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CHRISTENSEN ASSOCIATES ENERGY CONSULTING

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

Ex-Post and *Ex-Ante* Report

CALMAC Study ID PGE0459

Daniel G. Hansen

David A. Armstrong

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Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299

Voice 608.231.2266 Fax 608.231.2108

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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") non-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.

Decision 18-08-013 adopted new TOU periods and season definitions for all non-residential customer classes. The season definition is changing from May through October to June through September; and the peak period is changing from noon to 6:00 p.m. to 4:00 to 9:00 p.m. for commercial and industrial (C&I) customers and to 5:00 to 8:00 p.m. for agricultural customers.

ES.1 Resources Covered

The C&I rates A-1, A-6, A-10, E-19, and E-20 will be phased out and replaced by rates B-1, B-6, B-10, B-19, and B-20. Similarly, the agricultural rates AG-1A, AG-1B, AG-4A, AG-4B, AG-4C, AG-5A, AG-5B, AG-5C, AG-VA, AG-VB, AG-RA, AG-RB will be phased out and replaced by AG-A1, AG-A2, AG-B, AG-C, AG-FA, AG-FB, and AG-FC. The new rates became available on a voluntary basis in November 2019 (C&I) and March 2020 (Ag). Customer transitions to the new rates will begin in March 2021, with November (C&I) and March (Ag) transitions occurring annually.

Because this is the first year of the evaluation, relatively few customers are on the new TOU rates (*e.g.*, Schedule B-1). Therefore, our first task was to obtain billing data that allowed us to tabulate the number of customers associated with each potential rate transition (*e.g.*, from Schedules A-6 to B-6). Specifically, we requested billing data for the entire program year (September 2019 through October 2020) and the "pre-treatment" year (September 2018 through October 2019). After restricting the sample to customers enrolled during the entire timeframe, we tabulated rate changes by month including the "from" rate and the "to" rate (*e.g.*, from Schedule A-1 to B-1). We focused on customers who were on a legacy TOU rate for the entire sample timeframe until they switched to a new TOU rate sometime during the program year.

The following transitions are included, with the size group in parentheses[1]:

- A-1 to B-6 (under 20kW)
- A-1 TOU to B-1 (under 20kW)
- A-1 TOU to B-6 (under 20kW)
- A-10 TOU to B-10 (20 to 200kW)
- A-6 to B-6 (under 20kW)
- E-19 to B-19 (200kW and over)
- E-20 to B-20 (200kW and over)

[1] Other size groups may have been present for a given rate transition, but we focus on the one with the highest number of customers.

- AG-4A to AG-A1 (under 20kW)
- AG-4A to AG-A2 (under 20kW)
- AG-4B to AG-B (20 to 200kW)
- AG-5A to AG-A2 (under 20kW)
- AG-5B to AG-C (20 to 200kW)

In this evaluation, the *ex-post* load impact estimates are not expected to be representative of the *ex-ante* load impacts, for two reasons. First, the enrolled customers in the *ex-post* study opted into the new TOU rates, perhaps based on rate comparison information provided by PG&E. Therefore, the observed populations are likely to have a self-selection issue we don't expect from widespread defaulting of customers onto the new TOU rates. Second, the low observed enrollment levels raise additional questions about whether the small observed sample sizes are representative of the coming default scenario. Because of these issues we determined that the best basis for this year's forecast is a simulation of TOU load impacts, informed by prior studies.

We limited the *ex-ante* impacts to the rates with the most expected customers in the large size category: Schedules B-10, B-19, B-20, and AG-C. Because our reference loads are developed from control group data prior to their new TOU rate selection (preventing us from observing actual choices of new TOU rates by customers on the various legacy TOU rates), we focus on the following rate transitions:

- A-10 TOU to B-10
- E-19 to B-19
- E-20 to B-20
- AG-5B and AG-5C to AG-C

ES.2 Evaluation Methodologies

The *ex-post* evaluation involved selecting quasi-experimental matched control groups and conducting difference-in-differences estimation using regression analysis. 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 new 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.

To develop the per-customer reference loads, we estimate regression equations from historical data and use the resulting coefficients and *ex-ante* weather conditions (provided by PG&E) to simulate reference loads for the scenarios required by the Protocols. The models use hourly load data from the pre-treatment period averaged across "cells" (*e.g.*, for the average customer in each TOU rate). These were combined with estimates of the hourly COVID effect on load, scaled to match PG&E's expected trajectory of COVID load effects during the forecast period.

The second component, the hourly load impacts, are simulated using the reference loads, tariff rates, and an assumed elasticity of demand. The tariff prices are first converted to an effective energy charge (EECs), which has two elements. The first element is simply the tariff's energy rates. The second element is a conversion of the tariff's demand rates into an energy rate, which is accomplished by dividing the demand rate by the number of hours in the month to which it applies. Loads on the new TOU rate are simulated by applying the assumed elasticity to the change in EECs on an hourly basis. The load impact is the difference between the simulated loads on the new and legacy TOU rates.

ES.3 Ex-Post Load Impacts

Tables ES.1 and ES.2 show the estimated summer peak-period load impacts for the C&I and Agricultural customers, respectively. The confidence intervals around the estimated load impacts tend to be wide and only one result is right signed (indicating a usage reduction during the Peak period) that is statistically significantly different from zero.

Table ES.1: C&I Total Summer Peak-Period Load Impacts

Rate Change	Size Group	Enrolled	Reference Load (MWh/hr)	Impact (MWh/hr)	% Impact (80% CI)	Temperature °F
A-1 to B-6	Under 20kW	484	0.53	0.00	-0.5% [-6.4 – 4.9%]	78.0
A-1 TOU to B-1	Under 20kW	256	0.44	0.01	2.2% [-6.7 – 9.7%]	83.0
A-1 TOU to B-6	Under 20kW	6,793	7.58	-0.10	-1.3% [-2.4 – -0.1%]	81.1
A-6 to B-6	Under 20kW	264	0.77	-0.03	-3.8% [-10.4 – 2.0%]	81.6
A-10 TOU to B-10	20 to 200kW	709	21.9	0.11	0.5% [-2.1 – 3.0%]	86.2
E-19 to B-19	Over 200kW	108	22.8	0.46	2.0% [-3.2 – 6.8%]	79.3
E-20 to B-20	Over 200kW	32	[redacted]			[redacted]

Table ES.2: Agricultural Total Summer Peak-Period Load Impacts

Rate Change	Size Group	Enrolled	Reference Load (MWh/hr)	Impact (MWh/hr)	% Impact (80% CI)	Temperature °F
AG-4A to AG-A1	Under 20kW	222	0.23	0.03	12.8% [-13.5 – 29.2%]	93.9
AG-4A to AG-A2	Under 20kW	192	0.49	0.04	7.5% [-1.7 – 15.2%]	90.7
AG-4B to AG-B	20 to 200kW	168	2.23	0.12	5.3% [-4.0 – 13.1%]	89.6
AG-5A to AG-A2	Under 20kW	115	0.54	-0.04	-6.9% [-13.5 – -1.0%]	90.6
AG-5B to AG-C	20 to 200kW	199	7.4	0.04	0.6% [-6.5 – 6.8%]	95.8

ES.4 Ex-Ante Load Impacts

The *ex-ante* load impacts were forecast for only the large (over 200kW) customers. Figure ES.1 summarizes the average RA-window (4:00 to 9:00 p.m.) impact for each month of 2021, by rate. The values reflect PG&E 1-in-2 peak day weather conditions. A few things to note:

- There are no impacts in January and February because new enrollments begin in March 2021.
- The bulk of the load impacts are provided by the B-19 and B-20 customers.
- May and October load impacts represent a load *increase* relative to usage on the legacy TOU rate. This is largely due to the change in the summer definition from May through October to June through September. The two months that changed from summer to winter (May and October) have significantly lower effective energy charges during the RA window, due to differences in both the energy and demand rates.

Figure ES.1: 2021 Monthly Average RA Window Load Impacts

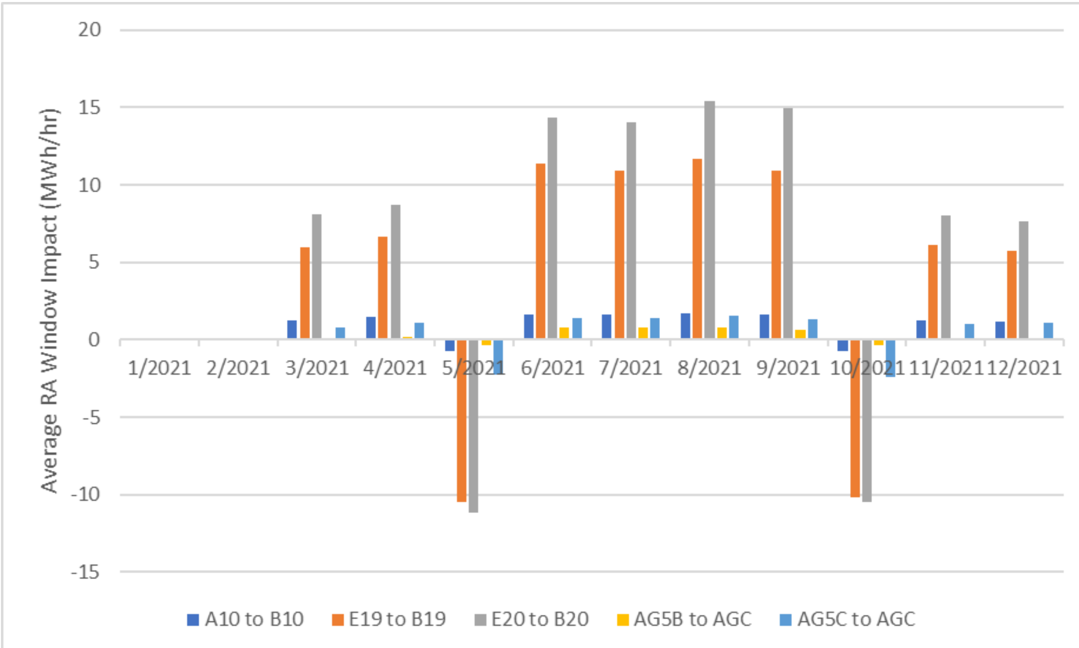
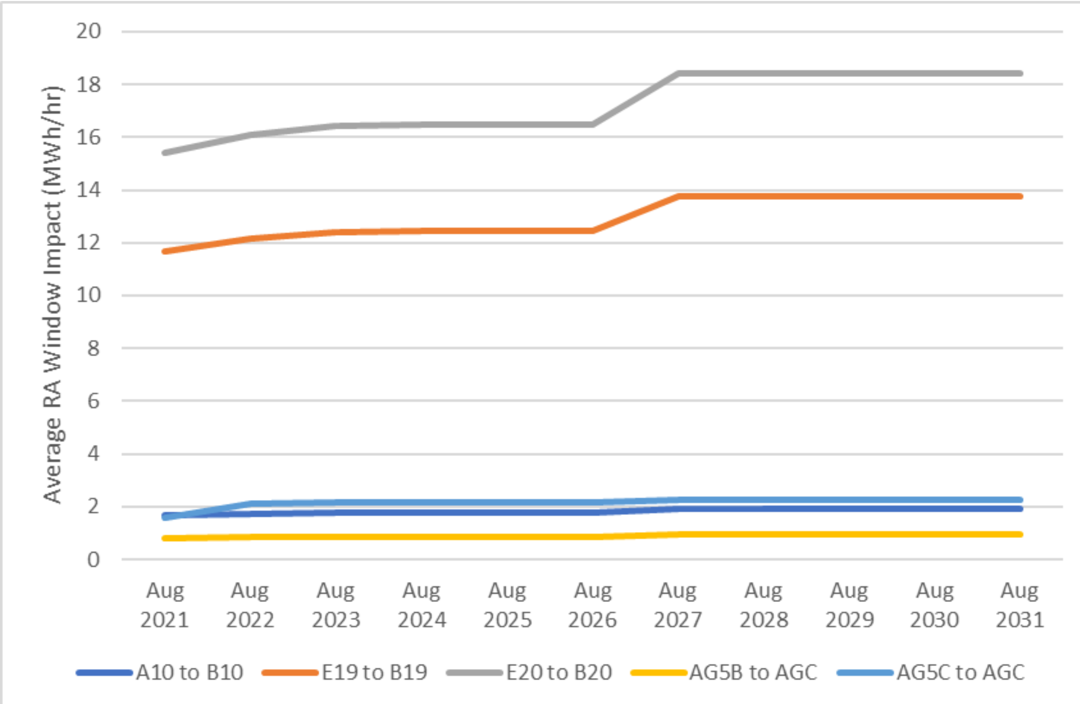


Figure ES.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the RA window for the PG&E 1-in-2 weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern.

Figure ES.2: August Average RA Window Load Impacts by Year



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") non-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.

Decision 18-08-013 adopted new TOU periods and season definitions for all non-residential customer classes. The season definition is changing from May through October to June through September; and the peak period is changing from noon to 6:00 p.m. to 4:00 to 9:00 p.m. for commercial and industrial (C&I) customers and to 5:00 to 8:00 p.m. for agricultural customers.

Thus, the C&I rates A-1, A-6, A-10, E-19, and E-20 will be phased out and replaced by rates B-1, B-6, B-10, B-19, and B-20. Similarly, the agricultural rates AG-1A, AG-1B, AG-4A, AG-4B, AG-4C, AG-5A, AG-5B, AG-5C, AG-VA, AG-VB, AG-RA, AG-RB will be phased out and replaced by AG-A1, AG-A2, AG-B, AG-C, AG-FA, AG-FB, and AG-FC. The new rates became available on a voluntary basis in November 2019 (C&I) and March 2020 (Ag). Customer transitions to the new rates will begin in March 2021, with November (C&I) and March (Ag) transitions occurring annually.

The primary goals of the evaluation are the following:

1. Estimate *ex-post* load impacts for each rate for the 2020 program year;
2. Develop *ex-ante* load impact forecasts for the rates for the eleven years following the program year (*e.g.*, 2021 through 2031); and
3. Account for the effect of COVID-19 on *ex-post* and *ex-ante* load impacts.

A key difference between this evaluation and most other TOU evaluations is that it seeks to estimate a *change* in a TOU load impact rather than a *total* TOU load impact relative to a non-TOU rate. This does not present a novel methodological challenge; it simply alters the "base" rate used in the analysis.

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. Section 5 contains the *ex-ante* load impact forecasts. Section 6 provides a series of comparisons of *ex-post* and *ex-ante* results.

2. Description of Time-of-Use Rates

The C&I rate schedules are largely differentiated by customer demand levels. Schedules B-1 and B-6 are non-demand rates applicable to customers with demand under 75 kW. Schedule B-6 differs from Schedule B-1 by removing the Summer Partial-Peak pricing period and increasing the Summer Peak to Off-Peak price ratio. The demand-based rates are applicable to the following demand ranges:

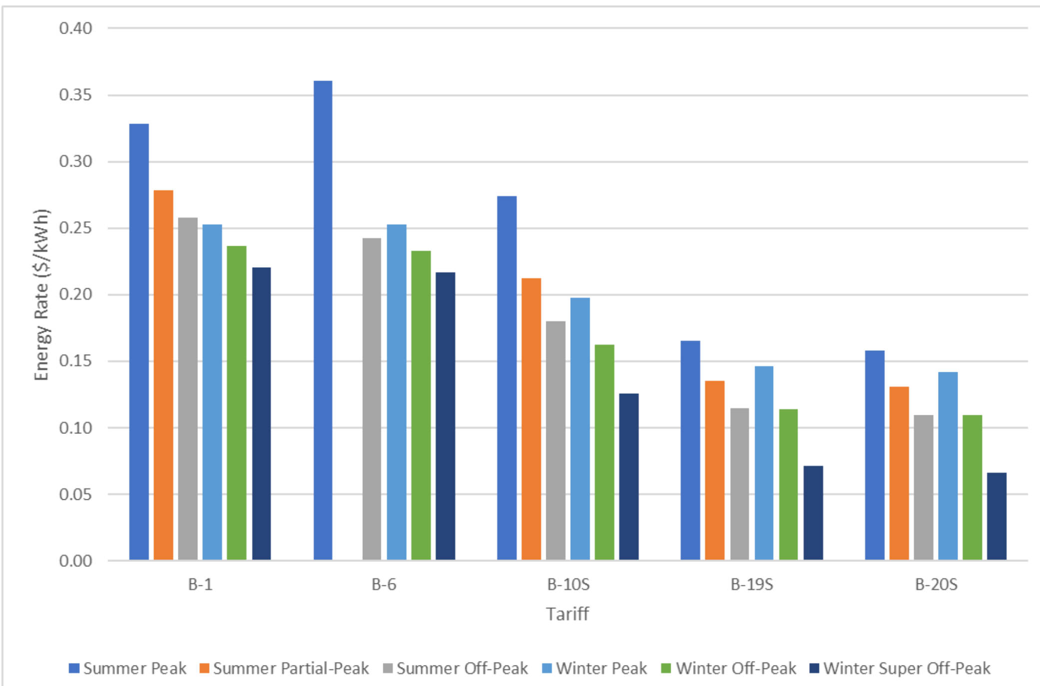
- Schedule B-10 = 75 to 499 kW;

- Schedule B-19 = 500 to 999 kW; and
- Schedule B-20 = over 999 kW.

