the TOU rate. (The presence of the control group ensures that this load increase does not simply reflect the typical increase in usage experienced by residential customers due to the Shelter in Place (SIP) order.)

Table ES.2: Peak-period Load Impacts by Rate, August Average Weekday

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-A	No	3,559	2.77	0.09	0.777	0.027	3.4% [-1.4 – 8.3%]	83.5
E-TOU-B	No	9,722	23.12	-0.36	2.378	-0.037	-1.5% [-3.0 – -0.1%]	83.8
E-TOU-C	No	21,642	23.45	0.08	1.084	0.004	0.3% [-1.5 – 2.2%]	84.2
E-TOU-D	No	7,299	23.16	0.46	3.173	0.064	2.0% [0.4 – 3.6%]	86.4
EV2-A	No	7,516	11.60	-0.23	1.543	-0.031	-2.0% [-6.5 – 2.5%]	81.2
E-TOU-B	Yes	1,025	2.68	0.13	2.610	0.131	5.0% [3.4 – 6.6%]	87.4
E-TOU-C	Yes	1,451	3.01	0.30	2.074	0.207	10.0% [8.3 – 11.7%]	90.3

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts were developed separately for the following TOU rates: E-TOU-C (NEM and non-NEM), E-TOU-D (NEM and non-NEM, and EV2-A (non-NEM only). In each case, the forecast represents *incremental* TOU load impacts, which are attributable to customers joining TOU rates during the forecast period. Customers who are already on TOU rates contribute to an *embedded* TOU load impact that is already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

Figure ES.1 shows the yearly enrollments forecast for the month of August, for each customer group. The forecast reflects the Default TOU process that ramps up during 2021 and concludes in early 2022, leading to a surge in E-TOU-C non-NEM enrollment. After that period, E-TOU-C non-NEM enrollment has modest annual increases (~0.6 percent) reflecting customer growth over time. E-TOU-C NEM enrollment has a higher long-term growth rate, at 2 to 4 percent over the 2024 to 2031 time period. E-TOU-D enrollment increases substantially in 2026 due to the termination of E-TOU-B, from which a significant share of customers are assumed to migrate to E-TOU-D due to the similarity in rate structures (omitting the baseline credit). EV2-A enrollment has the highest long-term growth rate, from roughly 20 to 40 percent per year, reflecting increased EV adoption over time.

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

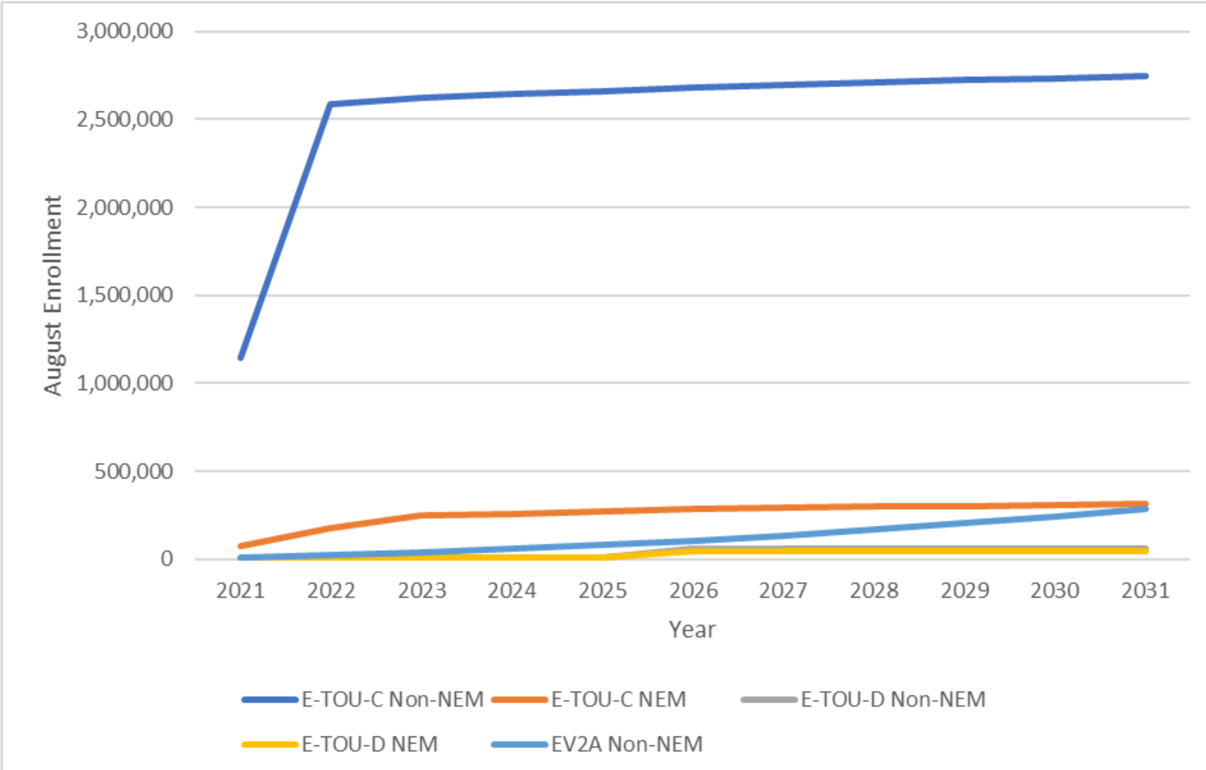
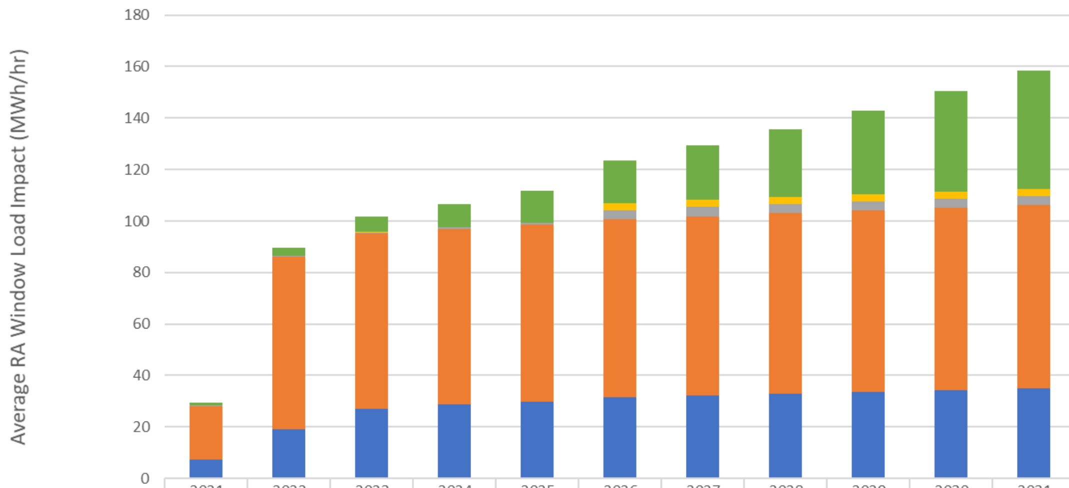


Figure ES.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 weather conditions. The load impact pattern across years parallels the corresponding enrollment pattern (as shown in Figure ES.1), though the higher percentage impacts for EV2-A and NEM rates leads to those rates having a higher share of load impacts than enrollments. For example, in 2023 the E-TOU-C non-NEM customers account for 90 percent of enrolled TOU customers but only 67 percent of the total TOU load impact.

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



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EV2A Non-NEM	0.8	3.1	5.9	8.9	12.4	16.5	21.1	26.4	32.4	38.9	45.9
E-TOU-D Non-NEM	0.2	0.3	0.3	0.3	0.3	2.8	2.8	2.8	2.8	2.8	2.8
E-TOU-D NEM	0.2	0.4	0.4	0.4	0.4	3.5	3.5	3.5	3.5	3.5	3.6
E-TOU-C Non-NEM	20.9	66.9	67.9	68.4	68.8	69.4	69.8	70.1	70.5	70.8	71.1
E-TOU-C NEM	7.2	19.1	27.1	28.6	29.9	31.4	32.1	32.9	33.6	34.3	35.0

Year

E-TOU-C NEM   E-TOU-C Non-NEM   E-TOU-D NEM   E-TOU-D Non-NEM   EV2A Non-NEM

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 2020, where the evaluations conform to the Load Impact Protocols adopted by the CPUC in D-08-04-050. The following rates are included in this evaluation (all have seasonally differentiated rates):

- E-TOU-A: closed to new enrollment on January 1, 2020 and will be eliminated on September 30, 2020.
- E-TOU-B: closed to new enrollment on May 1, 2020 and will be eliminated on October 31, 2025.
- E-TOU-C: available as a voluntary rate and serves as the default residential TOU rate. It has two TOU pricing periods (Peak and Off-Peak) that apply on all days of the year.
- E-TOU-D: available as a voluntary rate beginning in 2020. It differs from E-TOU-C by having a slightly shorter Peak period (5 to 8 p.m. vs. 4 to 9 p.m.), having weekends and holidays be all Off-Peak, and omitting the Baseline Credit.
- EV2-A: a whole-house EV rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak).[2]

The primary goals of the evaluation are the following:

1. Estimate *ex-post* load impacts for each rate for program year 2020;
2. Develop *ex-ante* load impact forecasts for the rates for 2021 through 2031; and
3. Account for the effect of shelter-in-place (SIP) orders on *ex-post* and *ex-ante* load impacts.

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 contains the *ex-ante* load impact forecasts. Section 6 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

During the 2020 program year, PG&E was in the process of modifying its portfolio of residential TOU rates. E-TOU-A, E-TOU-B, and EV-A were phased out, leaving E-TOU-C,

[2] EV-A is a whole-house electric vehicle (EV)-only rate that is closed to new enrollment. Its participants were migrated to EV2 in March 2020, so we plan to exclude the rate from our study. EV-B is an EV-only rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak). We have no means of estimating EV-only TOU impacts (there is no non-TOU EV-only rate to serve as a counterfactual), so this rate is also omitted from the study.

E-TOU-D, EV-B, and EV2-A as the available options going forward. E-TOU-C became available in 2018 and will serve as the default TOU rate in the coming years. E-TOU-A was closed to new enrollment at the end of 2019 and is scheduled for termination in September 2020. E-TOU-B was closed to new enrollment at the end of April 2020 and is scheduled for termination in October 2025. E-TOU-D opened for enrollment May 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 was limited to a subset of the total eligible population[3], 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. The Default Pilot was evaluated in a previous study, but continues to provide valuable information for the development of our *ex-ante* forecast.

All rates except EV2-A have two pricing periods: Peak and Off-Peak. (EV2-A adds a Partial Peak period.) 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-D is 5 p.m. to 8 p.m. on non-holiday weekdays. 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 and E-TOU-D are likely to appeal to higher-use customers due to the absence of the tiered structure. EV2-A does not contain the tiered structure and is only available to customers who charge an electric vehicle.

Many customers who have installed solar photovoltaic systems are also enrolled in a TOU rate and net metering (NEM). We attempt to estimate load impacts for NEM customers in this study, though challenges exist in forming a valid control group (as described later).

The primary *ex-post* analyses contained in this study examine E-1 customers who voluntarily opted into E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, or EV2-A during the 2020 program year (October 2019 through September 2020).

[3] 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.

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 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. TOU customers who are net metered are included in this evaluation with some modifications to the methodology to account for the nature of their photovoltaic (PV) systems. 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 not included in the study. For the embedded 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.

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 Peak-period usage can experience a bill reduction on a TOU rate 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 five groups of customers, defined as those who changed rates from E-1 to E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, and EV2-A. In addition, we present *ex-post* impacts for NEM customers on E-TOU-B and E-TOU-C.[4]

3.1.2 Evaluation Methods

Estimating the load impacts of the TOU rates, as in all evaluations, requires a method for estimating what 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. If feasible, the two approaches may be combined in a difference-in-differences approach, as in our

[4] The sample sizes for E-TOU-A , E-TOU-D, and EV2-A NEM customers were too small to merit reporting the results.

previous evaluations. Load impacts are calculated as the difference between the counter-factual reference loads and the observed loads of the enrolled customers.

The incremental TOU load impacts will be estimated using customers who enrolled in E-TOU-A, E-TOU-B, E-TOU-C, or E-TOU-D on or after October 1, 2020. Each rate will be separately analyzed and include only customers who transitioned from E-1.[5]

<u>Control Group Selection</u>

For the newly enrolled former E-1 customers in E-TOU-A, E-TOU-B, E-TOU-C, and E-TOU-D, the control group selection approach involves matching the newly enrolled TOU customers to customers who remain on E-1 throughout the analysis period. A two-step matching process is used. In the first stage, we request monthly billing data for the pre-treatment year (*i.e.*, October 2018 through September 2019) 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.[6]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles[7], 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 perfect 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.

Once the matched control group customers are selected, 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).

[5] The TOU load impacts are presumably based on relative price changes as the customer changes from the pre-TOU rate to the TOU rate. By focusing on customers transitioning from E-1 (as opposed to changing from one TOU rate to another), we get a "clean" estimate of behavioral changes from a non-TOU rate to a TOU rate.

[6] We then select the four nearest neighbors for each treatment customer for inclusion in the Stage 2 match. Exact matching was conducted within climate region.

[7] 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 were defined as the extreme (*i.e.*, hot in summer) profile, the middle 50 percent of days were defined as the typical profile, and all weekend days constituted the third profile.

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:[8]

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

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

In some cases, small sample sizes prevent robust estimation for all months and subgroups. This problem can be especially acute in the early months of the analysis (October through December), when relatively few customers are enrolled in the TOU rate compared to the months later in the program year. In other cases (particularly the NEM customer analyses), we pool the load impact estimate across LCAs to mitigate the effect of the small sample sizes.

Other Analysis Objectives

Recall that PG&E is interested in the following analysis:

- Load impacts by CARE status;

[8] 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.

- The confidence intervals around each hour as well as the average Peak-period hour;
- Differences in load impacts by structural benefiter status;
- Key drivers of demand response; and
- The effect of Shelter-in-Place orders on TOU load impacts.

The load impacts by CARE status can be estimated using a straightforward extension of our proposed analysis, by simply restricting the regression samples to the appropriate customers. The load impacts by structural benefiter status are estimated by including an interaction variable in our regression equation, thus estimating a separate load impact for the benefiters. The hour-specific confidence intervals are directly estimated in our models, with the period-wide confidence intervals separately estimated using period-specific models (rather than hour-specific models).

Our assessment of the key drivers of demand response is limited to factors we can observe, including type of customer (*e.g.*, climate region, CARE status, or usage level), day type (*e.g.*, month of year), and weather conditions (*e.g.*, whether does hotter temperatures are associated with higher load impacts).

Regarding differentiating load impacts for customers who do and do not receive a structural benefit from switching to the TOU rate, customers with relatively less Peak-period usage can experience a bill reduction on TOU without modifying their load profile. Such customers can be referred to as “structural benefiters.” PG&E provided its customer-specific indicators of structural benefiters, which we use to provide summaries of load impacts. We also summarize the share of the treatment customers who are benefiters, which provides an indication of the extent to which customers self-select onto the rate based on their load profile.

From our current work with PG&E, we have learned that the shelter-in-place orders have tended to increase residential loads somewhat significantly, with the increases concentrated in the mid-day hours. These SIP-induced load changes could affect TOU load impacts in multiple ways: there is more load available to curtail or shift; but people are likely to be home more often and may have higher demands for electricity use during weekdays. The evaluation will contain a mix of pre-SIP and SIP loads, which allows us to compare load impacts across months. That comparison has the advantage of including many or most of the same customers across months (TOU adoption occurs progressively during the program year) but suffers from not being able to compare the same month in SIP and non-SIP conditions.

<u>EV-B and EV2-A Load Impacts</u>

This discussion begins with the EV2-A whole-house rate, where “whole house” means that all customer usage (including the EV charging) is billed using the TOU rate. (EV-A is also a whole-house rate, but it is closed to new enrollment.) In contrast, EV-B requires a separate meter and apply only to customer’s EV charging.

