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2024 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program

CALMAC Study ID – PGE0503

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EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations of Pacific Gas and Electric's (PG&E) SmartAC™ program for 2024. The evaluation produces estimates of the ex-post load impacts for each hour of each event dispatched in 2024, and it develops ex-ante load impact forecasts for the program through 2027[1].

ES.1 Resources Covered

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers that was integrated into the CAISO wholesale market in program year 2018. SmartAC™ program participants receive a one-time incentive for allowing PG&E to cycle their AC for up to 6 hours per day in response to CAISO market awards, during periods of system or local area emergencies for PG&E capacity, or for limited testing for a maximum of 100 hours per summer (May 1 through October 31). Upon enrollment in SmartAC™, PG&E installs a Zigbee AC load control switch on the participant's central AC unit that communicates bi-directionally over the AMI network. Legacy technology, installed prior to August 2017, is capable of one-way communication over commercial paging systems and includes programmable communicating thermostats (PCT) and switches. When events are dispatched, PG&E sends signals to the PCTs and switches.

PG&E employs a combination of events including system-wide serial events or at the Sub-Load Aggregation Point (sub-LAP) level. System-wide events include all participants and can be initiated based on CAISO or PG&E emergencies or for testing purposes. System-wide test events generally dispatch all SmartAC™ customers throughout the service territory except for a random sample of SmartAC™ customers that serve as the control group based on the last digit of the factory programmed serial number of their installed device (i.e., one or more serial groups are withheld from the event).[2] During sub-LAP events, all SmartAC™ participants with devices that are associated with a given sub-LAP are dispatched for the event.[3] Two events during PY2024 were serial test events with one serial group withheld from the event dispatches, while the remaining fifteen events were CAISO market awards.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts for the 2024 program year, including:
    a. Hourly and average daily load impacts for each event;
    b. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, local capacity area (LCA), CARE/non-CARE customers, net-metering solar customers (NEM), housing type (i.e., detached vs. shared wall residences), AC usage intensity, and device type (i.e., two-way vs. one-way; by one-way device type: UtilityPro, Gen 1, and Gen 2);

[1] Given the CPUC's approval to sunset the SmartAC program, we only present ex-ante forecasts up to 2027.

[2] Currently, not all installed devices have a serial number that conforms to this serial group selection process. For these devices, customers are randomly assigned to a serial group at the time of device installation.

[3] In PY2024, several events involved separate dispatch of one-way and two-way devices.

c. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;

d. The opt-out/override rate by customer segment; and

e. The persistence of load reductions across event hours for multiple hour events.

2. Produce ex-ante load impact forecasts for 2025 to 2027 by sub-LAP and LCA on an aggregate and per-customer basis for a typical event day and the monthly system worst load day for May through October. Forecasts are based on the following four sets of weather conditions:

   a. PG&E's peaking conditions in a 1-in-2 weather year;

   b. PG&E's peaking conditions in a 1-in-10 weather year;

   c. CAISO peaking conditions in a 1-in-2 weather year; and

   d. CAISO peaking conditions in a 1-in-10 weather year.

ES.2 Evaluation Methodologies

In this evaluation, we estimate load impacts by comparing SmartAC™ customer loads to that of a control group on event days, net of the differences in loads on non-event days with comparable weather conditions. For system-wide serial test events in which at least one serial group is withheld from the event, we use this random sample of SmartAC™ customers as an additional control group. For all events, we use a matched control group consisting of residential customers who are not enrolled in any demand response programs, including SmartAC™ or SmartRate™. Matched control group customers are selected based on the similarity of available customer characteristics (e.g., rate schedule, sub-LAP, AC usage level, CARE status, NEM status) as well as usage patterns on non-event days.

We then estimate event-day load impacts using a regression-based difference-in-differences method, which produces estimates of standard errors, and thus confidence intervals around the estimated event hour or event day usage reductions. This approach also adjusts for differences in usage between the treated SmartAC™ customers and the control group on event-like non-event days, thus representing a difference-in-differences evaluation approach.

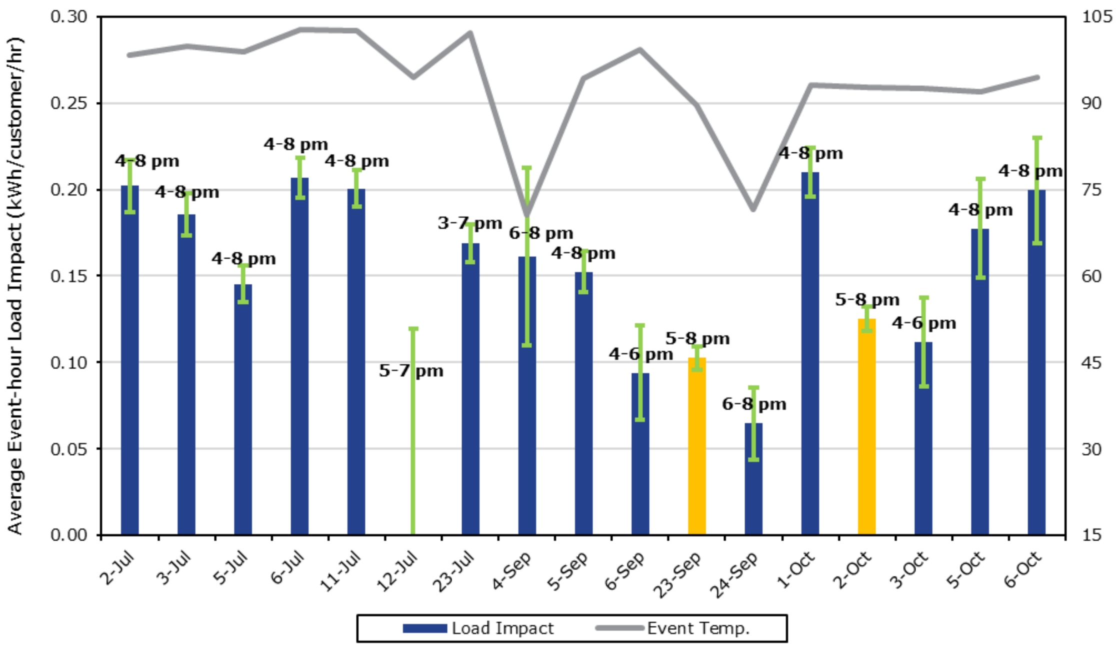
ES.3 Ex-Post Load Impacts

Figure ES-1 summarizes the ex-post load impact estimates (in kWh/customer/hour) for the average full event hour for all SmartAC™ events in PY2024, along with a 90 percent confidence interval (corresponding to the 5th and 95th percentile uncertainty-adjusted load impacts). There are seventeen events dispatched, which includes one one-way only events, seven two-way only events, and nine events with both device types.[4] The yellow bars indicate the serial test events on September 23rd and October 2nd, while the blue bars correspond to the sub-LAP events. These results indicate that SmartAC™ customers had statistically significant load reductions on each of the seventeen event days, except for the event on July 12th, ranging from

[4] The reason for the separate dispatch of one-way and two-way devices for some events is at the start of the program year, one-way devices were left out due to the transition to a new dispatch system. In order to catch up with the missing hours compared to customers with two-way devices, some customers with one-way devices were dispatched for additional events.

0.06 to 0.21 kWh/customer/hour.[5] Compared to past years, the effect of temperature on load impacts is less significant as there is variation in sub-LAPs, device types, and device performance across events in 2024. Load impacts are generally lower than past years with comparable temperatures, which is partially attributed to dispatch issues of two-way devices.

Figure ES-1: Average Event-Hour Load Impacts by Event



In addition to the overall load impacts, we examine patterns of load impacts at the sub-LAP level and how load impacts are distributed across customer subgroups.

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are dispatched in future years under standardized weather conditions.

Estimating ex-ante load impacts requires three key pieces of information:

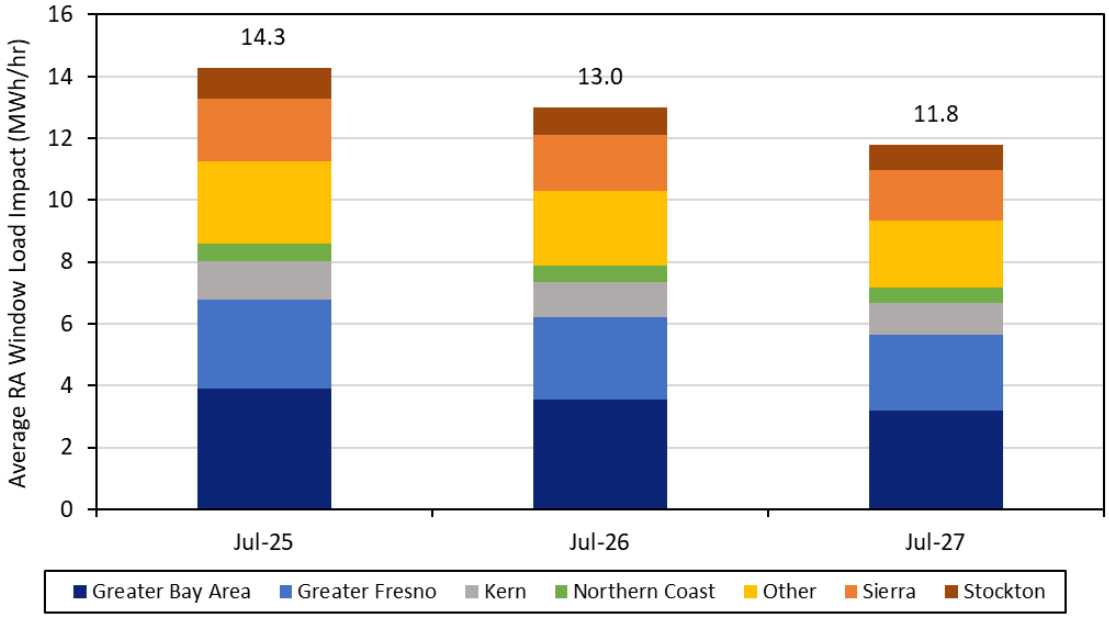
1. An *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customers;
2. *Reference loads* by customer type; and
3. A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions (if applicable), as determined in the ex-post evaluation.

Figure ES-2 summarizes the ex-ante program load impact forecast for 2025 to 2027 for SmartAC™ by plotting the average aggregate load impacts for the first four hours of the resource

[5] Only 184 customers in PGNC were dispatched on July 12, 2024.

adequacy (RA) window over time by LCA.[6] For this comparison we use the PG&E 1-in-2 scenario for July system worst days. The trend of declining aggregate load impacts is driven by declining enrollments due to program attrition, as SmartAC™ is closed to new participants beginning in 2024. Aggregate load impacts steadily decline by about 9.3 percent per year, consistent with the percentage decline in enrollments.

Figure ES-2: Aggregate Load Impacts over RA Window for PG&E 1-in-2 July System Worst Day Scenario (2025-2027)



[6] We use the first four hours of the RA window in 2024, as opposed to the full five hours in previous years, to better reflect ex-post event window (all ex-post events this year ended by 8 p.m.).

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations of Pacific Gas and Electric's (PG&E) SmartAC™ program for 2024. The evaluation produces estimates of the ex-post load impacts for each hour of each event dispatched in 2024, and it develops ex-ante load impact forecasts for the program through 2027.

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers that was integrated into the CAISO wholesale market in program year 2018. SmartAC™ program participants receive a one-time incentive for allowing PG&E to cycle their AC for up to 6 hours per day in response to CAISO market awards, during periods of system or local area emergencies for PG&E capacity, or for limited testing for a maximum of 100 hours per summer (May 1 through October 31).

Upon enrollment in SmartAC™, PG&E installs a Zigbee AC load control switch on the participant's central AC unit that communicates bi-directionally over the AMI network. Legacy technology, installed prior to August 2017, is capable of one-way communication over commercial paging systems and includes programmable communicating thermostats (PCT) and switches. During past years, as part of the second phase of the Reliability Order Instituting Rulemaking decision (D.21-12-015), PG&E was authorized to offer SmartAC™ customers with one-way devices a $25 incentive for PG&E to upgrade their switch to a two-way Zigbee device. Enrollment in the SmartAC™ program has been closed since 2024.[7] When events are dispatched, PG&E sends signals to the PCTs and switches. As dictated by the tariff, PG&E cycles the AC unit for residential customers for approximately 50 percent of the compressor run-time during each half-hour. Switches and some PCTs are cycled using adaptive algorithms.

PG&E employs a combination of events including system-wide serial events or at the Sub-Load Aggregation Point (sub-LAP) level. System-wide events include all participants and can be initiated based on CAISO or PG&E emergencies or for testing purposes. System-wide test events generally dispatch all SmartAC™ customers throughout the service territory except for a random sample of SmartAC™ customers that serve as the control group based on the last digit of the factory programmed serial number of their installed device (i.e., one or more serial groups are withheld from the event).[8] During sub-LAP events, all SmartAC™ participants with devices that are associated with a given sub-LAP are dispatched for the event. Historically, sub-LAP "addressing" was done by sending a signal to new SmartAC™ devices after installation to associate these devices with the appropriate sub-LAP. Since the CAISO wholesale market integration of the SmartAC™ program in 2018, a majority of SmartAC™ events are sub-LAP-level events, while a select number of serial events are dispatched for testing purposes.

Table 1.1 shows the details for each event in program year 2024 (PY2024).[9] There were seventeen SmartAC™ events dispatched in 2024. Fifteen events were CAISO market awards.

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[7] PG&E proposed closing the SmartAC program to new enrollments in its "Application for Pacific Gas and Electric Company (U 39 E) for approval of its demand response program, pilots, and budgets for programs years 2023-2027". The proposal was approved by the CPUC in Decision 23-12-005.

[8] Currently, not all installed devices have a serial number that conforms to this serial group selection process. For these devices, customers are randomly assigned to a serial group at the time of device installation.

[9] In this report, all event hours are based on prevailing time.

There were two serial test events on September 23rd and October 2nd. There was no emergency events dispatched in 2024.

There are two notable differences in the way customers were dispatched in sub-LAP events in PY2024. First, on most sub-LAPS event days, customers in different sub-LAPs were dispatched for different event hours, while in the past all sub-LAPs dispatched on the same day were often dispatched around the same hours. Second, customers with different device types within the same sub-LAP may not get dispatched on the same day. For July events, only two-way device customers were dispatched as one-way devices were left out due to the transition to a new dispatch system. On September 5th and 6th, only one-way device customers were dispatched for most sub-LAPs to catch up with the missing hours compared to customers with two-way devices. For events that happened in late September and October, both one-way and two-way device customers were dispatched.

Table 1.1: PY2024 SmartAC™ Events

Date	SmartRate™ Event?	Reason	Event Hours (p.m.)	Device Type Dispatched	Sub-LAPs/Serial Groups Dispatched	# Customers Dispatched
7/2	Yes	Market	4:00-6:00	Two-Way Only	PGNP, PGST, PGNC, PGP2	7,116
			6:00-8:00		PGSI, PGFG, PGSB	8,323
7/3	Yes	Market	4:00-6:00	Two-Way Only	PGNP, PGSI, PGKN, PGZP, PGNC, PGFG	11,640
			6:00-8:00		PGF1, PGSB, PGP2	11,708
7/5	No	Market	4:00-6:00	Two-Way Only	PGSI, PGST, PGF1, PGZP, PGP2	16,526
			6:00-8:00		PGNP, PGKN, PGNC, PGEB, PGSB	18,477
7/6	Yes	Market	4:00-6:00	Two-Way Only	PGNP, PGST, PGNC, PGEB, PGSB, PGP2	18,385
			6:00-8:00		PGSI, PGKN, PGF1, PGZP	13,940
7/11	Yes	Market	4:00-6:00	Two-Way Only	PGSI, PGKN, PGZP, PGEB, PGP2	16,374
			5:00-8:00		PGNC	166
			6:00-8:00		PGNP, PGST, PGF1, PGSB	15,751
7/12	No	Market	5:00-7:00	Two-Way Only	PGNC	184
7/23	Yes	Market	3:00-5:00	Two-Way Only	PGSI, PGST, PGKN, PGZP, PGNC, PGP2	10,741
			5:00-7:00		PGNP, PGF1, PGSB	13,730
9/4	Yes	Market	6:00-8:00	Both	PGFG	1,084
9/5	Yes	Market	4:00-6:00	One-Way; Both for PGEB	PGNC, PGEB, PGSB, PGP2	13,643
			6:00-8:00	One-Way Only	PGSI, PGST, PGF1	7,378
9/6	No	Market	4:00-6:00	One-Way Only	PGSI, PGNC	3,340
9/23	No	Test	5:00-8:00	Both	All Sub-LAPs, Serial Group 6 withheld	50,202

Date	SmartRate™ Event?	Reason	Event Hours (p.m.)	Device Type Dispatched	Sub-LAPs/Serial Groups Dispatched	# Customers Dispatched
9/24	No	Market	6:00-8:00	Both	PGSB, PGP2	8,007
10/1	No	Market	4:00-5:00	Both	PGNC	405
			4:00-6:00		PGFG, PGNB, PGSB, PGP2	9,999
			6:00-8:00		PGEB	10,846
10/2	No	Test	5:00-8:00	Both	All Sub-LAPs, Serial Group 4 withheld	50,172
10/3	No	Market	4:00-6:00	Both	PGSB, PGP2	7,999
10/5	No	Market	4:00-6:00	Both	PGNB, PGSB	2,799
			6:00-8:00		PGFG, PGP2	2,259
10/6	No	Market	4:00-6:00	Both	PGFG, PGSB	3,045
			6:00-8:00		PGNB, PGP2	2,013

SmartAC™ customers are permitted to be dually enrolled in SmartAC™ and the SmartRate™ program if they were enrolled before October 26, 2018, but subsequent new dual participation is prohibited. As of May 2024, SmartAC™ had over 60,000 active enrolled residential customers; approximately 4,400 of these customers were dually enrolled in SmartAC™ and SmartRate™. During days in which both SmartAC™ and SmartRate™ events are dispatched, the SmartRate™ customers are withheld from our summary of SmartAC™ events and the response from dually enrolled customers is attributed to the SmartRate™ program. Starting January 2024 new enrollment in the SmartAC™ program has been closed.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts for the 2024 program year, including:
    a. Hourly and average daily load impacts for each event;
    b. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, local capacity area (LCA), CARE/non-CARE customers, net-metering solar customers (NEM), housing type (i.e., detached vs. shared wall residences), AC usage intensity, and device type (i.e., two-way vs. one-way; by one-way device type: UtilityPro, Gen 1, and Gen 2);
    c. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;
    d. The opt-out/override rate by customer segment[10]; and
    e. The persistence of load reductions across event hours for multiple hour events.

2. Produce ex-ante load impact forecasts for 2025 to 2027 by sub-LAP and LCA on an aggregate and per-customer basis for a typical event day and the monthly system worst load day for May through October. Forecasts are based on the following four sets of weather conditions:
    a. PG&E's peaking conditions in a 1-in-2 weather year;
    b. PG&E's peaking conditions in a 1-in-10 weather year;

[10] The opt-out rate is the portion of program participants who request by phone or website to override the control of their AC device during specific events.

c. CAISO peaking conditions in a 1-in-2 weather year; and
d. CAISO peaking conditions in a 1-in-10 weather year.

The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

This report is organized as follows: Section 2 describes the evaluation methods used in the study; Section 3 contains ex-post load impact results; Section 4 contains ex-ante forecasts; Section 5 compares ex-post and ex-ante estimates to those from previous years; and Section 6 provides recommendations. Appendices describe the results of our control group matching process, additional analysis and contain electronic versions of the required Protocol table generators.

2. STUDY METHODOLOGY

The primary objectives of this evaluation were outlined in Section 1. This section describes the data and methods used to produce ex-post load impacts and ex-ante forecasts.