All schedules except B-1 differentiate rates by service level (Secondary, Primary, and Transmission). For all C&I schedules, the Peak period is from 4 to 9 p.m. on all days. All but Schedule B-6 have a Partial-Peak period from 2 to 4 p.m. and 9 to 11 p.m. on all summer days. In March, April, and May there is a Super Off-Peak period from 9 a.m. to 2 p.m. The Off-Peak period covers all other hours.

Figure 2.1 illustrates the energy rates by pricing period and tariff. Note that Schedules B-19 and B-20 have demand charges that apply only to Peak-period demand, thus increasing the effective rate during those hours.

Figure 2.1: Energy Rates by Tariff and Pricing Period, C&I Rates



The agricultural rates are differentiated by customer demand levels, load factors[2], and desire for flexibility in selecting off-peak days.

- Schedule AG-A1 is targeted to low load factor customers with demand less than 35 kW.
- Schedule AG-A2 is targeted to high load factor customers with demand less than 35 kW.[3]

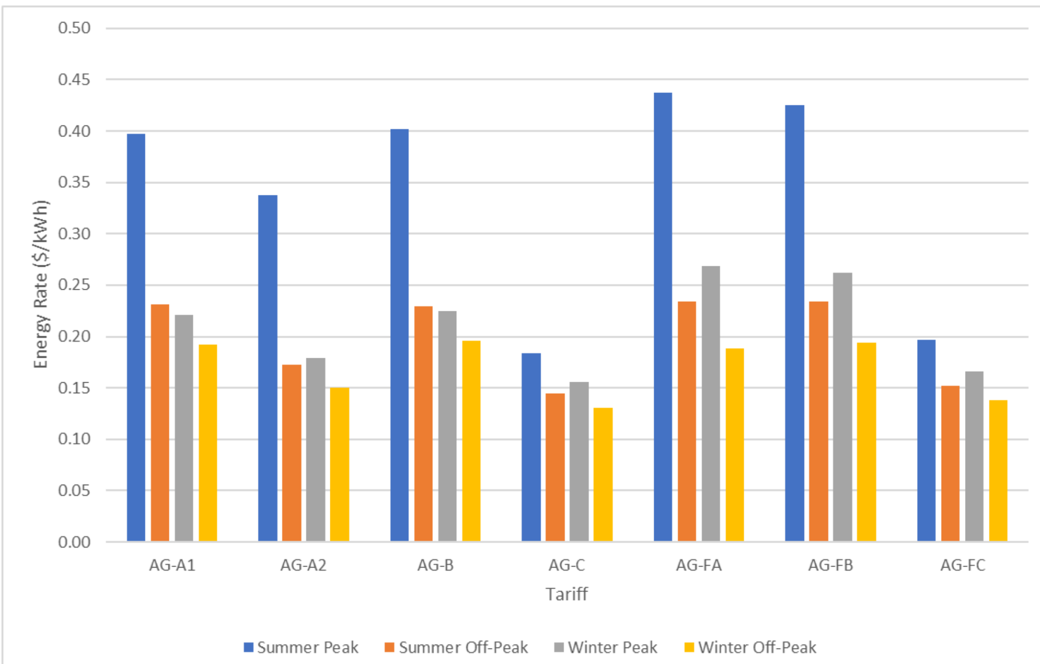
[2] Load factor is defined as the customer's average hourly usage divided by its maximum demand over a period of time (*e.g.*, a billing month or year). Values approaching zero reflect customers with high peak demand relative to their typical hourly usage, whereas values approaching one reflect customers with loads that are constant across hours.

[3] The increased appeal to high load factor customers is due to the higher demand and lower energy rates vs. AG-A1.

- Schedule AG-B is targeted to medium load factor customers with demand over 35 kW.
- Schedule AG-C is targeted to high load factor customers with demand over 35 kW.
- Schedules AG-FA, AG-FB, and AG-FC allow customers to choose two off days per week: Wednesday+Thursday, Saturday+Sunday, or Monday+Friday.
- Schedule AG-FA is targeted to customers with demand less than 35 kW.
- Schedules AG-FB and AG-FC are targeted to customers with demand over 35 kW with low and high load factors (respectively).

Figure 2.2 illustrates the energy rates by pricing period and tariff. Note that Schedules AG-C and AG-FC have demand charges that apply only to the summer Peak-period demand, thus increasing the effective rate during those hours.

Figure 2.2: Energy Rates by Tariff and Pricing Period, Ag Rates



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

In this section, we discuss the methods used to estimate the *ex-post* load impacts for PG&E's non-residential TOU rates.

Determining the Analyses to be Conducted

Because this is the first year of the evaluation, relatively few customers are on the new TOU rates (*e.g.*, Schedule B-1). Therefore, our first task was to obtain billing data that allowed us to tabulate the number of customers associated with each potential rate transition (*e.g.*, from Schedules A-6 to B-6). Specifically, we requested billing data for the entire program year (September 2019 through October 2020) and the "pre-treatment" year (September 2018 through October 2019). After restricting the sample to customers enrolled during the entire timeframe, we tabulated rate changes by month including the "from" rate and the "to" rate (*e.g.*, from Schedule A-1 to B-1). We focused on customers who were on a legacy TOU rate for the entire sample timeframe until they switched to a new TOU rate sometime during the program year. We also developed pools of eligible control-group customers consisting of customers who were continuously enrolled in the legacy TOU rate of interest during the entire sample timeframe.

We conducted *ex-post* regression analyses for TOU rate transitions that had sufficiently large sample sizes. While we considered combining some rate schedules to increase sample sizes, we concluded that it would not improve the analysis because of differences between the customers in the rate schedules considered. For example, the AG-B customers in our analysis sample had typical demands less than half that of the AG-C customers.

Where *ex-post* load impacts can be estimated, the objective is to report load impacts as follows[4]:

- For the monthly system peak day and average weekday for each month of the calendar year;
- By Local Capacity Area (LCA);
- By industry group; and
- By size group.

Regarding reporting by size group, the nature of the rate schedules already segments customers across size groups (under 20 kW, 20 to 200 kW, and over 200 kW) to some extent. For example, Schedule B-20 consists almost entirely of customers in the over 200 kW size group. In our final *ex-post* models, we estimated load impacts for only the rate schedule / size group combinations with the highest sample sizes. In addition, we found that sample sizes were too small to reliably estimate load impacts across industry groups or LCAs. Therefore, load impact estimates are only reported for all customers within a rate schedule / size group. Finally, in a further effort to improve the load impact estimates in the face of small sample sizes, we estimated season-specific rather than month-specific load impacts. Our Excel-based Protocol table generator still reports

[4] Confidence intervals around the load impact estimates are established for each hour as well as the average peak-period hour.

monthly load impacts, associating the seasonal load impact to each month's reference and observed loads.

Statistical Estimates of Load Impacts

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 previous TOU 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 are estimated using customers who enrolled in a new TOU rate (*e.g.*, Schedule B-1) on or after October 1, 2019 from a legacy TOU rate (*e.g.*, Schedule A-1). Each rate is separately analyzed and include only customers who transitioned from a legacy TOU rate.

Control Group Selection

For the customers newly enrolled in one of the new TOU rates, the control group selection approach involves matching the new TOU rate adopters to customers who remain on a legacy TOU rate 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 (*e.g.*, October 2018 through September 2019) for the TOU and potential control group customers. During this time period, all customers are served on the legacy TOU rate, thus excluding treatment effects of the TOU rate from the matching process. We then apply propensity score matching using pre-treatment monthly billing data summary variables and customer characteristics (*e.g.*, rate schedule, industry group, size category, and weather station) to reduce the large number of available legacy TOU rate customers to a reduced set of preliminary matches for each new TOU rate customer.[5]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles,[6] for all new TOU rate customers and the preliminary matched legacy TOU rate customers. We apply Euclidean distance minimization to load profiles for the

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

[6] 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. A separate typical-day profile was also developed to validate the matches using out-of-sample data.

pre-enrollment period and select control group matches (with replacement) for each new TOU rate customer. In addition to the matching on seasonal profiles, the matching process is conducted by LCA, ensuring perfect matches by that characteristic. Separate matches are selected by season. Treatment customers were excluded from the analysis if the load profiles of their matched control customer were more than 30 percent higher or lower based on average daily usage. The matches were reviewed for each profile, including the excluded typical-day profile. We assessed the mean percentage error (MPE) and mean absolute percentage error (MAPE) across the 24 hours of each profile.

At the conclusion of the matching process, we requested hourly load data for the full analysis period for the new TOU rate customers and selected legacy TOU rate control group customers to be used in the *ex-post* load impact analysis.

Load Impact Estimation

The presence of matched control group customers means that the estimation equations for the incremental *ex-post* evaluation are 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 were estimated by rate schedule, season, and hour, where the customer-level fixed-effects models are of the following form:[7]

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

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

[7] Note that the customer and date fixed effects preclude the need to include stand-alone $NewTOU_c$ 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.

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
$NewTOU_c$	Variable indicating whether customer *c* is a treatment (1) or control group (0) customer
$Post_d$	Variable indicating that day *d* is in the post-enrollment period, when the treatment customer is enrolled in the new TOU rate
$Mean17_{c,d}$	Average temperature during the first 17 hours of day *d* at the weather station associated with customer *c*
α	Estimated constant coefficient
β_{NEWTOU}	Estimate of the change in the TOU load impact from legacy to new TOU rate
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

The hour-specific confidence intervals around the estimated load impacts are directly estimated in our models, with the period-wide confidence intervals separately estimated using period-specific models (rather than hour-specific models).

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. In this study we will examine the effect of COVID-19 on non-residential loads and (potentially) load impacts, though this will be implemented as part of the *ex-ante* study. An analysis of the effect on overall loads is fairly straightforward, comparing pre- and post-pandemic loads controlling for weather. An analysis of the effect of the pandemic on TOU *load impacts* is complicated by the recent introduction of the rates and the small sample sizes. That is, we do not have pre-COVID load impacts for month-to-month comparisons (*e.g.*, April 2019 vs. April 2020) because the new rate schedules were not in effect during those months of 2019. The small sample sizes, which led us to pool seasonal estimates, further reduces our ability to identify the effect of COVID on load impacts. That is, a pre- vs. post-COVID impact comparison largely overlaps with a winter vs. summer load impact comparison and seasonal differences are expected in the absence of a pandemic (*e.g.*, due to rate, weather, and behavioral differences across seasons).

3.2 Forecasting Ex-Ante Load Impacts

3.2.1 Objectives

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

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

3.2.2 *Ex-ante* evaluation approach

In this evaluation, the *ex-post* load impact estimates are not expected to be representative of the *ex-ante* load impacts, for two reasons. First, the enrolled customers in the *ex-post* study opted into the new TOU rates, perhaps based on rate comparison information provided by PG&E. Therefore, the observed populations are likely to have a self-selection issue we don't expect from widespread defaulting of customers onto the new TOU rates. Second, the low observed enrollment levels raise additional questions about whether the small observed sample sizes are representative of the coming default scenario.

Because of these issues we determined that the best basis for this year's forecast is a simulation of TOU load impacts, informed by prior studies. From the 2014 through 2016 program years, we conducted evaluations of the TOU load impacts associated with small business, medium business, and agricultural customers being transitioned to mandatory TOU rates.[8] These studies tended to find load reductions across all pricing periods (*i.e.*, akin to conservation) rather than a shift of usage from Peak to Off-Peak pricing periods. In addition, recent Statewide Critical Peak Pricing evaluations have found very low load impacts for small and medium sized customers.[9] Based on this evidence, we determined that a reasonable and conservative estimate of the change in TOU impacts for the small- and medium-sized non-residential customers is zero, and we did not undertake further effort to simulate their load impacts.

There is some evidence that large customers have higher demand response, in part from the CPP study referenced above. The assumptions used in this study are consistent with those of a high-level study of the potential load impacts from offering new time-of-use (TOU) rates for residential and non-residential customers requested by the Energy

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[8] For example, the PY2015 study: "2015 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report", CALMAC Study ID PGE0373.

[9] "Load Impact Evaluation of Non-Residential Critical Peak and Peak Day Pricing" by Applied Energy Group, as presented at the 2020 DRMEC Load Impact Workshop, May 1, 2020.

Division.[10] The remainder of this section describes how we developed the *ex-ante* forecast for the large C&I and agricultural customers.

As described above, the *ex-ante* forecast contains a range of day types and weather scenarios. For each of these, three components are required to complete the forecast:

- Per-customer reference loads associated with each customer type (*e.g.*, Schedule B-19 customers in the Greater Bay Area);
- Hourly load impacts associated with each reference load profile; and
- Enrollment forecasts that scale the per-customer forecasts to represent the total rate-level forecast.

To develop the per-customer reference loads, we estimate regression equations from historical data and use the resulting coefficients and *ex-ante* weather conditions (provided by PG&E) to simulate reference loads for the scenarios required by the Protocols. The models use hourly load data from the pre-treatment period averaged across "cells" (*e.g.*, for the average customer in each TOU rate).

Separate models are estimated by customer group (defined by rate and LCA) and season (summer and winter). The reference load regression model specification is the following:

$$Q_{i,t} = a + \sum_{i=2}^{24}\left(b_i^{Mean17} \times h_{i,t} \times Mean17_t\right) + \sum_{i=2}^{24}\left(b_i^{MON} \times h_{i,t} \times MON_t\right) + \sum_{i=2}^{24}\left(b_i^{FRI} \times h_{i,t} \times FRI_t\right) + \sum_{i=2}^{24} b_i^h \times h_{i,t} + \sum_{i=2}^{5} b_i^{DOW} \times DOW_{i,t} + \sum_{i=2}^{12} b_i^{MONTH} \times MONTH_{i,t} + e_{i,t}$$

The variables are explained in the table below.

Variable Name / Term	Variable / Term Description
$Q_{i,t}$	the group's average per-customer usage in hour *i* of day *t*
a and the various *b*'s	the estimated parameters
h_i	a dummy variable for hour *i*
$Mean17_t$	the average temperature during the first 17 hours of day *t*
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$DOW_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
$e_{i,t}$	the error term.

We separately estimated a similar model that used two years of data ending in September 2020 and included indicator variables for the dates likely affected by COVID (March 15, 2020 through September 2020). These hourly estimated COVID effects were

[10] "Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report", November 15, 2015.

used to adjust the reference loads accounting for PG&E's expected trajectory of COVID load effects during the forecast period.

The second component of the *ex-ante* forecast, the hourly load impacts, are simulated using the reference loads, tariff rates, and an assumed elasticity of demand. The tariff prices are first converted to an effective energy charge (EEC), which has two elements. The first element is simply the tariff's energy rates. The second element is a conversion of the tariff's demand rates into an energy rate, which is accomplished by dividing the demand rate by the number of hours in the month to which it applies. For example, an all-hours $10 per kW month demand charge would be converted to an EEC by dividing $10 by 730 hours (the average number of hours in a month), or approximately 1.4 cents per kWh. The addition of the EECs is particularly important for rate schedules that incorporate a Peak-period demand charge, as this charge effectively increases the cost of Peak-period usage in a manner similar to the corresponding energy rate.