The difficulty in evaluating EV2-A customers arises from not knowing when customers adopt an electric vehicle and begin charging at home. For example, many customers who transition from E-1 to EV2-A may have done so because of an EV purchase, while others had the EV while on E-1. In order to estimate customer demand response to the EV2-A rate, we need to observe customer charging (and other usage) behavior with and without the TOU prices. For customers who enroll in EV2-A at the same time they obtain and begin charging their EV, we have no way of knowing how the TOU rates affected their charging behavior. Therefore, the EV2-A load impact analysis focuses on customers who switched from E-1 to EV2-A during the current program year (*i.e.*, from October 1, 2019 through September 30, 2020). A significant complicating factor is that PG&E doesn't have comprehensive information on EV ownership. While EV ownership is required to enroll in the EV or EV2-A rates, a customer who is served on E-1 may have an electric vehicle without PG&E having a record of it.

To identify customers who had an electric vehicle prior to enrolling in the EV2-A rate, we estimate customer-specific structural breaks in usage. The structural break model identifies the most likely date on which there is a change to a customers' total usage that isn't accounted for in the regression specification. A statistical test provides a level of statistical significance from which we can subsequently identify which customers *do not* have a statistically significant structural break in their usage level. Customers that do not exhibit a statistically significant change in total usage during the analysis period (which included the current program year and the 12 months prior to it) are assumed to have been charging an electric vehicle during the entire analysis period (while being served on E-1 and EV2-A). The *ex-post* load impacts are subsequently estimated using a before/after analysis and represent change as a result of the TOU rate, and not from adopting an electric vehicle. This type of analysis depends on having a sufficient sample of customers that enrolled in EV2-A *and* have an electric vehicle for the entire analysis period (*i.e.*, pre- and post-EV2-A).

The EV-B rate presents further challenges that prevent the direct estimation of their *ex-post* load impacts. That is, because the rate only applies to metered EV usage, we are unable to obtain a counter-factual load that represents EV charging behavior in the absence of TOU pricing. If the customer joined from rate E-1, their usage on that rate will represent the whole house and thus not be comparable to the EV-only usage on EV-B. Due to this limitation, and the low enrollment projections for EV-B customers, the EV-B rate was excluded from this study.

<u>NEM Customer Load Impacts</u>

The NEM analysis is limited to customers migrating from E-1, which means the treatment customers will have been part of the NEM 1.0 regulations and therefore be of an older vintage than the NEM 2.0 customers who were required to enroll in a TOU rate upon attaining NEM status. Because of this, the NEM analysis is limited to a fairly small set of customers.

The NEM analysis uses methods that largely follow those described above, with three major distinctions. First, only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included.[9] Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.[10] Third, customers with large changes in net profiles between periods are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system or some other change unrelated to the adoption of a TOU rate. Each of these requirements helps prevent estimating TOU load impacts that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to only a behavioral response to TOU rates.[11]

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 (to the extent possible) 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.

Only incremental TOU impacts are forecast. The following rates are included in our *ex-ante* forecast:

- E-TOU-C, NEM and non-NEM
- E-TOU-D, NEM and non-NEM
- EV2-A non-NEM

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[9] With a matched control group, it is essential to create a counterfactual that mimics any changes a treatment customer faces. It becomes increasingly unlikely to find a suitable match for customers that become NEM during the analysis period or change their solar PV characteristics because the best practice would be to search for a control customer that made comparable changes at parallel points in time. Additionally, including controls in a regression for these changes is limited by the amount of overlap between the change and becoming a TOU customer. Essentially, it is more difficult to statistically disentangle effects the closer they occur to each other.

[10] The PV system capacity is included in the match and matches are excluded if the matched control-group customer's PV capacity is more than 1 kW different in the E-TOU-C analysis and more than 2 kW different for the other rates.

[11] For example, a high premise usage treatment customer with a larger solar generation system may be matched to a lower premise usage control customer with a smaller solar generation system based on similar net load profiles. If conditions are met so that solar generation is larger in the post-period, then any analysis based on net load profiles will exhibit that the treatment customer reduced their usage, relative to their own pre-treatment usage as well as relative to the control customer's usage.

The methods used to develop the forecast differ by rate, as described below.

3.2.2 *Ex-ante* evaluation approach

E-TOU-C Non-NEM

Typically, the *ex-ante* forecast is develop using the current *ex-post* impacts as its foundation. However in this evaluation, the *ex-post* impacts reflect the responses of a relatively small number of voluntary TOU adopters, whereas the bulk of the *ex-ante* forecast reflects large numbers of customers to be defaulted onto TOU rates. In our experience, voluntary TOU adopters tend to be more likely to self-select into the rate based on their load profile and have larger load impacts (on average) relative to defaulted customers. Therefore, the E-TOU-C *ex-ante* load impacts are based on the Default TOU pilot findings, which contain the best available information about load impacts when customers are defaulted onto the TOU rates.

Note that the Default TOU pilot was conducted at a "segment" level, where the primary segments of interest for this study were defined according to climate region (hot, moderate, and cool) and CARE status. Two additional segments represented all customers in a community choice aggregation (CCA) location (Sonoma Clean Power and MCE), while a final segment represented all PG&E NEM customers not in a CCA. Because our results are reported by LCA level, we calculated the share of customers in LCA within each segment.

Reference loads were developed using the interval data for the customers in the Default TOU study. This involves our typical process of estimating statistical models of customer usage as a function of weather conditions and variables that reflect typical usage patterns (*i.e.*, hour of day, day of week, month of year). Those parameters are then applied to the *ex-ante* scenario information (the month and weather conditions) to produce reference loads for each required scenario.

The Default TOU load impact are translated into our forecast by applying a constant percentage load impact by LCA, season, and hour, as estimated in the Default TOU first-year report.

E-TOU-D Non-NEM

In the case of the E-TOU-D non-NEM customer forecast, we were unable to apply the *ex-post* impacts because they are only available for part of the year (May through September), while the *ex-ante* forecast is required for all months. In this case, we adapt the E-TOU-B forecast developed in the previous evaluation. Both E-TOU-B and E-TOU-D are likely to appeal to higher-use customers (due to the absence of the baseline credit), with the primary difference between the rates being the shorter Peak period of E-TOU-D (limited to three hours, from 5 to 8 p.m vs. 4 to 9 p.m in E-TOU-B). Using E-TOU-B impacts from the previous evaluation avoids the (likely) COVID effects we observed in this year's evaluation. As we will describe later in the evaluation, it appears that voluntary TOU adopters made their choice partly based on an expectation that their usage would increase more than that of a typical customer, perhaps incurring the High

Usage Charge on Schedule E-1 if they didn't choose to move to a TOU rate. As a result, this year's *ex-post* impacts often appear quite low during the COVID-affected months, for a reason we suspect will not be duplicated in the upcoming default process.[12] Applying load impacts from the previous evaluation allows our forecast to reflect the expected response to the TOU rate.

The E-TOU-D forecast is applied as a constant percentage impact by season and hour. The percentages are based on estimates from the PY2019 E-TOU-B *ex-post* evaluation, modified as follows to reflect the different Peak period definition:

- Replace the HE17 impact with the E-TOU-B HE16 impact, aligning the pre-Peak hour with the E-TOU-D Peak-period definition.
- Replace the HE21 impact with the E-TOU-B HE22 impact, aligning the post-Peak hour with the E-TOU-D Peak-period definition.
- Change the HE18 impact to be the average of the E-TOU-B HE17 and HE18 impacts, which helps reduce the Peak period to match the duration under E-TOU-D.
- Change the HE20 impact to be the average of the E-TOU-B HE20 and HE21 impacts, which helps reduce the Peak period to match the duration under E-TOU-D.
- The HE19 impact is kept the same.

This method effectively "collapses" the five-hour Peak period in E-TOU-B to the three-hour Peak period of E-TOU-D.

E-TOU-C and E-TOU-D NEM

As with the E-TOU-C non-NEM forecast, we adapt the Default TOU findings in our forecast of E-TOU-C and E-TOU-D NEM impacts. The *ex-post* NEM impacts from this year are based on very small samples of voluntary TOU adopters, whereas the forecast reflects large numbers of defaulted customers and customers who are assigned a TOU rate under current NEM rules. The Default TOU study contains the best available information on NEM TOU impacts. A comparability issue arises when attempting to translate those estimates into the current study: the Default study used a combination of delivered and received loads, while the current study reflects only delivered loads.[13] To ensure that we examine comparable load impacts, we focus on the last two hours of the Peak period in the Default TOU study (7 to 9 p.m.) as those hours are the least likely to be affected by received loads (when the NEM customer is exporting to the grid). The average percentage impact across those two hours is applied to the E-TOU-C and

[12] That is, we don't expect the default process to coincide with a new COVID pandemic onset that causes an upward shock to many customer's usage levels, which could result in self-selection based on expected usage changes.

[13] PG&E separately provides hourly "delivered" loads, which represents energy delivered to and used by the customer, and "received" loads, which represents energy the customer exports to the grid. Hours in which the received load is greater than zero represent times in which the customer's PV generation exceeded their premise usage.

E-TOU-D Peak period hours in our *ex-ante* forecast. The reference loads for each rate are based on the available control-group customers from our *ex-post* study.

Our experience from studying NEM customers is that the load impact estimates are often less reliable than those of non-NEM customers, primarily due to uncertainties about the amount of energy produced by the PV systems. That is, our interest is in changes in premise use in response to a rate, but we only observe a customer's net energy consumption. Given that we are typically trying to estimate a fairly small TOU demand response (*e.g.*, low single-digit percentages), mismatches between treatment and control-group PV system output can overwhelm the TOU demand response.

<u>EV2-A Non-NEM</u>

The reference loads used in the EV2-A *ex-ante* forecast are based on the *ex-post* treatment customer loads during the pre-treatment year (prior to EV2-A adoption). We pool customers across LCAs to estimate the coefficients associated with the weather and shape variables, then simulate reference loads for each LCA using each LCA's *ex-ante* weather conditions.

The load impacts are derived from the current *ex-post* analysis, adjusted to account for the effect of COVID. The no-COVID load impacts are based on the February average weekday percentage load impacts, which was the last full month prior to the onset of the pandemic and had the largest sample size yielding most reliable estimates. The COVID load impacts are the average percentage impacts across April through September 2020. PG&E provided a forecast path of residential COVID impacts. In each forecast month, we apply a percentage load impact that is the weighted average of the COVID and no-COVID scenarios, where the weights are equal to the ratio of PG&E's forecast of that month's COVID effect divided by PG&E's starting COVID effect.

For each of the methods described above, the uncertainty-adjusted load impacts are based on the standard errors from the load impact estimates. Scenario-specific percent load impacts are 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. We will also compare current and previous *ex-post* load impacts, and current and previous *ex-ante* load impacts.

4. *Ex-Post* Load Impact Study Findings

This section reports *ex-post* load impact findings for the customers who migrated from the standard E-1 residential rate to E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, and EV2-A. Relevant subsections report reference loads and load impacts for the average weekday by season, climate region, CARE status, and structural benefiter 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 TOU service on or after October 1, 2019 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. Appendix Tables N.1 through N.4 show the number of treatment customers represented in each of the results presented in this section.

4.1 Peak-period Load Impact Summaries

In the sub-sections below, we summarize average Peak-period load impacts by rate and the following: by season, climate region, CARE status, and structural benefiter status. In each case, the Peak period is defined according the each schedule's TOU period definitions, as described in Section 2. The range of percentage load impacts contained in each table represents an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts required by the Protocols).

4.1.1 Peak-period impacts by Season

Table 4.1 shows the estimated Peak-period load impacts for the average weekday in February 2020, by rate. Note that there is no estimate for E-TOU-D because it was not yet available for enrollment. All rates except the E-TOU-B non-NEM customers have an estimated reduction in Peak-period usage, though the 80 percent confidence interval is often quite wide. The per-customer reference loads reflect the expected self-selection into the rates, with E-TOU-A customers having the lowest usage, E-TOU-B customers having the highest usage, and E-TOU-C falling in between the two.

Table 4.1: Peak-period Load Impacts by Rate, February Average Weekday[14]

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-A	No	4,287	2.66	0.36	0.620	0.083	13.5% [9.0 – 17.9%]	61.9
E-TOU-B	No	6,492	10.62	-0.15	1.637	-0.022	-1.4% [-3.8 – 1.1%]	60.1
E-TOU-C	No	9,261	7.74	0.60	0.836	0.065	7.8% [5.0 – 10.6%]	60.0
EV2-A	No	3,956	4.02	0.46	1.016	0.117	11.5% [7.6 – 15.5%]	60.2
E-TOU-B	Yes	556	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
E-TOU-C	Yes	389	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4.2 shows the estimated Peak-period load impacts for the average weekday in August 2020, by rate. E-TOU-D non-NEM customers are now included in the results and, as expected, they have the highest reference loads of the available options. (E-TOU-B and E-TOU-D will tend to appeal to high-use customers because of the absence of the baseline credit.) Note the reduction in the E-TOU-C non-NEM customer load impact, from 7.8 percent in February to 0.3 percent in August. As we will discuss in more depth in Section 4.2, this appears to be due to a COVID-based self-selection effect. That is, the results point to the possibility that customers who expected to have the largest increases in usage relative to pre-COVID times were more likely to voluntarily adopt a TOU rate. This leads to a “shift” in the hourly load impact profile, with many estimated increases in hourly usage on the TOU rate. (The presence of the control group ensures that this load increase does not simply reflect the typical increase in usage experienced by residential customers due to the Shelter in Place (SIP) order.)

This shift occurs in other rates as well, as illustrated in Section 4.2.

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

Table 4.2: Peak-period Load Impacts by Rate, August Average Weekday

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-A	No	3,559	2.77	0.09	0.777	0.027	3.4% [-1.4 – 8.3%]	83.5
E-TOU-B	No	9,722	23.12	-0.36	2.378	-0.037	-1.5% [-3.0 – -0.1%]	83.8
E-TOU-C	No	21,642	23.45	0.08	1.084	0.004	0.3% [-1.5 – 2.2%]	84.2
E-TOU-D	No	7,299	23.16	0.46	3.173	0.064	2.0% [0.4 – 3.6%]	86.4
EV2-A	No	7,516	11.60	-0.23	1.543	-0.031	-2.0% [-6.5 – 2.5%]	81.2
E-TOU-B	Yes	1,025	2.68	0.13	2.610	0.131	5.0% [3.4 – 6.6%]	87.4
E-TOU-C	Yes	1,451	3.01	0.30	2.074	0.207	10.0% [8.3 – 11.7%]	90.3

4.1.2 Peak-period impacts by Climate Region

Table 4.3 shows the average Peak-period load impact for the August 2020 average weekday, reported by climate region.[15] Due to smaller sample sizes, we omit NEM customers and the EV2-A rate from the summaries. Blue shading is used to help separate the rate-specific results. Many of the results in the table make intuitive sense: reference loads and temperatures are progressively higher as one moves from cool to moderate to hot climate regions. The level load impact (in kWh/hour/customer) tends to be higher in hotter climate regions, but this pattern does not hold across all rates.

[15] 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 4.3: Peak-period Load Impacts by Rate and Climate Region, August Average Weekday

Rate	Climate	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-A	Cool	0.422	-0.027	-6.3% [-12.7 – 0.2%]	70.9
	Moderate	0.793	0.060	7.5% [1.9 – 13.2%]	82.5
	Hot	[redacted]	[redacted]	[redacted]	[redacted]
E-TOU-B	Cool	1.166	-0.100	-8.6% [-12.7 – -5.0%]	68.8
	Moderate	2.413	-0.042	-1.8% [-3.6 – 0.1%]	80.8
	Hot	3.674	0.057	1.5% [-0.9 – 3.9%]	92.1
E-TOU-C	Cool	0.548	-0.013	-2.3% [-5.3 – 0.7%]	68.6
	Moderate	0.943	0.003	0.3% [-1.6 – 2.3%]	80.3
	Hot	1.971	-0.005	-0.2% [-3.7 – 3.2%]	91.7
E-TOU-D	Cool	1.474	-0.091	-6.2% [-10.3 – -2.1%]	70.2
	Moderate	3.133	0.114	3.7% [1.8 – 5.5%]	81.9
	Hot	4.228	0.118	2.8% [0.6 – 5.0%]	93.4

4.1.3 Peak-period impacts by CARE Status

Table 4.4 shows the average Peak-period load impact for the August 2020 average weekday, reported by CARE status. Due to smaller sample sizes, we omit NEM customers and the EV2-A rate from the summaries. Blue shading is used to help separate the rate-specific results. Comparing the CARE[16] and non-CARE customers within rate shows that CARE customers tend to experience hotter temperatures due to where they tend to reside in the service territory and, for the most part, have higher reference loads as a result of that. It is difficult to reach conclusions about differences in load impacts by CARE status due to the wide confidence intervals. The point estimates indicate higher load impacts for non-CARE customers, with the exception of the E-TOU-B customers.