2.1 Ex-post Load Impact Evaluation

We estimate load impacts by comparing SmartAC™ customer loads to that of a quasi-experimental matched control group of non-SmartAC™ customers on event days, net of the differences in loads on event-like non-event days. This regression-based approach, known as the difference-in-differences (D-in-D) method, can be used to produce estimates of standard errors to develop confidence intervals about the estimated event-hour or event-day load impacts. The eligible control-group customers consist of residential customers who are not enrolled in any demand response programs, including SmartAC™ or SmartRate™. We match control-group customers based on the similarity of available customer characteristics (e.g., sub-LAP, rate schedule, AC usage level, CARE status, NEM status) as well as usage patterns on non-event days.

2.1.1 Data

To address each of the load impact objectives listed in Section 1, the following data is required:

- *Customer* information for SmartAC™ customers and potential control-group customers (e.g., sub-LAP, LCA, weather station, rate schedule, housing type, CARE status, NEM status);
- Billing-based *interval load data* (i.e., hourly loads for each treatment and potential control group customer) for PY2024 (May 1 through October 31);
- *Weather data* (i.e., hourly temperatures and other variables for PY2024, by weather station);
- *Program event data* (i.e., dates and hours of SmartAC™ and SmartRate™ events and a list of SmartAC™ customers who are dually enrolled in both programs); and

- *Device Information* for SmartAC™ customers (i.e., the type and number of devices installed at each premise and the serial number to determine treatment and control groups for the serial event) as well as SmartAC™ customer opt-outs on each date.

2.1.2 Control Group Selection

The objective in selecting a quasi-experimental matched control group is to identify a group of customers that are as similar as possible to treatment customers, particularly in terms of their hourly load profiles. Due to the high number of potential control customers, we perform the matching in two stages. In the first stage, we use nearest neighbor matching to identify three control customers for each treatment customer that have the closest match in terms of average daily usage (based on monthly billing data), weather station and average cooling degree days, and customer characteristics such as CARE status, NEM status, dwelling type, and rate schedule. Following the first-stage matching, we obtain interval load data for the treatment customers and the paired-down set of matched control customers.

The first-stage matching allows for a more tractable matching process in the second stage using the interval load data. The second stage of the matching process uses propensity score matching to find a single control customer for each SmartAC™ customer with the closest hourly load profile on a selection of non-event, non-holiday, weekdays. Moreover, to ensure that customers are matched based on the sensitivity of their energy usage to weather conditions, we perform this matching process using two 24-hour load profiles drawn from different temperature profiles. The first 24-hour load profile reflects usage patterns during the hottest 10 percent of non-event days. The second 24-hour load profile reflects usage over a set of cooler days taken from the middle 50 percent of non-event days. In addition to two 24-hour load profiles, customers are also matched based on CARE status, NEM status, dwelling type, and AC usage level.[11] Finally, we require that SmartAC™ customers are matched to a control customer residing in the same sub-LAP area with a similar rate schedule (i.e., TOU rates vs. other rates).

Propensity score matching involves estimating a regression to determine each customer's probability (i.e., "propensity") of being assigned treatment based upon observable characteristics. Each SmartAC™ customer is then matched to the control customer with the nearest value in terms of their predicted probability, also known as their "propensity score." For the second stage matching, we assume the probability model is a logistic function of the following form:

$$logit(SmartAC_c) = \beta_0 + \sum_{h=1}^{24} \beta_{1,h} avgkW_{c,h} + \sum_{all\ j} \beta_{2,j} X_{c,j} + \varepsilon_c$$

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

[11] Propensity score matching does not guarantee that treatment customers are matched with a control that has the same CARE status, NEM status, etc. However, this approach leads to a similar distribution across these characteristics for the treatment group and control group.

Table 2.1: Propensity Score Model Terms

Symbol	Description
$SmartAC_c$	Variable indicating whether customer *c* is a SmartAC (1) or Control (0) customer
$avgkW_{c,h}$	Average load during hour *h* for customer *c*
$X_{c,j}$	The value of characteristic *j* for customer *c*
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated coefficient for hour *h* of 24-hour load profile
$\beta_{2,i}$	Estimated coefficient for customer characteristic *j*
ε_c	Error term for customer *c*

We estimate a logistic regression that includes two 24-hour profiles: one that averages customer load across hot days (i.e., the hottest 10 percent of non-event days) and one that averages customer load across a random selection of cooler days (i.e., days that fall between the 25th and 75th percentile of non-event days based on average temperature). Furthermore, we include indicators for CARE status, NEM status, type of dwelling, and AC usage level as customer characteristics in the regression. This model is estimated separately for each sub-LAP and three rate schedule groups (E1, TOU-B/TOU-D, and other rates which includes TOU-C).

To assess the validity of the control-group matching processes, we compare the characteristics and non-event-day load profiles of the matched control-group and treatment customers. More details about our matching process, including evaluation of match quality, are provided in Section 3.1 and Appendix A.

2.1.3 Analysis Methods

To produce estimates of ex-post load impacts, we estimate the following panel model for each hour of the day and sub-LAP:

$$kW_{c,d} = \beta_0 + \sum_{i=1}^{n}\left(\beta_{1,i} SmartAC_{i,c,d} \times Evt_{i,d}\right) + \sum_{all\ j} \beta_{2,j}\, X_{c,d,j} \times AC_c + C_c + D_d + \varepsilon_{c,d}$$

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

Table 2.2: Ex-Post Load Impacts Model Terms

Symbol	Description
$kW_{c,d}$	Load during a given hour for customer *c* on day *d*
$SmartAC_{c,d}$	Variable indicating whether customer *c* is a treated SmartAC customer (1) or Control (0) customer on the *i*th event day (control customers include SmartAC customers in withheld serial groups)
$Evt_{i,d}$	Variable indicating that day *d* is the *i*th event day (1) or not (0)
$X_{c,d,j}$	The value of weather variable *j* on day *d* for customer *c*
AC_c	Variable indicating customer *c*'s level of AC usage (no AC, low, medium, or high)
β_0	Estimated constant coefficient
$\beta_{1,i}$	Estimated load impact for event *i*
$\beta_{2,j}$	Estimated coefficient for weather variable *j*
C_c	Customer fixed effects
D_d	Date fixed effects
$\varepsilon_{c,d}$	Error term (correlated at the customer level)

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time and time-invariant customer characteristics (e.g., home size). In addition, the model includes time variant weather controls such as the mean temperature across the first 17 hours of the day[12]. The $\beta_{1,i}$ coefficients represent the estimated load impacts for each hour of every event day.[13]

For the serial test events, there is an additional control group that was not dispatched, which consists of SmartAC™customers with device serial numbers ending in 6 on September 23rd and those ending in 4 on October 2nd. We estimate load impacts for the serial test event and the sub-LAP events using one model, consistent with the PY2023 evaluation.

We estimate this model separately for each hour of the day using only event and event-like non-event days (i.e., the hottest 10 percent of non-event days). We estimate the distribution of load impacts across different customer subgroups by interacting the event variables with indicator variables for customer subgroups of interest (e.g., CARE vs. non-CARE). While this approach produces subgroup load impacts for each event, these results are not necessarily representative of the system-wide results but are limited to the sub-LAPs dispatched for sub-LAP events. Moreover, the matching procedure used for sub-LAP events does not guarantee that treatments and matched controls have the same subgroup status.

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. Thus, in addition to producing point estimates of the ex-post load impacts, we show the uncertainty around the estimated impacts. These methods use the estimated load-impact parameter values and the associated variances to derive scenarios of hourly load impacts.

We validate the ex-post load impact estimates against simple difference-in-difference calculations from load data. Specifically, for each sub-LAP and event day, we compare the average treatment customer hourly loads to the average control-group hourly loads. The comparisons include events during which the sub-LAP was not dispatched, which allow us to ensure that the event information we were provided is correct and that our methods do not produce “false positives” (i.e., estimated load impacts for dates/locations in which customers were not dispatched).

2.2 Developing Ex-Ante Load Impacts

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are dispatched in future years under standardized weather conditions.

Estimating ex-ante load impacts requires three key pieces of information:

1. An *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;

[12] The inclusion of weather variables may improve the effectiveness of the date fixed effects, particularly in models that include customers in different weather regions (e.g., models by sub-LAP). Similar to the previous year’s evaluation, we have allowed the relationship between weather and loads to vary by AC usage level. This was not necessary to do in evaluations prior to PY2022, as the relationship was comparable across these groups.

[13] When the estimated coefficient is negative or statistically insignificant during the event hour, we zero out the load impacts as these results might be a result of measurement error.

2. *Reference loads* by customer type; and
3. A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions (if applicable), as determined in the ex-post evaluation.

Ex-ante load impacts are developed for the years 2025 through 2027, both for the monthly system worst day load as well as a typical event day, under the four scenarios defined by both utility-specific and CAISO peaking conditions in both 1-in-2 (normal) and 1-in-10 (extreme) scenarios. Furthermore, ex-ante load impacts are developed for the following subgroups of customers:

1. Sub-LAP;
2. LCA; and
3. Customers enrolled in only SmartAC™ vs. customers dually enrolled in SmartAC™ and SmartRate™.

PG&E provided the enrollment forecasts and ex-ante weather conditions for each required scenario. This forecast also accounts for the closure of SmartAC™ to new enrollments.

2.2.1 Reference Loads

The *per-customer reference loads* are simulated based on regression models, which reflect customer load patterns on non-event days and estimate the relationship between load patterns and weather. Reference loads are simulated using the appropriate weather scenario data (i.e., the 1-in-2 and 1-in-10 weather-year conditions provided by PG&E) and month.

The regression model uses data for treatment customers from all non-holiday weekdays that do not coincide with SmartAC™ or SmartRate™ events from May 1 to October 31 in 2024. Average load profiles are created for each sub-LAP and enrollment segment (i.e., SmartAC™-only and dually enrolled customers). The regressions account for differences in loads by hour, day-of-week, or month by including various indicator control variables.

The ex-ante reference load regression model is as follows:

$$avgkW_{d,h} = \beta_0 + \sum_{h=1}^{24} \beta_{1,h}(CDD65_d \times H_h) + \sum_{h=1}^{24} \beta_{2,h}\left(CDD65_d{}^2 \times H_h\right) + \sum_{h=1}^{24} \beta_{3,h}H_h + \sum_{h=1}^{24} \beta_{4,h}(Mon_d \times H_h) + \sum_{h=1}^{24} \beta_{5,h}(Fri_d \times H_h) + D_d + M_d + \varepsilon_{d,h}$$

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

Table 2.3: Ex-Ante Reference Loads Model Terms

Symbol	Description
$avgkW_{d,h}$	Average load (kWh/customer/hour) on day *d* during hour *h*
$CDD65_d$	The cooling degrees on day *d*
$CDD65_d^2$	The cooling degrees on day *d* squared
H_h	Variable indicating that the hour is *h* (1) or not (0)
Mon_d	Variable indicating that day *d* is a Monday (1) or not (0)
Fri_d	Variable indicating that day *d* is a Friday (1) or not (0)
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated increase in average load during hour *h* that results from a one degree increase in cooling degrees
$\beta_{2,h}$	Estimated increase in average load during hour *h* that results from a one degree increase in squared cooling degrees
$\beta_{3,h}$	Estimated average load during hour *h*
$\beta_{4,h}$	Estimated difference in average load during hour *h* on Mondays
$\beta_{5,h}$	Estimated difference in average load during hour *h* on Fridays
D_d	Day of the week fixed effects
M_d	Month of the year fixed effects
$\varepsilon_{d,h}$	Error term (robust)

The model includes hour fixed effects to allow loads to vary by hour of the day. Monday and Friday hourly fixed effects allow for differences in load profiles on Mondays and Fridays. Day of the week fixed effects allow the daily load level to vary by day of the week. Month fixed effects allow the daily load level to vary by month of the year. The $\beta_{1,h}$ coefficients represent the estimated increase in average loads during hour *h* due to a one cooling degree day increase, while the $\beta_{2,h}$ coefficients represent the estimated increase in average loads during hour *h* due to an increase in squared cooling degrees by one. We estimate this model separately for each sub-LAP and enrollment segment to be consistent with the load impact model described in Section 2.2.2. We then aggregate results from the sub-LAP level models to LCA based on the share of customers in each sub-LAP and LCA in PY2024.

Reference loads are simulated by applying the cooling degree days from the weather scenarios provided by PG&E to the estimated $\beta_{1,h}$ and $\beta_{2,h}$ coefficients along with the other relevant load shape variables and fixed effects. The estimated reference loads for each month and weather scenario are assumed to be the monthly system worst day load (or typical event day) for a Wednesday event.

2.2.2 Load Impacts

The ex-ante *per-customer load impacts* are derived from an analysis of the current and previous ex-post load impact evaluations, with a focus on the effect of weather on the estimated load impacts. The resulting ex-ante per-customer load impacts are then coupled with the appropriate simulated ex-ante reference loads to develop the load impact forecast.

We develop an ex-ante forecast that projects program performance during sub-LAP events. We include load impacts from all sub-LAP and serial events in PY2021, PY2022, PY2023, and PY2024 and develop a model that estimates the relationship between ex-post load impacts (for both serial and sub-LAP events) and event day temperatures and simulate the model results for sub-LAP events.

We model the relationship between load impacts and weather conditions as follows:

$$Impact_{s,h,evt\ i} = \beta_0 + \beta_{1,h} Mean17_{s,evt\ i} \times H_h + \beta_2 Temperature_{s,h,evt\ i} + \delta_s Serial_{evt\ i} \times subLAP_s + \mu_s subLAP_s + \varepsilon_{s,h,evt\ i}$$

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

Table 2.4: Ex-Ante Load Impacts Model Terms

Symbol	Description
$Impact_{s,h,evt\ i}$	Estimated load impact in sub-LAP *s* during hour *h* on event *i*
$Mean17_{s,evt\ i}$	Average temperature over the first 17 hours of the day
H_h	Variable indicating if the hour is *h* (1) or not (0)
$Temperature_{s,h,evt\ i}$	Average temperature during hour *h*
$Serial_{evt\ i}$	Variable indicating if event *i* is a serial event (1) or not (0)
$subLAP_s$	Variable indicating if the sub-LAP is *s* (1) or not (0)
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated increase in load impact in hour *h* from a 1 degree increase in the average temperature over the first 17 hours of the day
β_2	Estimated increase in load impact from a 1 degree increase in event-hour temperature
δ_s	Estimated difference in load impacts in sub-LAP*s* during serial events
μ_s	Estimated difference in load impacts for sub-LAP *s*
$\varepsilon_{s,h,evt\ i}$	Error term (robust)

The $\beta_{1,h}$ coefficients represent the estimated increase in load impact during hour *h* that results from a one-degree increase in the average temperature over the first seventeen hours of the event day. The β_2 coefficient is the estimated increase in load impact that results from a one-degree increase in average event-hour temperature. The *δ* coefficient measures the additional load impacts during serial events, which may vary by sub-LAP, and the *μ* coefficients allow load impacts to vary by sub-LAP. The standard errors from this model are the basis for the uncertainty-adjusted load impacts.

We build our ex-ante load impact forecasts based on a combination of sub-LAP and serial events dispatched in 2021, 2022, 2023, 2024. PY2022 had dispatch issues of two-way devices. PY2024 also had lower performance compared to past years partly due to dispatch issues of two-way devices. We keep the weight in the regression the same for all years to account for the possibility that operational issues persist in the future. The load impacts simulated using this model are for sub-LAP events to reflect the nature of how events will be dispatched for the SmartAC™ program in future program years.[14]

In addition, we separately estimate the model using load impacts for one-way and two-way devices. We simulate ex-ante results using different weather scenarios and compute the aggregate load impacts by using the enrollment forecast for one-way and two-way devices. We assume that load impacts are comparable for SmartAC™-only and dually enrolled customers based on our examination of the relative performance of these customers in the past evaluations.

[14] To simulate the load impacts for sub-LAP events, we set $Serial_{evti}$ equal to zero so that the incremental load impacts during serial events are not included in the simulated load impacts.

The snapback during the three hours following the event (when the customer's AC unit is running more than it would have in the absence of the event day to bring the home's temperature back to the thermostat's set point) is modeled as a share of the total event-hour load impact by sub-LAP. That is, larger event-hour load impacts are associated with higher post-event snapback.

As in all recent load impact evaluations, we present results of analyses of the relationship between current ex-post and ex-ante load impacts, focusing on key factors causing differences between them (e.g., differences between observed temperatures in 2024 and the temperatures in the various weather scenarios). We also compare current and previous ex-post load impacts, and current and previous ex-ante load impacts.

3. EX-POST LOAD IMPACTS

This section documents the findings from the ex-post load impact analysis. The primary load impact results include estimates of the aggregate and per-customer event-hour load impacts for each event. Due to the nature of sub-LAP events (fifteen out of seventeen events), during which different sub-LAPs are dispatched for different events and, in most cases, different event hours, we are not able to present results for the typical event day.[15] Instead, we average the hourly load impacts across all potential, full event hours, or in some cases choose an illustrative event hour or event day. Our main findings are summarized in this section in various figures and data tables, while detailed results for each hour, event, and sub-LAP or LCA are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2, all results presented in this section are derived from D-in-D regression analyses of hourly data for SmartAC™ customers and a control group. In addition to the controls described in the estimated model in Section 2.1.3, we control for the seven concurrent SmartRate™ event days by including separate indicators for customers who are dually enrolled in SmartAC™ and SmartRate™. Furthermore, we drop SmartRate™-only events from the pool of SmartAC™ non-event days to ensure that non-event loads are comparable between SmartAC™ customers and controls on all non-event days.

3.1 Control Group Matching Results

In this section, we present summaries of our control group matching process. Our validity assessment focuses on comparisons of treatment and control-group loads for selected event-like non-event days. We also report statistics such as the mean absolute percentage error (MAPE) and mean percent error (MPE), which provide measures of accuracy and bias in the matches, respectively.[16]

Table 3.1 provides the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the RA window. We evaluate match quality based on the two 24-hour load profiles that we use in matching. The first

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[15] In the ex-post Protocol table generator, we use the average load impacts of the two serial events on September 23rd and October 2nd for the "typical event day."

[16] Note that "biased" matches do not necessarily adversely affect the estimated load impacts, as we employ a difference-in-differences estimation methodology that accounts for load differences during the matching period.

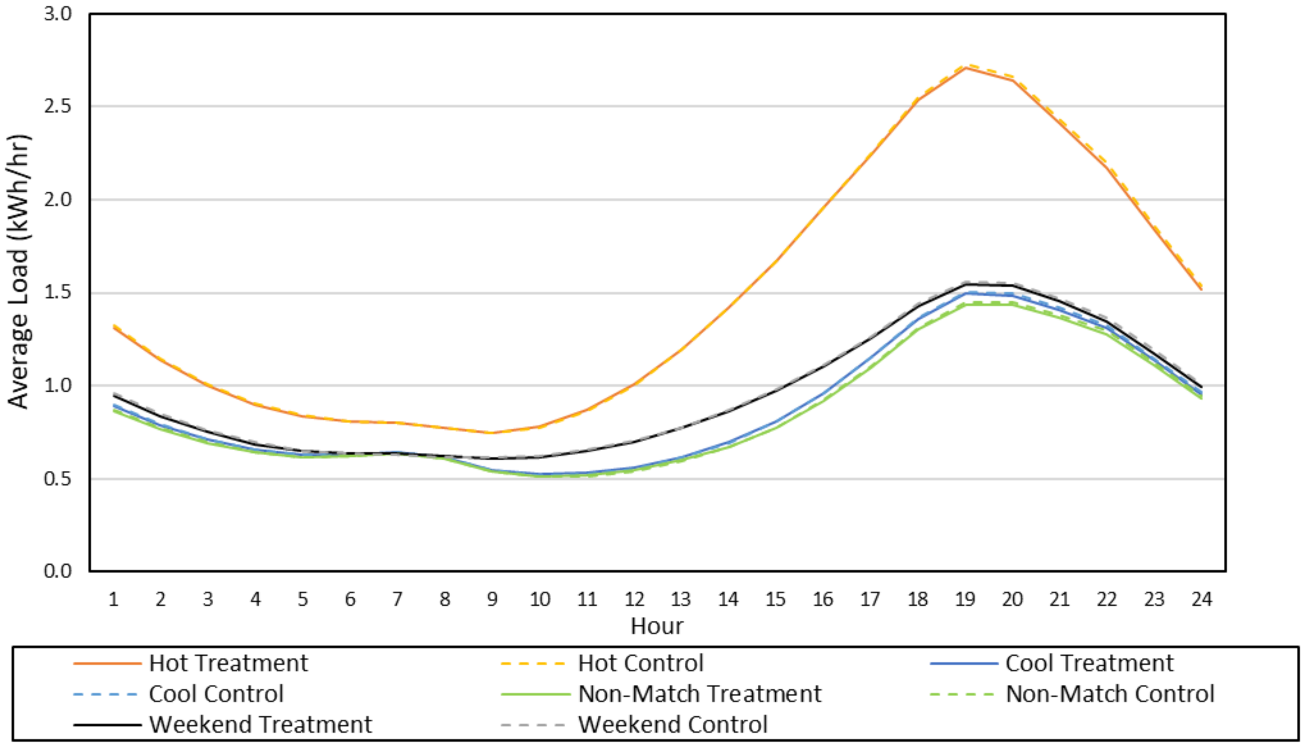
corresponds to the average load profile over the hottest 10 percent of event-like non-event days, while the second corresponds to a random sample of cooler days that ranks from 25% to 75% based on temperature. We also evaluate the match quality of the cooler days (i.e., the middle 50 percent of days based on temperature) that are not sampled for use in matching and the weekend non-event days, which helps assess whether there is good match quality on out-of-sample days. Additional results by sub-LAP are presented in Appendix A.