We assume an own-price elasticity of demand of -0.04. This is consistent with the elasticity of substitution assumed in the aforementioned Statewide TOU study.[11] Each hour's load on the new TOU rate is simulated as follows:

$Q_{New} = \exp\{\ln(Q_{Old}) + \varepsilon_d \times \ln(P_{New} / P_{Old})\}$

where,

- Q_{New} = usage on the new TOU rate;
- Q_{Old} = usage on the legacy TOU rate;
- P_{New} = EEC on the new TOU rate;
- P_{Old} = EEC on the legacy TOU rate;
- ε_d = elasticity of demand;
- exp = the exponential function; and
- ln = the natural log function.

The load impact is the difference between the simulated loads on the new and legacy TOU rates (Q_{New} and Q_{Old}, respectively).

We limited the *ex-ante* impacts to the rates with the most expected customers in the large size category: Schedules B-10, B-19, B-20, and AG-C. Because our reference loads are developed from control group data prior to their new TOU rate selection (preventing

[11] We did not perform these simulations using an elasticity of substitution (as was done in the Statewide study) because of the high number of effective pricing periods. That is, the distinct pricing periods for simulation purposes are defined as all combinations of legacy and new TOU rate pricing periods (*e.g.*, Off-Peak to Off-Peak, Off-Peak to Part-Peak, Off-Peak to Peak, *etc*.). A model that formally models substitutions across a high number of periods is difficult to derive, so we instead apply an own-price elasticity to each hour's price change. It can be shown that an own-price elasticity is approximately equal to an elasticity of substitution over relatively small changes in prices.

us from observing actual choices of new TOU rates by customers on the various legacy TOU rates), we focus on the following rate transitions:

- A-10 TOU to B-10
- E-19 to B-19
- E-20 to B-20
- AG-5B and AG-5C to AG-C

To develop uncertainty-adjusted load impacts, we simply assume a 0.005 standard deviation around our assumed elasticity of demand. Scenario-specific percentage load impacts are then simulated for the 10th, 30th, 50th, 70th, and 90th percentile load changes using the resulting distribution of load impacts.

4. *Ex-Post* Load Impact Study Findings

This section reports *ex-post* peak load impact findings for the customers who voluntarily migrated from a legacy TOU rate to one of the new TOU rates. The following transitions are included, with the size group in parentheses[12]:

- A-1 to B-6 (under 20kW)
- A-1 TOU to B-1 (under 20kW)
- A-1 TOU to B-6 (under 20kW)
- A-10 TOU to B-10 (20 to 200kW)
- A-6 to B-6 (under 20kW)
- E-19 to B-19 (200kW and over)
- E-20 to B-20 (200kW and over)
- AG-4A to AG-A1 (under 20kW)
- AG-4A to AG-A2 (under 20kW)
- AG-4B to AG-B (20 to 200kW)
- AG-5A to AG-A2 (under 20kW)
- AG-5B to AG-C (20 to 200kW)

In the following sub-sections, we summarize the average Peak-period load impacts by rate and season and show the typical summer hourly load impact by rate.

4.1 Peak-period load impacts

Tables 4.1 through 4.3 summarize the average Peak-period load impacts by rate and season. These tables show per-customer load levels, which helps illustrate the differences in average customer sizes across rates. The tables also include the number of customers in the statistical models[13], which highlights the small sample sizes frequently encountered in the analysis. It is frequently the case that the estimated load

[12] Other size groups may have been present for a given rate transition, but we focus on the one with the highest number of customers.
[13] This is different from the number of enrolled customers, as not all customers have the load data required for inclusion in the statistical models.

impacts are not statistically significantly different from zero, in large part due to the small sample sizes.

Table 4.1 shows the estimated peak-period load impacts for the C&I customers during the winter months. Notice that the two most intuitively reasonable results are associated with the rates with the largest sample sizes: A-1 TOU to B-6 and A-10 TOU to B-10. In both cases, load reductions are estimated for the peak period, with the 80 percent confidence interval indicating statistical significance at that level.[14]

Table 4.1: C&I Customer Average Winter Peak-Period Load Impacts

Rate Change	Size Group	Customers Modeled	Reference Load (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact (80% CI)	Temperature °F
A-1 to B-6	Under 20kW	57	2.06	-0.02	-0.8% [-3.0 – 1.3%]	60.0
A-1 TOU to B-1	Under 20kW	95	1.41	-0.04	-2.5% [-12.6 – 5.9%]	61.5
A-1 TOU to B-6	Under 20kW	694	1.51	0.03	1.8% [1.0 – 2.5%]	61.7
A-6 to B-6	Under 20kW	88	2.32	-0.11	-4.7% [-11.1 – 0.9%]	60.9
A-10 TOU to B-10	20 to 200kW	269	27.5	1.08	3.9% [1.7 – 6.1%]	62.8
E-19 to B-19	Over 200kW	26	196.8	-2.91	-1.5% [-6.0 – 2.7%]	61.9
E-20 to B-20	Over 200kW	6	[redacted]	[redacted]	[redacted]	[redacted]

Table 4.2 shows the C&I estimates for the summer Peak period. Because summer occurs later in our program year, the number of treatment customers is higher than it was during the winter months. The confidence intervals still tend to be wide and only one result is right signed (indicating a usage reduction during the Peak period) that is statistically significantly different from zero. Even this result, for E-20 to B-20 customers,

[14] We show the 80 percent confidence interval to conform to the Protocol's use of 10th to 90th percentile uncertainty-adjusted load impacts. Economic studies typically employ a more stringent test of statistical significance (*e.g.*, 95 percent is common).

is suspect as we'll show when we graph hourly load impacts. The load impact estimate appears to be the result of omitted variable bias rather than TOU demand response.[15]

Table 4.2: C&I Customer Average Summer Peak-Period Load Impacts

Rate Change	Size Group	Customers Modeled	Reference Load (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact (80% CI)	Temperature °F
A-1 to B-6	Under 20kW	452	1.09	-0.01	-0.5% [-6.4 – 4.9%]	78.0
A-1 TOU to B-1	Under 20kW	217	1.72	0.04	2.2% [-6.7 – 9.7%]	83.0
A-1 TOU to B-6	Under 20kW	6,672	1.12	-0.01	-1.3% [-2.4 – -0.1%]	81.1
A-6 to B-6	Under 20kW	218	2.92	-0.11	-3.8% [-10.4 – 2.0%]	81.6
A-10 TOU to B-10	20 to 200kW	683	30.9	0.16	0.5% [-2.1 – 3.0%]	86.2
E-19 to B-19	Over 200kW	9	210.8	4.28	2.0% [-3.2 – 6.8%]	79.3
E-20 to B-20	Over 200kW	21	[redacted]	[redacted]	[redacted]	[redacted]

Table 4.3 shows summer Peak-period load impacts for the agricultural rates. (There were no significant winter enrollments to examine.) Notice the very wide confidence interval around the average percentage impacts, demonstrating that the estimates are not statistically significantly different from zero.

[15] Omitted variable bias occurs when a relevant explanatory variable is not present in the model. In these models, there is ample opportunity for this bias to occur, as we tend to know relatively little about each customer's production plans. Our model's ability to explain variations in usage is limited to weather and typical patterns by hour, day type, and month.

Table 4.3: Agricultural Customer Average Summer Peak-Period Load Impacts

Rate Change	Size Group	Customers Modeled	Reference Load (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact (80% CI)	Temperature °F
AG-4A to AG-A1	Under 20kW	91	1.03	0.13	12.8% [-13.5 – 29.2%]	93.9
AG-4A to AG-A2	Under 20kW	120	2.56	0.19	7.5% [-1.7 – 15.2%]	90.7
AG-4B to AG-B	20 to 200kW	90	13.27	0.70	5.3% [-4.0 – 13.1%]	89.6
AG-5A to AG-A2	Under 20kW	99	4.71	-0.32	-6.9% [-13.5 – -1.0%]	90.6
AG-5B to AG-C	20 to 200kW	171	37.0	0.21	0.6% [-6.5 – 6.8%]	95.8

Tables 4.4 and 4.5 re-state the results shown in Tables 4.2 and 4.3 (respectively) as aggregate results. In these tables, enrollments are shown and the reference loads and impacts are expressed in MWh/hr rather than kWh/hr/customer.

Table 4.4: C&I Total Summer Peak-Period Load Impacts

Rate Change	Size Group	Enrolled	Reference Load (MWh/hr)	Impact (MWh/hr)	% Impact (80% CI)	Temperature °F
A-1 to B-6	Under 20kW	484	0.53	0.00	-0.5% [-6.4 – 4.9%]	78.0
A-1 TOU to B-1	Under 20kW	256	0.44	0.01	2.2% [-6.7 – 9.7%]	83.0
A-1 TOU to B-6	Under 20kW	6,793	7.58	-0.10	-1.3% [-2.4 – -0.1%]	81.1
A-6 to B-6	Under 20kW	264	0.77	-0.03	-3.8% [-10.4 – 2.0%]	81.6
A-10 TOU to B-10	20 to 200kW	709	21.9	0.11	0.5% [-2.1 – 3.0%]	86.2
E-19 to B-19	Over 200kW	108	22.8	0.46	2.0% [-3.2 – 6.8%]	79.3
E-20 to B-20	Over 200kW	32	[redacted]			[redacted]

Table 4.5: Agricultural Total Summer Peak-Period Load Impacts

Rate Change	Size Group	Enrolled	Reference Load (MWh/hr)	Impact (MWh/hr)	% Impact (80% CI)	Temperature °F
AG-4A to AG-A1	Under 20kW	222	0.23	0.03	12.8% [-13.5 – 29.2%]	93.9
AG-4A to AG-A2	Under 20kW	192	0.49	0.04	7.5% [-1.7 – 15.2%]	90.7
AG-4B to AG-B	20 to 200kW	168	2.23	0.12	5.3% [-4.0 – 13.1%]	89.6
AG-5A to AG-A2	Under 20kW	115	0.54	-0.04	-6.9% [-13.5 – -1.0%]	90.6
AG-5B to AG-C	20 to 200kW	199	7.4	0.04	0.6% [-6.5 – 6.8%]	95.8

4.2 Hourly Loads and Load Impacts

This subsection illustrates the August 2020 average weekday hourly load and load impact profiles for each included rate comparison. Each figure highlights the Peak period in blue and includes the reference loads (solid blue line), observed loads (solid orange line), and load impacts (dashed green line). Small sample sizes tended to make the load impacts unreliable, as shown in the tables of Section 4.1.