[16] CARE customers include customers who are always or sometimes reported to be CARE during our analysis period.

Table 4.4: Peak-period Load Impacts by Rate and CARE Status, August Average Weekday

Rate	CARE	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-A	No	0.726	0.031	4.3% [-1.6 – 10.2%]	81.9
	Always / Sometimes	0.975	0.008	0.8% [-7.1 – 8.8%]	87.7
E-TOU-B	No	2.382	-0.042	-1.8% [-3.5 – 0.0%]	82.4
	Always / Sometimes	2.367	-0.023	-1.0% [-3.3 – 1.3%]	87.3
E-TOU-C	No	0.997	0.007	0.7% [-1.6 – 3.0%]	82.7
	Always / Sometimes	1.365	-0.006	-0.5% [-3.4 – 2.5%]	87.8
E-TOU-D	No	3.140	0.087	2.8% [0.9 – 4.6%]	85.2
	Always / Sometimes	3.301	-0.030	-0.9% [-3.8 – 2.0%]	90.5

4.1.4 Peak-period impacts by Structural Benefiter Status

PG&E provided a variable indicating whether each TOU 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 TOU rate with the same usage pattern and level.

Table 4.5 summarizes the August 2020 Peak-period load impacts by benefiter status, for each rate. The wide confidence intervals around the estimated load impacts prevent us from reaching conclusions about differences in load impacts by benefiter status. However, Table 4.6 provides some useful information about the nature of the TOU adopters.

Table 4.5: Peak-period Load Impacts by Rate and Benefiter Status, August Average Weekday

Rate	Benefiter	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-A	No	1.020	-0.038	-3.7% [-10.0 – 2.6%]	86.4
	Yes	0.632	0.050	7.9% [-10.0 – 25.9%]	80.3
E-TOU-B	No	2.232	-0.011	-0.5% [-4.7 – 3.7%]	88.2
	Yes	2.316	-0.043	-1.9% [-8.9 – 5.1%]	82.7
E-TOU-C	No	1.247	-0.106	-8.5% [-11.4 – -5.6%]	87.2
	Yes	0.934	0.022	2.3% [-3.4 – 8.0%]	81.0
E-TOU-D	No	2.518	0.226	9.0% [-0.5 – 18.5%]	90.7
	Yes	3.015	0.032	1.1% [-11.7 – 13.9%]	84.7

Table 4.6 shows that the customers on each TOU rate largely consisted of structural benefiters. The extreme case is E-TOU-B, in which 91 percent of the incremental customers were classified as benefiters. Notice the high share of "not modeled" customers for E-TOU-D. While that rate's share of benefiters is lower than that of E-TOU-B, its share of non-benefiters (labeled "E1 benefiter") is even lower due to the high number of unclassified customers.

This table suggests a high rate of self-selection into the rates based on structural benefits. This is a significant factor in our choice to base the E-TOU-C *ex-ante* forecast on the results of the Default TOU pilot rather than these *ex-post* estimates.

Table 4.6: Share of Customers by Benefiter Status and Rate

Benefiter Status	E-TOU-A	E-TOU-B	E-TOU-C	E-TOU-D
E1 benefiter	27.5%	5.9%	16.0%	5.1%
Not Modeled	9.5%	3.0%	4.5%	29.3%
TOU benefiter	62.9%	91.1%	79.6%	65.6%

4.2 Average Hourly Load Impacts

This subsection illustrates the hourly load and load impact profiles for the average weekdays in February and August 2020. In addition to showing seasonal differences, they have the potential to reveal the effect of COVID on load impacts. In each case, we graph per-customer reference loads, observed loads, and load impacts with shading provided to indicate the rate's Peak period.

Figures 4.1 and 4.2 show the results for the E-1 to E-TOU-A non-NEM customers in February and August 2020, respectively. Both profiles show fairly pronounced Peak-period load impacts, though they begin prior to the onset of the Peak period in February.

Figure 4.1: E-TOU-A Non-NEM February Average Weekday Hourly Impacts

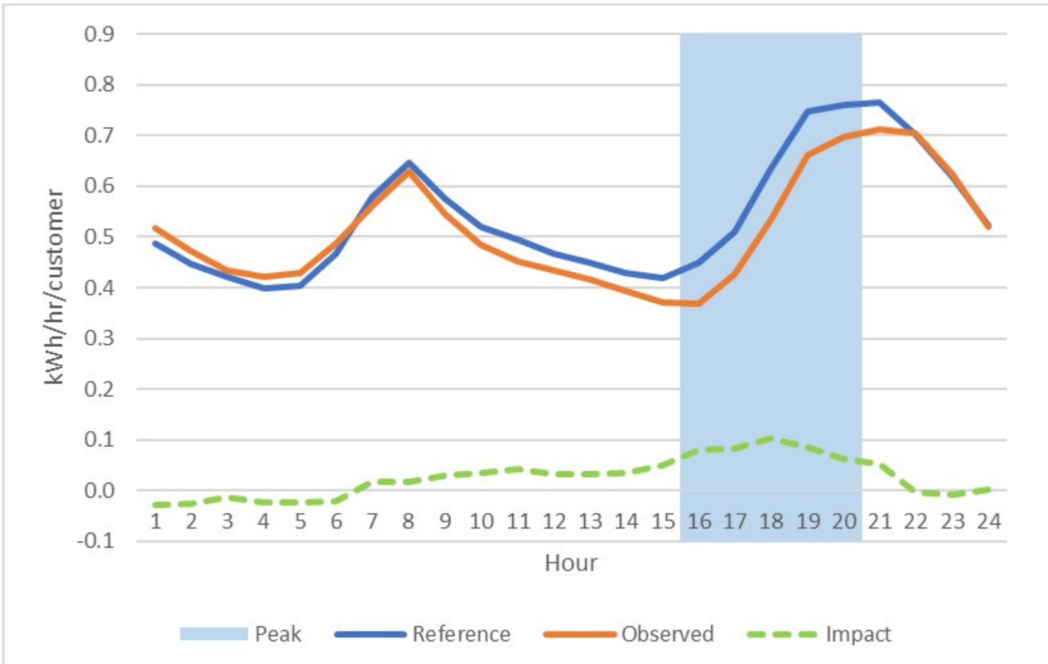
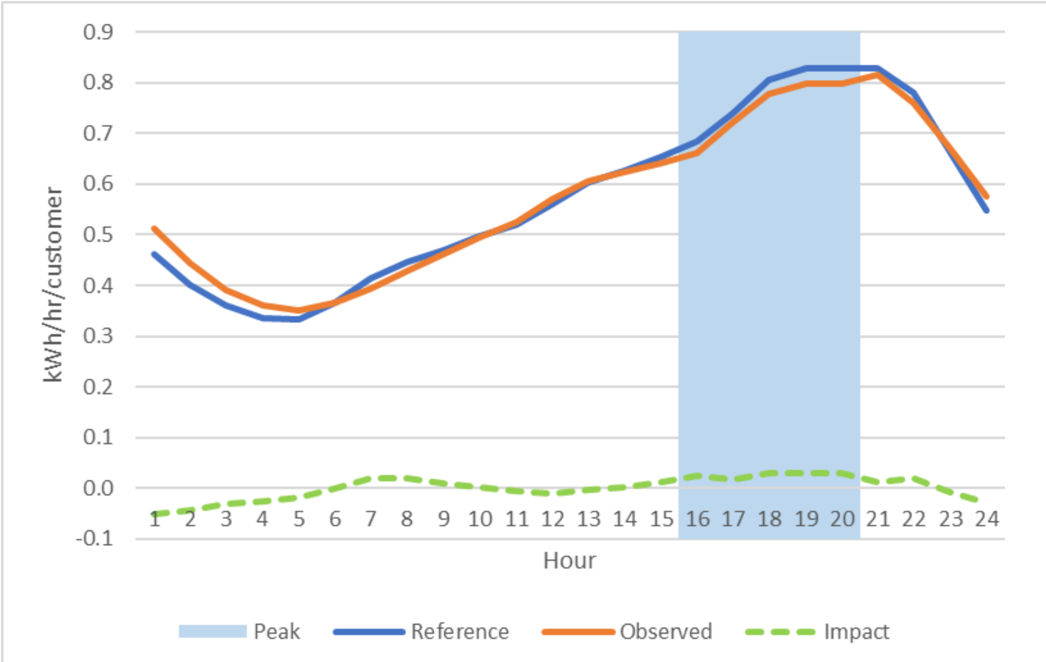


Figure 4.2: E-TOU-A Non-NEM August Average Weekday Hourly Impacts



Figures 4.3 and 4.4 show the estimates for E-TOU-B non-NEM customers in February and August 2020, respectively. Note the higher load levels relative to the E-TOU-A figures, showing how customer self-select by usage levels in response to each schedule's rates. The E-TOU-B load impacts tend to show overall load increases, particularly in August.[17] This means that treatment customers increased overall usage across years (*e.g.*, from August 2019 to August 2020) by more than the control-group customers. If you examine the pre-treatment match figures in Appendix M (*e.g.*, Figure M.3 shows the E-TOU-B non-NEM summer match quality), you will see that loads for the two groups lined up well in the pre-treatment year.

Recall that the customers in this study voluntarily adopted the TOU rates. One potential explanation for the estimated load increases on the TOU rates is that the customers who enrolled in a TOU rate did so in part because they expected to have unusual increases in their usage level, potentially due to shelter-in-place, and the TOU rate schedule would lead to a lower bill increase than Schedule E-1.

[17] While the February 2020 impacts in Figure 4.3 show overall load increases, that effect was not present in December 2019 or January 2020 when Peak-period impacts averaged 3.9 percent.

Figure 4.3: E-TOU-B Non-NEM February Average Weekday Hourly Impacts

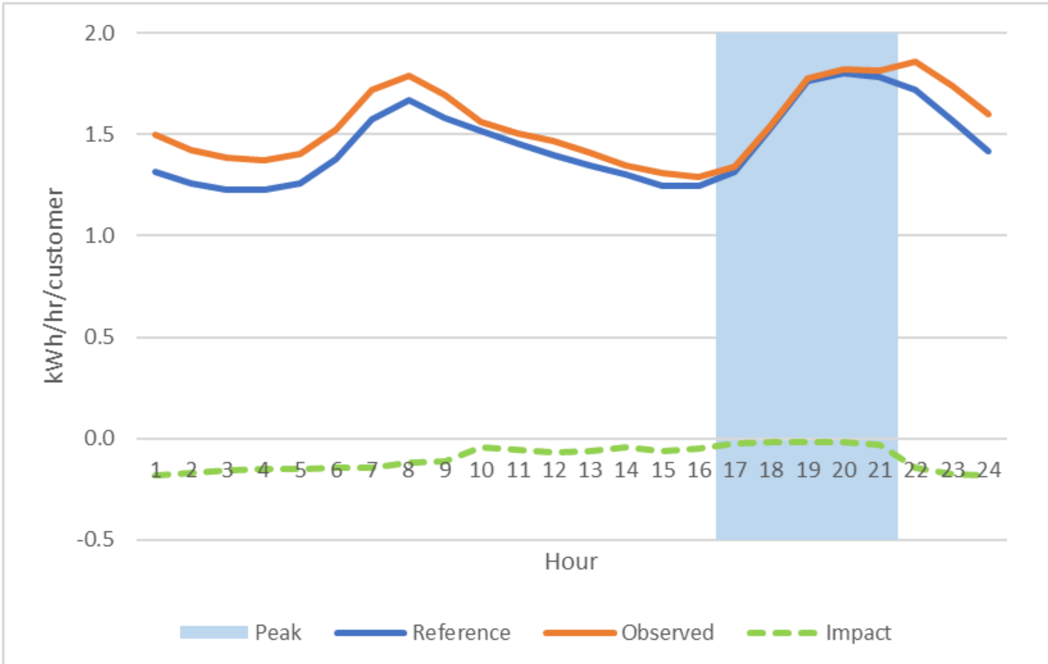
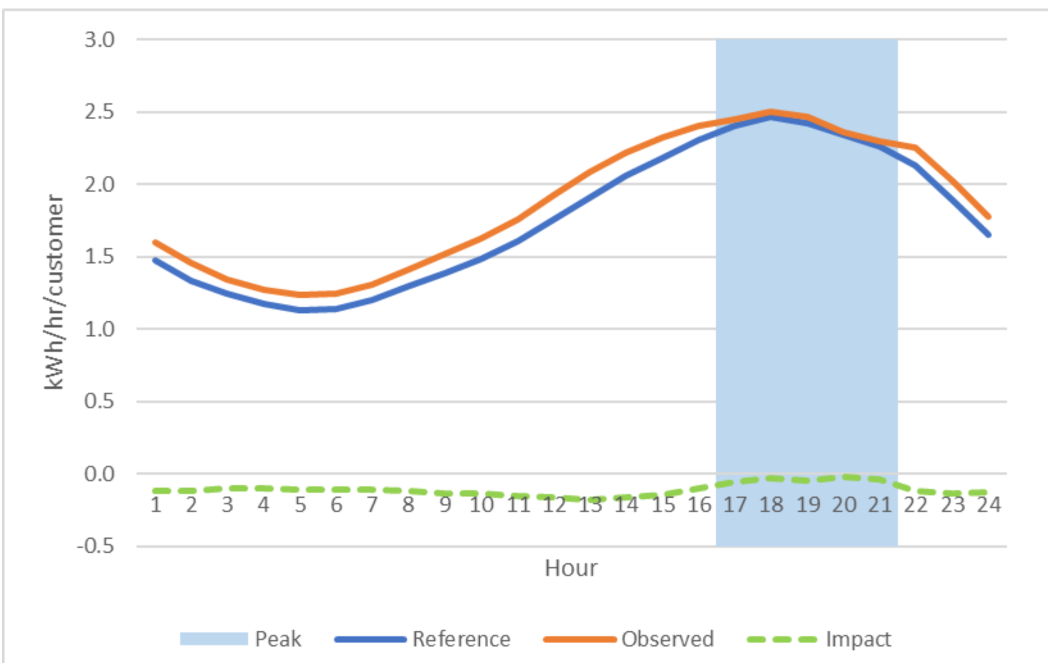


Figure 4.4: E-TOU-B Non-NEM August Average Weekday Hourly Impacts



Figures 4.5 and 4.6 show the estimates for E-TOU-C non-NEM customers in February and August 2020, respectively. These results may provide a better example of our "self selection based on anticipated usage increases" theory. That is, the February load impacts shown in Figure 4.5 seem as expected, with significant reductions during the

Peak period and load increases in the lower-priced periods. In contrast, the August impacts in Figure 4.6 show an overall load increase, but still provide some evidence of a response to TOU pricing with the "dips" down in observed loads during the Peak period (relative to surrounding hours – the overall load impact is negligible).