Table 3.1: Match Quality Statistics

Comparison Days	MPE	MAPE	MPE RA Window	MAPE RA Window
Hot Days	0.3%	0.5%	0.6%	0.6%
Cool Days	0.2%	0.6%	0.4%	0.4%
Non-Matching Cool Days	0.3%	0.6%	0.8%	0.8%
Weekend Days	0.8%	1.0%	0.8%	0.8%

Figure 3.1 illustrates the load profiles for selected event-like days for treatment and matched control customers. This figure contains the average hourly profiles for the treatment and matched control-group customers by day type including hot days, cooler days that were used in matching, cooler days that were not used in matching, and weekend days (not used in matching). The solid lines represent the average usage of treatment customers on hot days (yellow), cooler matching days (blue), cooler non-matching days (green), and weekend days (black). Similarly, the dashed lines represent the average usage of the matched control customers on hot days (yellow), cooler matching days (blue), cooler non-matching days (green), and weekend days (gray). Regardless of the comparison day, the average load profiles are nearly identical between treatment and control. Cool days that are used in matching have comparable loads to cool days that are not used in matching and the control loads on each type of day tracks the treatment loads very closely. Moreover, weekend loads have a comparable load shape to cool weekdays. These results also suggest that matches based on weekdays are appropriate for estimating load impacts for weekend events dispatched in PY2024.

Figure 3.1: Treatment and Control Non-Event Day Load Profiles



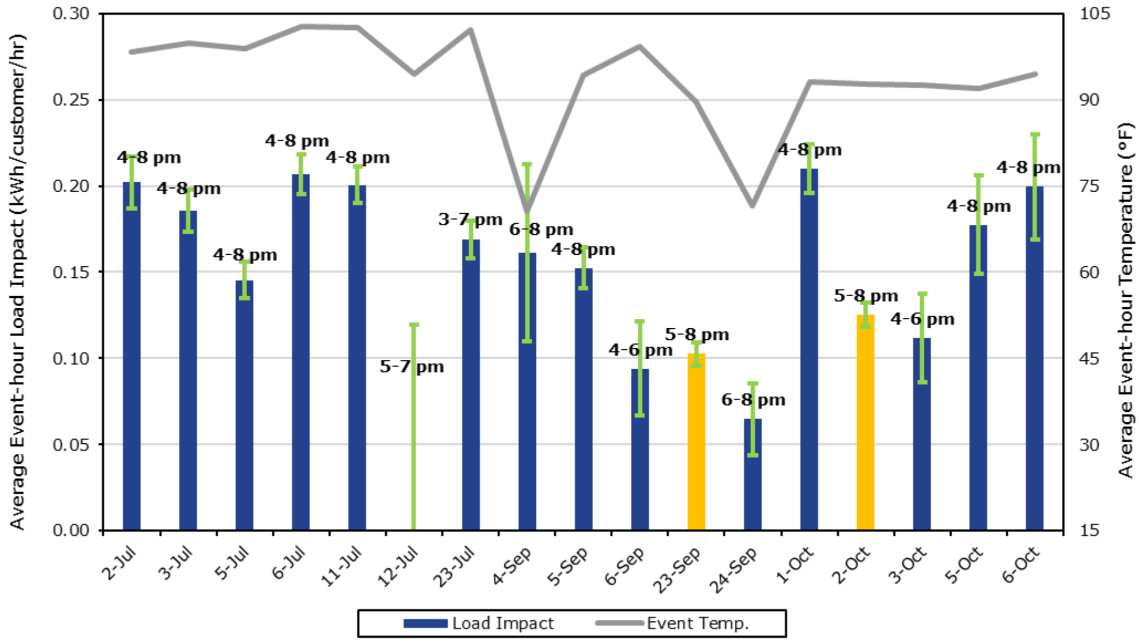
3.2 Overall Load Impacts

This section summarizes overall results for all SmartAC™ events. In later sections, we focus attention on sub-LAP events, serial events, and discuss how these load impacts are distributed across subgroups of interest.

The ex-post load impacts are summarized for all full event hours for the seventeen event days in Figure 3.2. The bars indicate the magnitude of the average per-customer load impact (in kWh/customer/hour) during the full event hours dispatched for each event, while the labels show the maximal range of full event hours over which all customers were dispatched.[17] The gold bars indicates the average per-customer load impact during the full event hours of the serial test events on September 23rd and October 2nd. The blue bars represent the sub-LAP events. The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile scenarios from the uncertainty-adjusted load impacts). The gray solid line represents the average temperatures experienced by the customers during the event.

[17] On non-serial event days, sub-LAPs were dispatched for different event hours. In Figure 3.2, we aggregate across hours during which customers were dispatched, while in the Protocol table generators, the hourly load impacts are aggregated across all sub-LAPs dispatched during the event day for each hour of the day, which can dampen the estimated load impacts during hours in which only a subset of sub-LAP are dispatched and when some sub-LAPs are having post-event snapbacks.

Figure 3.2: Average Event-Hour Load Impacts by Event



Overall results on days other than July 12th range from 0.06-0.21 kWh/customer/hour

These results indicate that SmartAC™ customers have statistically significant load reductions on sixteen of the seventeen event days,[18] ranging from 0.06 kWh/customer/hour on September 24th to 0.21 kWh/customer/hour on October 1st with an average of 0.15 kWh/customer/hour.

Differences in the sub-LAP and device types dispatched drive the variation in per-customer load impacts

Compared to past years, temperature has a smaller effect on load impacts because there is more heterogeneity in the sub-LAPs and device types dispatched. Figure 3.2 shows that some events with lower load impacts correspond to cooler event temperatures, while the event on September 4th has a relatively high load impact for low event temperatures and the event on September 6th has a relatively low impact for high event temperatures. Differences in the sub-LAPs and device types dispatched and variation in sub-LAP and device performance are driving load impact variation across events. For cases when the same sets of sub-LAPs and device types are dispatched, such as July 5th and July 6th, high temperature is associated with high load impacts.

The serial test events have lower impacts than the PY2022 serial event with comparable temperature

The temperatures of the serial events in PY2024 are comparable to the serial event on August 17th in PY2022, which had an average load impact of 0.20 kWh/customer/hour with an average

[18] The only event with statistically insignificant load impact is on July 12th, when only 184 customers in PGNC were dispatched. Low customer count makes the load impact estimates unreliable.

event hour temperature of 91.1°F. Both serial test events, on September 23rd and October 2nd, have lower load impacts with comparable temperatures.

The number of dispatched customers and average event temperatures drive large variation in aggregate event load impacts

Table 3.2 presents a more complete summary of event information, including the sub-LAPs dispatched, the sub-LAP-specific event hours, the type of event, and the number of customers dispatched, as well as average load impacts (per-customer and in aggregate), reference loads, and percentage load impacts across the full event hours for which each sub-LAP was dispatched for each event day. The event dates highlighted in light green are for two-way devices only, the event date highlighted in light orange is for one-way devices only, and the remaining event dates are for both device types. The correlation coefficient between the event temperature and per-customer load impacts is 0.34. The number of dispatched customers varies dramatically across events, from 184 customers dispatched for the sub-LAP event on July 12th to 50,202 customers for the serial event on September 23rd. Aggregate load impacts, which averaged 3.3 MWh/hour for event days other than July 12th, ranged from 0.17 MWh/hour on September 4th to 6.68 MWh/hour on July 6th.

Table 3.2: Average Event-Hour Load Impacts by Event

Date	SmartRate™ Event?	Type of Event	Event Hours (p.m.)	Sub-LAPs/Serial Groups Dispatched	# Called	Average Event Hour				
						Reference (kW/Cust)	Impact (kW/Cust)	% Impact	Aggregate Impact (MW)	Avg. Temp (°F)
7/2	Yes	Market	4-6	PGNP, PGST, PGNC, PGP2	15,439	2.71	0.20	7.5%	3.12	98.2
			6-8	PGSI, PGFG, PGSB						
7/3	Yes	Market	4-6	PGNP, PGSI, PGKN, PGZP, PGNC, PGFG	23,348	2.93	0.19	6.3%	4.33	99.8
			6-8	PGF1, PGSB, PGP2						
7/5	No	Market	4-6	PGSI, PGST, PGF1, PGZP, PGP2	35,003	2.86	0.15	5.1%	5.09	98.8
			6-8	PGNP, PGKN, PGNC, PGEB, PGSB						
7/6	Yes	Market	4-6	PGNP, PGST, PGNC, PGEB, PGSB, PGP2	32,325	3.17	0.21	6.5%	6.68	102.6
			6-8	PGSI, PGKN, PGF1, PGZP						
7/11	Yes	Market	4-6	PGSI, PGKN, PGZP, PGEB, PGP2	32,291	3.17	0.20	6.3%	6.49	102.5
			5-8	PGNC						
			6-8	PGNP, PGST, PGF1, PGSB						
7/12	No	Market	5-7	PGNC	184	3.20	0.00	0.0%	0.00	94.4
7/23	Yes	Market	3-5	PGSI, PGST, PGKN, PGZP, PGNC, PGP2	24,471	2.96	0.17	5.7%	4.13	102.2
			5-7	PGNP, PGF1, PGSB						
9/4	Yes	Market	6-8	PGFG	1,084	1.70	0.16	9.5%	0.17	70.5
9/5	Yes	Market	4-6	PGNC, PGEB, PGSB, PGP2	21,021	2.25	0.15	6.8%	3.20	94.3
			6-8	PGSI, PGST, PGF1						
9/6	No	Market	4-6	PGSI, PGNC	3,340	2.32	0.09	4.0%	0.31	99.3
9/23	No	Test	5-8	All Sub-LAPs, Serial Group 6 withheld	50,202	1.92	0.10	5.3%	5.14	89.6
9/24	No	Market	6-8	PGSB, PGP2	8,007	1.49	0.06	4.4%	0.52	71.5
10/1	No	Market	4-5	PGNC	21,250	2.04	0.21	10.4%	4.48	93.1
			4-6	PGFG, PGNB, PGSB, PGP2						
			6-8	PGEB						
10/2	No	Test	5-8	All Sub-LAPs, Serial Group 4 withheld	50,172	2.37	0.13	5.3%	6.28	92.8
10/3	No	Market	4-6	PGSB, PGP2	7,999	2.33	0.11	4.8%	0.89	92.6
10/5	No	Market	4-6	PGNB, PGSB	5,058	2.16	0.18	8.2%	0.90	91.9
			6-8	PGFG, PGP2						
10/6	No	Market	4-6	PGFG, PGSB	5,058	2.56	0.20	7.8%	1.01	94.4
			6-8	PGNB, PGP2						

Percentage load impacts range from 4 percent to 10 percent on event days other than July 12th

There is variation in the percentage load impacts ranging from 4 percent of reference loads on September 6th to 10.4 percent on October 1st. The is no strong correlation between percentage load impact and event temperatures because sub-LAPs and device types dispatched are different across events. Variation in sub-LAP and device performance leads to difference in percentage load impacts.

Load impacts are persistent across event hours for multiple hour events

Table 3.3 compares average per-customer load impacts and hourly temperatures across hours within each event to analyze whether load impacts persist across event hours.[19] On most event days, the event was two hours long. Load impacts are generally comparable across two-hour events. Larger declines in per-customer load impacts between the first and second event hour are associated with larger declines in hourly temperatures of at least three degrees. During the serial events on September 23rd and October 2nd, the load impacts for the first two hours are similar. Load impacts are lower in the third hour with lower temperatures.

Table 3.3: Persistence of Load Impacts Across Consecutive Events

Date	Full Event Hours (p.m.)	SmartRate™ Event?	Impact (kW/Cust)			Avg. Temp (°F)		
			Hour 1	Hour 2	Hour 3	Hour 1	Hour 2	Hour 3
7/2	4:00-6:00	Yes	0.25	0.25		103.0	102.3	
	6:00-8:00		0.17	0.16		96.7	92.3	
7/3	4:00-6:00	Yes	0.17	0.21		103.3	103.2	
	6:00-8:00		0.20	0.16		98.8	94.0	
7/5	4:00-6:00	No	0.13	0.14		104.1	104.4	
	6:00-8:00		0.17	0.15		96.9	91.0	
7/6	4:00-6:00	Yes	0.22	0.25		100.7	100.1	
	6:00-8:00		0.18	0.16		107.5	103.6	
7/11	4:00-6:00	Yes	0.22	0.24		105.1	103.6	
	5:00-8:00		0.00	0.00	0.00	101.5	98.7	93.3
	6:00-8:00		0.19	0.16		102.3	98.9	
7/12	5:00-7:00	No	0.00	0.00		96.7	92.0	
7/23	3:00-5:00	Yes	0.14	0.15		103.0	103.1	
	5:00-7:00		0.18	0.20		102.6	100.4	
9/4	6:00-8:00	Yes	0.19	0.14		74.0	67.0	
9/5	4:00-6:00	Yes	0.17	0.19		95.2	93.0	
	6:00-8:00		0.10	0.09		97.5	92.2	
9/6	4:00-6:00	No	0.09	0.10		100.0	98.5	
9/23	5:00-8:00	No	0.13	0.12	0.06	94.3	90.2	84.4
9/24	6:00-8:00	No	0.11	0.02		73.0	70.0	

[19] On non-serial event days, different sub-LAPs were dispatched for different event hours. Sub-LAPs dispatched at different times are summarized separately.

Date	Full Event Hours (p.m.)	Smart-Rate™ Event?	Impact (kW/Cust)			Avg. Temp (°F)		
			Hour 1	Hour 2	Hour 3	Hour 1	Hour 2	Hour 3
10/1	4:00-5:00	No	0.26			104.0		
	4:00-6:00		0.23	0.26		98.3	96.2	
	6:00-8:00		0.21	0.15		92.6	85.6	
10/2	5:00-8:00	No	0.16	0.15	0.07	98.3	92.4	87.7
10/3	4:00-6:00	No	0.10	0.12		94.1	91.0	
10/5	4:00-6:00	No	0.17	0.15		97.2	94.0	
	6:00-8:00		0.23	0.17		90.8	84.1	
10/6	4:00-6:00	No	0.22	0.24		99.7	95.6	
	6:00-8:00		0.20	0.11		91.7	87.1	

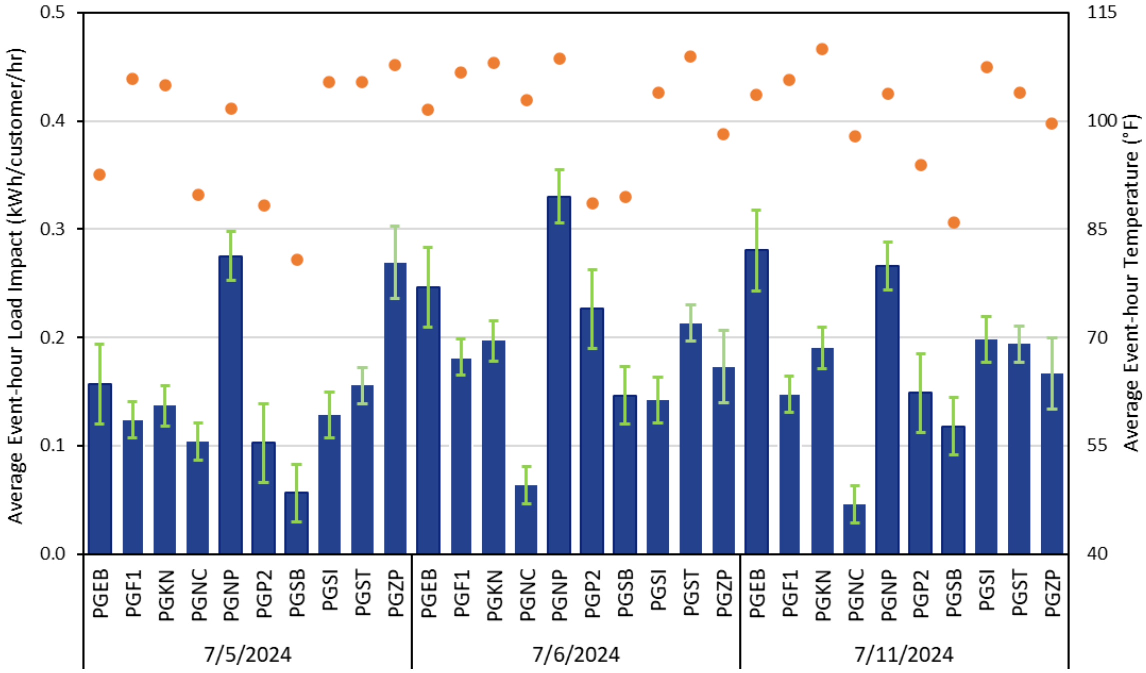
3.3 Sub-LAP Event Load Impacts

Next, we examine the results for sub-LAP events at the sub-LAP level. Figure 3.3 summarizes the sub-LAP level ex-post load impacts for the July 5th, July 6th, and July 11th events, for which most sub-LAPs were dispatched. The bars indicate the magnitude of the average per-customer load impacts (in kWh/customer/hour) across the sub-LAP-specific event hours. The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile scenarios from the uncertainty-adjusted load impacts). The orange scatter plot represents the average temperatures experienced by the customers in each sub-LAP during the event hours.

Temperature differences do not fully explain the variation across sub-LAPs

Load impact ranges from 0 kWh/customer/hour for PGNC on several event days to 0.33 kWh/customer/hour for PGNP on July 6th. These events are for two-way devices only. Historically, customers with two-way devices had higher load impacts than one-way devices, but their load impacts in 2024 are significantly lower than those in previous years across different event temperatures. The lower performance is partially explained by dispatch issues of two-way devices. We provide an analysis of how dispatch issues affect load impacts in Figure D.1. Figure 3.3 illustrates that event temperatures do not fully explain the variation in load impacts, as some lowest load impacts are associated with higher event temperatures. For example, the highest temperature was 110 degrees for PGKN on July 11th, but the load impacts in PGKN were much lower than PGEB and PGNP, which had much lower temperatures.

Figure 3.3: Load Impacts by Sub-LAP on July 5th, July 6th, and July 11th



Sub-LAP event load impacts range from 0.00 to 0.42 kWh/customer/hour

Table 3.4 provides the number of customers dispatched, the average event load impacts (per-customer and in aggregate), reference loads, and percentage load impacts for each sub-LAP event in 2024. The event dates highlighted in light green are for two-way devices only, the event date highlighted in light orange is for one-way devices only, and the remaining event dates are for both device types. Across all sub-LAP events, load impacts range from 0.00 kWh/customer/hour[20] for PGNC during July and September events to 0.42 kWh/customer/hour for PGFG on October 6th.