Figure 4.1: August Average Weekday Hourly Impacts, A-1 to B-6

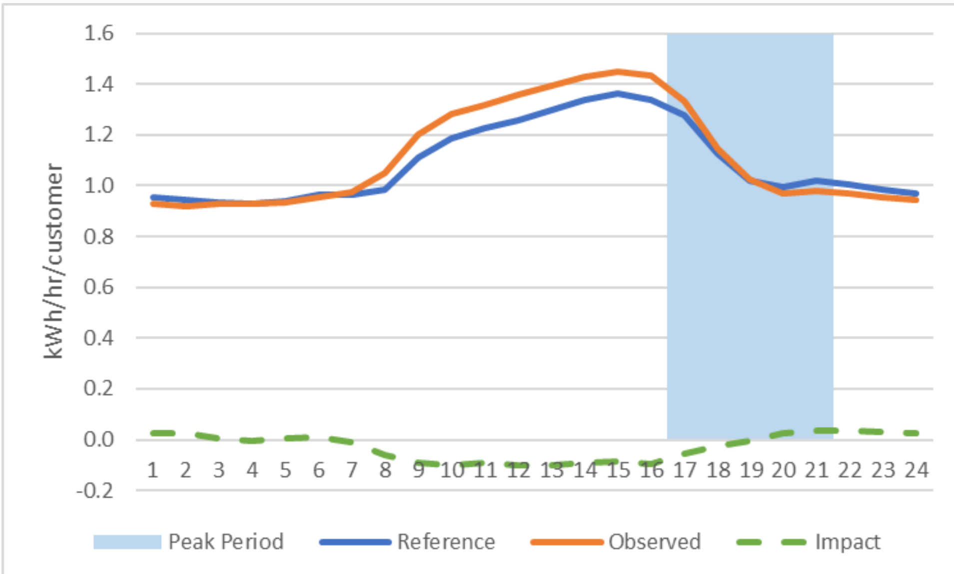


Figure 4.2: August Average Weekday Hourly Impacts, A-1 TOU to B-1

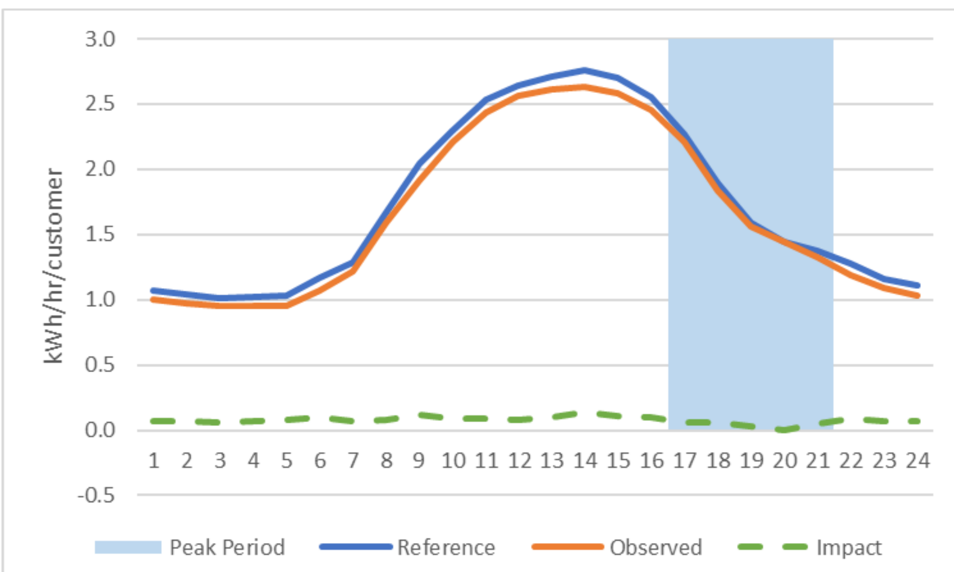


Figure 4.3: August Average Weekday Hourly Impacts, A-1 TOU to B-6

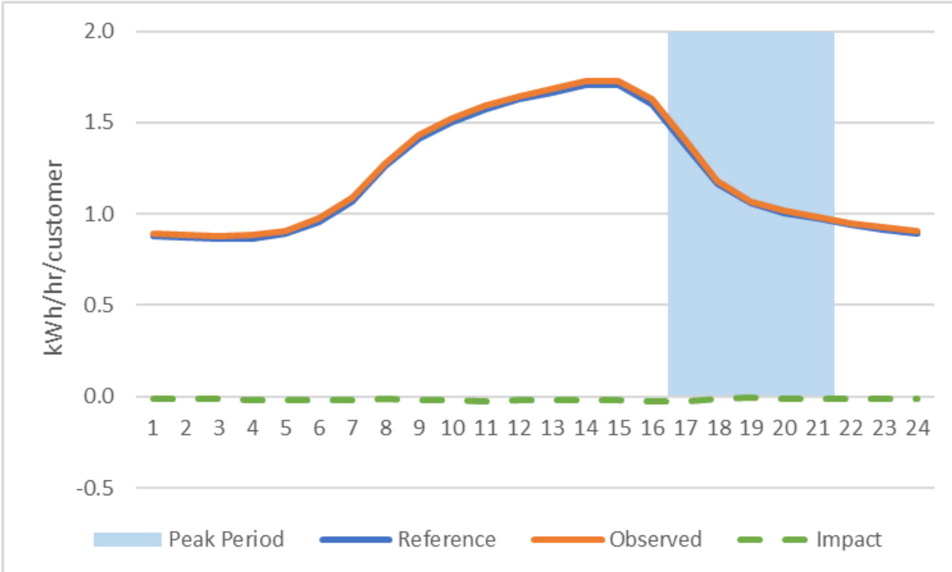


Figure 4.4: August Average Weekday Hourly Impacts, A-6 to B-6

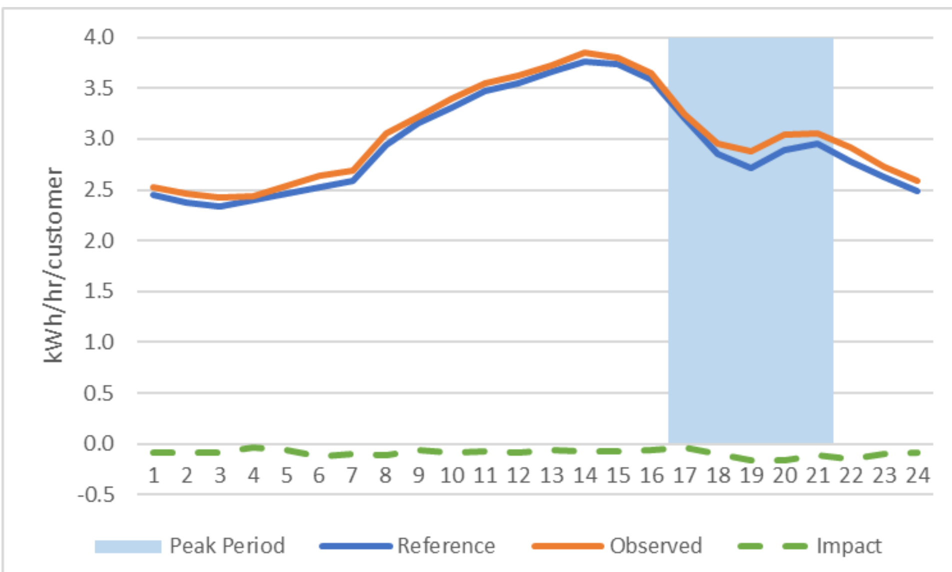


Figure 4.5: August Average Weekday Hourly Impacts, A-10 TOU to B-10

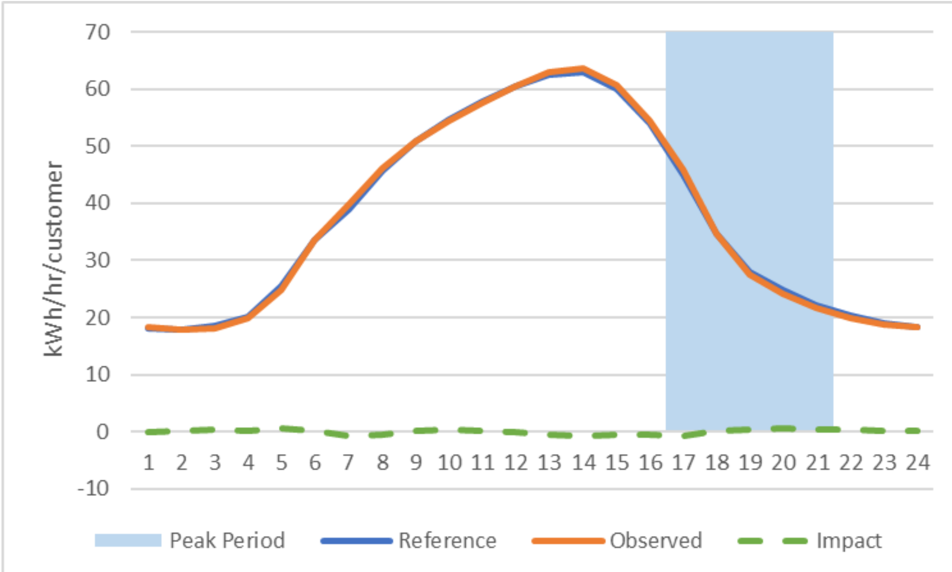


Figure 4.6: August Average Weekday Hourly Impacts, E-19 to B-19

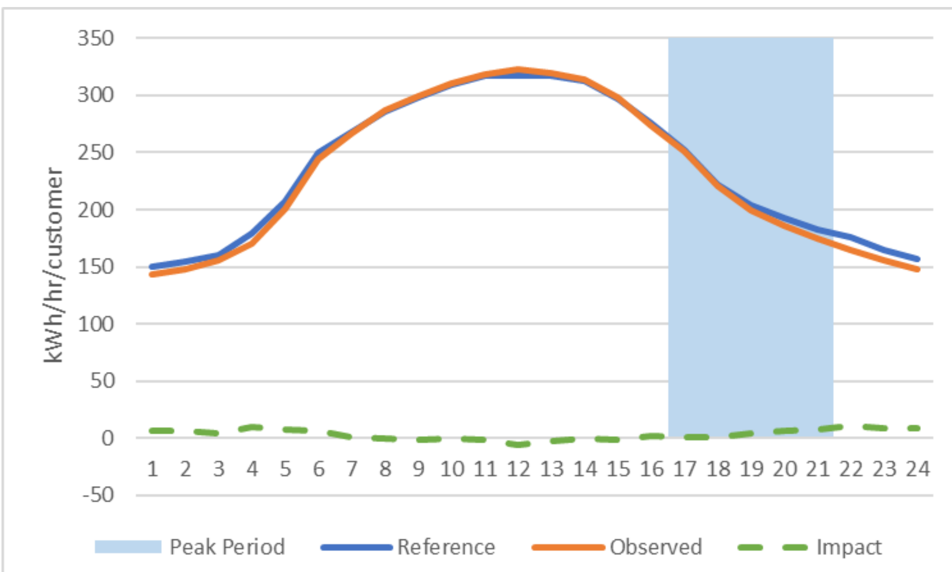


Figure 4.7 shows the load impacts for the E-20 to B-20 customers. Recall that the Peak-period load impact was statistically significant (Table 4.2), albeit with a wide confidence interval. The figure reveals the source of our concern about omitted variable bias affecting the estimated load impacts, as the observed loads are systematically lower than the reference loads. We suspect this could be due to COVID effects on overall usage being larger for the treatment customers than the control-group customers. That is, our matching process (illustrated for this group in appendix Figure E.7) considers only the pre-treatment year load profiles. We expect that some customers had larger COVID

effects on load than others, and if those differences correlate with being a treatment customer it would affect the TOU load impact estimate.

Figure 4.7: August Average Weekday Hourly Impacts, E-20 to B-20

[redacted]

Figures 4.8 through 4.12 show the Ag rate hourly load impacts. Recall from Table 4.3 that there are wide confidence intervals around the Peak-period load impacts, which is indicative of the effect of small sample sizes and (we suspect) high load variability of the Ag customers on the load impact estimates.

Figure 4.8: August Average Weekday Hourly Impacts, AG-4A to AG-A1

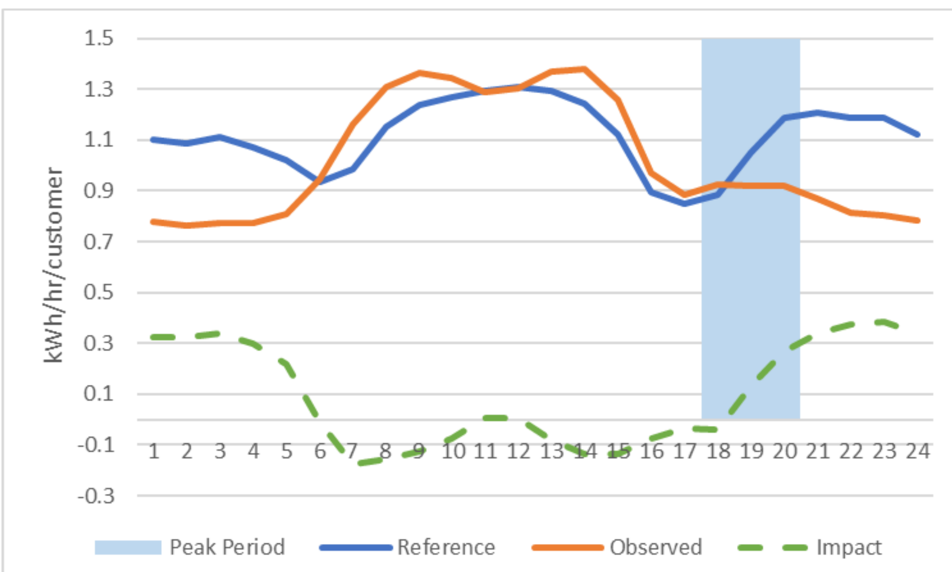


Figure 4.9: August Average Weekday Hourly Impacts, AG-4A to AG-A2

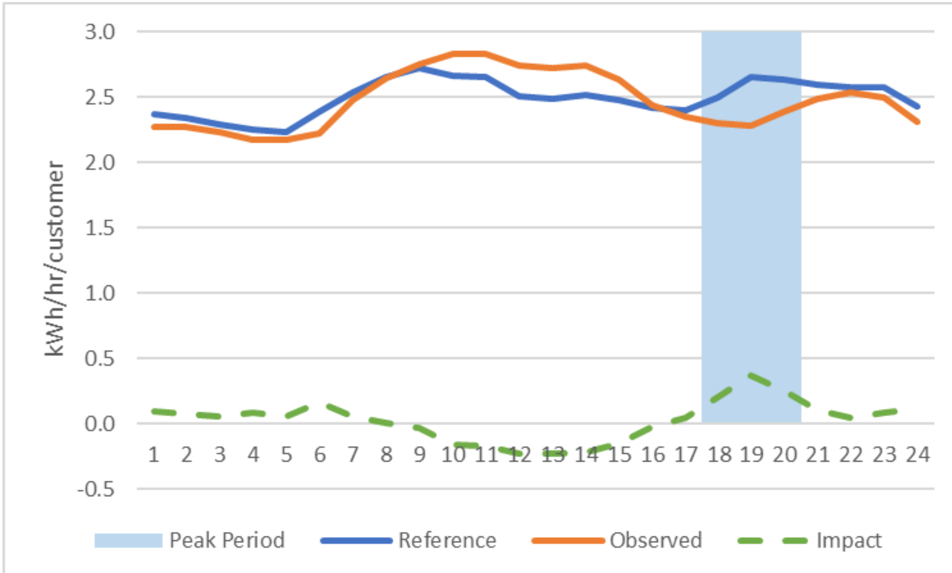


Figure 4.10: August Average Weekday Hourly Impacts, AG-4B TO AG-B

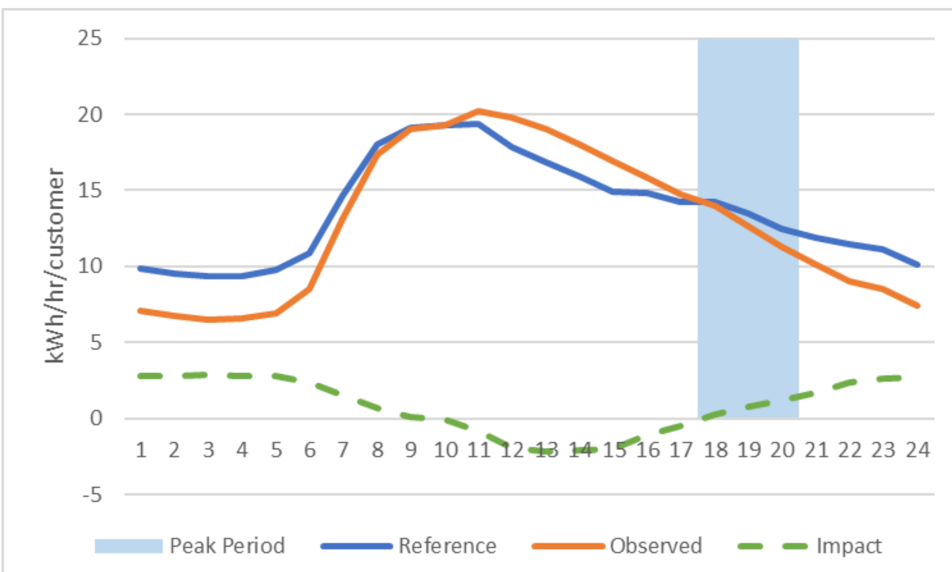


Figure 4.11: August Average Weekday Hourly Impacts, AG-5A to AG-A2

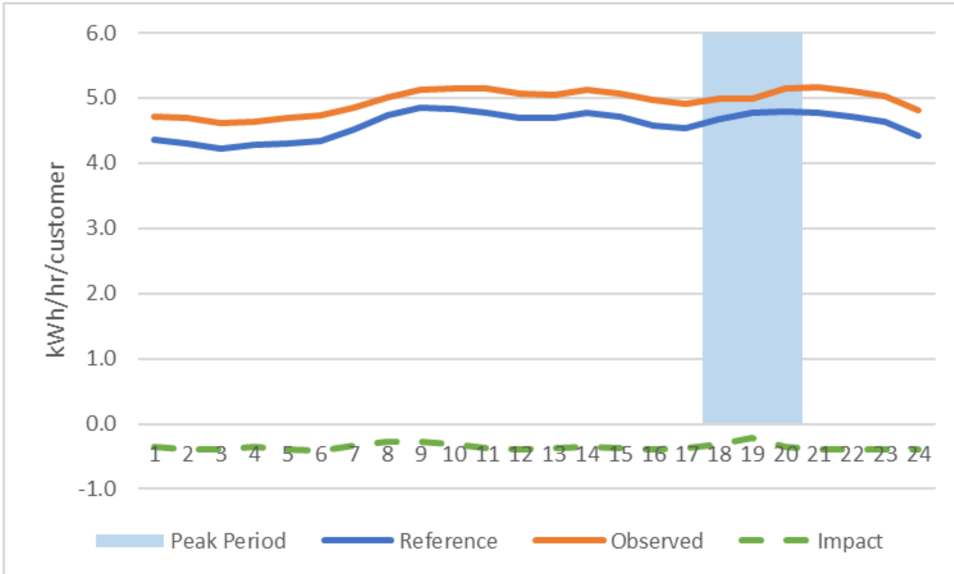
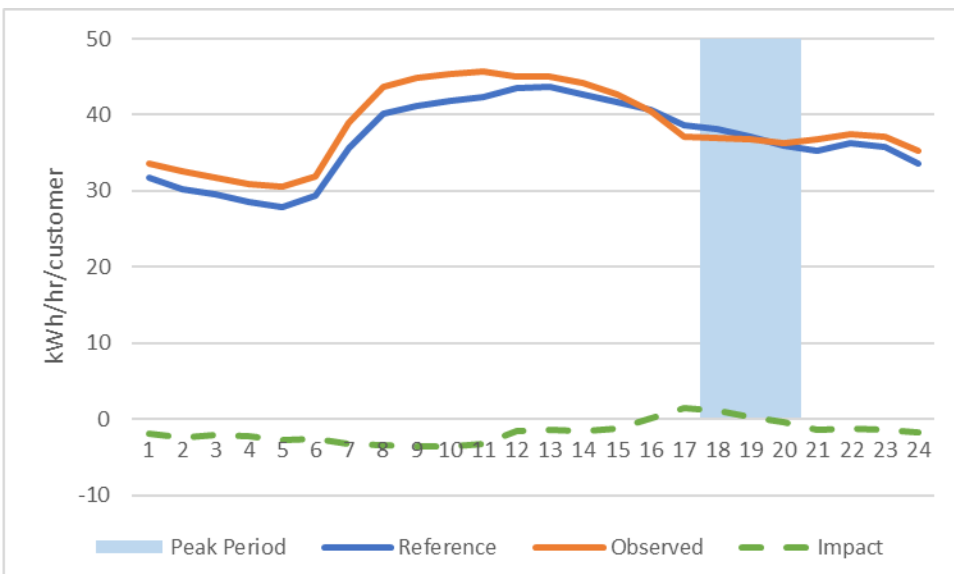