Figure 4.5: E-TOU-C Non-NEM February Average Weekday Hourly Impacts

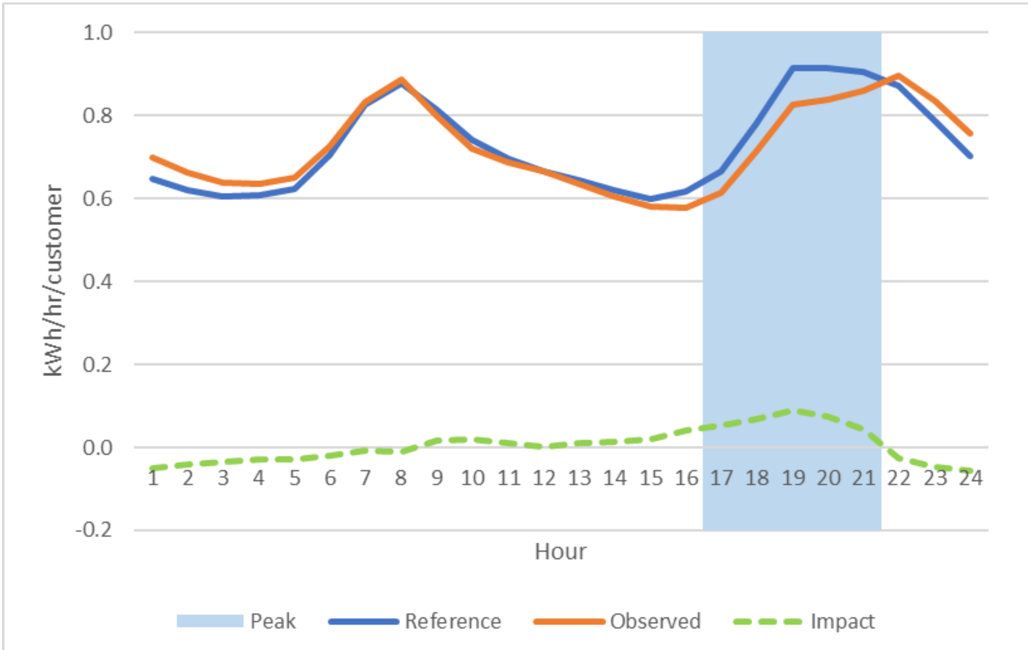


Figure 4.6: E-TOU-C Non-NEM August Average Weekday Hourly Impacts

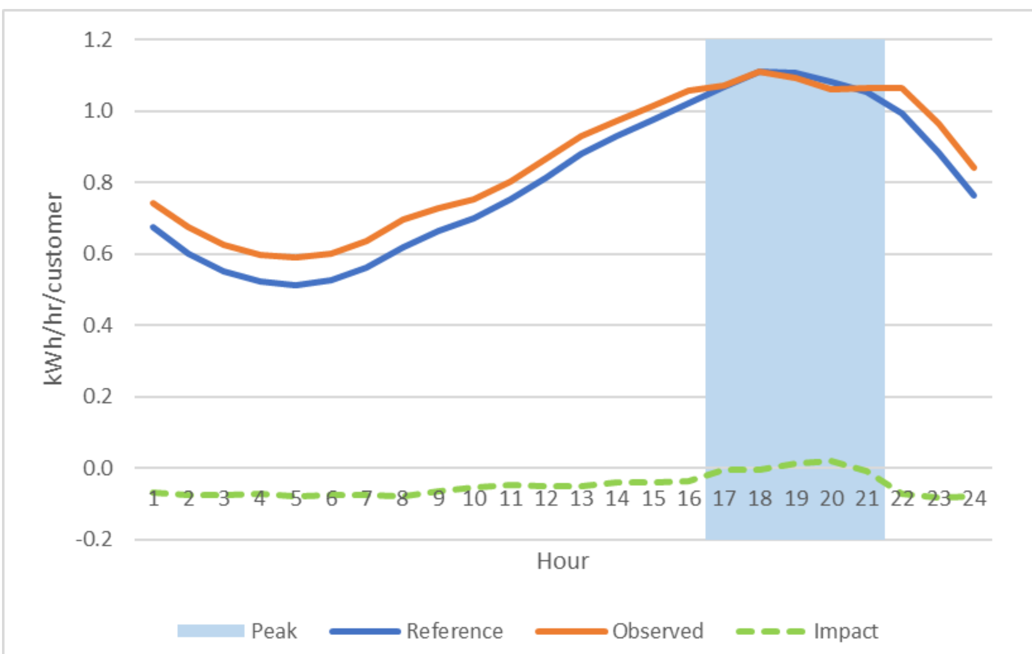
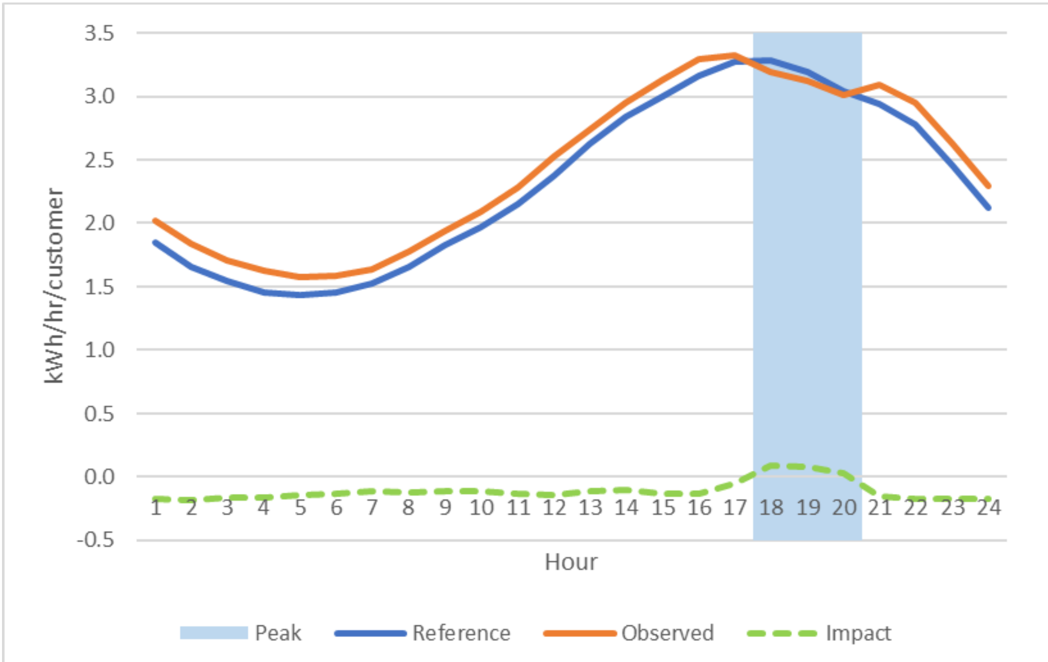


Figure 4.7 shows the estimates for E-TOU-D non-NEM customers in August 2020 (February estimates are not available for this rate). The figure is similar to the E-TOU-C Figure 4.6, in that loads increase overall but there is still some "notching" in the observed load during the Peak period.

Figure 4.7: E-TOU-D Non-NEM August Average Weekday Hourly Impacts

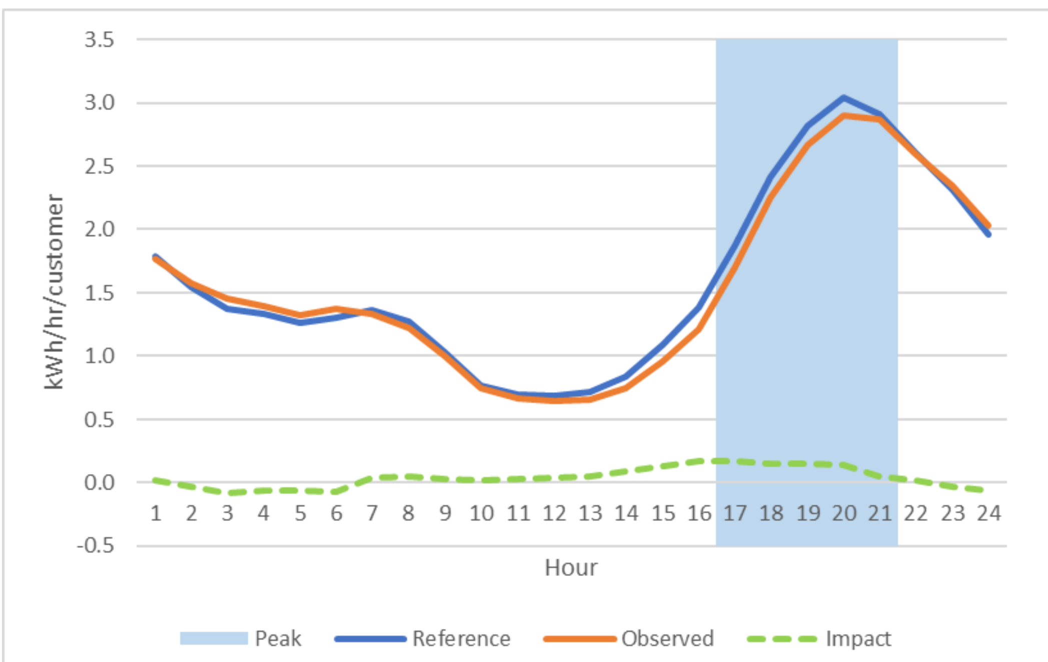


Figures 4.8 and 4.9 show the estimates for E-TOU-B NEM customers in February and August 2020, respectively. Notice the familiar "duck curve" profile that NEM customers exhibit, with low load levels in the middle of the day when solar output is at its peak, and higher loads in the early morning and later evening. These figures show Peak period usage reductions, but also some load reductions in hours prior to the Peak period.

Figure 4.8: E-TOU-B NEM February Average Weekday Hourly Impacts

[redacted]

Figure 4.9: E-TOU-B NEM August Average Weekday Hourly Impacts



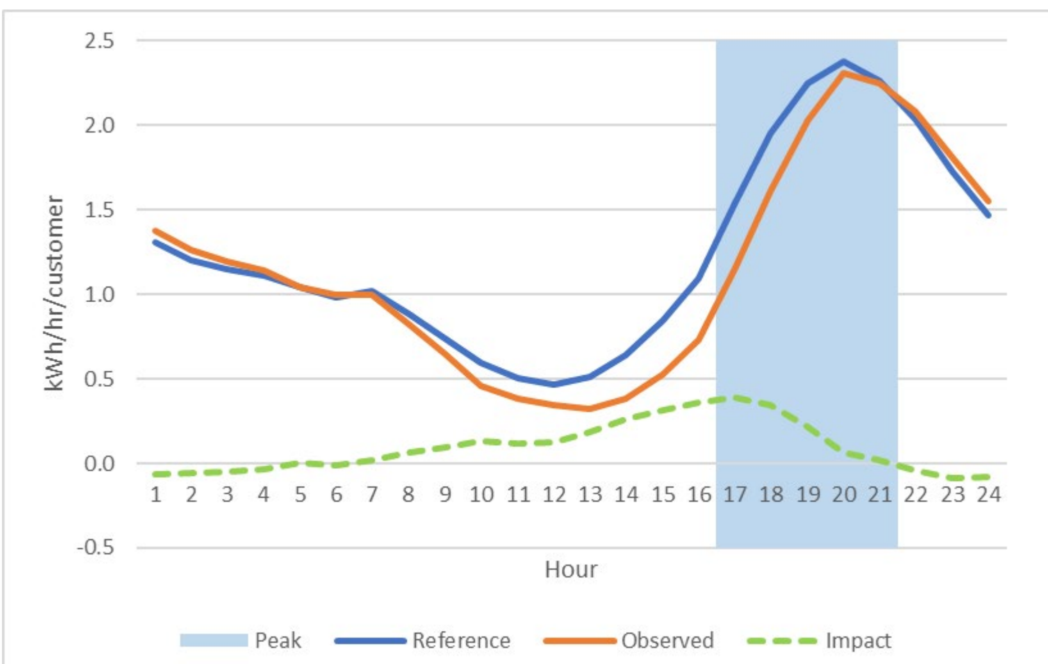
Figures 4.10 and 4.11 show the estimates for E-TOU-C NEM customers in February and August 2020, respectively. The February impacts are fairly small, while the August impacts are somewhat high across much of the day, not just the Peak period, perhaps

indicating a difficulty in accurately matching our treatment customers to control-group customers with similar PV system output.

Figure 4.10: E-TOU-C NEM February Average Weekday Hourly Impacts

[redacted]

Figure 4.11: E-TOU-C NEM August Average Weekday Hourly Impacts



Figures 4.12 and 4.13 show the estimates for EV2-A non-NEM customers in February and August 2020, respectively. Both figures exhibit high overnight / early morning loads

relative to customers on other rates, presumably due to EV charging. The February load impacts are dramatic, showing large load reductions in the Peak period with that load shifted to the inexpensive early morning hours. The August load impacts shown in Figure 4.13 show some load reductions in the Peak-period (and later) hours, but no corresponding load increase in the early hours of the day. This could be due to a reduction in EV use during the pandemic, resulting in less EV charging load to shift relative to February. In our *ex-ante* forecast, we reflect this COVID effect by having lower load impacts (reflective of August and other pandemic-affected months) dominate the forecast in the early years and load impacts similar to February dominate as the effects of the pandemic are assumed to wane and ultimately disappear. This is described in more detail in Section 3.2.2.

Figure 4.12: EV2-A Non-NEM February Average Weekday Hourly Impacts

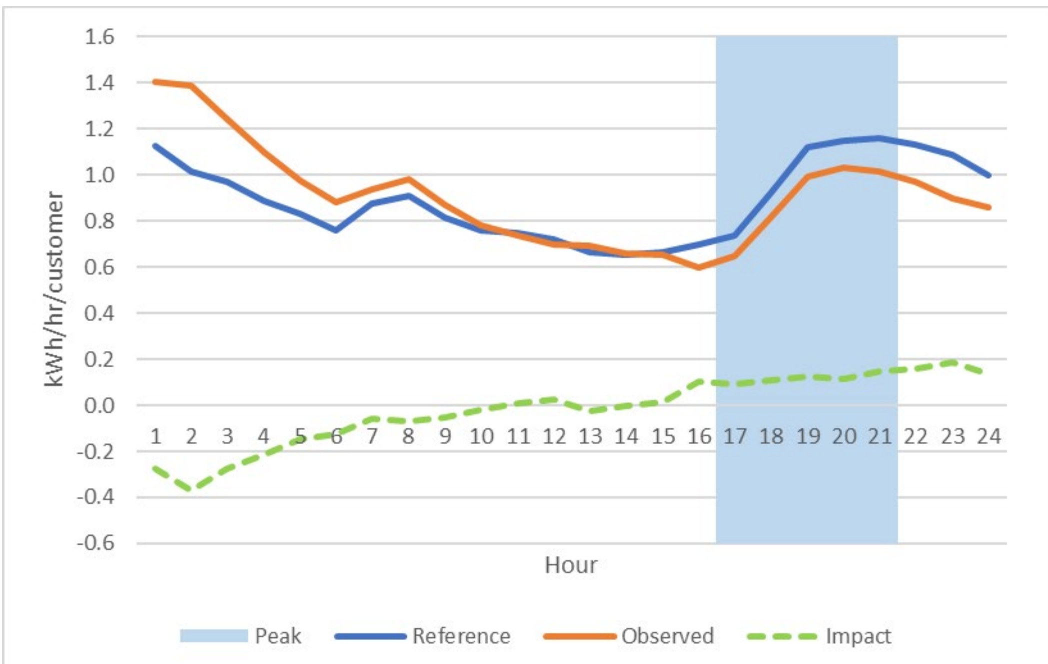
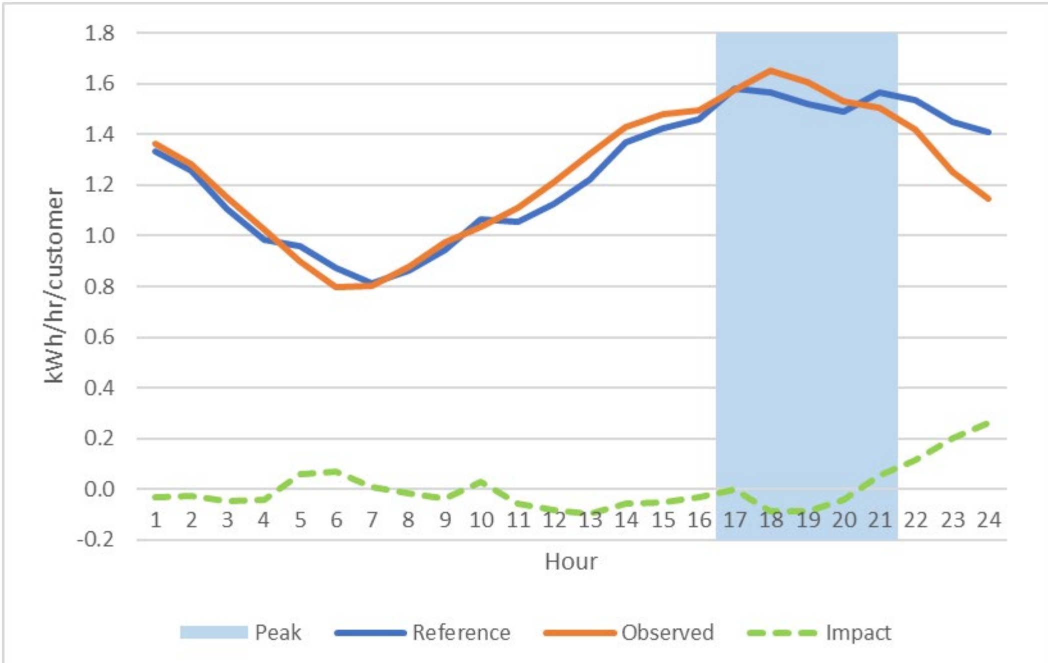


Figure 4.13: EV2-A Non-NEM August Average Weekday Hourly Impacts



5. *Ex-Ante* Load Impacts

5.1 Overview and Enrollment Forecasts

Ex-ante load impacts were developed separately for the following TOU rates: E-TOU-C (NEM and non-NEM), E-TOU-D (NEM and non-NEM, and EV2-A (non-NEM only). In each case, the forecast represents *incremental* TOU load impacts, which are attributable to customers joining TOU rates during the forecast period. Customers who are already on TOU rates contribute to an *embedded* TOU load impact that is already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

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.