PGEB has the highest aggregate load impacts

The number of customers dispatched varies across sub-LAPs. The highest load impact is 2.17 MWh/hour, which occurred on July 11th for PGEB. In percentage terms, the highest load impact is 16.4 percent (PGNB on October 1st).

[20] During July and September events, the load impact estimates are zeros for PGNC, which less than 300 customers. Low customer counts lead to unreliable estimates. In these cases, the zero load impacts are due to the estimates being negative and statistically insignificant.

Table 3.4: Average Event-Hour Load Impacts by Sub-LAP and Event for Sub-LAP Events

Date	Sub-LAP	Full Event Hours (p.m.)	# Dispatched	Average Event Hour				
				Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
7/2	PGFG	6:00-8:00	694	3.07	0.37	11.9%	0.25	93.5
	PGNC	4:00-6:00	167	2.84	0.00	0.0%	0.00	101.1
	PGNP	4:00-6:00	3,547	2.60	0.25	9.5%	0.88	103.9
	PGP2	4:00-6:00	1,423	2.60	0.32	12.3%	0.46	97.7
	PGSB	6:00-8:00	3,544	2.56	0.21	8.0%	0.73	90.4
	PGSI	6:00-8:00	4,085	2.85	0.09	3.2%	0.37	98.2
	PGST	4:00-6:00	1,979	2.85	0.22	7.6%	0.43	104.0
7/3	PGF1	6:00-8:00	6,741	3.37	0.15	4.3%	0.98	103.3
	PGFG	4:00-6:00	694	2.83	0.35	12.4%	0.24	91.0
	PGKN	4:00-6:00	2,275	2.97	0.16	5.3%	0.36	106.5
	PGNC	4:00-6:00	167	3.08	0.00	0.0%	0.00	99.9
	PGNP	4:00-6:00	3,546	2.70	0.22	8.2%	0.78	105.2
	PGP2	6:00-8:00	1,423	2.93	0.26	8.8%	0.37	85.7
	PGSB	6:00-8:00	3,544	2.64	0.21	7.9%	0.74	87.6
	PGSI	4:00-6:00	4,084	2.68	0.15	5.7%	0.63	103.2
	PGZP	4:00-6:00	874	2.72	0.27	10.1%	0.24	97.1
7/5	PGEB	6:00-8:00	8,196	2.85	0.16	5.5%	1.28	92.6
	PGF1	4:00-6:00	7,529	2.94	0.12	4.2%	0.93	105.9
	PGKN	6:00-8:00	2,520	3.43	0.14	4.0%	0.34	105.0
	PGNC	6:00-8:00	184	3.19	0.00	0.0%	0.00	89.7
	PGNP	6:00-8:00	4,004	3.12	0.28	8.8%	1.10	101.7
	PGP2	4:00-6:00	1,420	2.31	0.07	3.0%	0.10	88.3
	PGSB	6:00-8:00	3,573	2.15	0.04	2.1%	0.16	80.8
	PGSI	4:00-6:00	4,382	2.81	0.13	4.6%	0.56	105.3
	PGST	4:00-6:00	2,232	3.03	0.16	5.1%	0.35	105.4
	PGZP	4:00-6:00	963	3.12	0.27	8.6%	0.26	107.7
7/6	PGEB	4:00-6:00	7,754	2.88	0.25	8.5%	1.91	101.6
	PGF1	6:00-8:00	6,722	3.72	0.18	4.9%	1.22	106.7
	PGKN	6:00-8:00	2,272	3.86	0.20	5.1%	0.45	108.0
	PGNC	4:00-6:00	166	3.32	0.00	0.0%	0.00	102.9
	PGNP	4:00-6:00	3,538	3.00	0.33	11.0%	1.17	108.6
	PGP2	4:00-6:00	1,417	2.47	0.23	9.2%	0.32	88.6
	PGSB	4:00-6:00	3,537	2.20	0.15	6.6%	0.52	89.4
	PGSI	6:00-8:00	4,073	3.46	0.14	4.1%	0.58	103.9
	PGST	4:00-6:00	1,973	3.34	0.21	6.4%	0.42	109.0
	PGZP	6:00-8:00	873	3.48	0.12	3.4%	0.10	98.2

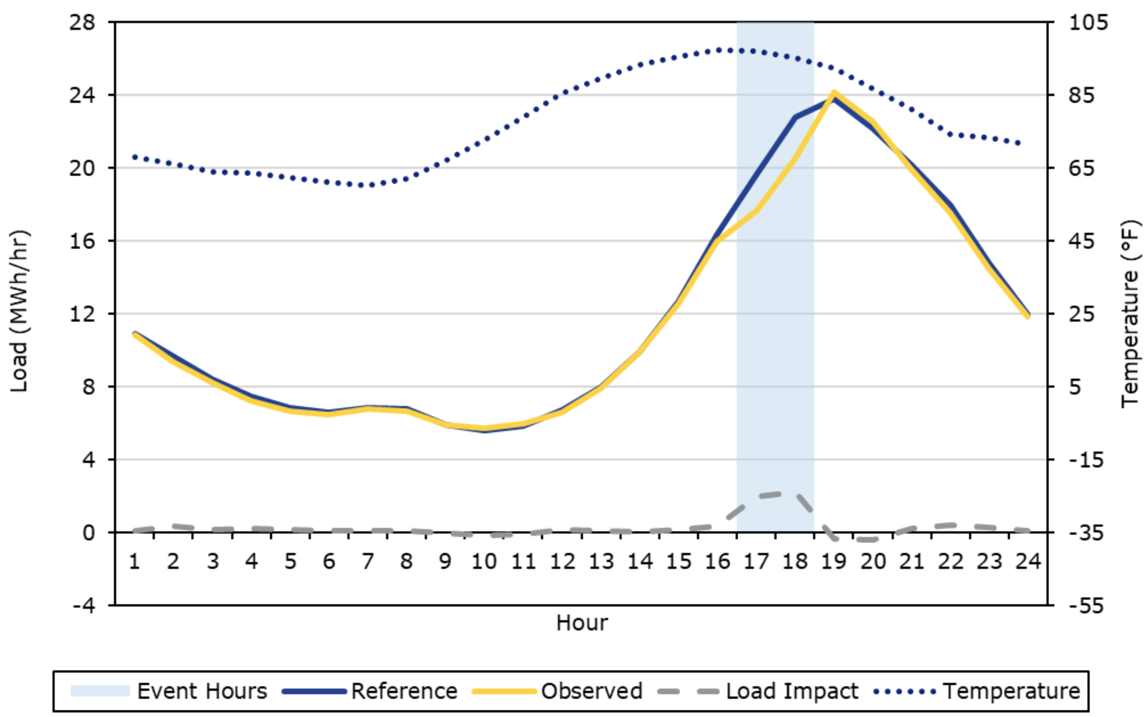
Date	Sub-LAP	Full Event Hours (p.m.)	# Dispatched	Average Event Hour				
				Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
7/11	PGEB	4:00-6:00	7,743	2.89	0.28	9.7%	2.17	103.6
	PGF1	6:00-8:00	6,718	3.74	0.15	4.0%	0.99	105.6
	PGKN	4:00-6:00	2,269	3.34	0.19	5.7%	0.43	110.0
	PGNC	5:00-8:00	166	3.38	0.00	0.0%	0.00	97.8
	PGNP	6:00-8:00	3,533	3.30	0.27	8.0%	0.94	103.7
	PGP2	4:00-6:00	1,417	2.65	0.15	5.6%	0.21	93.8
	PGSB	6:00-8:00	3,528	2.57	0.12	4.6%	0.41	85.9
	PGSI	4:00-6:00	4,071	3.03	0.20	6.5%	0.81	107.4
	PGST	6:00-8:00	1,972	3.75	0.19	5.2%	0.38	103.9
	PGZP	4:00-6:00	874	2.94	0.17	5.7%	0.15	99.6
7/12	PGNC	5:00-7:00	184	3.20	0.00	0.0%	0.00	94.4
7/23	PGF1	5:00-7:00	6,701	3.60	0.17	4.6%	1.11	108.0
	PGKN	3:00-5:00	2,261	2.83	0.13	4.7%	0.30	108.0
	PGNC	3:00-5:00	165	2.75	0.00	0.0%	0.00	100.8
	PGNP	5:00-7:00	3,516	3.09	0.29	9.5%	1.03	102.9
	PGP2	3:00-5:00	1,415	2.26	0.14	6.4%	0.20	90.6
	PGSB	5:00-7:00	3,513	2.44	0.14	5.5%	0.48	87.8
	PGSI	3:00-5:00	4,055	2.66	0.14	5.3%	0.57	104.6
	PGST	3:00-5:00	1,972	2.91	0.16	5.4%	0.31	104.5
	PGZP	3:00-5:00	873	2.66	0.15	5.6%	0.13	100.2
9/4	PGFG	6:00-8:00	1,084	1.70	0.16	9.5%	0.17	70.5
9/5	PGEB	4:00-6:00	10,354	2.05	0.20	9.9%	2.10	96.1
	PGF1	6:00-8:00	2,654	2.99	0.08	2.8%	0.22	98.2
	PGNC	4:00-6:00	200	1.78	0.00	0.0%	0.00	96.8
	PGP2	4:00-6:00	1,147	1.69	0.14	8.0%	0.16	86.5
	PGSB	4:00-6:00	1,942	1.64	0.12	7.5%	0.24	87.3
	PGSI	6:00-8:00	2,987	2.68	0.07	2.7%	0.21	92.4
	PGST	6:00-8:00	1,737	2.68	0.16	5.9%	0.27	93.9
9/6	PGNC	4:00-6:00	222	1.58	0.00	0.0%	0.00	95.0
	PGSI	4:00-6:00	3,118	2.37	0.10	4.2%	0.31	99.6
9/24	PGP2	6:00-8:00	2,554	1.57	0.10	6.4%	0.26	70.5
	PGSB	6:00-8:00	5,453	1.45	0.05	3.3%	0.26	72.0
10/1	PGEB	6:00-8:00	10,846	2.12	0.18	8.5%	1.95	89.1
	PGFG	4:00-6:00	1,122	2.14	0.32	14.8%	0.36	103.0
	PGNB	4:00-6:00	876	2.14	0.35	16.4%	0.31	100.1
	PGNC	4:00-5:00	405	1.82	0.26	14.3%	0.11	104.0
	PGP2	4:00-6:00	2,550	1.98	0.20	9.9%	0.50	97.2
	PGSB	4:00-6:00	5,451	1.86	0.23	12.4%	1.26	95.6
10/3	PGP2	4:00-6:00	2,550	2.42	0.14	5.9%	0.37	92.4
	PGSB	4:00-6:00	5,449	2.29	0.10	4.2%	0.53	92.6

Date	Sub-LAP	Full Event Hours (p.m.)	# Dispatched	Average Event Hour				
				Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
10/5	PGFG	6:00-8:00	1,121	2.23	0.25	11.1%	0.28	87.5
	PGNB	4:00-6:00	875	2.28	0.33	14.3%	0.29	97.4
	PGP2	6:00-8:00	1,138	2.19	0.15	6.9%	0.17	87.4
	PGSB	4:00-6:00	1,924	2.04	0.09	4.2%	0.16	94.8
10/6	PGFG	4:00-6:00	1,121	2.82	0.42	15.0%	0.48	101.0
	PGNB	6:00-8:00	875	2.51	0.28	11.3%	0.25	88.9
	PGP2	6:00-8:00	1,138	2.55	0.06	2.4%	0.07	89.8
	PGSB	4:00-6:00	1,924	2.44	0.11	4.6%	0.22	95.8

Load impacts are similar across sub-LAP event hours with post-event snapback

Figure 3.4 shows an example of the aggregate hourly reference loads, observed loads, and estimated load impacts using the September 5th sub-LAP event for PGEB, in which over 10,000 enrolled SmartAC™ customers with both 1-way and 2-way devices were dispatched from 4 to 6 p.m.[21] Table 3.5 contains these hourly results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts (not displayed in Figure 3.4). Load impacts peak at 2.2 MWh during the second event hour (5 to 6 p.m.), and there is statistically significant post-event snapback the first hour after the event during which loads increase by 0.34 MWh/hour.

Figure 3.4: Hourly Load Impacts on September 5, 2024



[21] In PY2024, there is no overlap of event hours between sub-LAPs for most events, so we choose a single sub-LAP to illustrate the hourly load impacts.

Table 3.5: Hourly Load Impacts and Uncertainty Adjusted Estimates on September 5, 2024

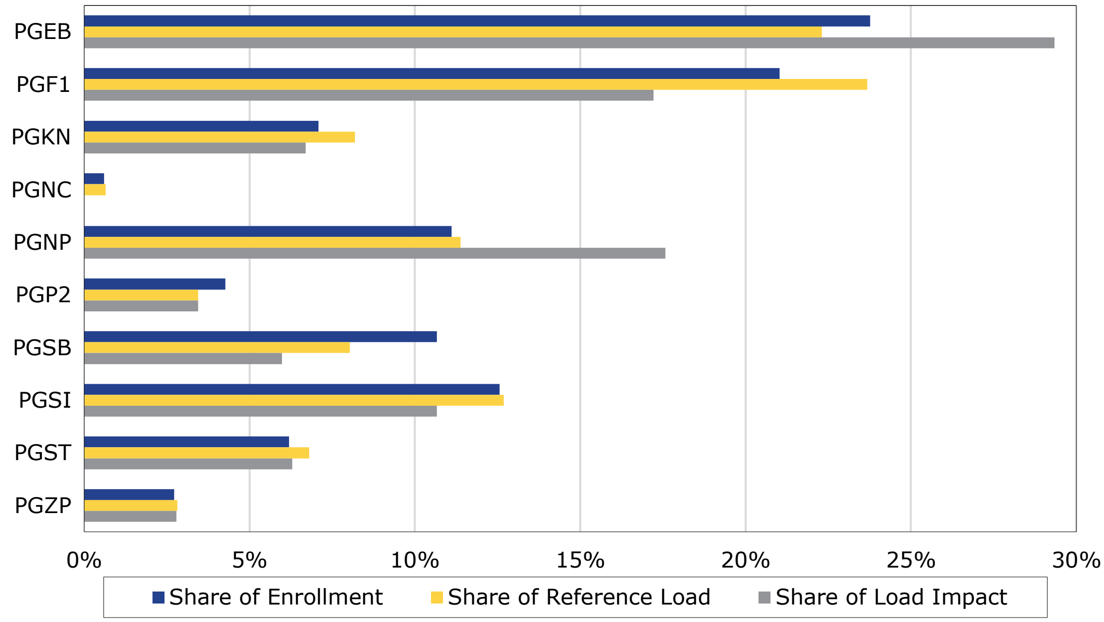
Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour)- Percentiles			Standard Errors	Statistically Significant
					5th %ile	50th%ile	95th %ile		
1	10.9	10.8	0.08	68.1	-0.19	0.08	0.35	0.16	No
2	9.7	9.3	0.33	66.2	0.08	0.33	0.59	0.16	Yes
3	8.4	8.2	0.20	64.0	-0.04	0.20	0.43	0.14	No
4	7.5	7.2	0.22	63.6	0.01	0.22	0.43	0.13	Yes
5	6.8	6.7	0.16	62.3	-0.03	0.16	0.34	0.11	No
6	6.6	6.5	0.12	61.1	-0.03	0.12	0.27	0.09	No
7	6.9	6.8	0.11	60.1	-0.03	0.11	0.24	0.08	No
8	6.8	6.7	0.11	62.0	-0.03	0.11	0.24	0.08	No
9	5.9	5.9	-0.03	67.0	-0.17	-0.03	0.11	0.08	No
10	5.6	5.7	-0.13	72.7	-0.27	-0.13	0.02	0.09	No
11	5.9	6.0	-0.08	79.0	-0.23	-0.08	0.07	0.09	No
12	6.8	6.6	0.15	85.4	-0.02	0.15	0.32	0.10	No
13	8.0	7.9	0.10	89.4	-0.09	0.10	0.29	0.12	No
14	9.9	9.9	0.01	93.4	-0.20	0.01	0.23	0.13	No
15	12.7	12.5	0.14	95.4	-0.10	0.14	0.38	0.15	No
16	16.3	16.0	0.34	97.2	0.09	0.34	0.60	0.16	Yes
17	19.7	17.7	2.00	97.1	1.73	2.00	2.27	0.16	Yes
18	22.8	20.6	2.20	95.2	1.92	2.20	2.48	0.17	Yes
19	23.8	24.2	-0.34	92.3	-0.64	-0.34	-0.05	0.18	Yes
20	22.1	22.5	-0.37	86.7	-0.64	-0.37	-0.09	0.17	Yes
21	20.1	19.9	0.20	81.0	-0.06	0.20	0.47	0.16	No
22	18.0	17.6	0.40	74.1	0.13	0.40	0.66	0.16	Yes
23	14.8	14.5	0.32	73.4	0.07	0.32	0.57	0.15	Yes
24	12.0	11.8	0.10	71.4	-0.13	0.10	0.34	0.14	No

By Period:	Estimated Reference Energy Use (MWh/hour)	Observed Event Day Energy Use (MWh/hour)	Estimated Change in Energy Use (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles			Standard Errors	Statistically Significant
					5th %ile	50th %ile	95th %ile		
Daily	287.9	281.5	6.33	77.4	4.15	6.33	8.52	1.33	Yes
Avg. Event Hour***	21.2	19.1	2.10	96.1	1.91	2.10	2.30	0.12	Yes

PGEB, PGF1, PGNP and PGSI produced 74 percent of load reductions

Next, we look at how load impacts are distributed across sub-LAPs. We focus this analysis on the load impacts from the events on July 5th, July 6th, and July 11th during event hours. Figure 3.5 compares the sub-LAP shares of estimated aggregate event-hour load impacts, reference loads, and enrollments. Out of customers dispatched for the events, PGEB, PGF1, PGNP, and PGSI have 68 percent of enrolled customers and produce 74 percent of the total load reductions. The share of load impacts for PGEB, PGNP, and PGZP exceeds the share of enrollments and reference loads. On the other hand, the share of load impacts for PGF1, PGKN, PGNC, PGSB, and PGSI are lower than the share of enrollments and reference loads.

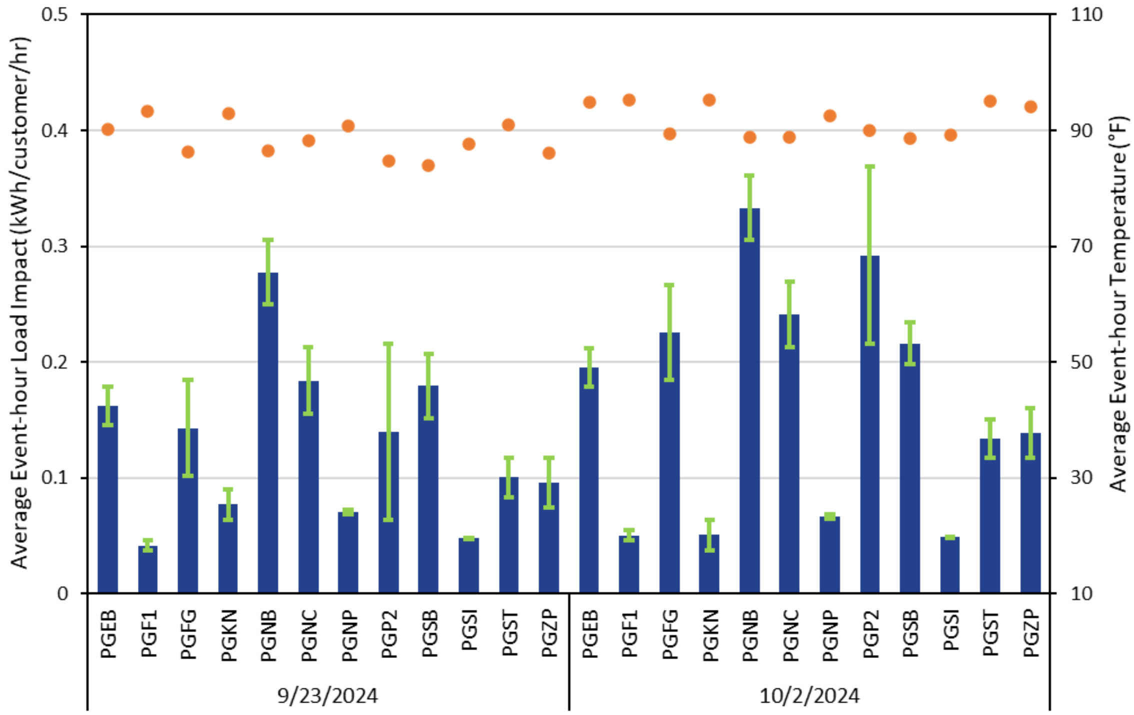
Figure 3.5: Share of Load Impacts by Sub-LAP for July 5, July 6, and July 11, 2024



3.4 Serial Test Event Load Impacts

Next, we examine the results for the serial test events on September 23rd and October 2nd. Figure 3.6 and Table 3.6 summarize the load impacts by sub-LAP. The bars indicate the magnitude of the average per-customer load impacts (in kWh/customer/hour) across the full serial event hours. The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile scenarios from the uncertainty-adjusted load impacts). The orange scatter plot represents the average event temperatures for each sub-LAP.