Figure 4.12: August Average Weekday Hourly Impacts, AG-5B to AG-C



5. *Ex-Ante* Load Impacts

5.1 Overview and Enrollment Forecasts

As described in Section 3.2, the *ex-ante* load impacts were forecast for only the large (over 200kW) customers. The following rate transitions are included in the forecast:

- A-10 TOU to B-10

- E-19 to B-19
- E-20 to B-20
- AG-5B to AG-C
- AG-5C to AG-C

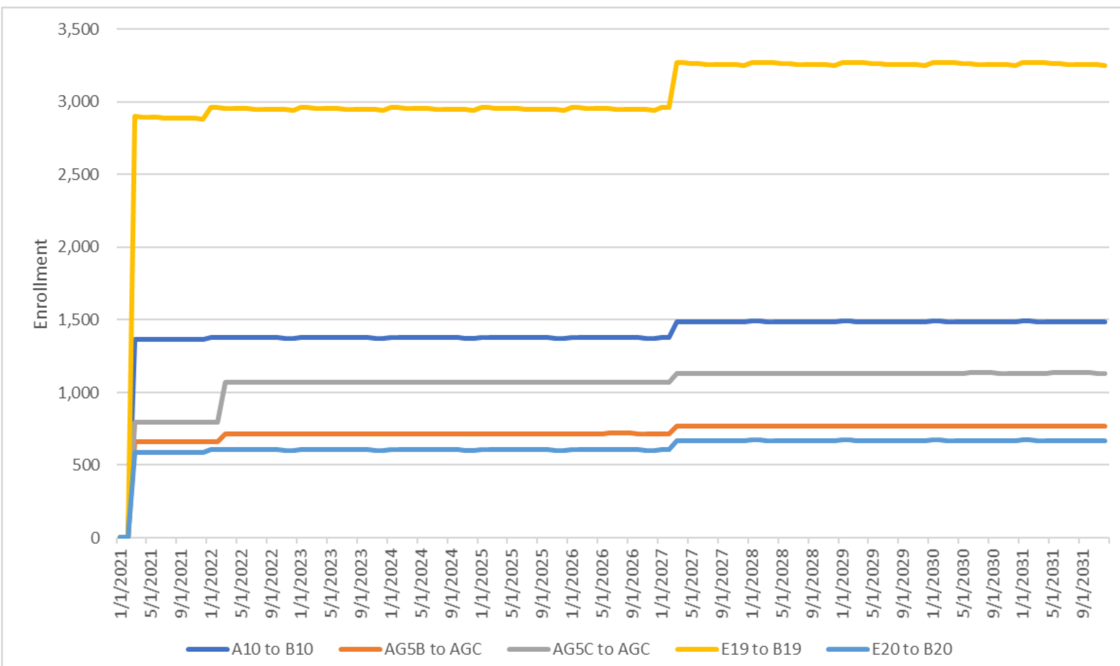
As with all *ex-ante* studies, we develop four sets of results associated with distinct weather scenarios, which are distinguished by:

- 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 monthly enrollments by rate for the forecast period. Most of the incremental TOU enrollments occur in March 2021. Schedule B-19 has the highest enrollment, peaking at 3,272 in 2031.

Figure 5.1: *Ex-Ante* Enrollment Forecast by Rate



5.2 Ex-Ante Load Impact Results

The following sub-sections present the *ex-ante* forecasts for each of the forecast rate transitions.

Figure 5.2 summarizes the average RA-window (4:00 to 9:00 p.m.) impact for each month of 2021, by rate. The values reflect PG&E 1-in-2 peak day weather conditions. A few things to note:

- There are no impacts in January and February because new enrollments begin in March 2021.
- The bulk of the load impacts are provided by the B-19 and B-20 customers.
- May and October load impacts represent a load *increase* relative to usage on the legacy TOU rate. This is largely due to the change in the summer definition from May through October to June through September. The two months that changed from summer to winter (May and October) have significantly lower effective energy charges during the RA window, due to differences in both the energy and demand rates.

Figure 5.2: 2021 Monthly Average RA Window Load Impacts

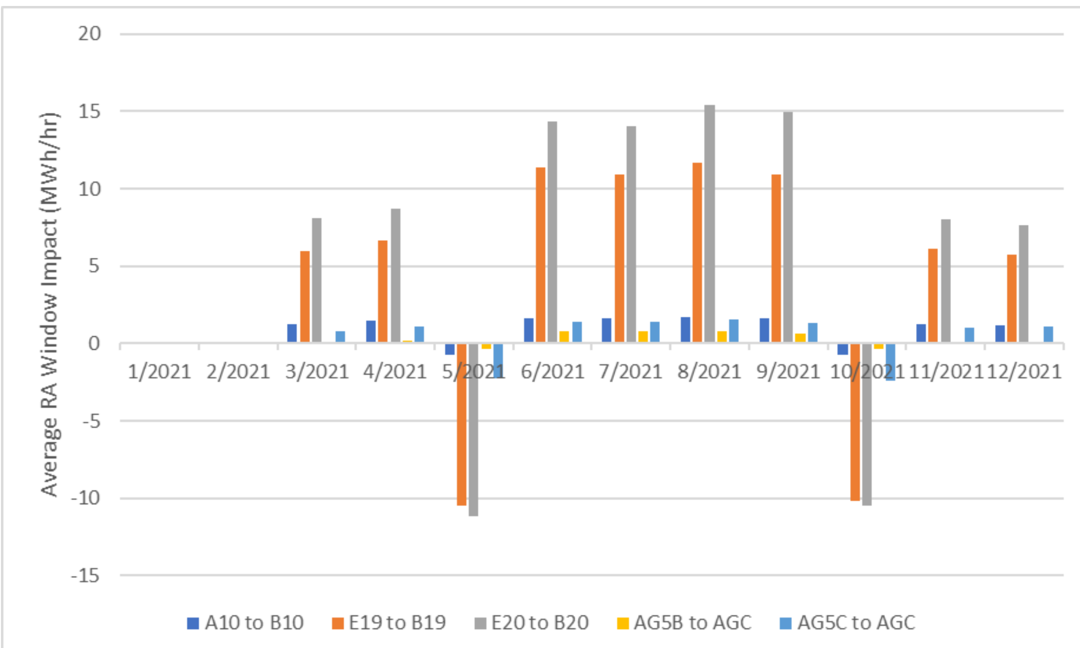
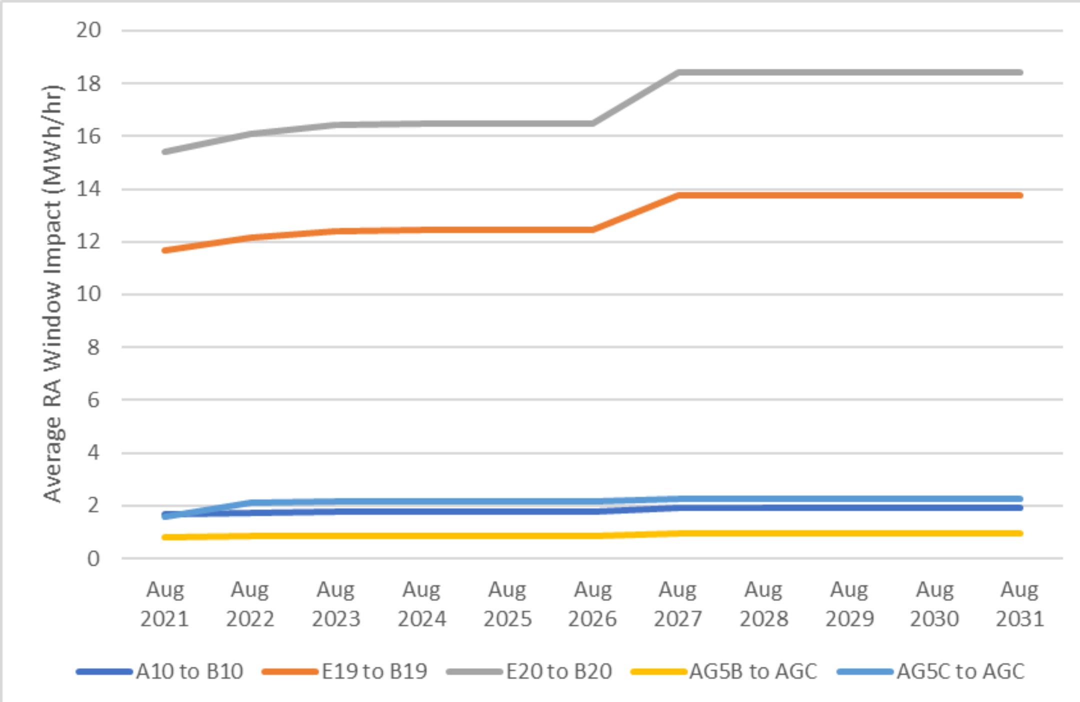


Figure 5.3 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the RA window for the PG&E 1-in-2 weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern, as shown in Figure 5.1.

Figure 5.3: August Average RA Window Load Impacts by Year



The following sub-sections provide additional summaries of the load impacts associated with each included rate transition.

5.2.1 *Ex-ante* load impacts for A-10 TOU to B-10 customers

Table 5.1 shows the A-10 TOU to B-10 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is little variation in the load impact across weather scenarios. The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.1: A-10 TOU to B-10 *Ex-Ante* Load Impacts, 2021 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	0.0	0.0	0.0	0.0
March	1.4	1.3	1.3	1.3
April	1.5	1.4	1.5	1.4
May	-0.8	-0.7	-0.8	-0.7
June	1.6	1.6	1.7	1.6
July	1.7	1.6	1.7	1.6
August	1.7	1.6	1.7	1.7
September	1.6	1.6	1.7	1.6
October	-0.8	-0.7	-0.8	-0.7
November	1.4	1.3	1.3	1.3
December	1.2	1.2	1.1	1.2

Figures 5.4 and 5.5 show the August and December 2021 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The load impacts tend to be small, peaking at 1.2 percent in August and 0.9 percent in December.

Figure 5.4: A-10 TOU to B-10 Hourly *Ex-Ante* Load Impacts, 2021 August PG&E 1-in-2 Peak Day

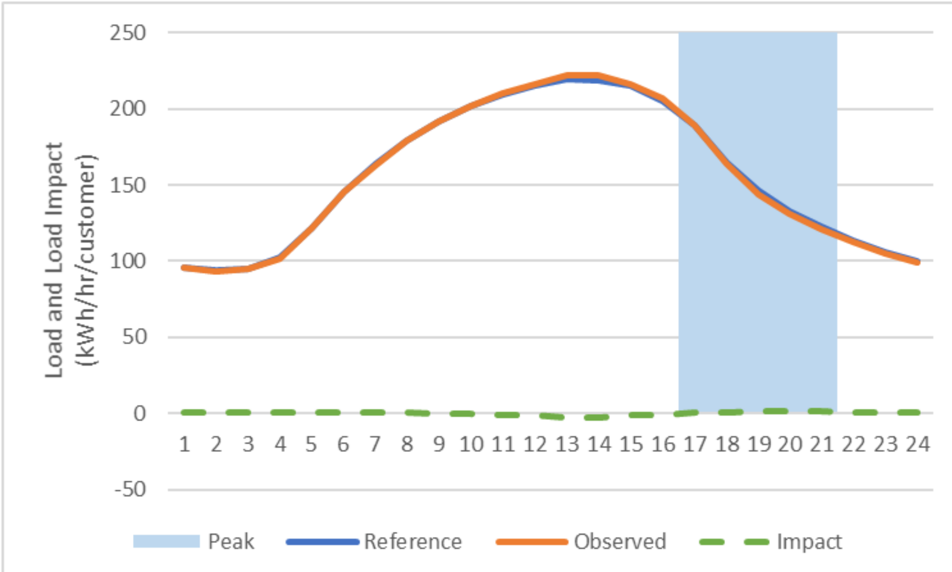
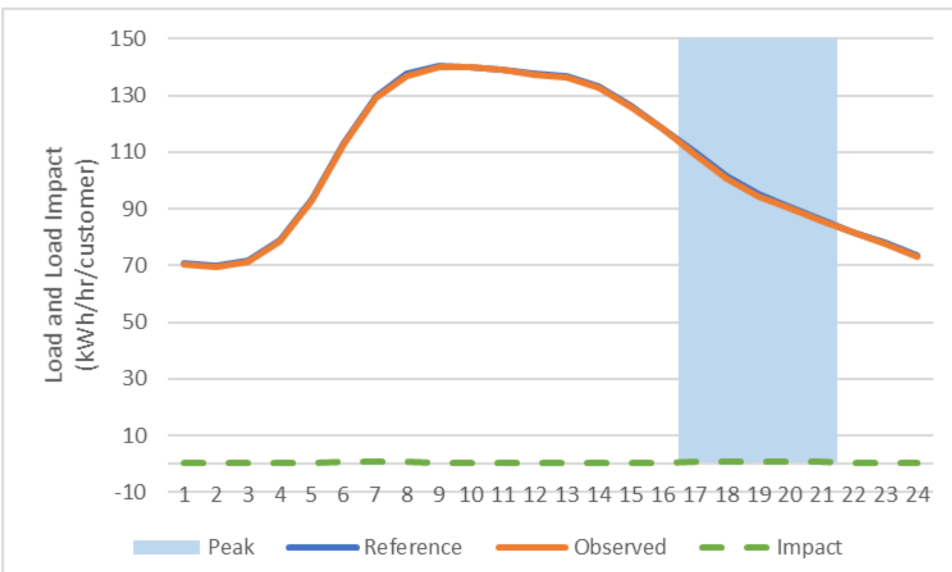


Figure 5.5: A-10 TOU to B-10 Hourly *Ex-Ante* Load Impacts, 2021 December PG&E 1-in-2 Peak Day



5.2.2 *Ex-ante* load impacts for E-19 to B-19 customers

Table 5.2 shows the E-19 to B-19 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is some variation in the load impact across weather scenarios, though the span (the difference between the highest and lowest load impact) is within 1 MW in all but one month (May). The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.2: E-19 to B-19 *Ex-Ante* Load Impacts, 2021 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	0.0	0.0	0.0	0.0
March	6.3	6.0	6.1	6.0
April	6.8	6.6	6.9	6.7
May	-10.9	-10.3	-11.7	-10.5
June	11.4	11.4	11.9	11.4
July	11.2	10.7	11.3	10.9
August	11.8	11.3	12.0	11.7
September	10.8	10.6	11.2	10.9
October	-10.5	-10.2	-10.9	-10.2
November	6.4	6.3	6.3	6.1
December	5.7	5.9	5.6	5.8

Figures 5.6 and 5.7 show the August and December 2021 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 3.9 percent to decreases of 2.4 percent. In December, the range is smaller, from 0.2 percent load increases to 0.9 percent load decreases.