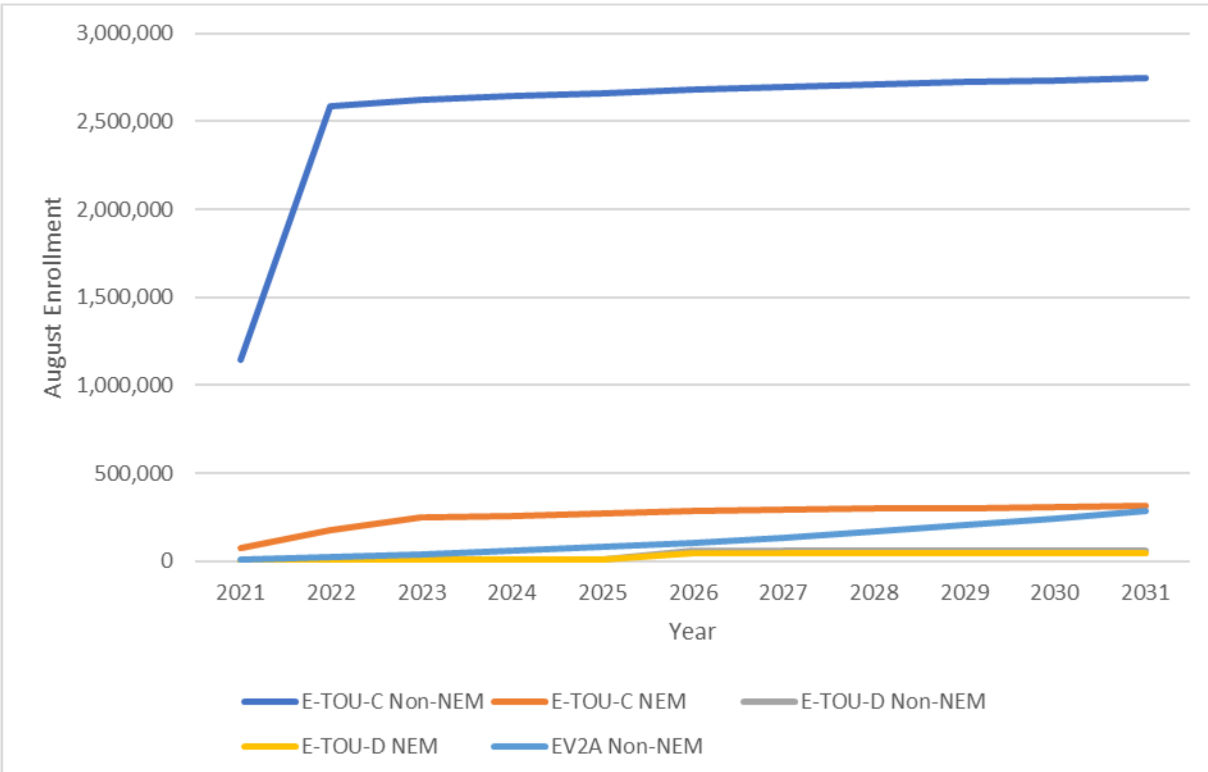
The weather conditions for each scenario were provided by PG&E.

Figure 5.1 shows the yearly enrollments forecast for the month of August[18], for each customer group. The forecast reflects the Default TOU process that ramps up during 2021 and concludes in early 2022, leading to a surge in E-TOU-C non-NEM enrollment. After that period, E-TOU-C non-NEM enrollment has modest annual increases (~0.6

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

percent) reflecting customer growth over time. E-TOU-C NEM enrollment has a higher long-term growth rate, at 2 to 4 percent over the 2024 to 2031 time period. E-TOU-D enrollment increases substantially in 2026 due to the termination of E-TOU-B, from which a significant share of customers are assumed to migrate to E-TOU-D due to the similarity in rate structures (omitting the baseline credit). EV2-A enrollment has the highest long-term growth rate, from roughly 20 to 40 percent per year, reflecting increased EV adoption over time.

Figure 5.1: Forecast August Enrollments by Year and Customer Group



5.2 Ex-Ante Load Impact Results

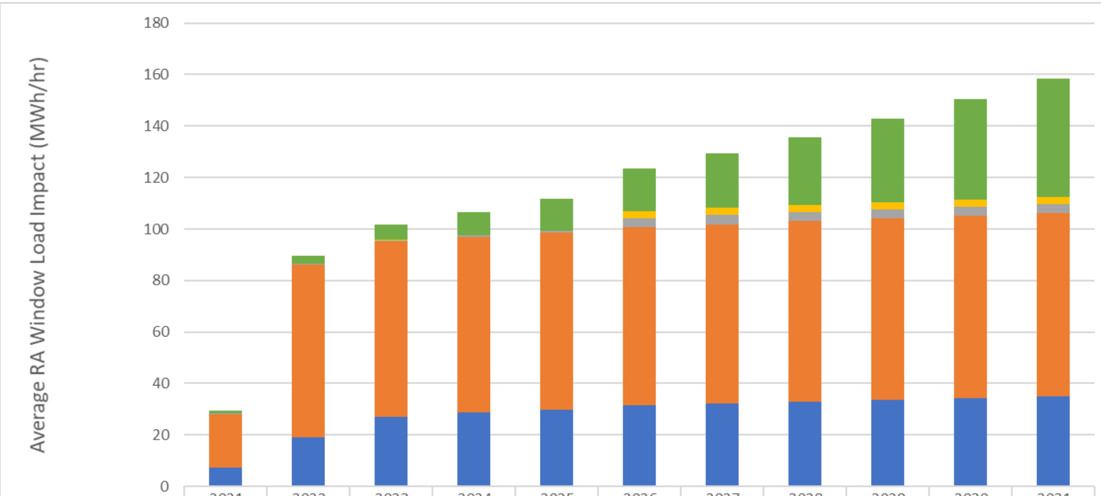
Ex-ante load impacts are developed for five groups of customers:

- E-TOU-C non-NEM;
- E-TOU-D non-NEM;
- E-TOU-C NEM;
- E-TOU-D NEM; and
- EV2-A non-NEM.

The following sub-sections present the *ex-ante* forecasts for each of these groups. The E-TOU-C and E-TOU-D NEM customer forecasts are presented together in one sub-section.[19]

Figure 5.2 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 parallels the corresponding enrollment pattern (as shown in Figure 5.1), though the higher percentage impacts for EV2-A and NEM rates leads to those rates having a higher share of load impacts than enrollments. For example, in 2023 the E-TOU-C non-NEM customers account for 90 percent of enrolled TOU customers but only 67 percent of the total TOU load impact.

Figure 5.2: Average RA Window Load Impacts by Year, *August PG&E 1-in-2 Peak Month*



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EV2A Non-NEM	0.8	3.1	5.9	8.9	12.4	16.5	21.1	26.4	32.4	38.9	45.9
E-TOU-D Non-NEM	0.2	0.3	0.3	0.3	0.3	2.8	2.8	2.8	2.8	2.8	2.8
E-TOU-D NEM	0.2	0.4	0.4	0.4	0.4	3.5	3.5	3.5	3.5	3.5	3.6
E-TOU-C Non-NEM	20.9	66.9	67.9	68.4	68.8	69.4	69.8	70.1	70.5	70.8	71.1
E-TOU-C NEM	7.2	19.1	27.1	28.6	29.9	31.4	32.1	32.9	33.6	34.3	35.0

5.2.1 *Ex-ante* load impacts for E-TOU-C non-NEM customers

Table 5.1 shows the E-TOU-C non-NEM customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. Incremental enrollments begin in April 2021, so load impacts are zero for the first three months of the year. Load impacts increase

[19] The forecasts are combined because the basis of each forecast is the same, as described in Section 3.2.2.

significantly in June, coinciding with a large increase in enrollments due to the Default TOU process.

Table 5.1: E-TOU-C Non-NEM *Ex-Ante* Load Impacts, 2021 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	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	0.0
February	0	0.0	0.0	0.0	0.0
March	0	0.0	0.0	0.0	0.0
April	138,735	1.2	1.3	1.2	1.3
May	499,690	5.5	4.2	7.3	4.7
June	903,414	17.0	16.7	21.2	16.8
July	1,156,117	24.4	19.1	26.1	21.6
August	1,145,416	21.4	18.6	24.4	20.9
September	1,324,172	22.9	20.6	28.2	24.5
October	1,548,049	15.2	14.2	18.6	13.6
November	1,924,590	15.5	15.9	16.4	17.3
December	1,978,104	21.2	19.8	21.8	20.7

Figure 5.3 shows the hourly loads and load impacts associated with the August 2021 PG&E 1-in-2 weather scenario. The Peak-period load impact averages 1.8 percent. Figure 5.4 shows the same information for January 2022. The Peak-period load impact averages 1.1 percent. We expect to see higher per-customer impacts in the summer compared to winter.

Figure 5.3: E-TOU-C Non-NEM *Ex-Ante* Load Impacts, August 2021 PG&E 1-in-2 Peak Day

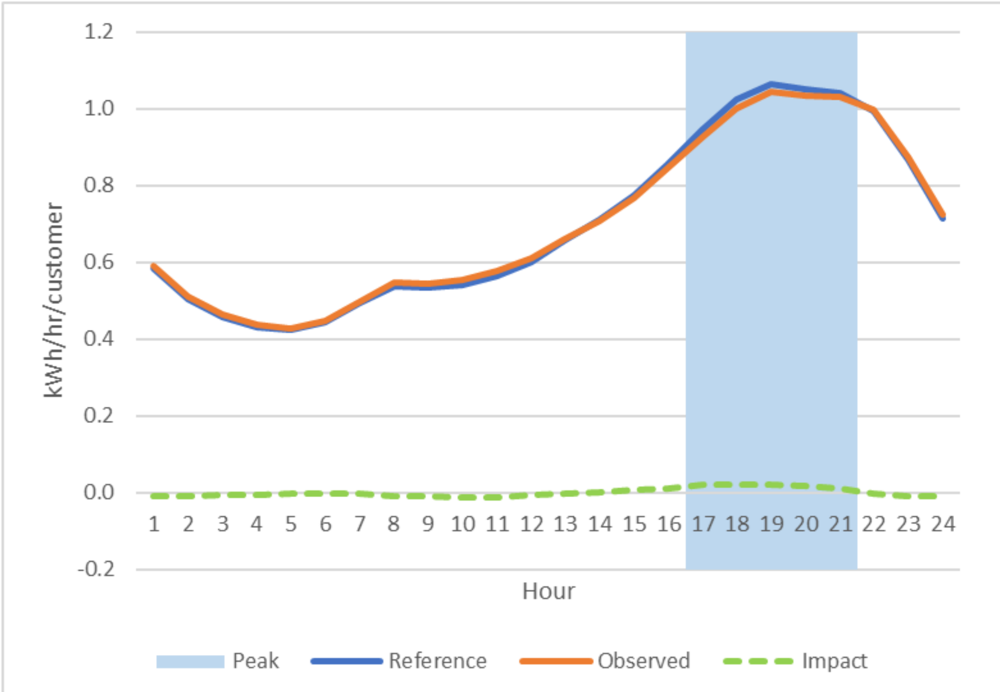
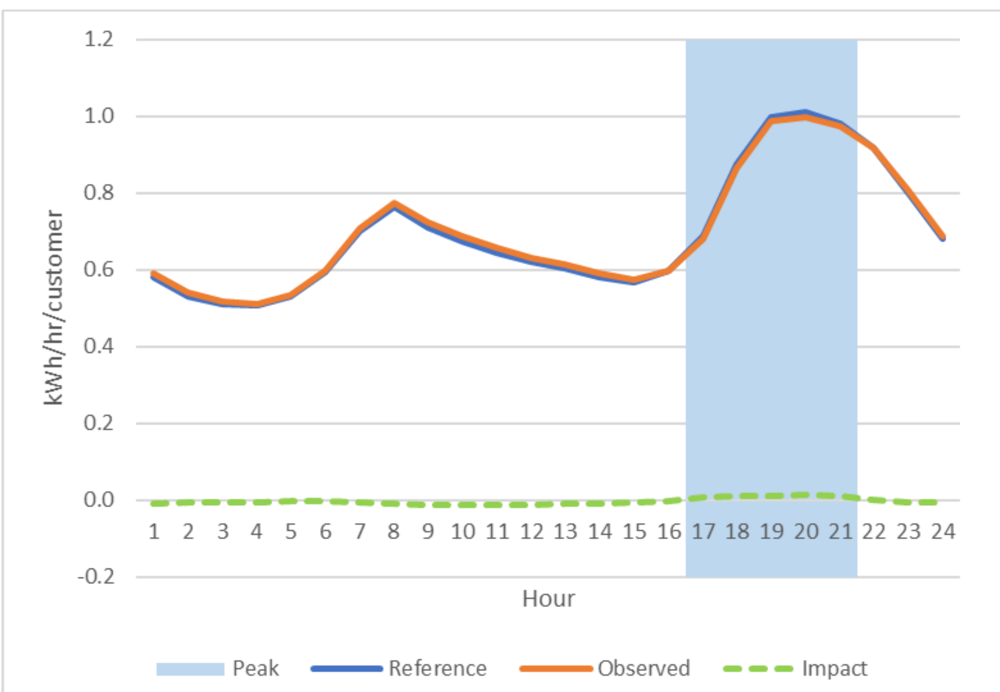


Figure 5.4: E-TOU-C Non-NEM *Ex-Ante* Load Impacts, January 2022 PG&E 1-in-2 Peak Day



5.2.2 *Ex-ante* load impacts for E-TOU-D non-NEM customers

Table 5.2 shows the E-TOU-D non-NEM customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. Incremental enrollments begin in February 2021, so load impacts are zero for January. Enrollment increases steadily throughout the year, but at a decreasing rate. That pattern is reflected in the load impacts.

Table 5.2: E-TOU-D Non-NEM *Ex-Ante* Load Impacts, 2021 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	675	0.03	0.03	0.04	0.04
March	1,273	0.06	0.06	0.06	0.06
April	1,797	0.09	0.08	0.09	0.08
May	2,263	0.14	0.12	0.17	0.13
June	2,679	0.12	0.12	0.14	0.12
July	3,043	0.16	0.14	0.17	0.15
August	3,374	0.16	0.14	0.17	0.16
September	3,652	0.16	0.15	0.17	0.16
October	3,895	0.23	0.20	0.25	0.20
November	4,123	0.17	0.18	0.19	0.20
December	4,326	0.25	0.23	0.25	0.24

Figure 5.5 shows the hourly loads and load impacts associated with the August 2021 PG&E 1-in-2 weather scenario. The Peak-period load impact averages 3.1 percent. Figure 5.6 shows the same information for January 2022. The Peak-period load impact averages 4.2 percent. Because of differences in the reference load levels in the two months shown, the level load impact is more similar than the percentage load impact (0.088 kWh/hr for August vs. 0.091 kWh/hr for January). While one might expect the winter load impact to be lower than the summer load impact, the forecast is representative of the PY2019 E-TOU-B *ex-post* load impacts upon which it is based.