Figure 3.6: Average Event-Hour Load Impacts by Sub-LAP for the Serial Events



Serial event load impacts range from 0.04 to 0.33 kWh/customer/hour

Load impact ranges from 0.04 kWh/customer/hour for PGF1 on September 23rd to 0.33 kWh/customer/hour for PGNB on October 2nd. The lowest average temperature was 84 degrees for PGSB on September 23rd and the highest was 95.33 degrees for PGKN on October 2nd. While PGF1, PGKN, PGNP, and PGST had some of the highest event temperatures, these sub-LAPs under-performed relative to other sub-LAPs with comparable or lower temperatures.

Table 3.6: Average Event-Hour Load Impacts by Sub-LAP for the Serial Events

Date	Event Hours (p.m.)	Smart-Rate™ Event?	Sub-LAP	# Dispatched	Average Event Hour				
					Reference (kW/Cust)	Impact (kW/Cust)	% Impact	Aggregate Impact (MW)	Avg. Temp (°F)
9/23	5-8	No	PGEB	9,650	1.82	0.16	8.9%	1.56	90.2
			PGF1	9,106	2.22	0.04	1.9%	0.38	93.2
			PGFG	996	1.57	0.14	9.1%	0.14	86.3
			PGKN	2,753	2.40	0.08	3.2%	0.21	93.0
			PGNB	785	1.72	0.28	16.1%	0.22	86.4
			PGNC	370	1.86	0.18	9.9%	0.07	88.2
			PGNP	7,824	1.91	0.07	3.7%	0.55	90.9
			PGP2	2,245	1.66	0.14	8.4%	0.31	84.7
			PGSB	4,856	1.63	0.18	11.0%	0.87	84.0
			PGSI	6,536	1.75	0.05	2.8%	0.32	87.6
			PGST	3,817	2.08	0.10	4.8%	0.38	91.0
			PGZP	1,264	2.01	0.10	4.8%	0.12	86.0

Date	Event Hours (p.m.)	Smart-Rate™ Event?	Sub-LAP	# Dispatched	Average Event Hour				
					Reference (kW/Cust)	Impact (kW/Cust)	% Impact	Aggregate Impact (MW)	Avg. Temp (°F)
10/2	5-8	No	PGEB	9,693	2.52	0.19	7.7%	1.89	94.9
			PGF1	9,087	2.43	0.05	2.1%	0.46	95.3
			PGFG	1,002	2.40	0.23	9.4%	0.23	89.3
			PGKN	2,786	2.65	0.05	1.9%	0.14	95.3
			PGNB	787	2.48	0.33	13.4%	0.26	88.9
			PGNC	355	1.96	0.24	12.3%	0.09	88.8
			PGNP	7,782	2.15	0.07	3.1%	0.52	92.5
			PGP2	2,262	2.59	0.29	11.3%	0.66	90.0
			PGSB	4,814	2.36	0.22	9.1%	1.04	88.6
			PGSI	6,587	2.05	0.05	2.4%	0.32	89.3
			PGST	3,794	2.48	0.13	5.4%	0.51	95.1
			PGZP	1,223	2.59	0.14	5.3%	0.17	94.1

Load impacts for the serial event on October 2nd taper off during the third hour

Figure 3.7 shows the average aggregate hourly reference loads, observed loads, and estimated load impacts for the October 2nd serial event from 5 to 8 p.m. Table 3.7 contains the hourly results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts (not displayed in Figure 3.7). Load impacts peak at 8.2 MWh during the first hour of this event (5 to 6 p.m.), which is likely due to higher temperatures in the first event hour. Figure 3.7 also illustrates that there is significant post-event snapback for the serial event.

Figure 3.7: Hourly Load Impacts on October 2, 2024

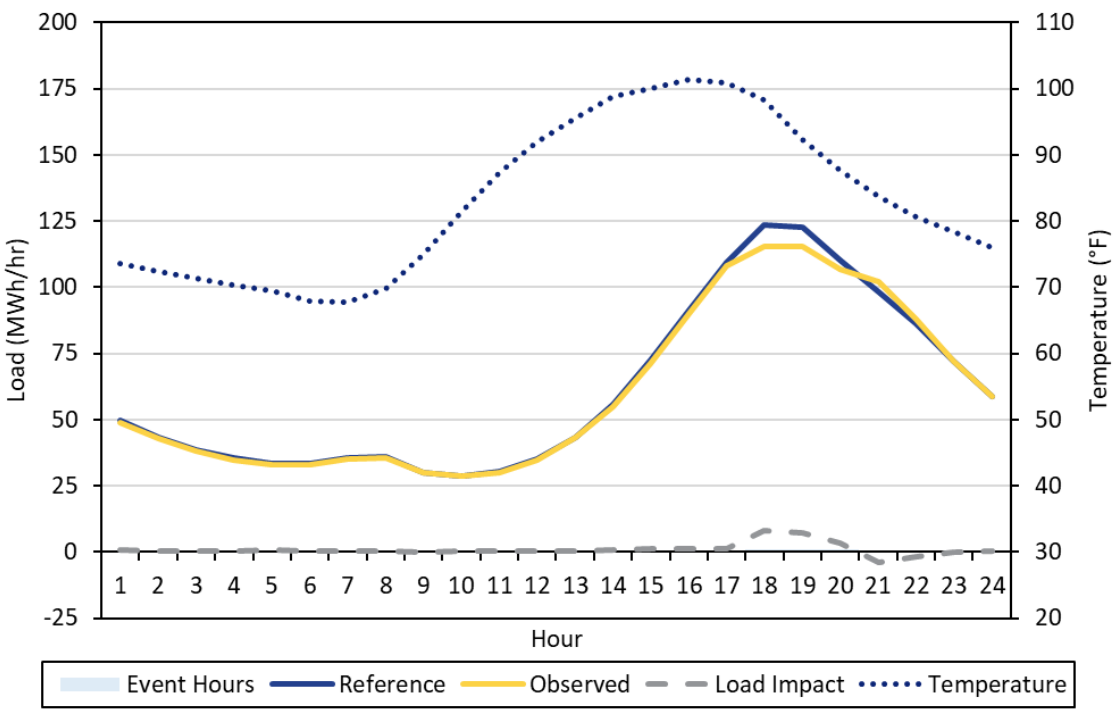


Table 3.7: Hourly Load Impacts and Uncertainty Adjusted Estimates on October 2, 2024

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour)- Percentiles			Standard Errors	Statistically Significant
					5th %ile	50th%ile	95th %ile		
1	49.6	48.9	0.72	73.7	0.25	0.72	1.20	0.29	Yes
2	43.4	42.9	0.52	72.4	0.07	0.52	0.98	0.28	Yes
3	38.7	38.1	0.58	71.3	0.17	0.58	0.99	0.25	Yes
4	35.4	34.8	0.57	70.3	0.20	0.57	0.94	0.23	Yes
5	33.6	32.9	0.70	69.5	0.37	0.70	1.02	0.20	Yes
6	33.4	33.1	0.36	67.9	0.08	0.36	0.64	0.17	Yes
7	35.6	35.1	0.44	67.7	0.18	0.44	0.70	0.16	Yes
8	35.9	35.4	0.55	69.8	0.28	0.55	0.83	0.17	Yes
9	30.0	30.1	-0.03	75.0	-0.31	-0.03	0.26	0.18	No
10	28.8	28.5	0.28	81.6	-0.04	0.28	0.59	0.19	No
11	30.4	30.2	0.23	87.3	-0.12	0.23	0.57	0.21	No
12	35.1	34.7	0.39	92.0	0.01	0.39	0.77	0.23	Yes
13	43.5	43.1	0.36	95.5	-0.08	0.36	0.79	0.26	No
14	55.7	55.0	0.73	98.8	0.24	0.73	1.23	0.30	Yes
15	72.3	71.1	1.16	100.0	0.61	1.16	1.72	0.34	Yes
16	91.2	90.2	1.04	101.4	0.44	1.04	1.64	0.36	Yes
17	109.5	108.1	1.32	100.9	0.68	1.32	1.95	0.39	Yes
18	123.4	115.2	8.21	98.3	7.56	8.21	8.85	0.39	Yes
19	122.7	115.4	7.32	92.4	6.70	7.32	7.94	0.38	Yes
20	110.1	106.8	3.32	87.7	2.73	3.32	3.90	0.35	Yes
21	98.0	101.9	-3.90	83.7	-4.47	-3.90	-3.32	0.35	Yes
22	86.2	88.0	-1.86	80.7	-2.41	-1.86	-1.32	0.33	Yes
23	72.1	72.1	-0.05	78.4	-0.57	-0.05	0.46	0.31	No
24	58.8	58.6	0.19	75.9	-0.28	0.19	0.66	0.29	No
By Period:	Estimated Reference Energy Use (MWh/hour)	Observed Event Day Energy Use (MWh/hour)	Estimated Change in Energy Use (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles 5th %ile	50th %ile	95th %ile	Standard Errors	Statistically Significant
Daily	1,473.4	1,450.3	23.13	83.0	18.20	23.13	28.07	3.00	Yes
Avg. Event Hour***	118.7	112.5	6.28	92.8	5.92	6.28	6.64	0.22	Yes

3.5 Subgroup Load Impacts

This section summarizes how SmartAC™ load impacts are distributed across subgroups of interest including: CARE/non-CARE customers, NEM/non-NEM customers, housing type, AC usage intensity, device type (one-way versus two-way and by one-way device type) and different rate groups.[22] Additional results for these subgroups, including the load profiles, can be found in electronic form in Protocol table generators provided along with this report.[23]

The average ex-post load impacts are summarized for each subgroup in Figure 3.8. These comparisons are based on the average load impacts from the two serial events. The blue and gray bars indicate the magnitude of the average per-customer load impact (in kWh/customer/hour) within each subgroup. The green bands correspond to 90 percent confidence intervals around these estimates. The orange scatter plot represents the average temperatures experienced by customers in each subgroup.

[22] ExpressStat customers are excluded from the analysis because there are too few customers in this subgroup to estimate load impacts reliably.

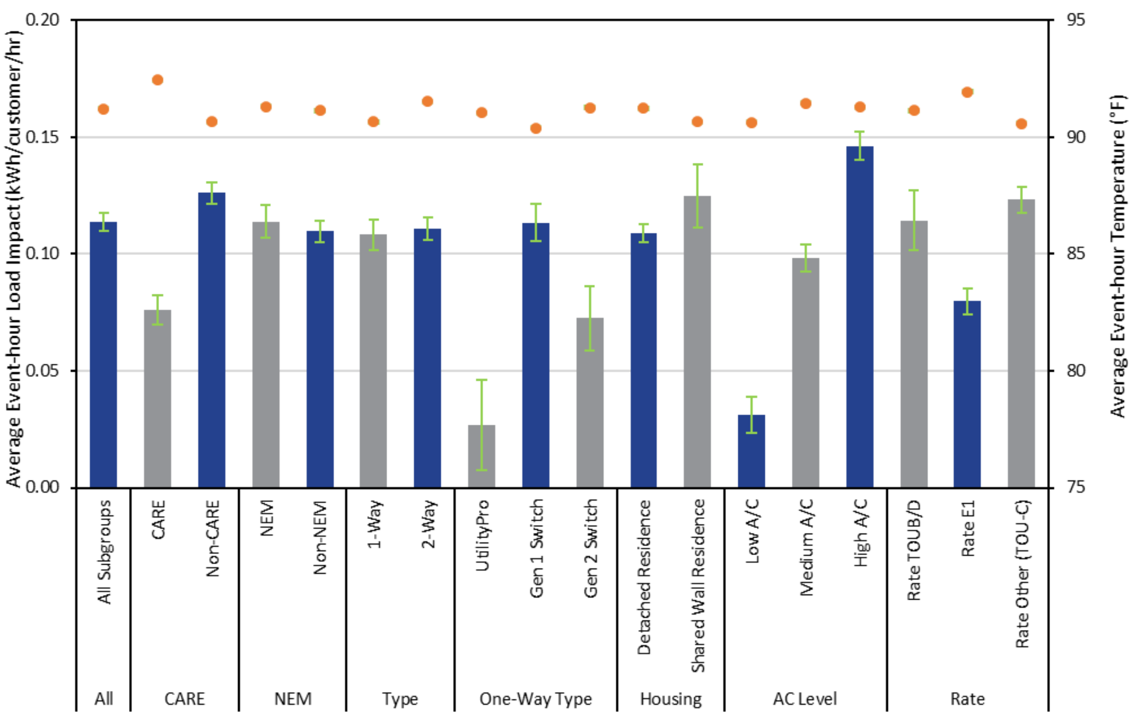
[23] Ex-post load impacts of SmartAC™ and SmartRate™ dually customers on dual event days are included within the SmartRate report.

Figure 3.8 shows that there are statistically significant load impacts for every subgroup. Customers in the various subgroups are not evenly distributed across PG&E's service territory, so the differences in load impacts can be driven by location and device performance.

Results that are similar to past evaluations include:

- Gen 1 and Gen 2 switches had higher load impacts than UtilityPro thermostats. Load impacts for UtilityPro thermostats are 0.05 kWh/customer/hour lower than Gen 2 switches despite comparable event temperatures, however the gap is smaller than previous years, mostly due to lower Gen 2 impacts.
- Load impacts increase with AC usage intensity, with high AC usage customers having significantly higher load impacts than medium and low AC usage customers.
- NEM customers have slightly higher load impacts (and slightly higher temperatures) compared to non-NEM customers.[24]

Figure 3.8: Average Event-Hour Load Impacts by Subgroup



[24] Prior to 2022, NEM customers had comparable or lower load impacts than non-NEM customers. Since 2022, NEM customers started having higher load impacts than non-NEM customers as more events in September and October were dispatched. Solar irradiance declines throughout the summer after peaking in June, which could lead NEM customers to have higher loads in September and October compared to earlier months for comparable temperatures. As a result, NEM customers may have higher potential for load reductions for events that occur later in the summer.

Results that differ from past evaluations include:

- CARE customers have lower load impacts than non-CARE customers despite higher average event-hour temperatures.[25]
- Detached (single family) residences have lower load impacts than Shared Wall (multi-family) residences.
- While one-way devices have slightly lower load impacts (and slightly lower temperature) compared to two-way devices, the gap is much smaller than past years due to lower performance of two-way devices.
- Customers on an E1 rate have the lowest per-customer load impacts despite the highest average event-hour temperatures.

Two-way devices have lower performance compared to past years partly because of dispatch issues. The other differences are likely due to varying sub-LAP performance compared to previous years. For example, PGKN has the highest share of CARE customers and it has much worse performance compared to previous years (Figure C.4).

Table 3.8 provides the detailed information underlying Figure 3.8, including the average number of customers dispatched, the total number of enrolled customers in each subgroup, the average load impacts, reference loads, percentage load impacts, and temperatures. The comparisons of percentage load impacts follow the same patterns as per-customer load impacts.

[25] In PY2022 and PY2020, CARE customers had comparable load impacts to non-CARE customers. In PY2023, PY2021, and PY2019, CARE customers had higher load impacts than non-CARE customers.

Table 3.8: Average Event-Hour Load Impacts by Subgroup

Subgroup	# Dis-Patched	# Enrolled	Average Load Impacts				
			Reference (kWh/cust /hour)	Impact (kWh/cust /hour)	% Impact	Agg. Impact (MWh/ hour)	Avg. Temp (°F)
All SmartAC™ Customers	50,187	56,616	2.14	0.11	5.31%	5.71	91.2
CARE	15,382	17,234	2.22	0.08	3.43%	1.17	92.5
Non-CARE	34,792	39,368	2.10	0.13	5.99%	4.39	90.7
NEM	19,703	22,261	2.46	0.11	4.64%	2.25	91.3
Non-NEM	30,472	34,341	1.94	0.11	5.64%	3.34	91.1
1-Way	18,337	20,646	2.16	0.11	5.02%	1.99	90.7
2-Way	31,850	35,935	2.13	0.11	5.21%	3.53	91.5
UtilityPro	1,918	2,157	2.19	0.03	1.22%	0.05	91.0
Gen 1 Switch	12,360	13,924	2.11	0.11	5.37%	1.40	90.4
Gen 2 Switch	4,004	4,496	2.22	0.07	3.26%	0.29	91.3
Detached Residence	47,810	53,918	2.17	0.11	5.01%	5.20	91.2
Shared Wall Residence	2,342	2,658	1.52	0.12	8.23%	0.29	90.7
Low A/C	5,627	6,355	1.10	0.03	2.83%	0.18	90.6
Medium A/C	17,725	19,992	2.02	0.10	4.87%	1.75	91.5
High A/C	24,169	27,247	2.57	0.15	5.68%	3.53	91.3
Rate TOUB/D	5,723	6,454	2.60	0.11	4.40%	0.65	91.1
Rate E1	20,747	23,397	2.09	0.08	3.82%	1.65	91.9
Rate Other (TOU-C)	23,718	26,766	2.06	0.12	5.98%	2.92	90.6

3.6 Event Override Rate

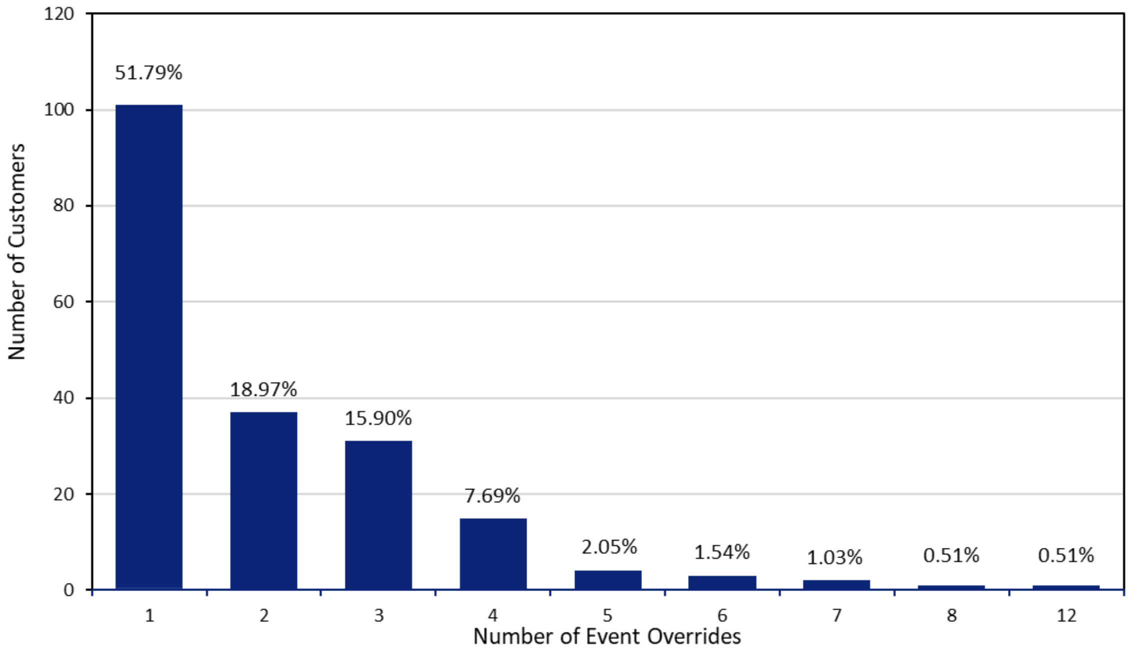
Customers can override (opt out of) SmartAC™ events. Table 3. summarizes the number of overrides by event day, including the number of enrolled customers in the sub-LAPs dispatched for each event. In total, the overrides correspond to 0.12% percent of dispatched customers during PY2024 events. There were no events with high override rates—all were below one percent. Additional tables in Appendix B break down override rates by sub-LAP for each event. All sub-LAPs have override rates below 1 percent.