Figure 5.6: E-19 to B-19 Hourly *Ex-Ante* Load Impacts, 2021 August PG&E 1-in-2 Peak Day

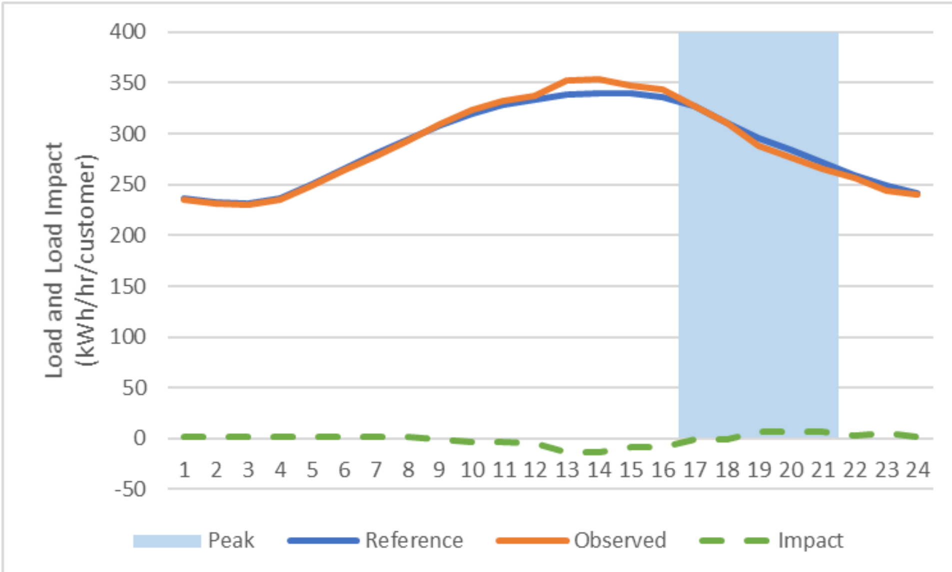
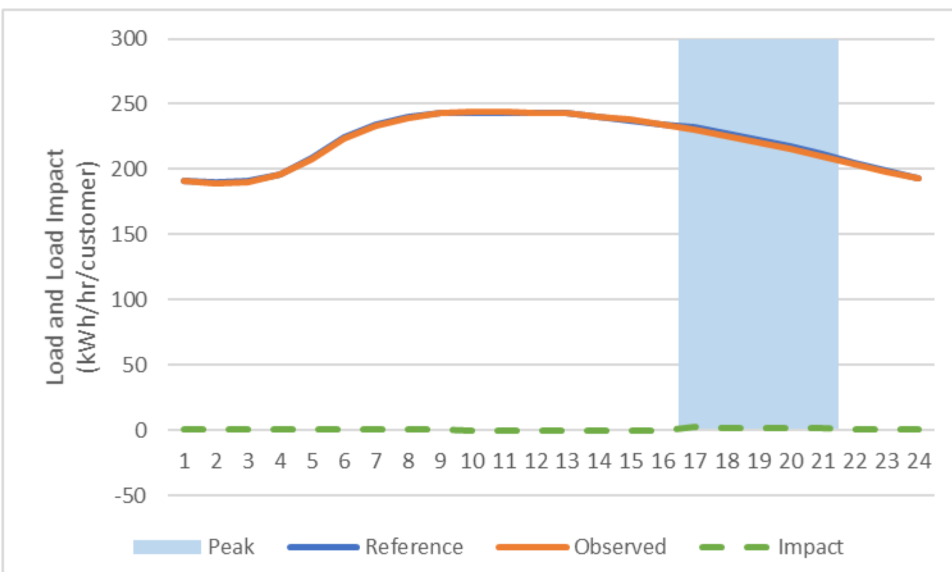


Figure 5.7: E-19 to B-19 Hourly *Ex-Ante* Load Impacts, 2021 December PG&E 1-in-2 Peak Day



5.2.3 *Ex-ante* load impacts for E-20 to B-20 customers

Table 5.3 shows the E-20 to B-20 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is some variation in the load impact across weather scenarios, though the span is within 1 MW in all months. The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.3: E-20 to B-20 *Ex-Ante* Load Impacts, 2021 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	0.0	0.0	0.0	0.0
March	8.5	8.1	8.2	8.1
April	8.9	8.7	9.0	8.7
May	-11.4	-11.1	-11.9	-11.2
June	14.3	14.3	14.7	14.3
July	14.3	13.9	14.4	14.0
August	15.5	15.1	15.7	15.4
September	14.8	14.6	15.1	14.9
October	-10.8	-10.5	-11.0	-10.5
November	8.3	8.3	8.2	8.1
December	7.6	7.8	7.5	7.6

Figures 5.8 and 5.9 show the August and December 2021 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 3.8 percent to decreases of 2.5 percent. In December, the range is smaller, from 0.1 percent load increases to 1.0 percent load decreases.

Figure 5.8: E-20 to B-20 Hourly *Ex-Ante* Load Impacts, 2021 August PG&E 1-in-2 Peak Day

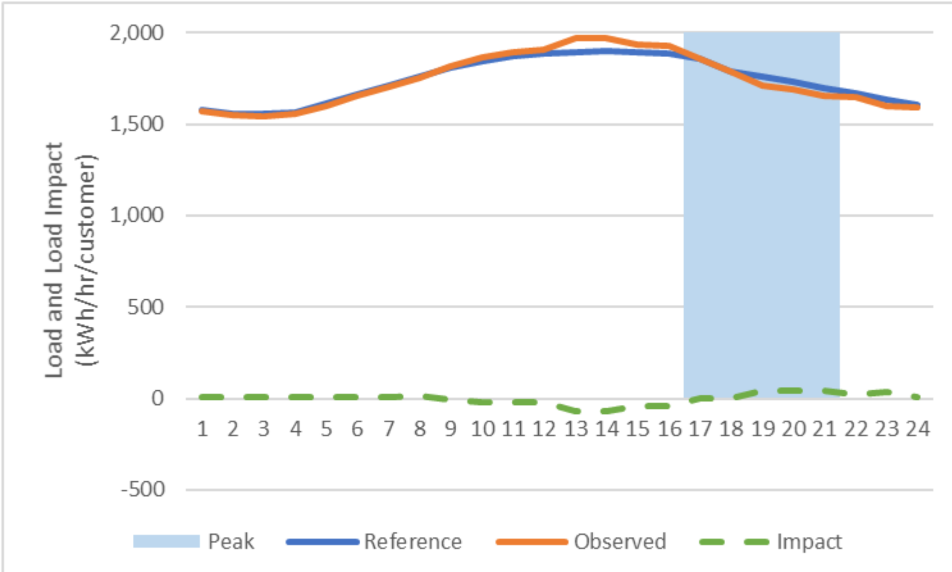
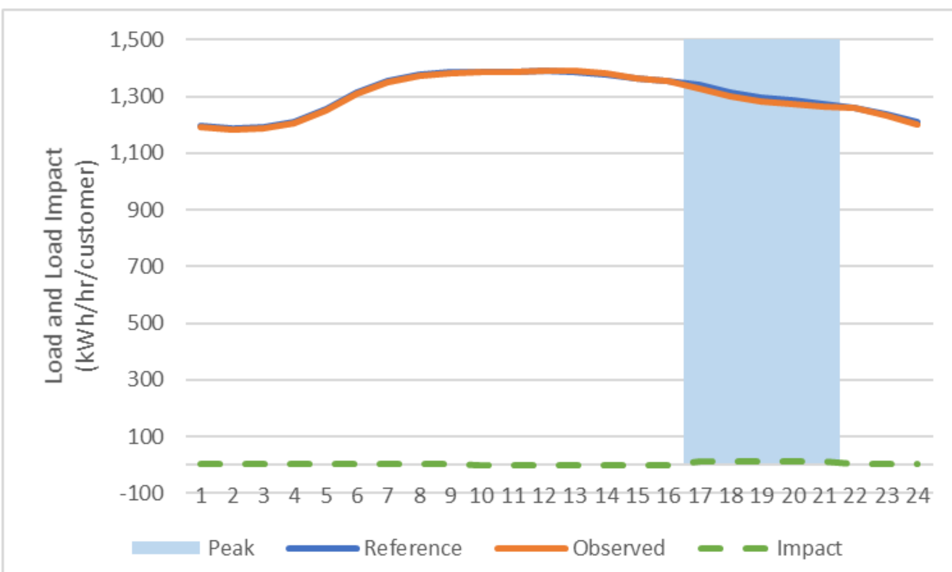


Figure 5.9: E-20 to B-20 Hourly *Ex-Ante* Load Impacts, 2021 December PG&E 1-in-2 Peak Day



5.2.4 *Ex-ante* load impacts for AG-5B to AG-C customers

Table 5.4 shows the AG-5B to AG-C load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is some variation in the load impact across weather scenarios, though the span is less than 0.1 MW in all months. The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.4: AG-5B to AG-C *Ex-Ante* Load Impacts, 2021 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	0.0	0.0	0.0	0.0
March	0.1	0.1	0.1	0.1
April	0.2	0.2	0.2	0.2
May	-0.4	-0.4	-0.4	-0.4
June	0.8	0.8	0.8	0.8
July	0.8	0.8	0.8	0.8
August	0.8	0.8	0.8	0.8
September	0.6	0.6	0.6	0.7
October	-0.4	-0.4	-0.4	-0.4
November	0.1	0.1	0.1	0.1
December	0.1	0.1	0.1	0.1

Figures 5.10 and 5.11 show the August and December 2021 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 3.2 percent to decreases of 4.7 percent. In December, the range is smaller, from 0.2 percent load decreases to 1.4 percent load decreases.

Figure 5.10: AG-5B to AG-C Hourly *Ex-Ante* Load Impacts, 2021 August PG&E 1-in-2 Peak Day

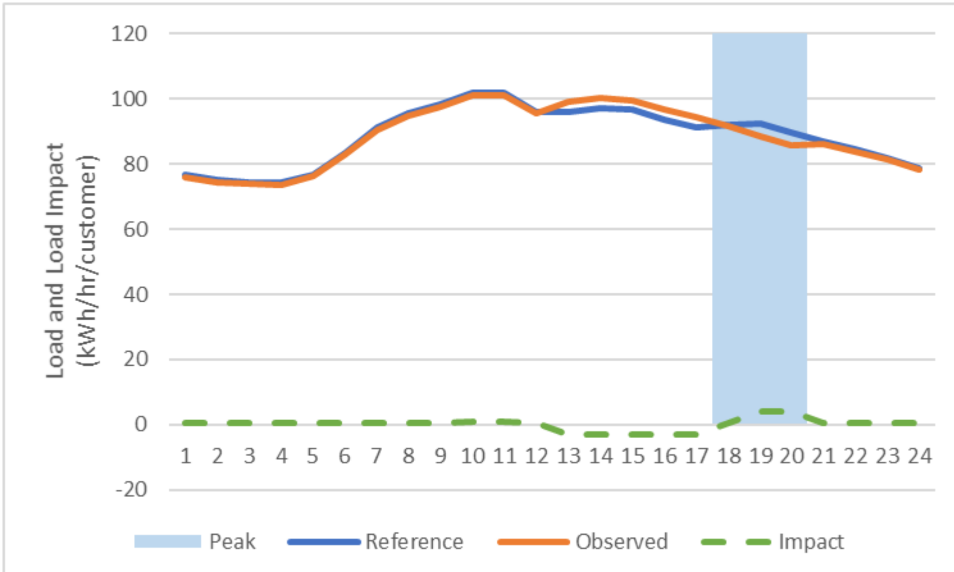
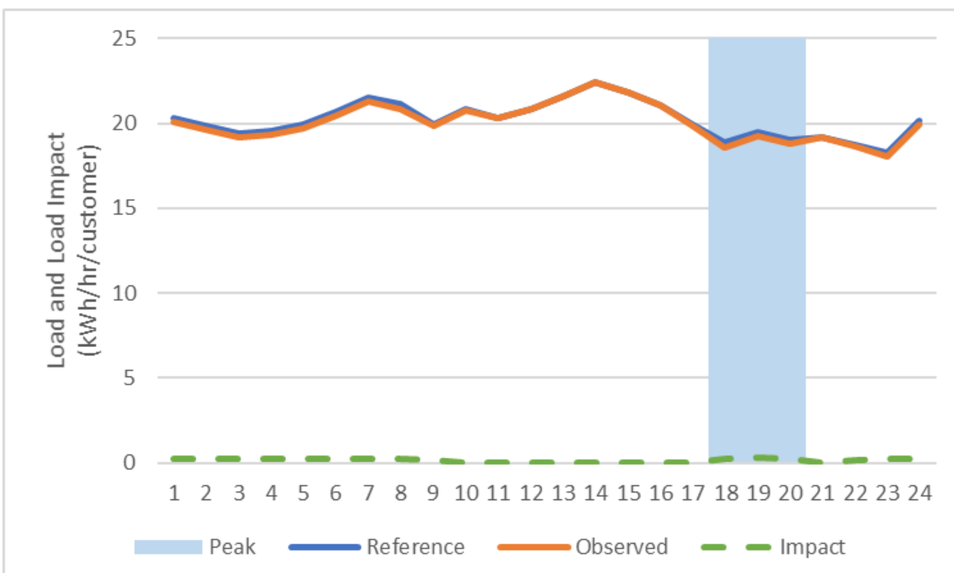


Figure 5.11: AG-5B to AG-C Hourly *Ex-Ante* Load Impacts, 2021 December PG&E 1-in-2 Peak Day



5.2.5 *Ex-ante* load impacts for AG-5C to AG-C customers

Table 5.5 shows the AG-5C to AG-C load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2021 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is some variation in the load impact across weather scenarios, though the span is less than 0.2 MW in all months. The load decreases are highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.5: AG-5C to AG-C *Ex-Ante* Load Impacts, 2021 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	0.0	0.0	0.0	0.0
March	0.9	0.8	0.8	0.8
April	1.2	1.1	1.2	1.1
May	-2.4	-2.3	-2.4	-2.3
June	1.4	1.4	1.4	1.4
July	1.5	1.4	1.5	1.4
August	1.6	1.5	1.6	1.6
September	1.3	1.3	1.3	1.3
October	-2.5	-2.4	-2.5	-2.4
November	1.1	1.1	1.0	1.0
December	1.1	1.1	1.0	1.1

Figures 5.12 and 5.13 show the August and December 2021 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 3.2 percent to decreases of 3.0 percent. In December, the range is smaller, from 0.6 percent load decreases to 1.8 percent load decreases.

Figure 5.12: AG-5C to AG-C Hourly *Ex-Ante* Load Impacts, 2021 August PG&E 1-in-2 Peak Day

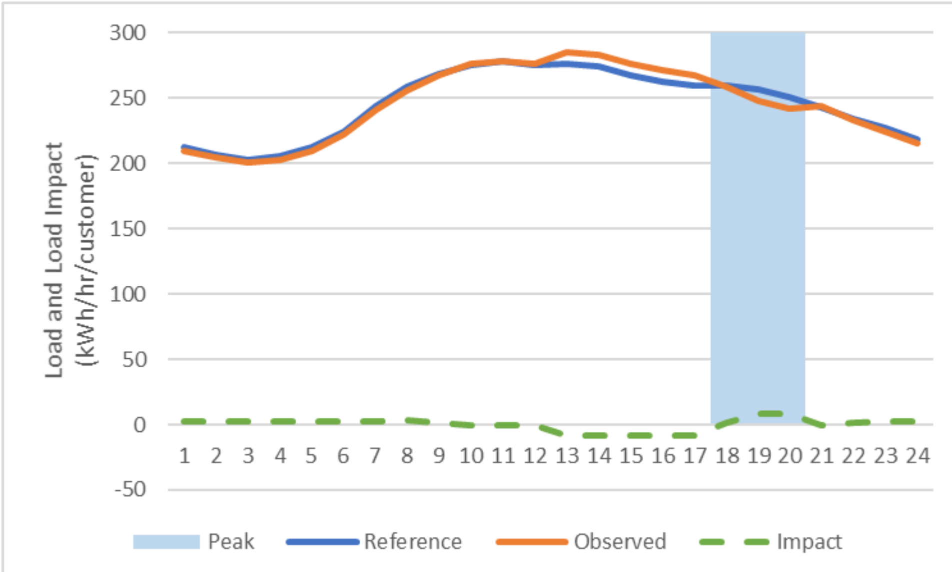
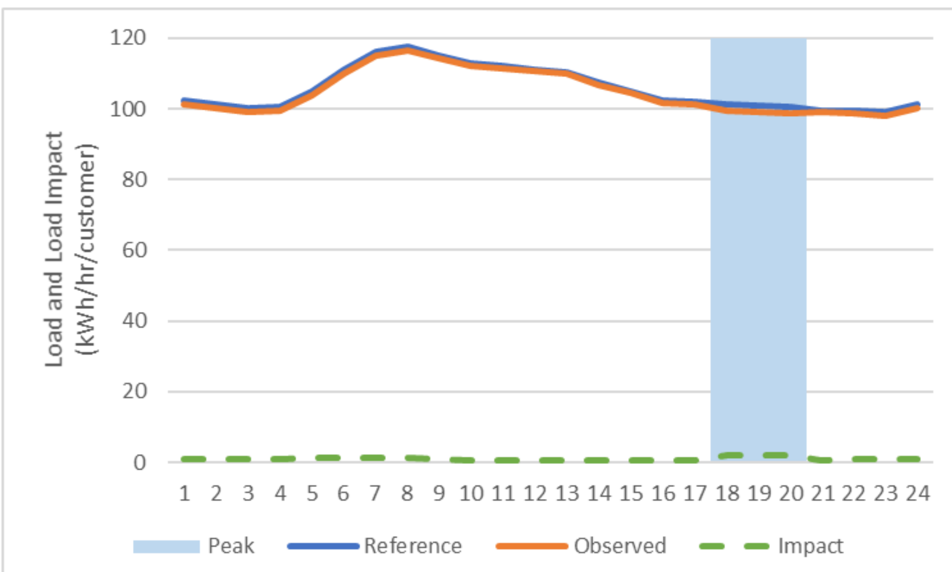


Figure 5.13: AG-5C to AG-C Hourly *Ex-Ante* Load Impacts, 2021 December PG&E 1-in-2 Peak Day



6. Comparisons of Results

In an effort to clarify the relationships between *ex-post* and *ex-ante* results, the annual load impact evaluations typically include comparisons of 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.