Figure 5.5: E-TOU-D Non-NEM *Ex-Ante* Load Impacts, August 2021 PG&E 1-in-2 Peak Day

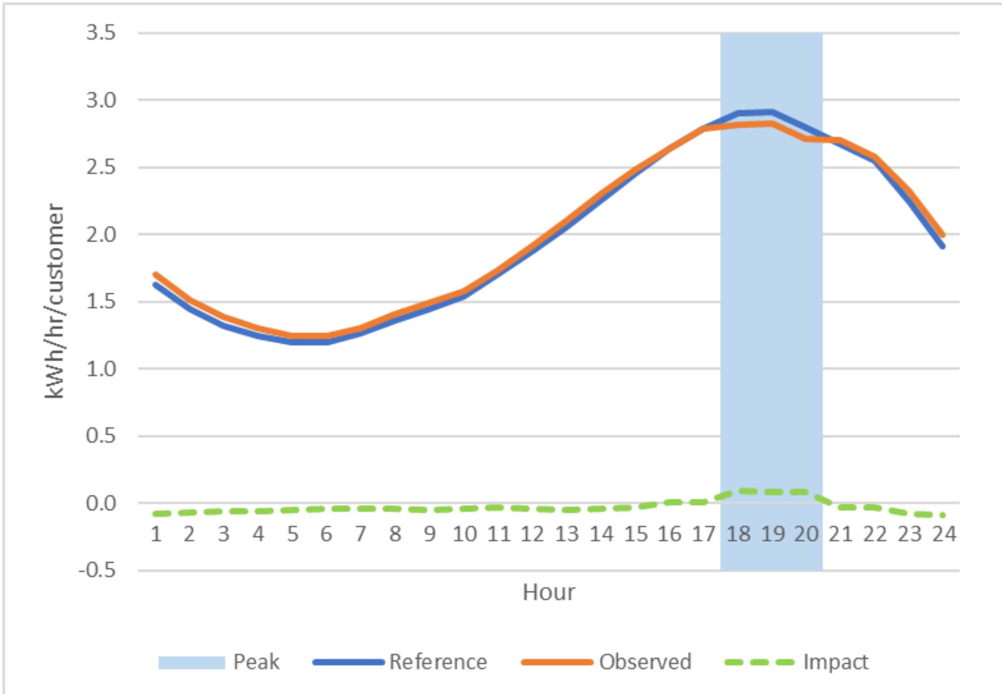
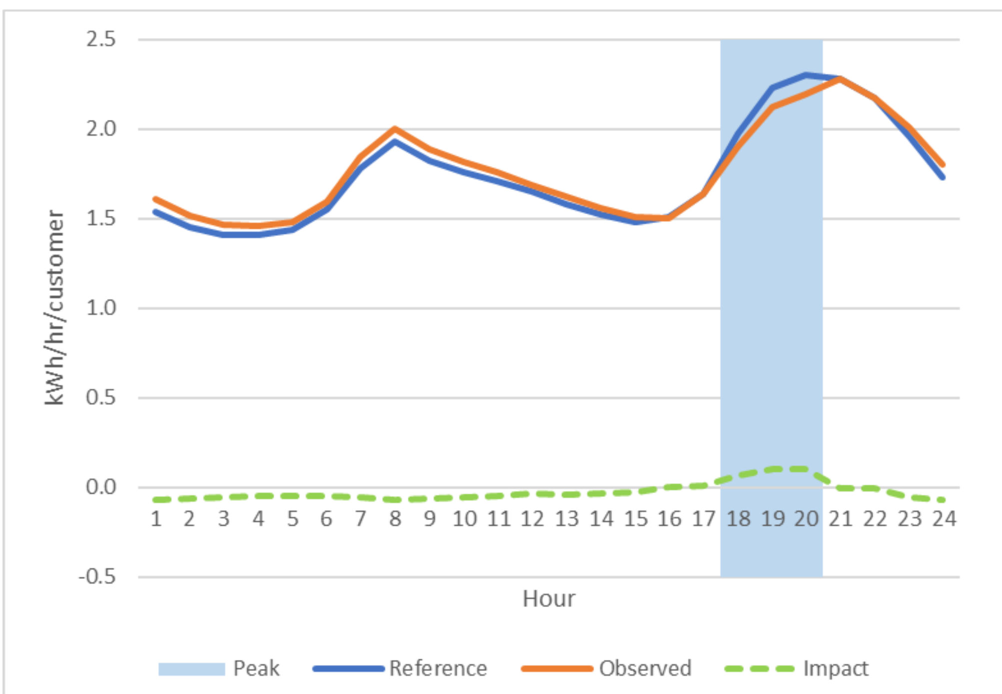


Figure 5.6: E-TOU-D Non-NEM *Ex-Ante* Load Impacts, January 2022 PG&E 1-in-2 Peak Day



5.2.3 *Ex-ante* load impacts for EV2-A non-NEM customers

Table 5.3 shows the EV2-A non-NEM customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. Incremental enrollments begin in February 2021, so load impacts are zero for January. Enrollment increases steadily throughout the year at approximately 1,100 customers per month, which is mirrored in the change in load impacts across months.

Table 5.3: EV2-A Non-NEM *Ex-Ante* Load Impacts, 2021 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	921	0.06	0.06	0.07	0.07
March	1,983	0.12	0.13	0.13	0.13
April	3,048	0.17	0.18	0.16	0.18
May	4,119	0.36	0.29	0.45	0.32
June	5,199	0.50	0.50	0.61	0.49
July	6,280	0.68	0.56	0.71	0.61
August	7,369	0.79	0.69	0.86	0.77
September	8,468	0.85	0.77	1.00	0.89
October	9,567	0.88	0.82	1.04	0.81
November	10,675	0.81	0.83	0.84	0.86
December	11,788	1.10	1.06	1.12	1.09

Figure 5.7 shows the hourly loads and load impacts associated with the August 2021 PG&E 1-in-2 weather scenario. The Peak-period load impact averages 7.2 percent. Figure 5.8 shows the same information for January 2022. The Peak-period load impact averages 8.2 percent. Because of differences in the reference load levels in the two months shown, the level load impact is higher in August (0.105 kWh/hr for August vs. 0.093 kWh/hr for January). The change in percentage load impacts reflects the COVID assumptions. As COVID effects are assumed to decline, EV2-A load impacts exhibit greater load shifting from late in the day to the early hours of the day.

Figure 5.7: EV2-A Non-NEM *Ex-Ante* Load Impacts, August 2021 PG&E 1-in-2 Peak Day

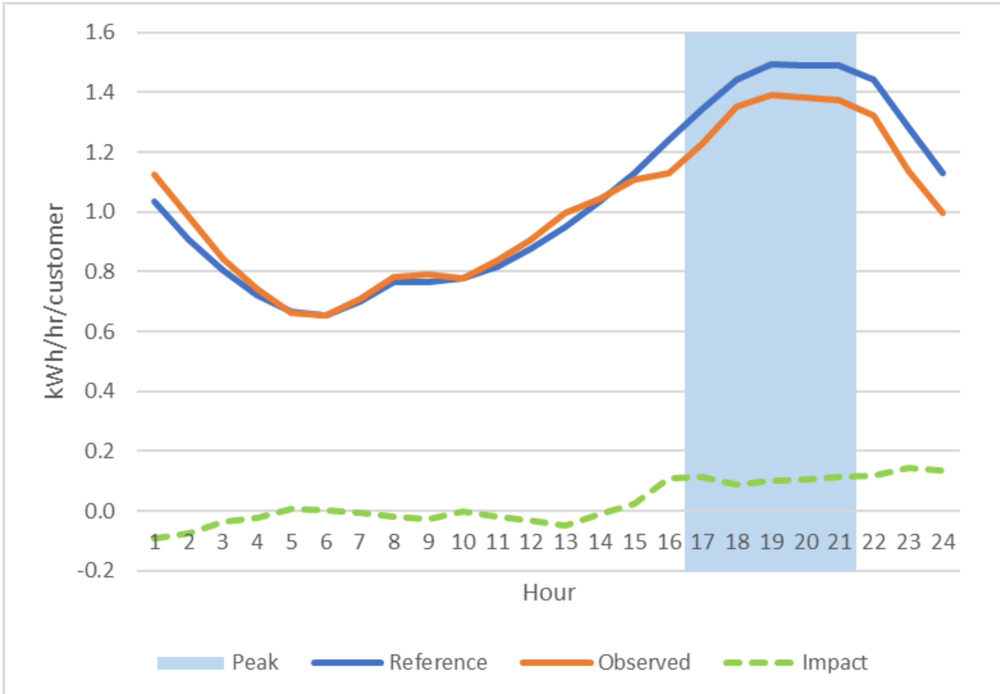
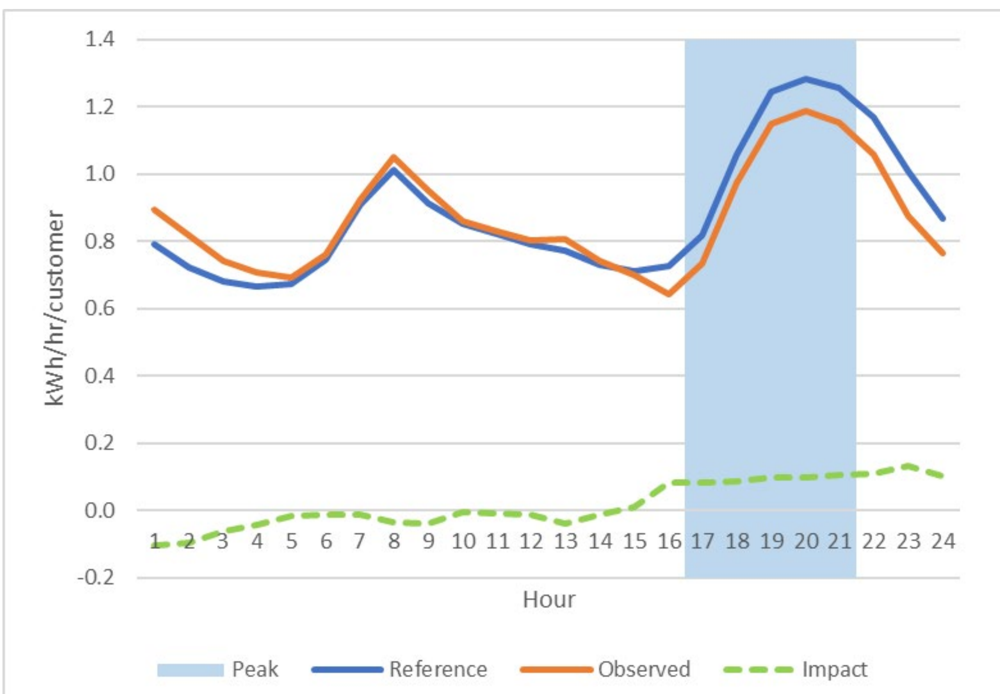


Figure 5.8: EV2-A Non-NEM *Ex-Ante* Load Impacts, January 2022 PG&E 1-in-2 Peak Day



5.2.4 *Ex-ante* load impacts for E-TOU-C and E-TOU-D NEM customers

Tables 5.4 and 5.5 show the NEM customer load impacts for E-TOU-C and E-TOU-D, respectively. The E-TOU-C incremental enrollments begin in April, while they begin in February for E-TOU-D. Load impacts are zero prior to those months. As was the case in the non-NEM results, E-TOU-C load impacts display strong growth during the year, reflecting increasing enrollments. E-TOU-D enrollments are much lower due to enrollments only increasing by hundreds per month rather than the 12,000 to 20,000 per month for E-TOU-C.

Table 5.4: E-TOU-C NEM *Ex-Ante* Load Impacts, 2021 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	0	0.00	0.00	0.00	0.00
March	0	0.00	0.00	0.00	0.00
April	20,222	0.64	0.69	0.62	0.68
May	32,331	1.95	1.67	2.33	1.74
June	46,730	4.22	4.22	4.81	4.27
July	61,094	6.37	5.60	6.66	5.84
August	72,914	7.57	6.33	7.98	7.25
September	85,787	7.84	7.17	8.49	8.12
October	102,956	6.34	5.41	6.79	5.42
November	121,809	5.29	5.39	5.47	5.64
December	135,963	7.32	7.05	7.47	7.25

Table 5.5: E-TOU-D NEM *Ex-Ante* Load Impacts, 2021 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	614	0.02	0.02	0.02	0.02
March	1,161	0.03	0.03	0.03	0.03
April	1,640	0.04	0.04	0.03	0.04
May	2,062	0.09	0.08	0.11	0.08
June	2,442	0.16	0.16	0.18	0.17
July	2,775	0.21	0.19	0.22	0.20
August	3,077	0.23	0.19	0.24	0.22
September	3,330	0.21	0.20	0.22	0.22
October	3,551	0.15	0.13	0.16	0.13
November	3,758	0.10	0.10	0.11	0.11
December	3,945	0.13	0.13	0.14	0.13

Figures 5.9 and 5.11 show the hourly loads and load impacts associated with the August 2021 PG&E 1-in-2 weather scenario for NEM customers on E-TOU-C and E-TOU-D, respectively. In both cases, the Peak-period load impact averages 3.7 percent. Figures 5.10 and 5.12 show the same information for January 2022. The Peak-period load impacts average 2.7 percent in both figures. As described in Section 3.2.2, we assumed a constant percentage load impact in the Peak period for both rates that varied only by season. In addition, the per-customer reference loads by LCA are the same for both rates. Differences in the program-level reference loads occur due to the rates having different distributions of customers across the LCAs.

Figure 5.9: E-TOU-C NEM *Ex-Ante* Load Impacts, August 2021 PG&E 1-in-2 Peak Day

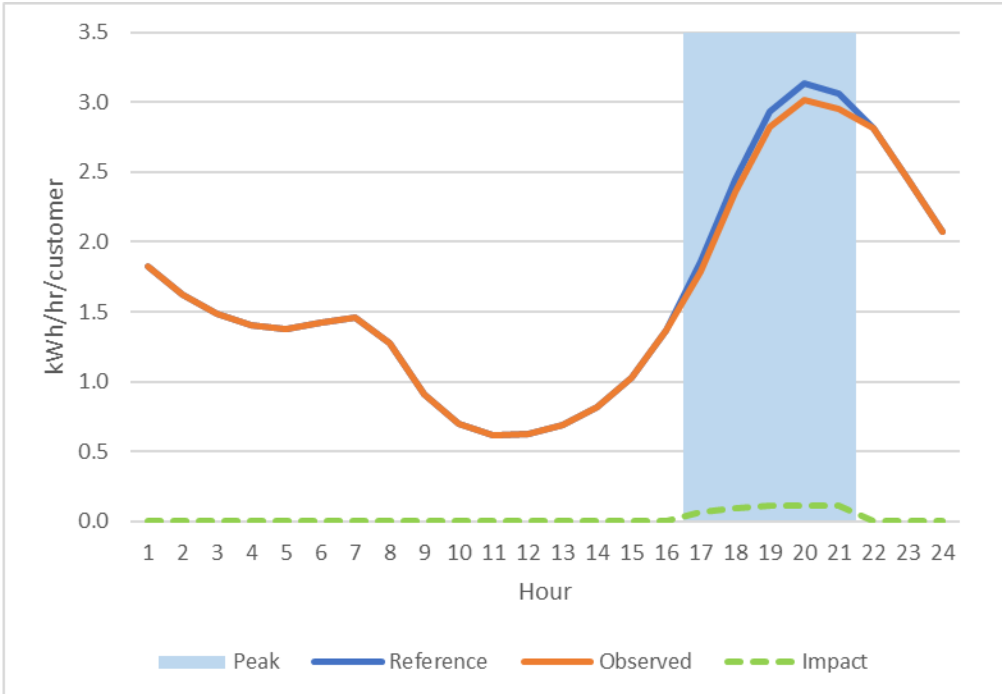


Figure 5.10: E-TOU-C NEM *Ex-Ante* Load Impacts, January 2022 PG&E 1-in-2 Peak Day

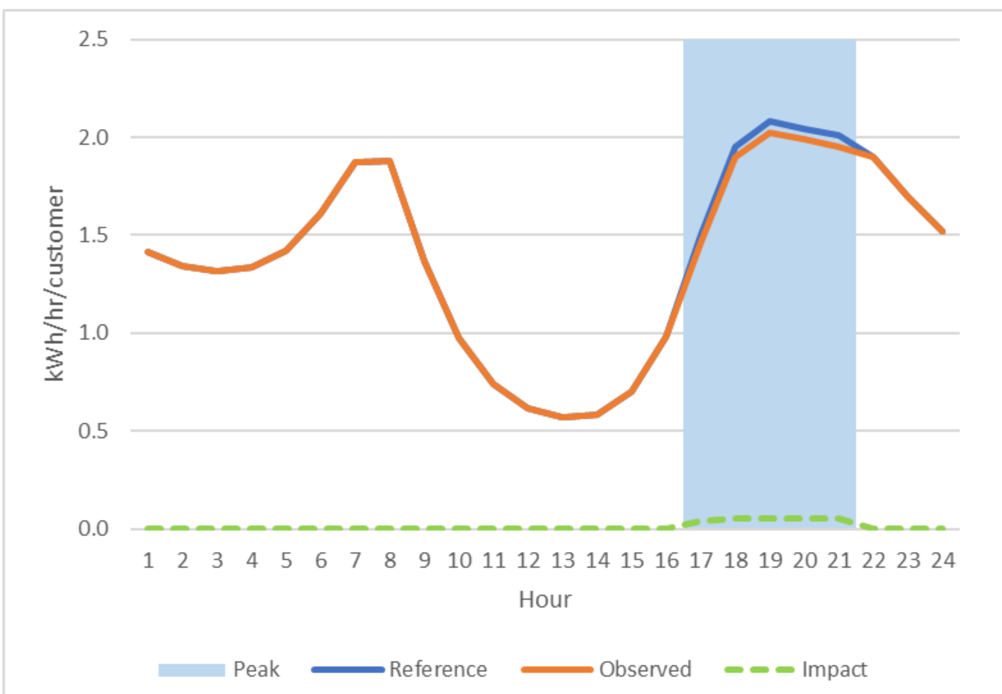


Figure 5.11: E-TOU-D NEM *Ex-Ante* Load Impacts, August 2021 PG&E 1-in-2 Peak Day