Table 3.9: Customer Overrides by Event Day

Date	Event Hours (p.m.)	Sub-LAPs Dispatched	Smart - Rate™ Event?	# Overrides	# Dispatched	Override Rate
7/2	4-6	PGNP, PGST, PGNC, PGP2	Yes	17	15,439	0.11%
	6-8	PGSI, PGFG, PGSB				
7/3	4-6	PGNP, PGSI, PGKN, PGZP, PGNC, PGFG	Yes	51	23,348	0.22%
	6-8	PGF1, PGSB, PGP2				
7/5	4-6	PGSI, PGST, PGF1, PGZP, PGP2	No	73	35,003	0.21%
	6-8	PGNP, PGKN, PGNC, PGEB, PGSB				
7/6	4-6	PGNP, PGST, PGNC, PGEB, PGSB, PGP2	Yes	86	32,325	0.27%
	6-8	PGSI, PGKN, PGF1, PGZP				
7/11	4-6	PGSI, PGKN, PGZP, PGEB, PGP2	Yes	77	32,291	0.24%
	5-8	PGNC				
	6-8	PGNP, PGST, PGF1, PGSB				
7/12	5-7	PGNC	No	1	184	0.54%
7/23	3-5	PGSI, PGST, PGKN, PGZP, PGNC, PGP2	Yes	32	24,471	0.13%
	5-7	PGNP, PGF1, PGSB				
9/4	6-8	PGFG	Yes	0	1,084	0.00%
9/5	4-6	PGNC, PGEB, PGSB, PGP2	Yes	7	21,021	0.03%
	6-8	PGSI, PGST, PGF1				
9/6	4-6	PGSI, PGNC	No	0	3,340	0.00%
9/23	5-8	All Sub-LAPs, Serial Group 6 withheld	No	14	50,202	0.03%
9/24	6-8	PGSB, PGP2	No	1	8,007	0.01%
10/1	4-5	PGNC	No	5	21,250	0.02%
	4-6	PGFG, PGNB, PGSB, PGP2				
	6-8	PGEB				
10/2	5-8	All Sub-LAPs, Serial Group 4 withheld	No	19	48,949	0.04%
10/3	4-6	PGSB, PGP2	No	4	7,999	0.05%
10/5	4-6	PGNB, PGSB	No	6	5,058	0.12%
	6-8	PGFG, PGP2				
10/6	4-6	PGFG, PGSB	No	7	5,058	0.14%
	6-8	PGNB, PGP2				
			Total	**400**	**335,029**	**0.12%**

Figure 3.9 illustrates the extent to which customers opted out of multiple events. The y-axis represents the number of customers that opted out of each event, and the percentages on top of each bar represent the shares of customers. About 52 percent of the customers that opted out of any event in 2024 did so only once, while 19 percent of customers opted out of two events, and 16 percent of customers opted out of three events.

Figure 3.9: Number of Event Day Overrides by Customer



4. EX-ANTE LOAD IMPACTS

This section provides the SmartAC™ ex-ante load impact forecast for the period from 2025 to 2027. The forecasts are based on analyses of per-customer load impacts from ex-post evaluations, weather-sensitive reference loads, and incorporation of PG&E's forecasts of program enrollments. The PY2024 ex-ante forecast also reflects SmartAC™ performance during sub-LAP events, consistent with recent evaluations.

Results are presented for customers who are enrolled in SmartAC™-only and for customers who are dually enrolled in SmartAC™ and SmartRate™. We present the following: figures showing the PG&E's enrollment forecast by LCA; a figure showing the forecast of aggregate load impacts; a table and figures showing the hourly reference loads and load impacts on a typical event day; a figure summarizing how ex-ante load impacts vary by month and weather scenario; and a figure showing the share of load impacts on a typical event day by LCA. Detailed results for each hour, weather scenario, month, forecast year, and enrollment segment (i.e., SmartAC™-only and dually enrolled customers) are available in electronic form in Protocol table generators provided along with this report.

Figure 4.1 shows PG&E's enrollment forecast by LCA from 2025 to 2027. The total enrollments in July of each year are displayed above the chart.

PG&E expects enrollments to steadily decrease in 2025 through 2035 for the SmartAC™ program. As of January 2025, there were approximately 56,000 enrolled customers. Similar to last year, PG&E decided not to de-enroll roughly 20,000 customers using one-way devices. Instead, PG&E plans to replace one-way devices primarily for maintenance purposes through 2027, with up to 3,000 one-way devices to be replaced by two-way devices, year over year. Additionally, no marketing efforts will be made to backfill attrition, and furthermore, new enrollments are not allowed. As such, PG&E forecasts an annual attrition rate of approximately 10.5 percent in 2025 based on historical enrollment trends, which would yield a customer base of approximately 41,700 customers by the end of 2027. PG&E also projects a 7% annual attrition rate for SmartRate™ dual enrollments and holds ELRP A.4 enrollments static throughout the forecast horizon.

Figure 4.1: Changes in Enrollment by LCA (2025-2027)

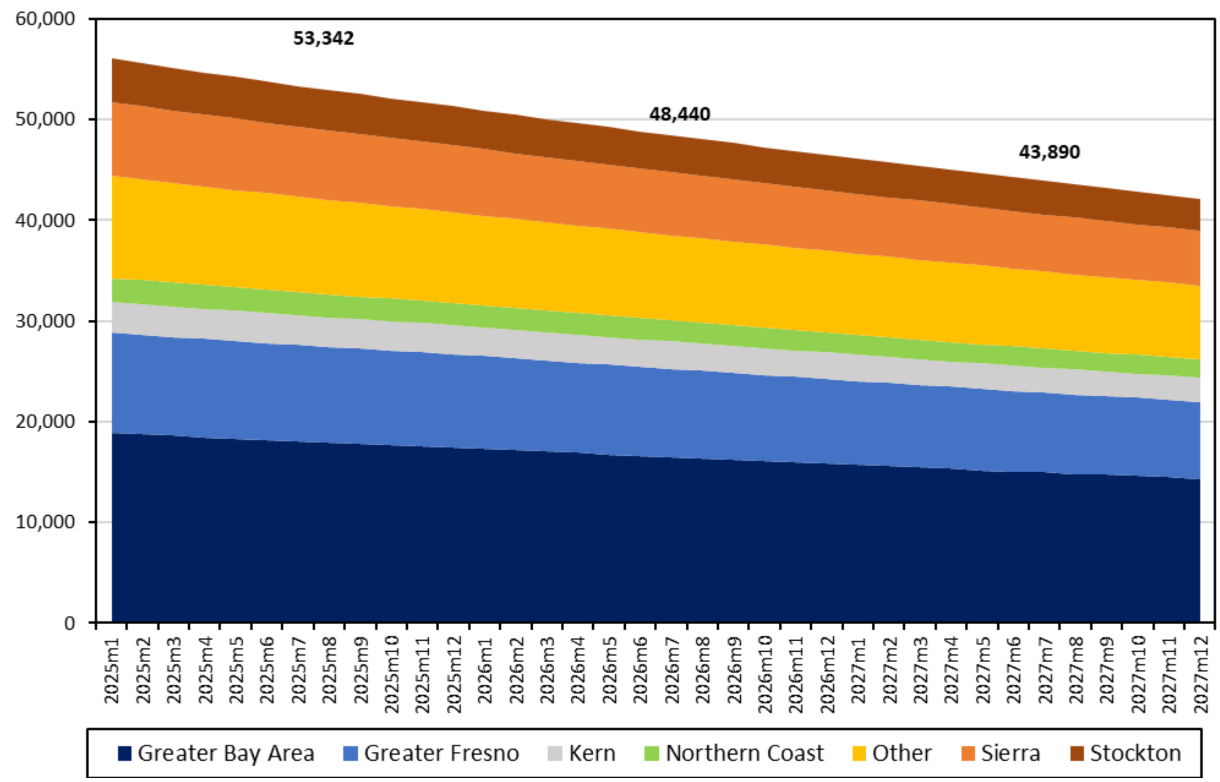


Figure 4.2 illustrates the changes in aggregate load impacts during the first four hours of the Resource Adequacy (RA) window (4 to 8 p.m.) over the forecast period by comparing load impacts for all SmartAC™ customers by LCA for the PG&E 1-in-2 scenario for a July system worst day. Aggregate load impacts decrease by about 9.3 percent per year, which is consistent with the percentage decline of enrollments.

Figure 4.2: Aggregate Load Impacts over RA Window by LCA for PG&E 1-in-2 July System Worst Day Scenario (2025-2027)

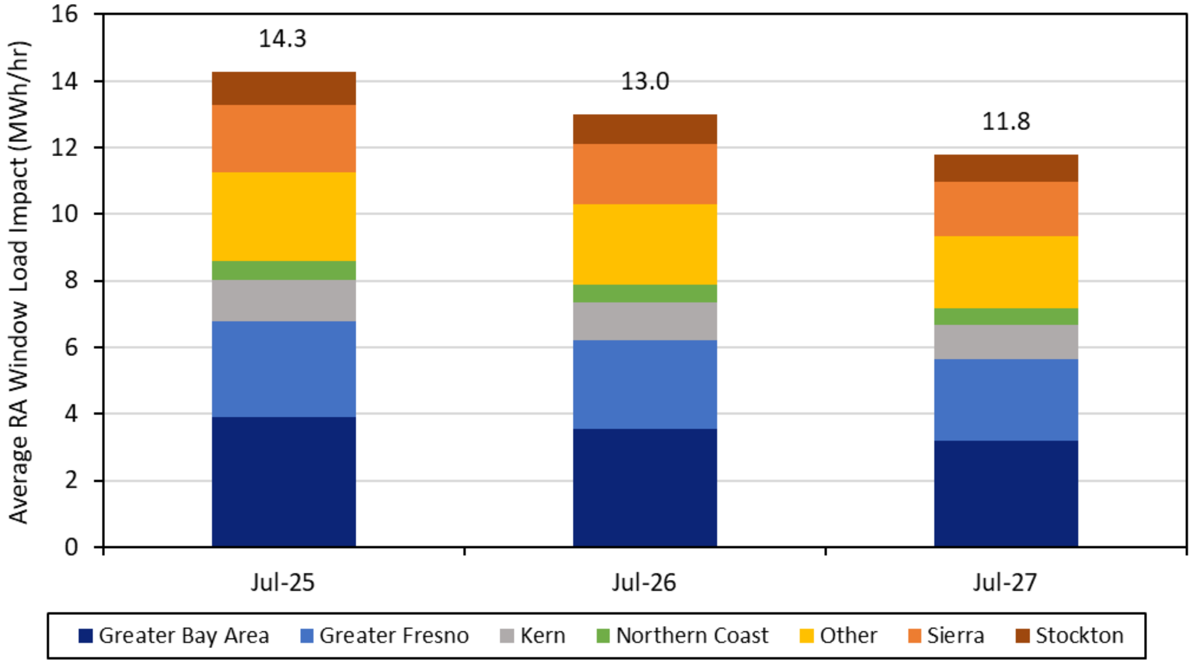


Figure 4.3 illustrates the aggregate reference loads, observed loads, and load impacts for all SmartAC™ customers on a July system worst day in 2025 for the PG&E 1-in-2 weather scenario. Ex-ante load impacts peak during the second event hour. The average July event window load impact is 14.3 MWh/hour, or 10.7 percent of the average event window (the first four hours of the RA window) reference loads.

Figure 4.3: Aggregate Hourly Loads and Load Impacts for July System Worst Day, *PG&E 1-in-2 Scenario* in 2025: All SmartAC™ Customers

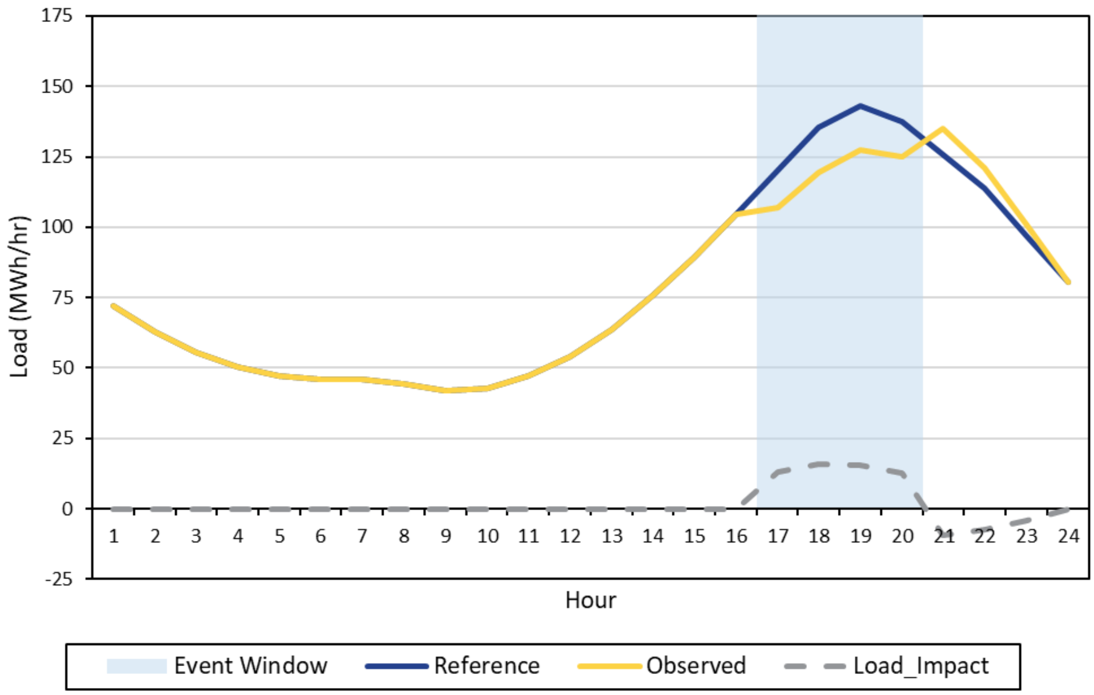


Figure 4.4 illustrates the aggregate reference loads, observed loads, and load impacts for SmartAC™-only customers on a July system worst day in 2025 for the PG&E 1-in-2 weather scenario. The shape of the ex-ante loads and load impacts is similar to the results for all SmartAC™ program customers. The average event window load impact is 13.1 MWh/hour, or 10.5 percent of the average event window reference loads.

Figure 4.4: Aggregate Hourly Loads and Load Impacts for July System Worst Day, *PG&E 1-in-2* Scenario in 2025: SmartAC™-only Customers

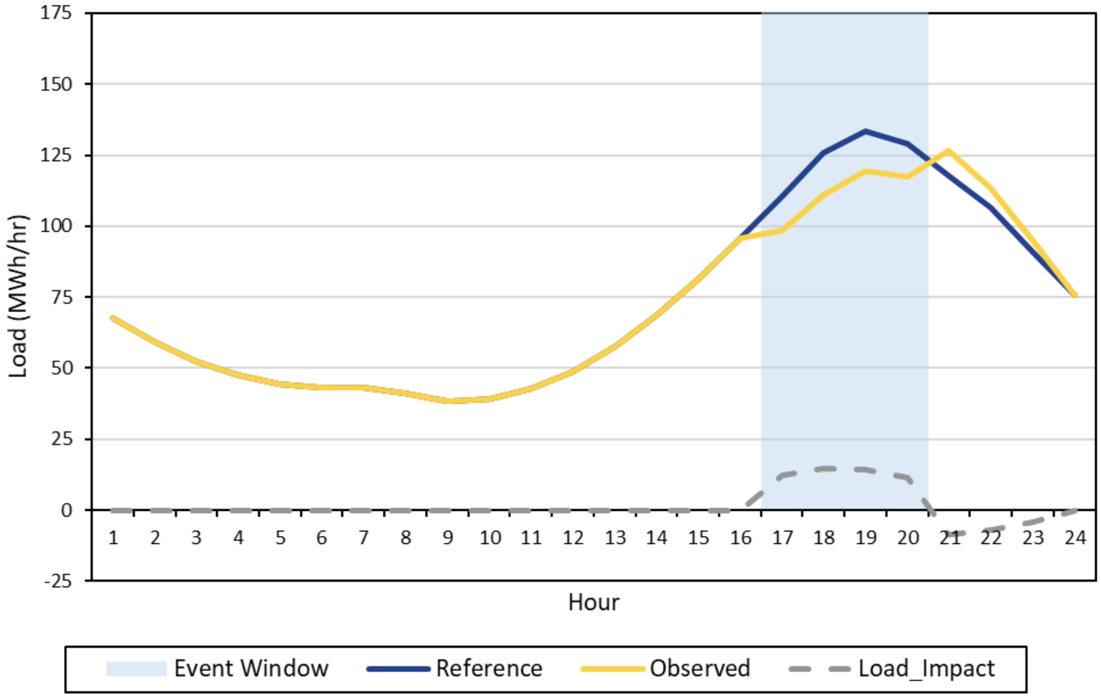


Figure 4.5 illustrates the aggregate reference load, observed load, and load impact for customers who are dually enrolled in SmartAC™ and SmartRate™ on a July system worst day in 2025 for the PG&E 1-in-2 weather scenario. The shape of the reference loads differs for dually enrolled customers, with a peak at HE 19 instead of the HE 18 peak for SmartAC™-only customers. The magnitude of the aggregate loads and load impacts is much smaller compared to SmartAC™-only customers due to lower enrollments. The average event window load impact is 1.1 MWh/hour, or 12.2 percent of the average event window reference loads.