In this case, there is no previous evaluation because this evaluation is the first in a series evaluating the transition of non-residential customers to the new TOU rates. Therefore, this section is limited to a comparison of the *ex-post* and *ex-ante* impacts presented in this study.

In each of the tables below, we compare the PY2020 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2021 produced in this study. The top panel of each table shows the aggregate results while the bottom panel shows per-customer results.

Recall that the *ex-ante* forecast was not based on the *ex-post* estimates, so these comparisons reflect the differences between the limited evidence available from voluntary adoptions versus the simulations we performed for larger scale defaults onto the new TOU rates.

Table 6.1 provided the *ex-post* vs. *ex-ante* comparison for the A-10 to B-10 customers. The large size group was not included in the *ex-post* study of this rate transition, so no comparison can be made.

Table 6.1 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, A-10 to B-10

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday	*Ex-Ante* for Aug. 2021 Avg. Weekday
Total	# SAIDs	n/a	1,367
	Reference (MW)	n/a	190.5
	Load Impact (MW)	n/a	1.5
	Avg. Temp.	n/a	78.1
Per SAID	Reference (kW)	n/a	139.4
	Load Impact (kW)	n/a	1.1
	% Load Impact	n/a	0.8%

Table 6.2 provides the *ex-post* vs. *ex-ante* comparison for the E-19 to B-19 customers. The customers in the *ex-ante* study tend to have higher reference loads, but lower level and percentage load impacts. The total *ex-ante* impact is much higher due to the higher enrollment level.

Table 6.2 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, E-19 to B-19

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday	*Ex-Ante* for Aug. 2021 Avg. Weekday
Total	# SAIDs	108	2,891
	Reference (MW)	22.8	813.8
	Load Impact (MW)	0.5	11.1
	Avg. Temp.	79.3	77.0
Per SAID	Reference (kW)	210.8	281.5
	Load Impact (kW)	4.3	3.8
	% Load Impact	2.0%	1.4%

Table 6.3 provides the *ex-post* vs. *ex-ante* comparison for the E-20 to B-20 customers. The customers in the *ex-ante* study tend to have higher reference loads, but much lower level and percentage load impacts. The total *ex-ante* impact is still higher than that of the *ex-post* study due to the higher enrollment level.

Table 6.3 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, E-20 to B-20

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday	*Ex-Ante* for Aug. 2021 Avg. Weekday
Total	# SAIDs	[redacted]	589
	Reference (MW)		999.0
	Load Impact (MW)		14.8
	Avg. Temp.		79.3
Per SAID	Reference (kW)		1,696.1
	Load Impact (kW)		25.2
	% Load Impact		1.5%

Table 6.4 provides the *ex-post* vs. *ex-ante* comparison for the AG-5B to AG-C customers. The large size group was not included in the *ex-post* study of this rate transition, so no comparison can be made.

Table 6.4 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, AG-5B to AG-C

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday	*Ex-Ante* for Aug. 2021 Avg. Weekday
Total	# SAIDs	n/a	662
	Reference (MW)	n/a	55.9
	Load Impact (MW)	n/a	0.7
	Avg. Temp.	n/a	88.9
Per SAID	Reference (kW)	n/a	84.4
	Load Impact (kW)	n/a	1.1
	% Load Impact	n/a	1.3%

Table 6.5 provides the *ex-post* vs. *ex-ante* comparison for the AG-5C to AG-C customers. The large size group was not included in the *ex-post* study of this rate transition, so no comparison can be made.

Table 6.5 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, AG-5C to AG-C

Level	Outcome	*Ex-Post* for Aug. 2020 Avg. Weekday	*Ex-Ante* for Aug. 2021 Avg. Weekday
Total	# SAIDs	n/a	795
	Reference (MW)	n/a	190.1
	Load Impact (MW)	n/a	1.5
	Avg. Temp.	n/a	86.8
Per SAID	Reference (kW)	n/a	239.1
	Load Impact (kW)	n/a	1.9
	% Load Impact	n/a	0.8%

Table 6.6 reviews the primary sources of differences between PY2020 *ex-post* August average weekday load impacts and the corresponding *ex-ante* load impacts. The most significant differences are in the enrollments that scale the per-customer *ex-ante* load impacts to the program level and the methodology (estimation vs. simulation).

Table 6.6: *Ex-Post* versus *Ex-Ante* Factors

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Enrollment	140 SAIDs during the August 2020 average weekday for the two rates with large customers included in the *ex-post* study (B-19 and B-20).	3,480 SAIDs in August 2021 for those same two rates.	The enrollment level directly scales the per-customer *ex-ante* load impacts. The *ex-ante* forecast reflects the transition of customers from legacy rates to the new TOU rates.
Methodology	Applies difference-in-differences estimates to voluntary adopters of the new TOU rates during PY2020.	Simulates load impacts using an own-price elasticity applied to each hour's change in the effective energy charge (EEC), which is a modified energy rate that includes the demand charge (by dividing the demand rate by the number of hours in the month over which it is assessed). The reference loads were based on all eligible control-group customers, not accounting for matching (and therefore self-selection into the rates during the voluntary period).	We expect our simulation of default customer impacts to lead to lower estimates that are more predictable than we can obtain by estimating estimates from a small sample of voluntary customers.

Appendices

Appendix A Agricultural *Ex-Post* Load Impact Tables:

8a. PGE_2020_NonRes_TOU_Ag _Ex_Post_CONFIDENTIAL.xlsx

Appendix B C&I *Ex-Post* Load Impact Tables:

8b. PGE_2020_NonRes_TOU_CI_Ex_Post_CONFIDENTIAL.xlsx

Appendix C Agricultural *Ex-Ante* Load Impact Tables:

8c. PGE_2020_NonRes_TOU_Ag_Ex_Ante_CONFIDENTIAL.xlsx

Appendix D C&I *Ex-Ante* Load Impact Tables:

8d. PGE_2020_NonRes_TOU_CI _Ex_Post_CONFIDENTIAL.xlsx

Appendix E *Ex-Post* Analysis Match Quality

Appendix E. Match Quality

This appendix presents the summaries of our control-group matching process. Figures E.1 through E.12 illustrate the seasonal matches for the various rate changes. Each figure contains the average hourly profiles for the treatment and matched control-group customers by season for the withheld load profile (representing mild days). These provide an out-of-sample evaluation of the match quality. Two patterns emerge from the figures: match quality tends to be better where the number of customers is higher (shown in each figure's title); and match quality tends to be better for C&I rates than Agricultural rates. Note that poor match quality for a given analysis group doesn't necessarily prevent obtaining reasonable load impact estimates, because the difference-in-differences methodology removes the load differences during the pre-treatment year from the load impact estimation.

Figure E.1: Summer and Winter Match Quality, A-1 to B-6 (N=448)

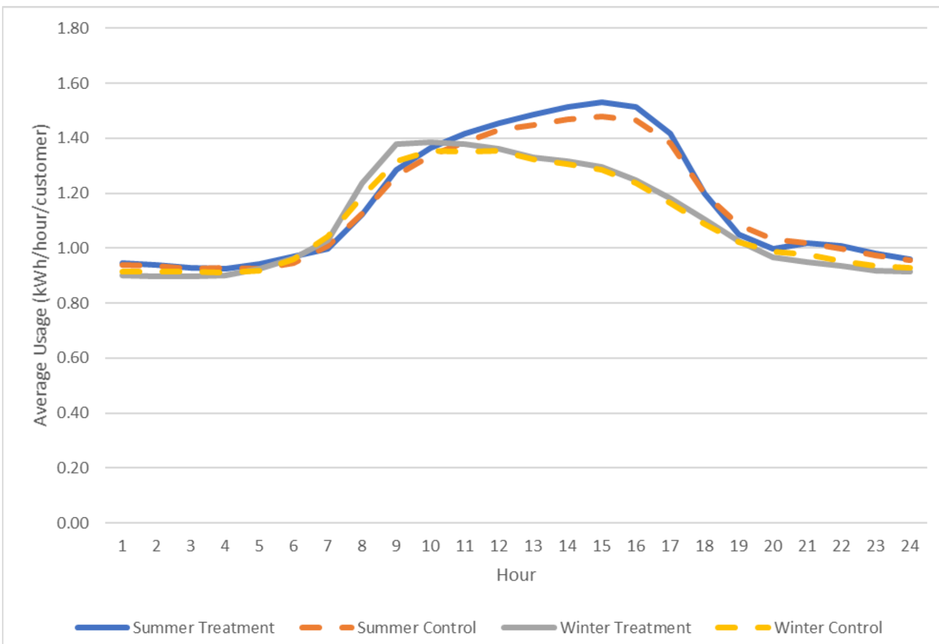


Figure E.2: Summer and Winter Match Quality, A-1 TOU to B-1 (N=214)

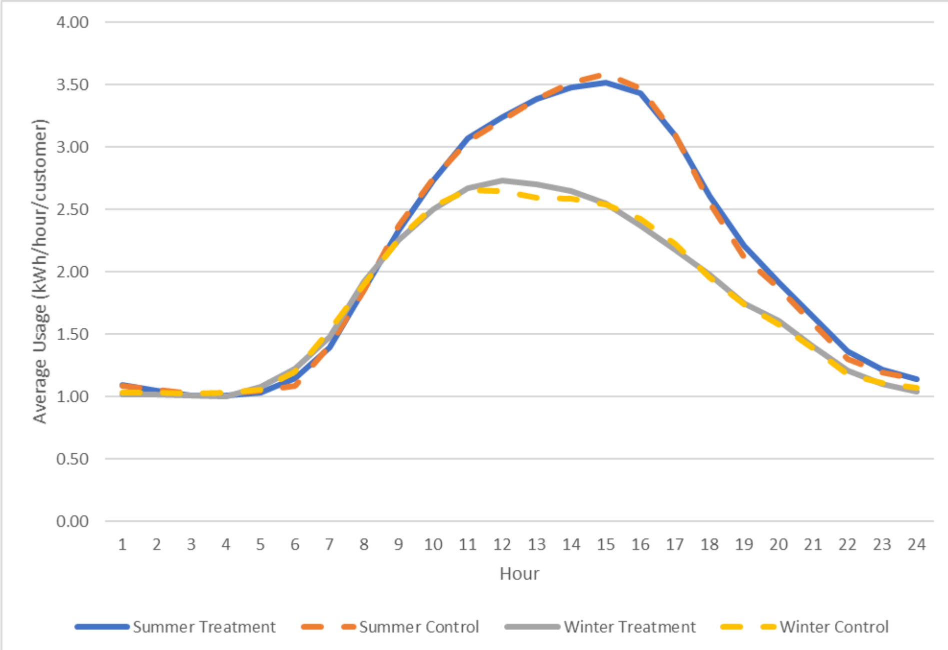


Figure E.3: Summer and Winter Match Quality, A-1 TOU to B-6 (N=6,666)

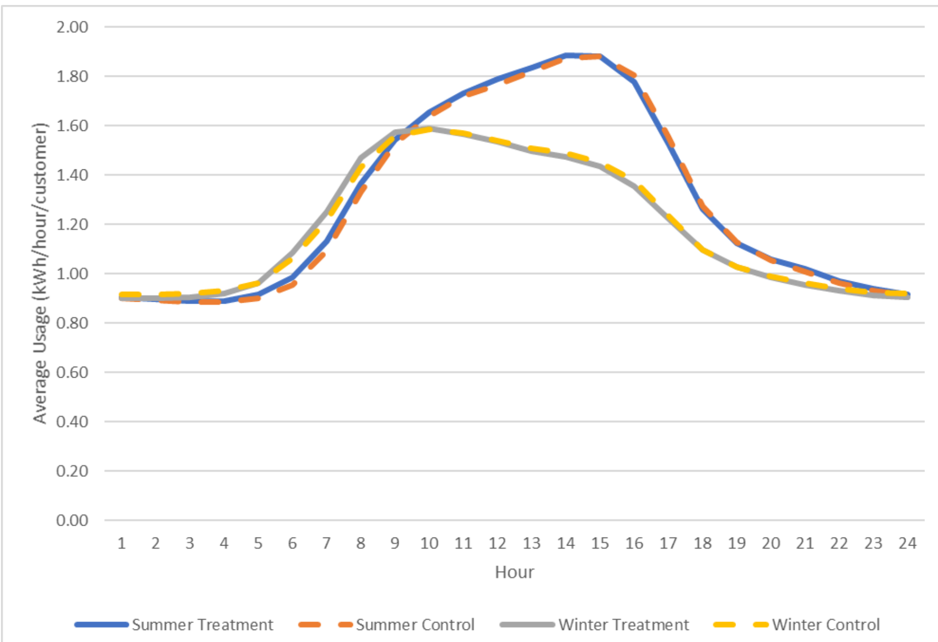


Figure E.4: Summer and Winter Match Quality, A-10 TOU to B-10 (N=683)

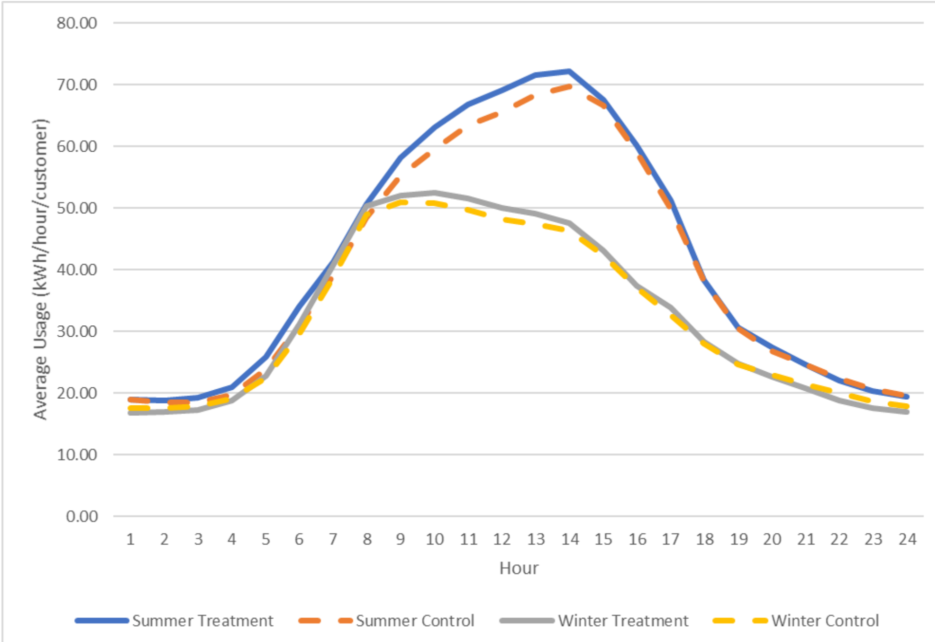


Figure E.5: Summer and Winter Match Quality, A-6 to B-6 (N=218)