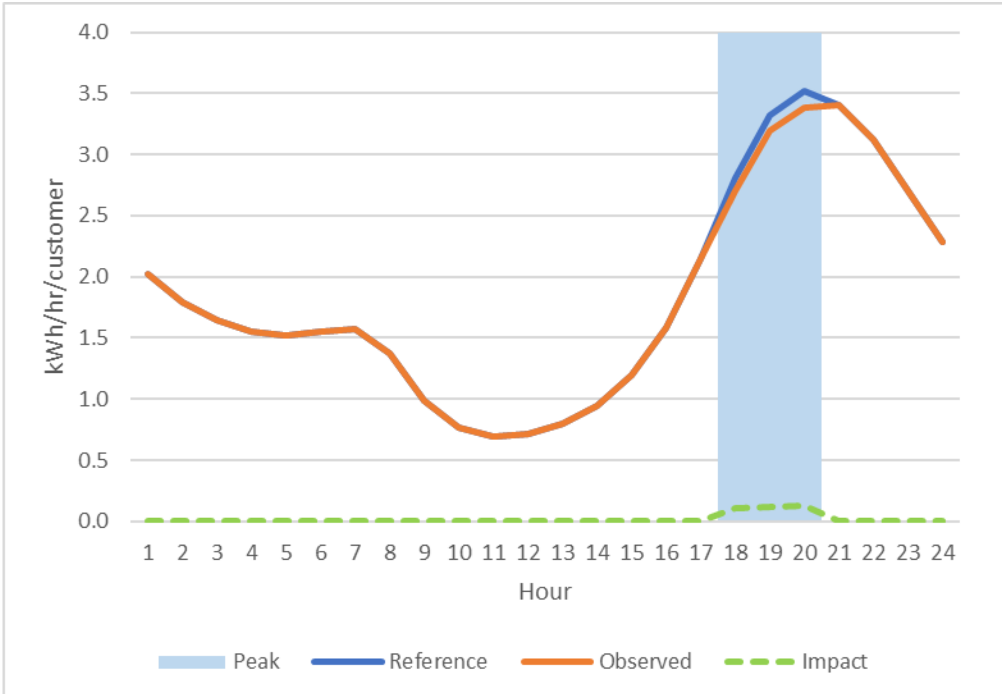
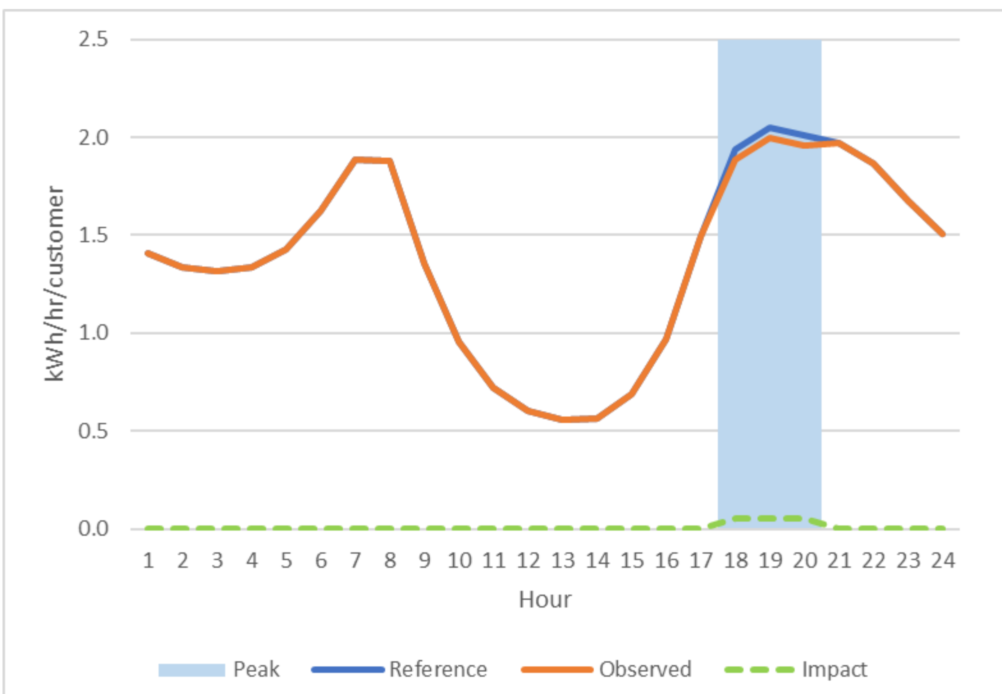


Figure 5.12: E-TOU-D NEM *Ex-Ante* Load Impacts, January 2022 PG&E 1-in-2 Peak Day



6. 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 PY2020. The term “previous” refers to findings in report for PY2019. In the final comparison above, we illustrate the linkage between the PY2020 *ex-post* load impacts and the *ex-ante* forecast (of the 1-in-2 August peak day) for 2021. While the study includes several rates, we focus on the E-TOU-C non-NEM forecast, which accounts for 90 percent or more of the residential TOU enrollments through 2023.[20]

6.1 Previous versus current ex-post E-TOU-C non-NEM load impacts

Table 6.1 shows the average Peak-period reference loads and load impacts for the August average weekday during the current and previous program years. In both cases, the load impacts represent non-NEM customers who voluntarily enrolled in E-TOU-C rather than being defaulted onto the rate. (In contrast, the E-TOU-C *ex-ante* forecasts are based on load impacts for defaulted customers.) The load impacts were quite different across years. During PY2020, E-TOU-C attracted significantly lower usagecustomers vs. PY2019 (1.08 vs. 1.70 kWh/hr/customer). In addition, the percentage load impact was essentially zero in PY2020 after being 6.2 percent in PY2019. We believe this is due to the COVID self-selection effect described in Section 4.

[20] In addition, there are no prior study load impacts for the NEM, EV2-A, or E-TOU-D customers, which restricts the comparisons that can be made.

Table 6.1: Comparison of Average August Weekday Peak-period *Ex-Post* Impacts in PY2019 and PY2020, E-TOU-C Non-NEM

Level	Outcome	PY2019	PY2020
Total	# SAIDs	15,818	21,642
	Reference (MW)	26.91	23.45
	Load Impact (MW)	1.67	0.08
	Avg. Temp.	86.4	84.2
Per SAID	Reference (kW)	1.70	1.08
	Load Impact (kW)	0.11	0.00
	% Load Impact	6.2%	0.3%

6.2 Previous versus current ex-ante E-TOU-C non-NEM load impacts

In this sub-section, we compare the *ex-ante* forecast prepared following PY2019 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). In both cases, the forecast reflects defaulted customers in its enrollments and the per-customer reference loads and load impacts are primarily taken from the Default TOU pilot evaluation.

Table 6.2 reports the incremental load impact forecast for the August 2022 average weekday under PG&E 1-in-2 peak weather conditions. Enrollment levels are somewhat lower in the current study, reflecting the updated E-TOU-C default schedule and excluding customers do not fulfill the default eligibility requirements. However, the per-customer level and percentage load impacts are the same in the two evaluations, refecting their shared basis.

Table 6.2: Comparison of Average August 2022 Weekday Peak-period *Ex-Ante* Impacts in PY2019 and PY2020 Studies, E-TOU-C Non-NEM

Level	Outcome	Previous Study	Current Study
Total	# SAIDs	3,389,280	2,584,217
	Reference (MW)	3,163	2,534
	Load Impact (MW)	61.7	51.0
	Avg. Temp.	77.2	78.3
Per SAID	Reference (kW)	0.93	0.98
	Load Impact (kW)	0.02	0.02
	% Load Impact	2.0%	2.0%

6.3 Previous ex-ante versus current ex-post E-TOU-C non-NEM load impacts

Table 6.3 provides a comparison of the *ex-ante* forecast of August 2020 average weekday load impacts prepared following PY2019 and the *ex-post* PY2020 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. Enrollment and per-customer load impacts were much lower than forecast, likely due to unforeseen pandemic effects.

Table 6.3 Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts, E-TOU-C Non-NEM

Level	Outcome	*Ex-Ante* for Aug. 2020 Avg. Weekday from PY2019 Study	*Ex-Post* for Aug. 2020 Avg. Weekday from PY2020 Study
Total	# SAIDs	113,782	21,642
	Reference (MW)	105.06	23.45
	Load Impact (MW)	1.69	0.08
	Avg. Temp.	78.5	84.2
Per SAID	Reference (kW)	0.92	1.08
	Load Impact (kW)	0.01	0.00
	% Load Impact	1.6%	0.3%

6.4 Current ex-post versus current ex-ante E-TOU-C non-NEM load impacts

Table 6.4 compares the PY2020 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2021 produced in this study. This is an apples-to-oranges comparison, as the *ex-post* impacts relate to customers who voluntarily enrolled in E-TOU-C while the *ex-ante* forecast reflects customers who were defaulted onto the rate. Moreover, the total counts in the *ex-post* impacts reflect the August 2020 population before the E-TOU-C default, while the *ex-ante* forecast reflects a much larger populaton of customers who are expected to default in the 2021 year. The forecast was not based on the *ex-post* impacts from this study, as we had far better information about Default TOU load impacts from the Default TOU pilot study. While the pilot simulated the default process for a large number of customers, this *ex-post* evaluation is based on the load impacts of a comparatively low number of customers who voluntarily adopted E-TOU-C (some of which did so during a pandemic).

Table 6.4 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, E-TOU-C Non-NEM

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday from PY2020 Study	*Ex-Ante* for Aug. 2021 Avg. Weekday from PY2020 Study
Total	# SAIDs	21,642	1,145,416
	Reference (MW)	23.45	916
	Load Impact (MW)	0.08	16.2
	Avg. Temp.	84.2	73.1
Per SAID	Reference (kW)	1.08	0.80
	Load Impact (kW)	0.00	0.01
	% Load Impact	0.3%	1.8%

Appendices

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

2a. PGE_2020_Res_TOU_ETOUA_Ex_Post_PUBLIC.xlsx

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

2b. PGE_2020_Res_TOU_ETOUB_Ex_Post_ PUBLIC.xlsx

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

2c. PGE_2020_Res_TOU_ETOUC_Ex_Post_ PUBLIC.xlsx

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

2d. PGE_2020_Res_TOU_ETOUD_Ex_Post_ PUBLIC.xlsx

Appendix E E-1 to EV2-A *Ex-Post* Load Impact Tables:

2e. PGE_2020_Res_TOU_EV2A_Ex_Post_ PUBLIC.xlsx

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

2f. PGE_2020_Res_TOU_ETOUB_NEM_Ex_Post_ PUBLIC.xlsx

Appendix G E-1 to E-TOU-D NEM *Ex-Post* Load Impact Tables:

2g. PGE_2020_Res_TOU_ETOUC_NEM_Ex_Post_ PUBLIC.xlsx

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

2h. PGE_2020_Res_TOU_ETOUC_Inc_Ex_Ante_ PUBLIC.xlsx

Appendix I E-TOU-D Incremental *Ex-Ante* Load Impact Tables:

2i. PGE_2020_Res_TOU_ETOUD_Inc_Ex_Ante_ PUBLIC.xlsx

Appendix J E-TOU-C NEM Incremental *Ex-Ante* Load Impact Tables:

2j. PGE_2020_Res_TOU_ETOUC_NEM_Inc_Ex_Ante_ PUBLIC.xlsx

Appendix K E-TOU-D NEM Incremental *Ex-Ante* Load Impact Tables:

2k. PGE_2020_Res_TOU_ETOUD_NEM_Inc_Ex_Ante_ PUBLIC.xlsx

Appendix L EV2-A Incremental *Ex-Ante* Load Impact Tables:

2l. PGE_2020_Res_TOU_EV2A_Inc_Ex_Ante_ PUBLIC.xlsx

Appendix M *Ex-Post* Analysis Match Quality

Appendix N Regression Sample Sizes

Appendix M. Match Quality

This appendix presents the summaries of our control-group matching process. Figures M.1 through M.11 illustrate the seasonal matches for E-TOU-A, E-TOU-B, E-TOU-C, E-TOU-D, E-TOU-B NEM, and E-TOU-C NEM customers. (The EV2-A analysis does not use a control group, so the rate is not present in this appendix.) Each figure contains the average hourly profiles for the treatment and matched control-group customers on the average weekday that was withheld from the matching process (*i.e.*, it represents and out-of-sample match quality). The mean percentage error (MPE) and mean absolute percentage error (MAPE) values associated with each figure are summarized in Tables M.1 and M.2.