Figure 4.5: Aggregate Hourly Loads and Load Impacts for July System Worst Day, *PG&E 1-in-2* Scenario in 2025: Dually Enrolled Customers

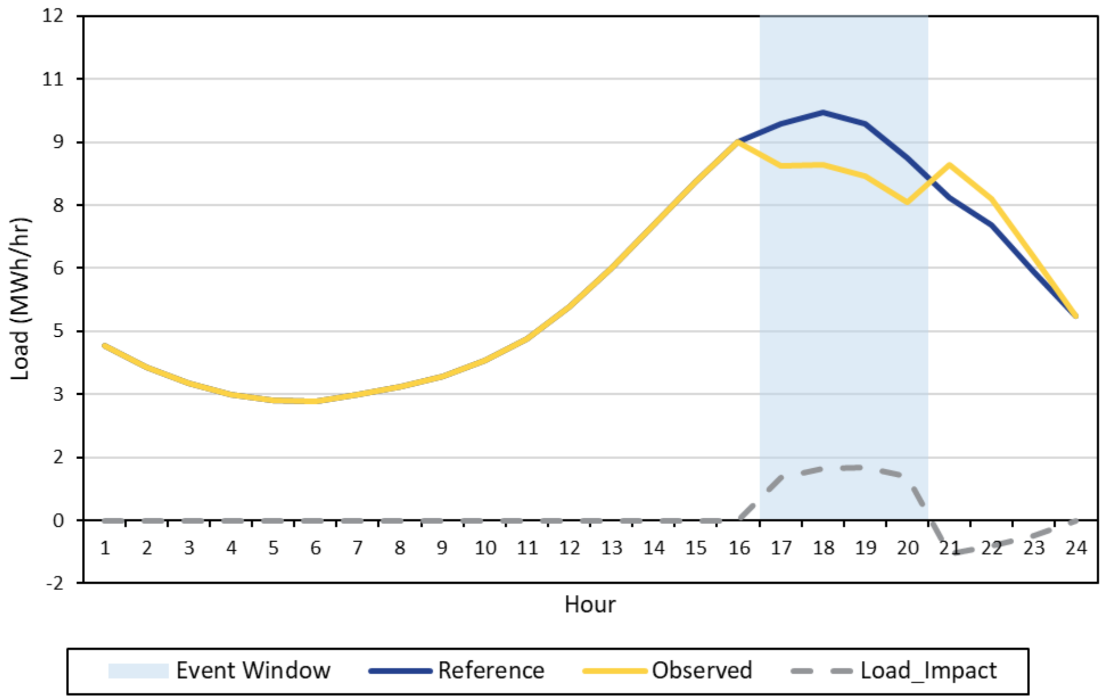


Table 4.1 summarizes average loads and load impacts, percentage load impacts, and average temperatures for the RA window on a July system worst day in 2025 for the PG&E 1-in-2 weather scenario by LCA and enrollment segment. Per-customer load impacts range from 0.22 kWh/customer/hour for Greater Bay Area to 0.42 for Kern. The differences are mainly due to temperatures and event performance in these LCAs. There is large variation in aggregate load impacts due to the distribution of enrolled customers across LCAs. Greater Bay Area has the largest aggregate load impacts of 3.9 MWh/hour, and Northern Coast has the largest percent load impact of 15.4 percent of reference loads from dually enrolled customers.

Table 4.1: Average RA Window Load Impacts for *PG&E 1-in-2* July System Worst Day in 2025 by LCA and Enrollment Segment

Enrollment Segment	LCA	Enrolled	Average RA Window Hour: Reference (kW/cust/hr)	Impact (kW/cust/hr)	% Load Impact	Aggregate Impact (MW/hr)	Avg. Temp (°F)
All	Greater Bay Area	18,068	2.12	0.22	10.2%	3.9	90.9
	Greater Fresno	9,567	3.03	0.30	10.0%	2.9	103.3
	Kern	2,946	3.01	0.42	13.9%	1.2	103.3
	Northern Coast	2,285	2.03	0.25	12.1%	0.6	88.7
	Other	9,472	2.58	0.28	10.9%	2.7	100.2
	Sierra	6,953	2.52	0.29	11.5%	2.0	99.9
	Stockton	4,051	2.76	0.25	9.1%	1.0	99.2
	Total	**53,342**	**2.51**	**0.27**	**10.7%**	**14.3**	**97.9**
Dually Enrolled	Greater Bay Area	558	1.97	0.25	12.9%	0.1	94.2
	Greater Fresno	814	2.81	0.31	11.1%	0.3	103.3
	Kern	270	2.85	0.42	14.6%	0.1	103.3
	Northern Coast	111	1.75	0.27	15.4%	0.0	90.8
	Other	1,144	2.22	0.27	12.4%	0.3	100.3
	Sierra	434	2.22	0.29	12.9%	0.1	99.9
	Stockton	601	2.41	0.26	11.0%	0.2	99.2
	Total	**3,932**	**2.37**	**0.29**	**12.2%**	**1.1**	**100.1**
SmartAC Only	Greater Bay Area	17,510	2.13	0.21	10.1%	3.8	90.8
	Greater Fresno	8,753	3.05	0.30	9.9%	2.6	103.3
	Kern	2,676	3.03	0.42	13.9%	1.1	103.3
	Northern Coast	2,174	2.04	0.25	12.0%	0.5	88.6
	Other	8,328	2.63	0.28	10.7%	2.3	100.2
	Sierra	6,519	2.54	0.29	11.4%	1.9	99.9
	Stockton	3,450	2.83	0.25	8.8%	0.9	99.2
	Total	**49,410**	**2.52**	**0.27**	**10.5%**	**13.1**	**97.7**

Figure 4.6 illustrates the seasonality and variation by weather scenario in the forecasted load impacts by comparing aggregate load impacts for the average hour in the first four hours of the Resource Adequacy (RA) window in 2025 across months and weather scenarios. The highest load impact comes from the PG&E 1-in-10 scenario in September (18.80 MWh/hour), and the second highest load impact comes from the PG&E 1-in-10 scenario in August (16.71 MWh/hour). For the CAISO 1-in-10 scenario, the load impacts are also highest in September (16.66 MWh/hour). The

load impact for the PG&E 1-in-2 (15.51 MWh/hour) and CAISO 1-in-2 (16.31 MWh/hour) scenarios are highest in June.

Figure 4.6: Aggregate Load Impacts over RA Window in 2025 by Month and Weather Scenario

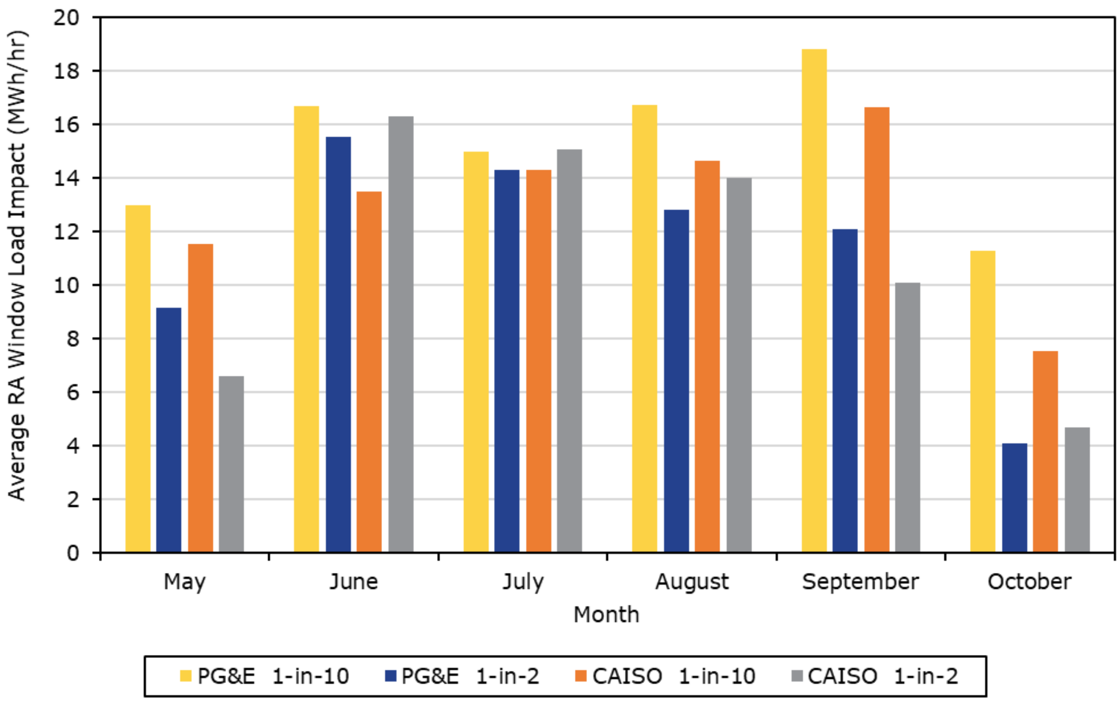
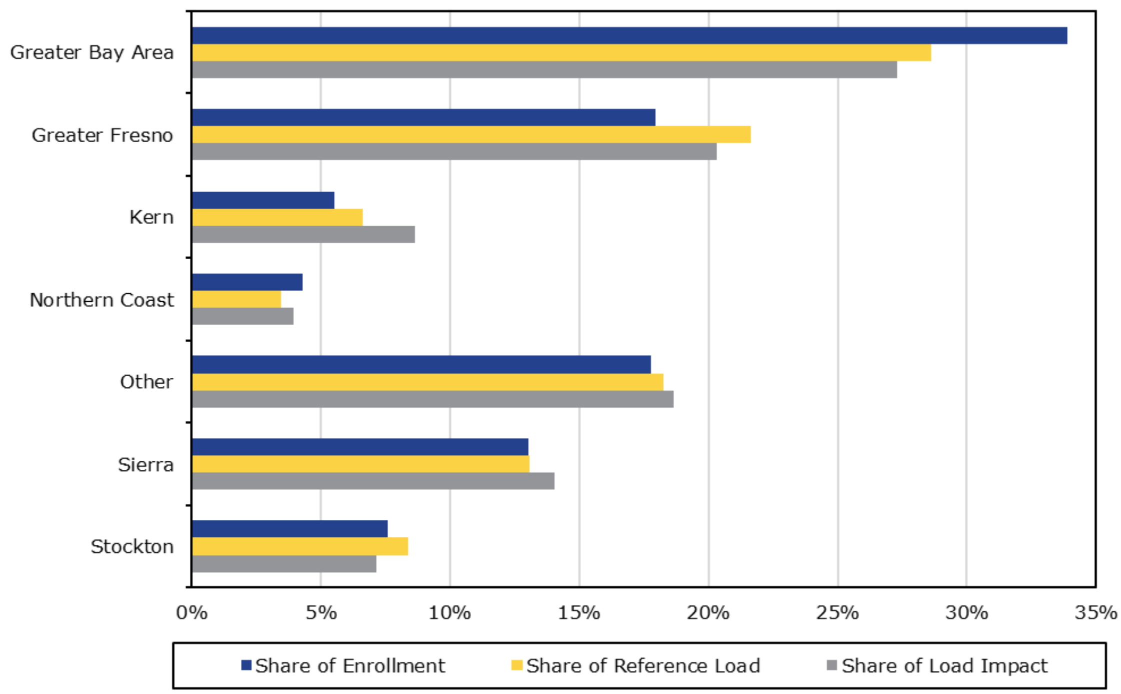


Figure 4.7 compares the LCA shares of average event window load impacts, reference loads, and enrollments on a July system worst day for the PG&E 1-in-2 scenario in 2025. The load impacts for the SmartAC™ program are highest in the Greater Bay Area with 27 percent of aggregate load impacts, 34 percent of enrolled customers, and 29 percent of reference loads. The top four LCAs in terms of enrollments and load impacts, including the Greater Bay Area, Greater Fresno, Other, and Sierra, contribute 80 percent of the aggregate load reductions for SmartAC™. Kern, Sierra, and Other have a higher share of load impacts compared to the share of enrollments or reference loads. The rest of the LCAs have a similar or lower share of load impacts compared to the share of enrollments or reference loads.

Figure 4.7: RA Window Load Impacts for *PG&E 1-in-2* July System Worst Day in 2025 by LCA



5. LOAD IMPACT RECONCILIATIONS

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts for SmartAC™, 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 PY2024. The term "previous" refers to findings in reports for PY2023. In the final comparison above, we illustrate the linkage between the PY2024 ex-post load impacts and the "current" ex-ante forecast.

5.1 Previous vs. Current Ex-Post

In this section we compare ex-post load impacts from the current and previous studies. We compare results for sub-LAP events to the results from PY2023.

Table 5.1 compares the average per-customer reference loads, load impacts, and temperatures for sub-LAP events for the current and previous program years across the most common event hours from 5 to 7 p.m. The bottom row of the table compares average load impacts across sub-

LAPs that had events in both years. About 21,879 fewer customers were dispatched for sub-LAP events in 2024 relative to 2023 due to program attrition and separate dispatch by device type.[26] The reference loads in PY2024 are slightly higher than PY2023. Overall, load impacts were 0.13 kWh/customer/hour lower in PY2024, with average event-hour temperatures that were 2 degrees higher in PY2024. Of the twelve sub-LAPs that had sub-LAP events in both years, seven sub-LAPs had lower load impacts in PY2024 compared to PY2023. PGEB, PGF1, PGKN, PGNC, PGSB, PGSI, and PGST had lower load impacts despite higher or comparable event temperatures. PGFG, PGNB, PGNP, PGP2, and PGZP had higher load impacts with higher event temperatures in PY2024.

Table 5.1: Previous vs. Current Ex-Post Load Impacts (5-7 p.m.)

Sub-LAP	Avg. # dispatched		Reference (kW/cust/hr)		Load Impact (kW/cust/hr)		Avg Temp (°F)	
	PY2023	PY2024	PY2023	PY2024	PY2023	PY2024	PY2023	PY2024
PGEB	12,264	9,521	2.56	2.61	0.30	0.23	94.6	97.0
PGF1	11,006	7,529	3.22	3.48	0.39	0.16	104.1	106.7
PGFG	1,148	1,121	1.85	2.53	0.06	0.33	77.0	91.7
PGKN	3,293	2,520	3.33	3.48	0.54	0.17	107.6	107.9
PGNB	934	875	1.70	2.43	0.11	0.32	87.4	95.3
PGNC	428	194	2.54	2.90	0.27	0.00	93.2	96.5
PGNP	9,581	4,004	2.91	3.06	0.25	0.29	102.0	104.8
PGP2	2,752	1,892	1.77	2.36	0.15	0.18	86.2	88.6
PGSB	5,782	3,962	1.68	2.25	0.16	0.15	85.3	88.2
PGSI	9,932	3,750	3.06	2.97	0.35	0.14	102.1	102.9
PGST	4,644	2,232	3.12	3.26	0.24	0.19	99.8	104.2
PGZP	1,444	963	2.68	3.18	0.22	0.24	95.9	100.8
Common Sub-LAPs	**52,592**	**30,713**	**2.96**	**3.07**	**0.33**	**0.20**	**100.61**	**102.65**

5.2 Previous vs. Current Ex-Ante

In this section, we compare the ex-ante forecast from the previous study to the ex-ante forecast contained in the current study. The comparison includes average load impacts across the first four hours of the RA window from 4 to 8 p.m.

Table 5.2 reports the average event window load impacts for the July 2025 system worst day under PG&E 1-in-2 weather conditions. The enrollments in the PY2023 forecast of 2025 were slightly higher than the PY2024 forecast. Per-customer references loads are comparable in both forecasts. However, the per-customer load impacts are higher in the PY2023 forecast because the PY2024 forecast gives more weights to the worse performance in PY2022 and PY2024. Aggregate load impacts are higher in the PY2023 forecast due to higher enrollments and per-customer load impacts.

[26] For PY2023, two sub-LAPs only have dual events (PGEB, PGFG), so the average number of customers dispatched for these sub-LAPs exclude dually enrolled customers.

Table 5.2: Previous vs. Current Ex-Ante Load Impacts (RA Window)

Level	Outcome	July System Worst Day 2025	
		PY2023 Utility 1-in-2	PY2024 Utility 1-in-2
Total	Enrollments	55,695	53,342
	Reference (MW)	140	134
	Load Impact (MW)	18	14
	Avg. RA Window Temp (°F)	98	98
	Avg. Daily Temp (°F)	84	85
	% Load Impact	13.1%	10.7%
Per Participant	Reference (kW)	2.51	2.51
	Load Impact (kW)	0.33	0.27

5.3 Previous Ex-ante vs. Current Ex-Post

In this section, we compare the ex-ante forecast from the previous study to the ex-post results during sub-LAP events contained in the current study. There are limitations from making such a comparison. The PY2023 ex-ante forecast is for sub-LAPs events assuming both one-way and two-way devices are dispatched within each sub-LAP. In PY2024, only a limited number of sub-LAPs had events when both device types were dispatched, and sub-LAPs were often dispatched at different hours for the same event. The highest number of sub-LAPs dispatched at the same time is on October 1st from 4 to 5 p.m. We compare these load impacts to the forecast for a July system worst day for the PG&E 1-in-10 Scenario to get a closer match of temperatures to the October 1st event, though the temperatures in the weather scenario are still lower than the ex-post event.

Table 5.3 provides a comparison of the PY2023 ex-ante forecast of 2024 load impacts to the ex-post load impacts on October 1, 2024. There are about 350 fewer customers in ex-post compared to the ex-ante forecast. The per-customer load impact is 0.03 kwh/customer/hour higher in ex-post than ex-ante with a much higher average event-hour temperature. The reference loads are also higher on October 1st compared to the forecast. The percentage load impacts are comparable between the ex-ante forecast and the ex-post estimate.

Table 5.3: Previous Ex-Ante vs. Current Ex-Post Load Impacts (4-5 p.m.)

Level	Outcome	PY2023 Ex-Ante	PY2024 Ex-Post
Total	Enrollments	10,754	10,404
	Reference (MW)	20.6	20.9
	Load Impact (MW)	2.5	2.7
	Avg. Evt Hour Temp (°F)	85.7	99.6
	Avg. Daily Temp (°F)	77.8	79.6
	% Load Impact	12.2%	12.8%
Per Participant	Reference (kW)	1.91	2.01
	Load Impact (kW)	0.23	0.26

5.4 Current Ex-Post vs. Current Ex-Ante

In this section, we compare the ex-post findings by device type to the ex-ante forecast for 2025 contained in the current study during the event hours from 5 to 7 p.m.

Table 5.4 compares the ex-post load impacts across all sub-LAP events in 2024, by device type, to the ex-ante load impact forecast for a July system worst day with PG&E 1-in-2 weather conditions in 2025. Per-customer load impacts are higher in the forecast compared to ex-post load impacts because the forecast assumes all customers are dispatched. The enrollment forecast for 2025 is higher than the ex-post number because the ex-post number only includes customers who were dispatched for sub-LAP events in PY2024,[27] while the forecast assumes all customers are dispatched.

Table 5.4: Current Ex-Post vs. Ex-Ante Load Impacts (5-7 p.m.)

Level	Outcome	PY2024 Ex-Post Sub-LAP Event Load Impacts			PY2024 Forecast
		1-Way	2-Way	All	2025
Total	Enrollments	14,244	36,234	50,478	53,342
	Reference (MW)	36.1	108.7	144.9	139.2
	Load Impact (MW)	2.1	7.3	9.3	15.7
	Avg. Event Temp (°F)	94.8	101.1	99.3	98.6
	Avg. Daily Temp (°F)	83.0	87.7	86.4	84.6
	% Load Impact	5.6%	6.7%	6.4%	11.3%
Per Participant	Reference (kW)	2.54	3.00	2.87	2.61
	Load Impact (kW)	0.14	0.20	0.19	0.29

Table 5.5 documents the various potential reasons for differences between the ex-post and ex-ante load impacts. The main reason for higher per-customer load impacts in the ex-ante forecast includes previous years with better event performance. The aggregate load impacts in 2025 are higher than ex-post due to higher enrollment forecasts and higher per-customer load impacts. Per-customer reference loads are lower in the forecast compared to 2024 due to lower daily temperatures in the forecast. Percentage load impacts are higher in the forecast because of higher load impacts and lower reference loads.

[27] Customers with one-way devices in PGKN, PGNP, and PGZP were not dispatched for any events in PY2024.

Table 5.5: Comparison of Ex-Post and Ex-Ante Factors

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 94.8°F for one-way devices, 101.1°F for two-way devices, and 99.3°F overall.	Average event-hour temperature of 98.6°F.	The higher overall temperature in ex-post may produce high per customer load impacts (ceteris paribus).
Device Composition	About 84% of devices dispatched are two-way devices.[28]	About 66% are two-way devices.	Lower ex-ante percentage of two-way devices is due to higher enrollment forecast but slow swap-out rate.
Enrollment	50,478	53,342	Higher ex-ante enrollments increase the aggregate load impacts.
Methodology	Difference-in-Differences with matched control group.	Simulated load impacts from the ex-post using events in 2021-2024.	Incorporating events in PY2021 and PY2023 increases the per-customer load impacts because those years had better performance than in PY2024.

6. RECOMMENDATIONS

In PY2024, load impacts are lower than previous program years. To improve event performance, we recommend PG&E monitor the status of two-way devices in the system during the program season to identify and remedy dispatch problems and continue to investigate other causes that may lead to device under-performance.

It's important to note that 1-way devices were not included in events until the final two months of the season. Their inclusion for the entire season will likely yield more favorable outcomes. It is recommended that 1-way devices participate in all dispatches in future seasons.