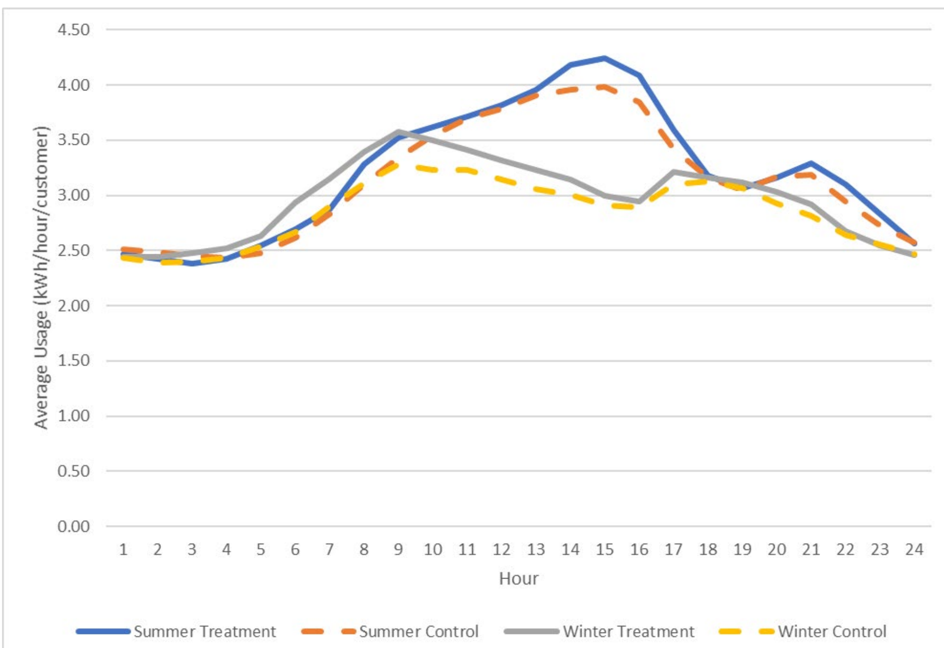


Figure E.6: Summer and Winter Match Quality, E-19 to B-19 (N=93)

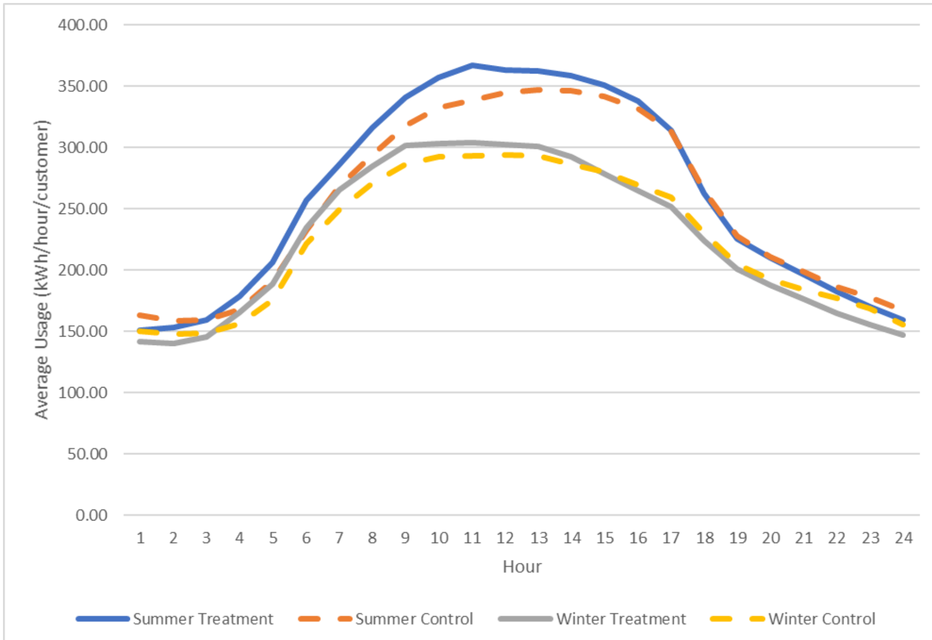


Figure E.7: Summer and Winter Match Quality, E-20 to B-20 (N=21)

[redacted]

Figure E.8: Summer and Winter Match Quality, AG-4A to AG-A1 (N=92)

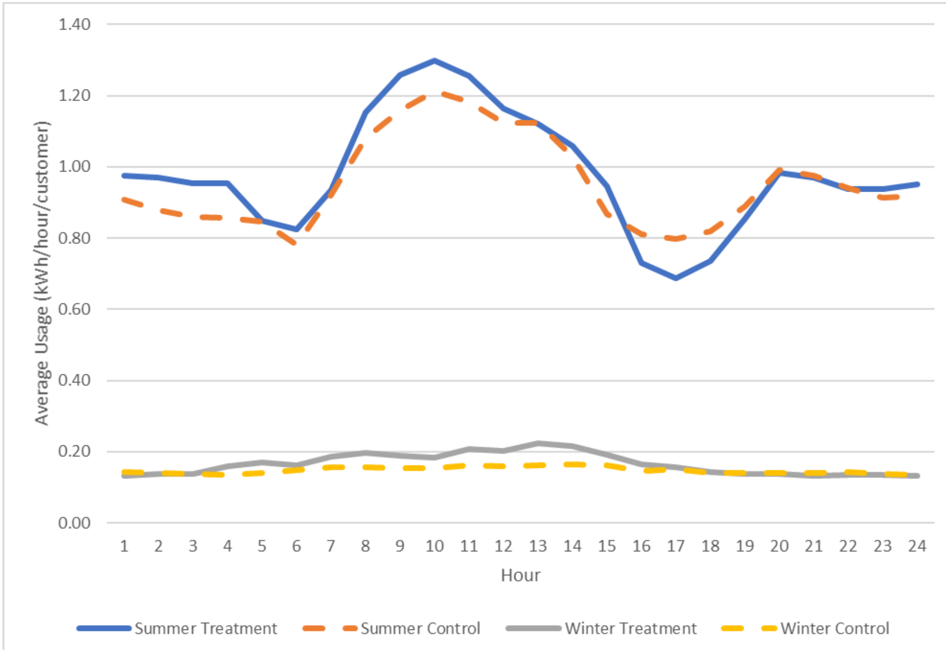


Figure E.9: Summer and Winter Match Quality, AG-4A to AG-A2 (N=120)

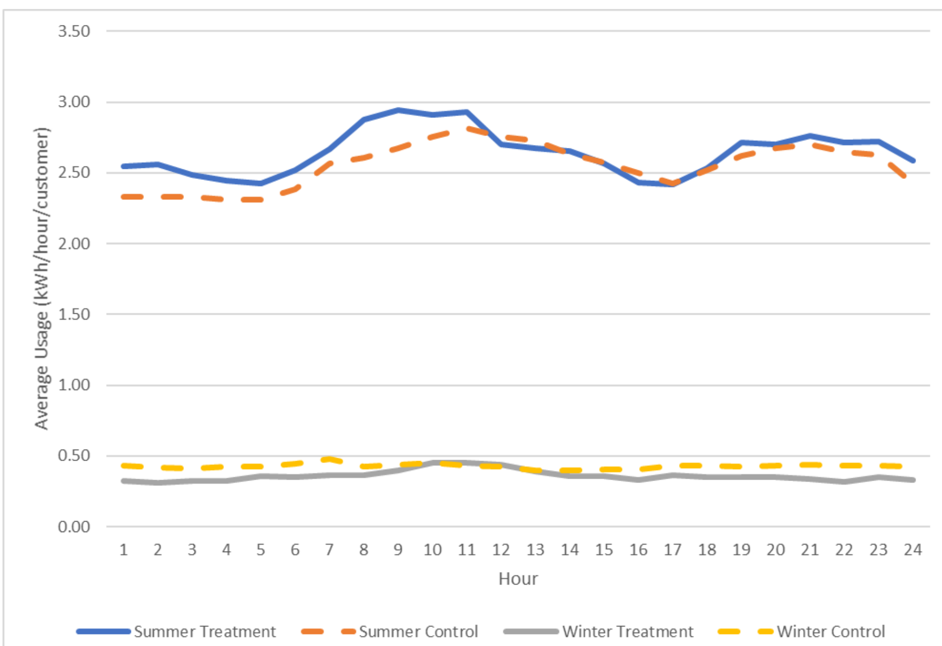


Figure E.10: Summer and Winter Match Quality, AG-4B to AG-B (N=90)

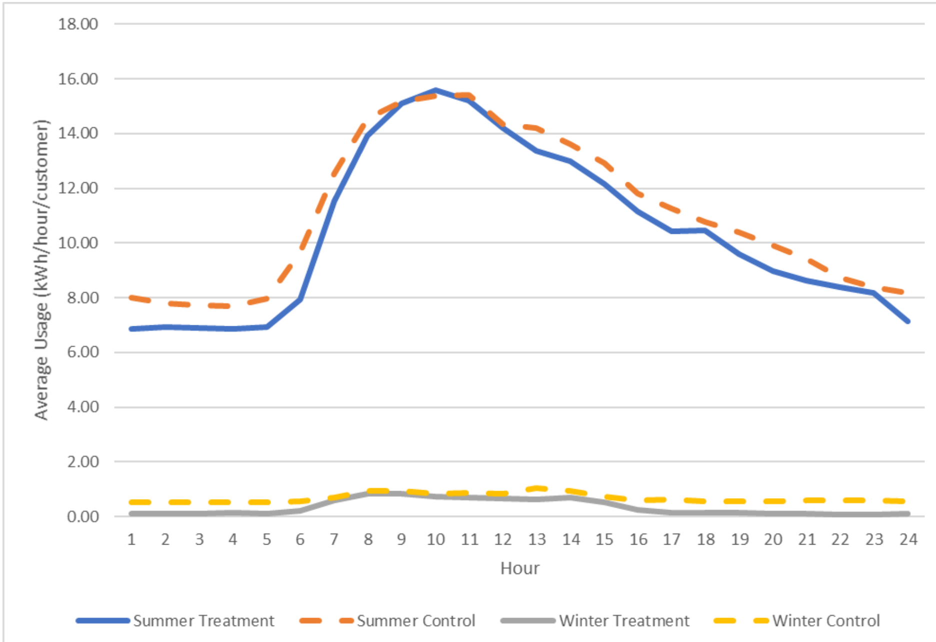


Figure E.11: Summer and Winter Match Quality, AG-5A to AG-A2 (N=99)

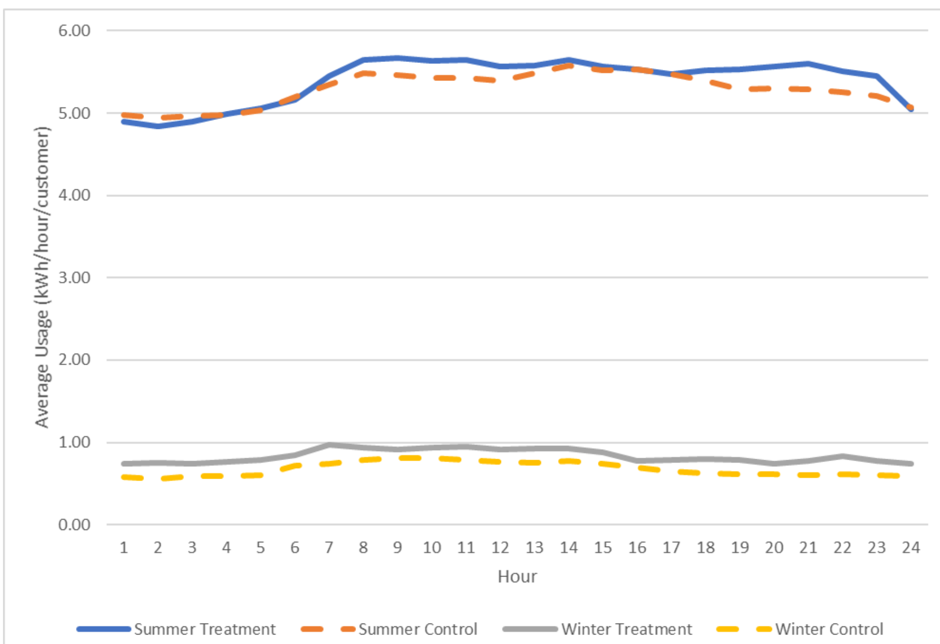


Figure E.12: Summer and Winter Match Quality, AG-5B to AG-C (N=170)

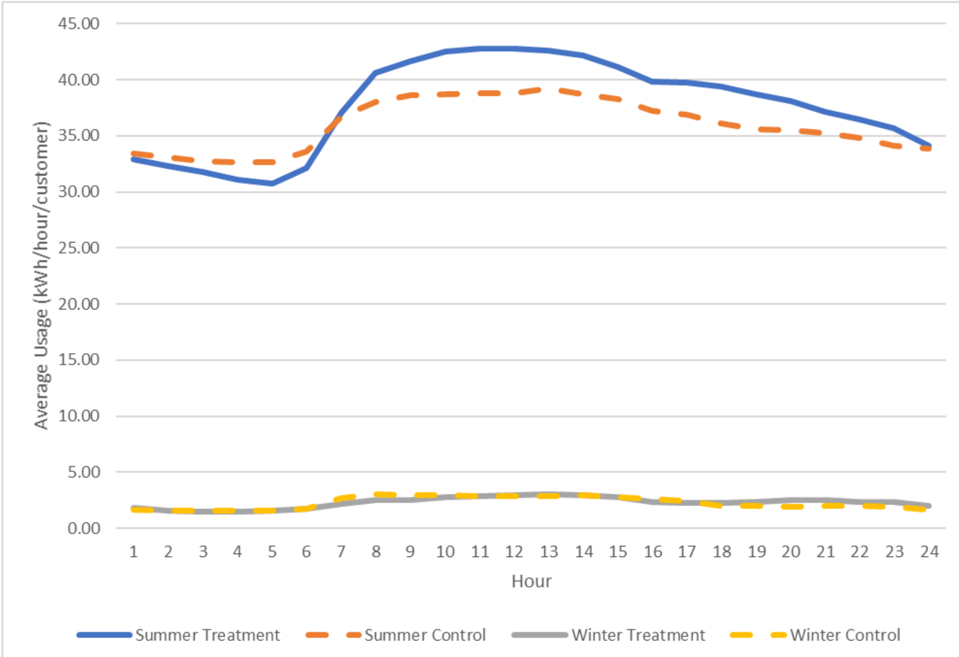


Table E.1 summarizes the mean percentage error (MPE) and mean absolute percentage error (MAPE) values for the load profiles shown in the figures above. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy. Note that the highest percentage values (in the AG-4B to AG-B winter matches) are affected by the treatment customer loads being close to zero.

Table E.1: MPE and MAPE Values for the Out-of-Sample Profiles

Rate Change	Size	Summer		Winter		N
		MPE	MAPE	MPE	MAPE	
A-1 to B-6	Under 20kW	-0.9%	1.7%	-0.1%	1.6%	448
A-1 TOU to B-1	Under 20kW	-0.6%	1.7%	0.0%	1.8%	214
A-1 TOU to B-6	Under 20kW	-0.7%	1.0%	0.4%	1.1%	6,666
A-6 to B-6	Under 20kW	-2.0%	2.8%	-3.8%	3.9%	218
A-10 TOU to B-10	20 to 200kW	-3.0%	3.3%	-0.1%	3.2%	683
E-19 to B-19	Over 200kW	-2.0%	4.3%	0.1%	4.2%	93
E-20 to B-20	Over 200kW	-4.5%	5.1%	-3.9%	4.6%	21
AG-4A to AG-A1	Under 20kW	-1.9%	5.6%	-8.8%	11.1%	92
AG-4A to AG-A2	Under 20kW	-3.4%	4.0%	19.5%	20.2%	120
AG-4B to AG-B	20 to 200kW	7.9%	8.0%	247.9%	247.9%	90
AG-5A to AG-A2	Under 20kW	-1.8%	2.3%	-19.1%	19.1%	99
AG-5B to AG-C	20 to 200kW	-3.9%	5.8%	-1.7%	10.2%	170