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

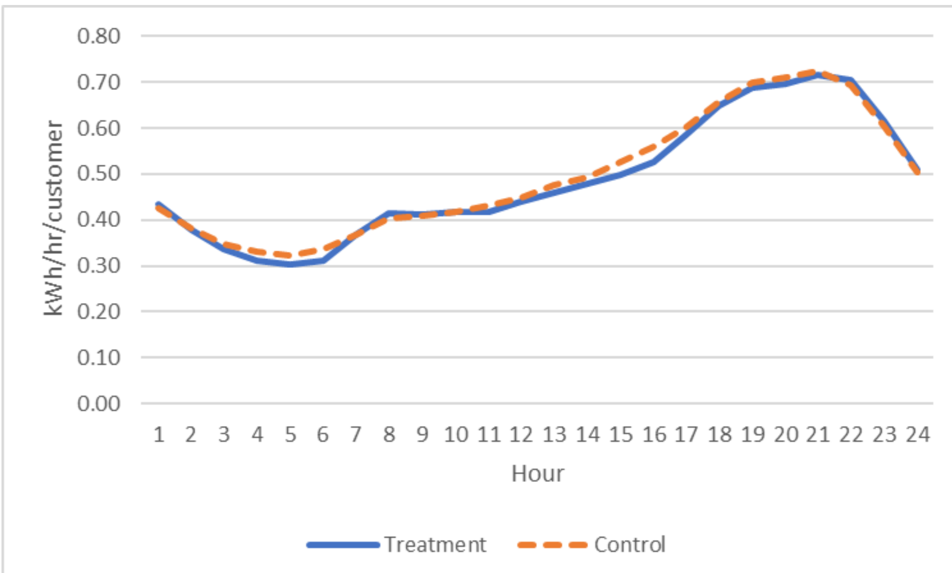


Figure M.2: E-TOU-A Winter Match Quality

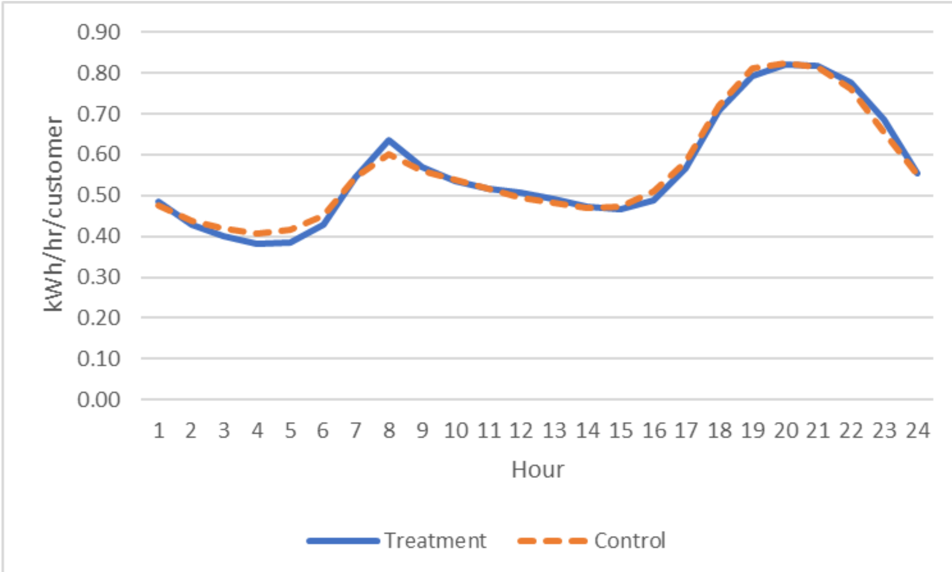


Figure M.3: E-TOU-B Summer Match Quality

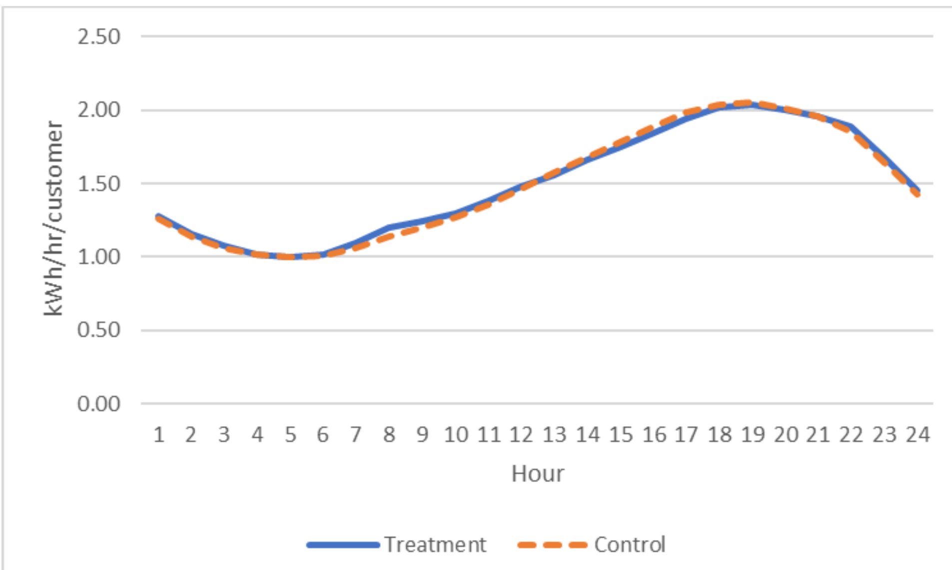


Figure M.4: E-TOU-B Winter Match Quality

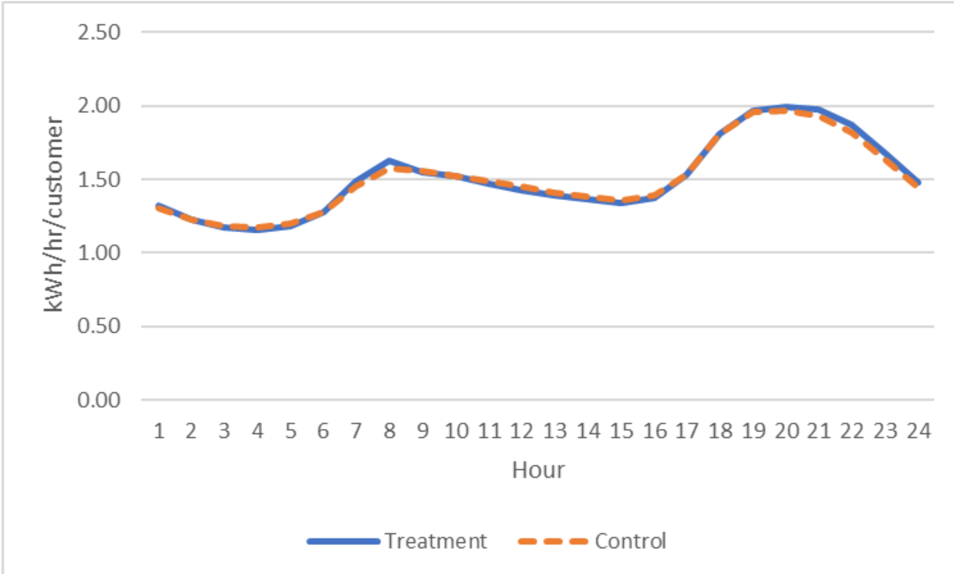


Figure M.5: E-TOU-C Summer Match Quality

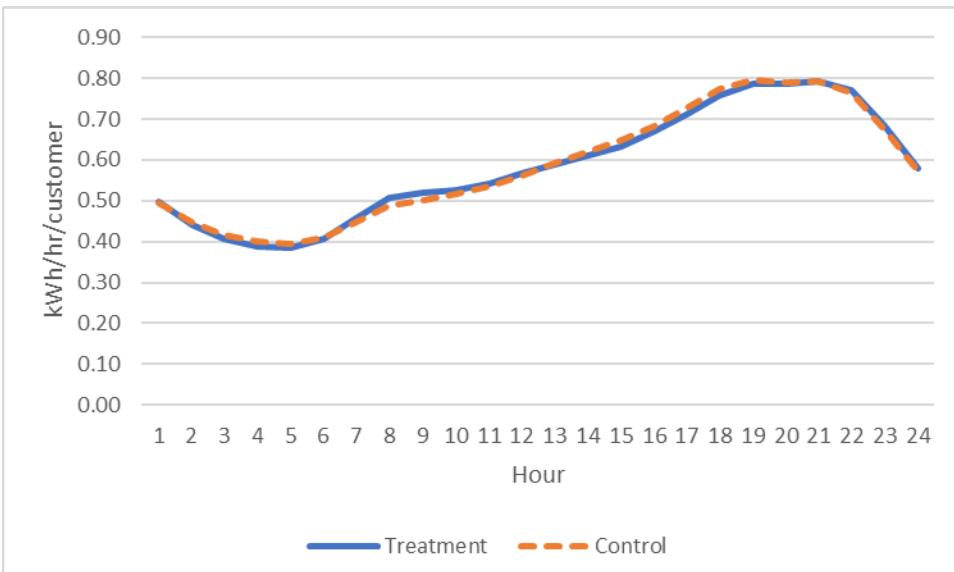


Figure M.6: E-TOU-C Winter Match Quality

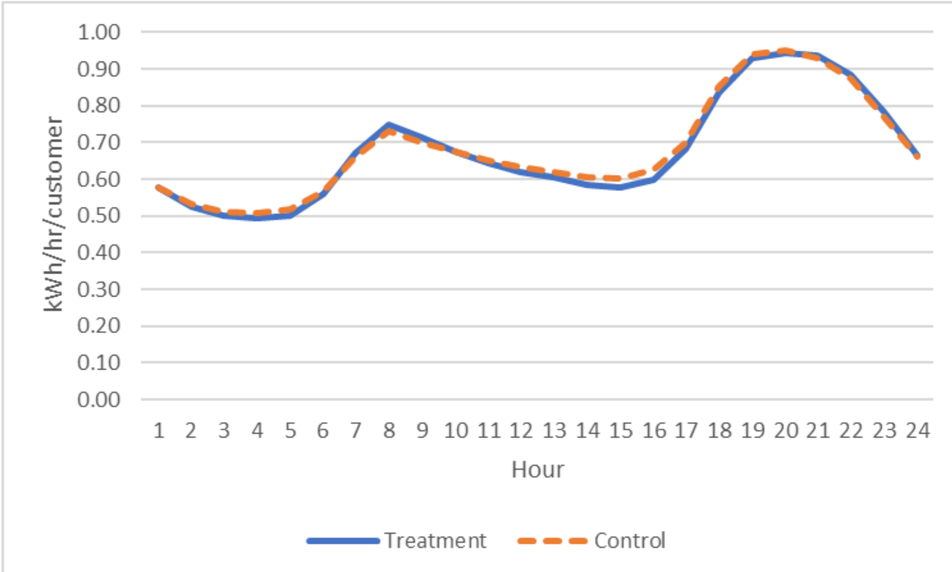


Figure M.7: E-TOU-D Summer Match Quality

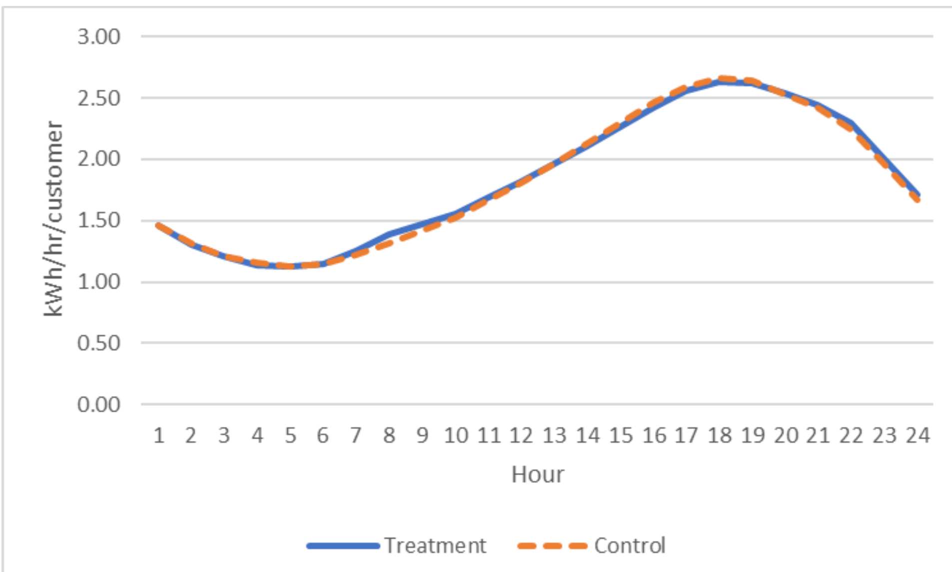


Figure M.8: E-TOU-B NEM Summer Quality

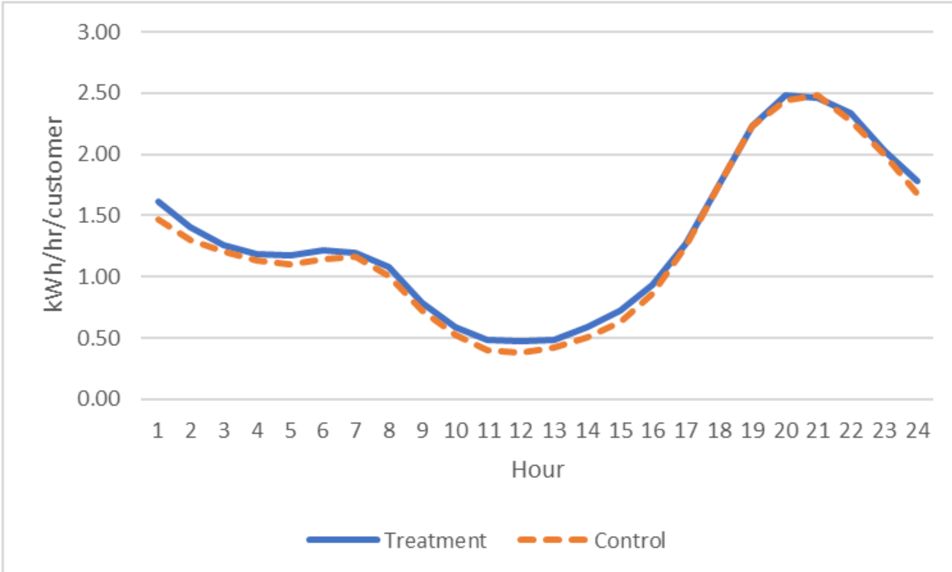


Figure M.9: E-TOU-B NEM Winter Match Quality

[redacted]

Figure M.10: E-TOU-C NEM Summer Match Quality

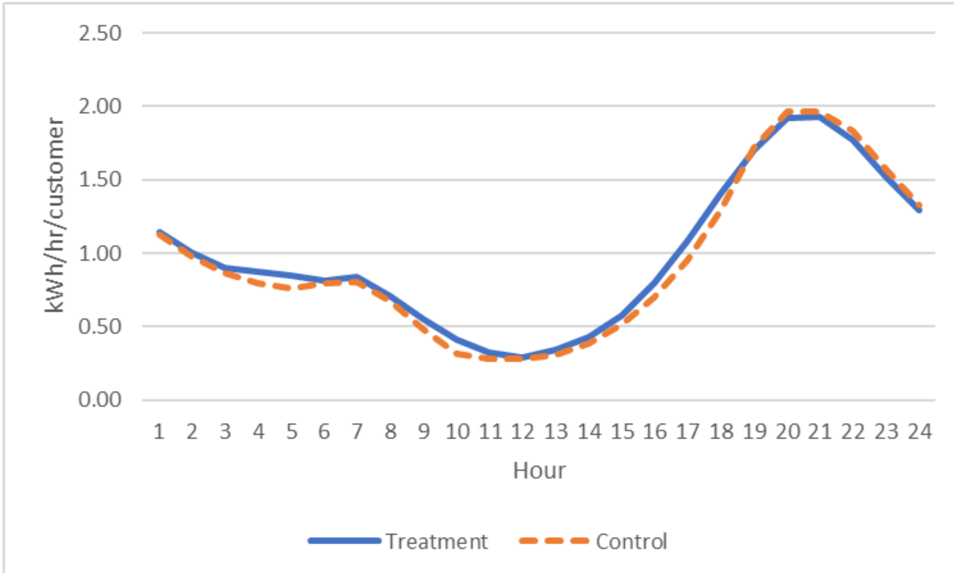


Figure M.11: E-TOU-C NEM Winter Match Quality

Tables M.1 and M.2 the MPE and MAPE values calculated across all 24 hours and the RA window (4 to 9 p.m.) of the load profiles shown in the figures above. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy. Table M.2 shows the non-NEM customers while Table M.2 shows the NEM customers.

Table M.1: MPE and MAPE for the Withheld Profile, Non-NEM Analyses

Season	Rate	All Hours		RA Window	
		MPE	MAPE	MPE	MAPE
Summer	E-TOU-A	2.0%	2.9%	1.7%	1.7%
	E-TOU-B	-0.7%	1.6%	0.9%	0.9%
	E-TOU-C	0.2%	1.6%	1.2%	1.2%
	E-TOU-D	-0.6%	1.4%	0.3%	0.9%
Winter	E-TOU-A	0.8%	2.7%	1.4%	1.5%
	E-TOU-B	-0.2%	1.2%	-0.7%	0.9%
	E-TOU-C	1.2%	2.0%	1.3%	1.6%

Table M.2: MPE and MAPE for the Withheld Profile, NEM Analyses

Season	Rate	All Hours		RA Window	
		MPE	MAPE	MPE	MAPE
Summer	E-TOU-B	-6.7%	6.8%	-0.5%	0.9%
	E-TOU-C	-5.7%	7.0%	-2.8%	5.0%
Winter	E-TOU-B	[redacted]	[redacted]	[redacted]	[redacted]
	E-TOU-C	[redacted]	[redacted]	[redacted]	[redacted]

Appendix N. Regression Sample Sizes

This appendix presents the number of treatment customers represented in the *ex-post* impacts presented in Section 4. The number of customers in the models is typically quite a bit lower than the number of enrolled customers the model represents due to restrictions we apply to ensure a valid load impact estimate.

Table N.1: Sample Sizes for Peak-period Load Impacts by Rate and Season

Rate	NEM	# SAIDs in February Model	# SAIDs in August Model
E-TOU-A	No	587	443
E-TOU-B	No	2,149	3,713
E-TOU-C	No	1,933	4,896
E-TOU-D	No	n/a	1,824
EV2-A	No	233	485
E-TOU-B	Yes	92	171
E-TOU-C	Yes	36	114

Table N.2: Sample Sizes for Peak-period Load Impacts by Rate and Climate Region

Rate	Climate	# SAIDs in the Model
E-TOU-A	Cool	156
	Moderate	237
	Hot	50
E-TOU-B	Cool	1,248
	Moderate	1,704
	Hot	762
E-TOU-C	Cool	1,729
	Moderate	2,574
	Hot	593
E-TOU-D	Cool	462
	Moderate	902
	Hot	460

Table N.3: Sample Sizes for Peak-period Load Impacts by Rate and CARE Status

Rate	CARE	# SAIDs in the Model
E-TOU-A	No	290
	Always / Sometimes	153
E-TOU-B	No	2,524
	Always / Sometimes	1,189
E-TOU-C	No	3,614
	Always / Sometimes	1,282
E-TOU-D	No	1,453
	Always / Sometimes	371

Table N.4: Sample Sizes for Peak-period Load Impacts by Rate and Benefiter Status

Rate	Benefiter	# SAIDs in the Model
E-TOU-A	No	143
	Yes	280
E-TOU-B	No	200
	Yes	3,442
E-TOU-C	No	761
	Yes	3,945
E-TOU-D	No	72
	Yes	1,229