For some sub-LAPs, temperatures in the ex-ante scenarios are significantly different than those experienced during ex-post events for the past few years. We recommend that future revisions of the ex-ante temperatures create a better alignment between ex-post and ex-ante sub-LAP weather scenarios to make ex-ante forecasts more helpful for program planning and operation.

[28] Since the first seven events are two-way only events, customers with two-way devices get dispatched for many more hours compared to customers with one-way devices.

7. APPENDICES

The following Appendices accompany this report. Appendix A presents further information about the match quality by sub-LAP in our ex-post analysis. Appendix B provides further details of event override rates by sub-LAP and event. Appendix C illustrates how we evaluated the quality of our ex-post load impact evaluation and ex-ante forecast. Appendix D presents the dispatch issues of two-way devices in 2024. Additional appendices consist of Excel files that can produce the tables required by the Protocols.

Appendix E	3a. PGE_2024_SAC_Ex_Post_PUBLIC
Appendix F	3b. PGE_2024_SAC_Ex_Ante_PUBLIC

Appendix A. Additional Control Group Matching Results

Table A-1 provides the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well as over the RA window. Also included are the mean error (ME) and mean absolute error (MAE) which show the errors in terms of kWh/customer/hour differences rather than percentage differences. Again, we evaluate match quality based on 24-hour load profiles for hot days and cooler days used in matching as well as days not using in matching.

The MPE and MAPE are higher by sub-LAP than the overall results. The average MAPE is 2.1 percent for all hours and 1.5 percent for the RA window. Table A-1 demonstrates that all ME and MAE values are less than 0.05 kWh/customer/hour in absolute terms.

Table A.1: Match Quality Statistics by Sub-LAP

Sub-LAP	Comparison Days	24 Hour Load Profile				RA Window			
		MPE (%)	ME (kW)	MAPE (%)	MAE (kW)	MPE (%)	ME (kW)	MAPE (%)	MAE (kW)
PGEB	Hot Days	1.0%	0.01	1.0%	0.01	0.8%	0.00	0.8%	0.03
	Cool Days	0.9%	0.01	1.1%	0.01	0.8%	0.00	0.8%	0.02
	Non-Matching Cool Days	1.0%	0.01	1.3%	0.01	1.6%	0.00	1.6%	0.02
	Weekend Days	1.3%	0.01	1.5%	0.01	1.2%	0.01	1.2%	0.02
PGF1	Hot Days	1.3%	0.02	1.3%	0.02	1.2%	0.00	1.2%	0.03
	Cool Days	0.9%	0.01	0.9%	0.01	1.1%	0.00	1.1%	0.02
	Non-Matching Cool Days	1.0%	0.01	1.0%	0.01	1.3%	0.00	1.3%	0.02
	Weekend Days	1.4%	0.02	1.4%	0.02	1.3%	0.01	1.3%	0.02
PGFG	Hot Days	0.8%	0.02	2.8%	0.03	3.6%	0.00	3.6%	0.03
	Cool Days	0.3%	0.01	2.2%	0.02	2.2%	0.00	2.2%	0.02
	Non-Matching Cool Days	-0.3%	0.00	2.6%	0.02	2.4%	0.00	2.4%	0.02
	Weekend Days	1.8%	0.02	3.0%	0.02	3.6%	0.01	3.6%	0.02
PGKN	Hot Days	-0.6%	-0.02	0.9%	0.02	-0.6%	0.00	0.7%	0.03
	Cool Days	-0.3%	-0.01	1.1%	0.01	-0.7%	0.00	0.7%	0.02
	Non-Matching Cool Days	0.2%	0.00	1.3%	0.01	-0.5%	0.00	0.6%	0.02
	Weekend Days	0.5%	0.00	1.3%	0.01	0.0%	0.01	0.3%	0.02
PGNB	Hot Days	0.4%	0.00	4.2%	0.04	-1.7%	0.00	1.9%	0.03
	Cool Days	2.2%	0.02	5.0%	0.03	0.4%	0.00	2.0%	0.02
	Non-Matching Cool Days	2.2%	0.02	4.9%	0.03	0.4%	0.00	1.6%	0.02
	Weekend Days	2.0%	0.01	3.9%	0.03	0.7%	0.01	1.9%	0.02
PGNC	Hot Days	-4.0%	-0.03	4.3%	0.04	-0.4%	0.00	1.0%	0.03
	Cool Days	-5.1%	-0.03	5.6%	0.04	-1.5%	0.00	2.1%	0.02
	Non-Matching Cool Days	-3.0%	-0.01	4.5%	0.03	1.0%	0.00	1.8%	0.02
	Weekend Days	-2.2%	-0.01	3.3%	0.03	0.0%	0.01	2.1%	0.02

Sub-LAP	Comparison Days	24 Hour Load Profile				RA Window			
		MPE (%)	ME (kW)	MAPE (%)	MAE (kW)	MPE (%)	ME (kW)	MAPE (%)	MAE (kW)
PGNP	Hot Days	0.1%	0.00	0.9%	0.01	0.5%	0.00	0.6%	0.03
	Cool Days	-0.2%	0.00	0.9%	0.01	0.2%	0.00	0.4%	0.02
	Non-Matching Cool Days	0.1%	0.00	1.0%	0.01	0.8%	0.00	1.0%	0.02
	Weekend Days	0.5%	0.01	0.9%	0.01	0.9%	0.01	0.9%	0.02
PGP2	Hot Days	-1.6%	-0.01	1.7%	0.02	-0.5%	0.00	0.7%	0.03
	Cool Days	-1.8%	-0.01	1.8%	0.01	-1.7%	0.00	1.7%	0.02
	Non-Matching Cool Days	-2.2%	-0.02	2.2%	0.02	-1.9%	0.00	1.9%	0.02
	Weekend Days	-1.8%	-0.01	1.8%	0.01	-1.1%	0.01	1.1%	0.02
PGSB	Hot Days	-1.0%	-0.01	1.3%	0.01	0.0%	0.00	0.4%	0.03
	Cool Days	-0.8%	0.00	1.0%	0.01	-0.6%	0.00	0.8%	0.02
	Non-Matching Cool Days	-1.1%	-0.01	1.4%	0.01	-0.6%	0.00	0.9%	0.02
	Weekend Days	-0.2%	0.00	0.8%	0.01	-0.5%	0.01	0.8%	0.02
PGSI	Hot Days	0.5%	0.01	0.6%	0.01	0.9%	0.00	0.9%	0.03
	Cool Days	0.5%	0.01	0.7%	0.01	0.6%	0.00	0.6%	0.02
	Non-Matching Cool Days	0.6%	0.01	0.8%	0.01	0.9%	0.00	0.9%	0.02
	Weekend Days	1.2%	0.01	1.3%	0.01	1.0%	0.01	1.0%	0.02
PGST	Hot Days	-0.2%	0.00	1.1%	0.02	-0.1%	0.00	0.7%	0.03
	Cool Days	-0.3%	0.00	0.8%	0.01	0.2%	0.00	0.5%	0.02
	Non-Matching Cool Days	-0.1%	0.00	0.7%	0.01	0.9%	0.00	0.9%	0.02
	Weekend Days	0.2%	0.00	0.7%	0.01	0.6%	0.01	0.6%	0.02
PGZP	Hot Days	-0.6%	0.00	1.3%	0.02	0.5%	0.00	0.6%	0.03
	Cool Days	-0.4%	0.00	1.2%	0.01	0.7%	0.00	0.7%	0.02
	Non-Matching Cool Days	-0.4%	0.00	1.6%	0.01	1.3%	0.00	1.3%	0.02
	Weekend Days	0.5%	0.01	1.5%	0.01	0.8%	0.01	0.8%	0.02

Appendix B. Event Overrides by Event and Location

Table B-1 shows customers overrides by sub-LAP for each event day. All override rates are below one percent.

Table B.1: Overrides by Sub-LAP and Event Day

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Overrides	# Dispatched	Override Rate
7/2	PGFG	6:00-8:00	Yes	2	694	0.3%
	PGNC	4:00-6:00		0	167	0.0%
	PGNP	4:00-6:00		6	3,547	0.2%
	PGP2	4:00-6:00		3	1,423	0.2%
	PGSB	6:00-8:00		3	3,544	0.1%
	PGSI	6:00-8:00		2	4,085	0.0%
	PGST	4:00-6:00		1	1,979	0.1%
7/3	PGF1	6:00-8:00	Yes	5	6,741	0.1%
	PGFG	4:00-6:00		4	694	0.6%
	PGKN	4:00-6:00		1	2,275	0.0%
	PGNC	4:00-6:00		1	167	0.6%
	PGNP	4:00-6:00		15	3,546	0.4%
	PGP2	6:00-8:00		6	1,423	0.4%
	PGSB	6:00-8:00		11	3,544	0.3%
	PGSI	4:00-6:00		7	4,084	0.2%
	PGZP	4:00-6:00		1	874	0.1%
7/5	PGEB	6:00-8:00	No	13	8,196	0.2%
	PGF1	4:00-6:00		7	7,529	0.1%
	PGKN	6:00-8:00		3	2,520	0.1%
	PGNC	6:00-8:00		0	184	0.0%
	PGNP	6:00-8:00		15	4,004	0.4%
	PGP2	4:00-6:00		6	1,420	0.4%
	PGSB	6:00-8:00		14	3,573	0.4%
	PGSI	4:00-6:00		10	4,382	0.2%
	PGST	4:00-6:00		4	2,232	0.2%
	PGZP	4:00-6:00		1	963	0.1%

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Overrides	# Dispatched	Override Rate
7/6	PGEB	4:00-6:00	Yes	18	7,754	0.2%
	PGF1	6:00-8:00		5	6,722	0.1%
	PGKN	6:00-8:00		1	2,272	0.0%
	PGNC	4:00-6:00		0	166	0.0%
	PGNP	4:00-6:00		19	3,538	0.5%
	PGP2	4:00-6:00		6	1,417	0.4%
	PGSB	4:00-6:00		18	3,537	0.5%
	PGSI	6:00-8:00		10	4,073	0.2%
	PGST	4:00-6:00		6	1,973	0.3%
	PGZP	6:00-8:00		3	873	0.3%
7/11	PGEB	4:00-6:00	Yes	11	7,743	0.1%
	PGF1	6:00-8:00		5	6,718	0.1%
	PGKN	4:00-6:00		4	2,269	0.2%
	PGNC	5:00-8:00		0	166	0.0%
	PGNP	6:00-8:00		17	3,533	0.5%
	PGP2	4:00-6:00		7	1,417	0.5%
	PGSB	6:00-8:00		13	3,528	0.4%
	PGSI	4:00-6:00		12	4,071	0.3%
	PGST	6:00-8:00		4	1,972	0.2%
	PGZP	4:00-6:00		4	874	0.5%
7/12	PGNC	5:00-7:00	No	1	184	0.5%
7/23	PGF1	5:00-7:00	Yes	5	6,701	0.1%
	PGKN	3:00-5:00		1	2,261	0.0%
	PGNC	3:00-5:00		0	165	0.0%
	PGNP	5:00-7:00		10	3,516	0.3%
	PGP2	3:00-5:00		3	1,415	0.2%
	PGSB	5:00-7:00		3	3,513	0.1%
	PGSI	3:00-5:00		7	4,055	0.2%
	PGST	3:00-5:00		1	1,972	0.1%
	PGZP	3:00-5:00		2	873	0.2%
9/4	PGFG	6:00-8:00	Yes	0	1,084	0.0%
9/5	PGEB	4:00-6:00	Yes	3	10,354	0.0%
	PGF1	6:00-8:00		1	2,654	0.0%
	PGNC	4:00-6:00		0	200	0.0%
	PGP2	4:00-6:00		1	1,147	0.1%
	PGSB	4:00-6:00		0	1,942	0.0%
	PGSI	6:00-8:00		1	2,987	0.0%
	PGST	6:00-8:00		1	1,737	0.1%
9/6	PGNC	4:00-6:00	No	0	222	0.0%
	PGSI	4:00-6:00		0	3,118	0.0%

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Overrides	# Dispatched	Override Rate
9/23	PGEB	5:00-8:00	No	2	9,650	0.0%
	PGF1	5:00-8:00		1	9,106	0.0%
	PGFG	5:00-8:00		0	996	0.0%
	PGKN	5:00-8:00		1	2,753	0.0%
	PGNB	5:00-8:00		0	785	0.0%
	PGNC	5:00-8:00		0	370	0.0%
	PGNP	5:00-8:00		4	7,824	0.1%
	PGP2	5:00-8:00		1	2,245	0.0%
	PGSB	5:00-8:00		3	4,856	0.1%
	PGSI	5:00-8:00		1	6,536	0.0%
	PGST	5:00-8:00		0	3,817	0.0%
	PGZP	5:00-8:00		1	1,264	0.1%
9/24	PGP2	6:00-8:00	No	1	2,554	0.0%
	PGSB	6:00-8:00		0	5,453	0.0%
10/1	PGEB	6:00-8:00	No	1	10,846	0.0%
	PGFG	4:00-6:00		2	1,122	0.2%
	PGNB	4:00-6:00		0	876	0.0%
	PGNC	4:00-5:00		0	405	0.0%
	PGP2	4:00-6:00		2	2,550	0.1%
	PGSB	4:00-6:00		0	5,451	0.0%
10/2	PGEB	5:00-8:00	No	3	9,693	0.0%
	PGF1	5:00-8:00		1	9,087	0.0%
	PGFG	5:00-8:00		4	1,002	0.4%
	PGKN	5:00-8:00		0	2,786	0.0%
	PGNB	5:00-8:00		2	787	0.3%
	PGNC	5:00-8:00		0	355	0.0%
	PGNP	5:00-8:00		4	7,782	0.1%
	PGP2	5:00-8:00		2	2,262	0.1%
	PGSB	5:00-8:00		1	4,814	0.0%
	PGSI	5:00-8:00		2	6,587	0.0%
	PGST	5:00-8:00		0	3,794	0.0%
10/3	PGP2	4:00-6:00	No	2	2,550	0.1%
	PGSB	4:00-6:00		2	5,449	0.0%
10/5	PGFG	6:00-8:00	No	2	1,121	0.2%
	PGNB	4:00-6:00		2	875	0.2%
	PGP2	6:00-8:00		1	1,138	0.1%
	PGSB	4:00-6:00		1	1,924	0.1%
10/6	PGFG	4:00-6:00	No	2	1,121	0.2%
	PGNB	6:00-8:00		2	875	0.2%
	PGP2	6:00-8:00		1	1,138	0.1%
	PGSB	4:00-6:00		2	1,924	0.1%

Appendix C. Scatterplots of Load Impacts and Temperature

Figure C.1 through Figure C.12 show scatterplots of hourly ex-post and ex-ante load impacts compared to average temperatures from PY2024 for all sub-LAPs by device type. PGCC is dropped from this analysis as it no long receives CAISO market awards in 2024 due to low customer count. The red dots show the ex-post load impacts of sub-LAP events in 2024. The blue dots show the ex-post load impacts of sub-LAP events in 2021, 2022 and 2023, while the blue line shows the linear relationship between load impacts and hourly temperatures in all four years. The green dots and line show the ex-ante load impacts from the PY2024 forecast. The results are limited to the hours where ex-post and ex-ante have overlapping event hours from 4 to 8 p.m. For the ex-ante load impacts we use the June, July, August, September, and October system worst day weather conditions for the PG&E 1-in-10 weather scenario for 2024.

For most sub-LAPs, the two-way device load impacts (right) are higher than one-way device load impacts (left) from 2021 to 2023. In 2024 one-way devices and two-way devices tend to have worse performance than in previous years. Given similar temperatures, the forecasted ex-ante load impacts tend to be in line with the results from ex-post. Considering the lower performance for some sub-LAPs in 2022 and 2024[29], the inclusion of ex-post results from 2022 and 2024 in the forecast assumes some level of operational issues in the future. Furthermore, the forecasts by device type have slightly different relationships between per-customer load impacts and temperature.

[29] Appendix D provides a comparison for the load impact estimates between all devices and those that were successfully dispatched only.

Figure C.1: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGEB

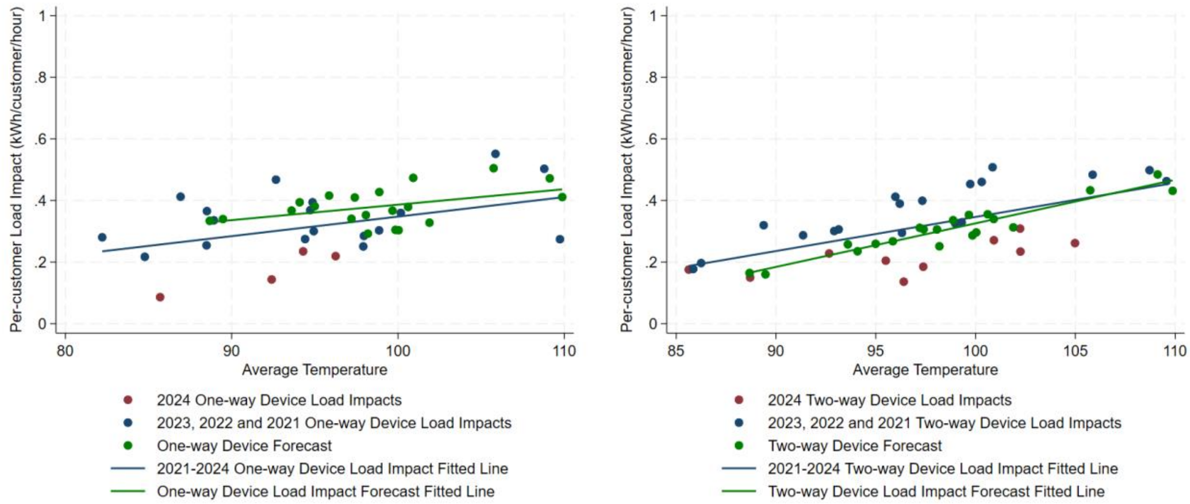


Figure C.2: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGF1

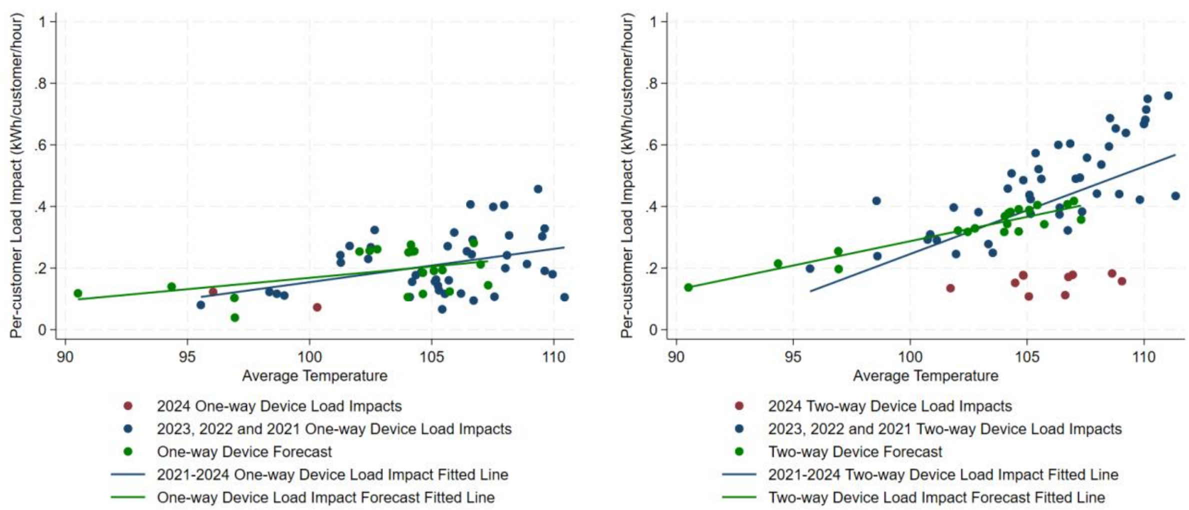


Figure C.3: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGFG

[redacted]

Figure C.4: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGKN

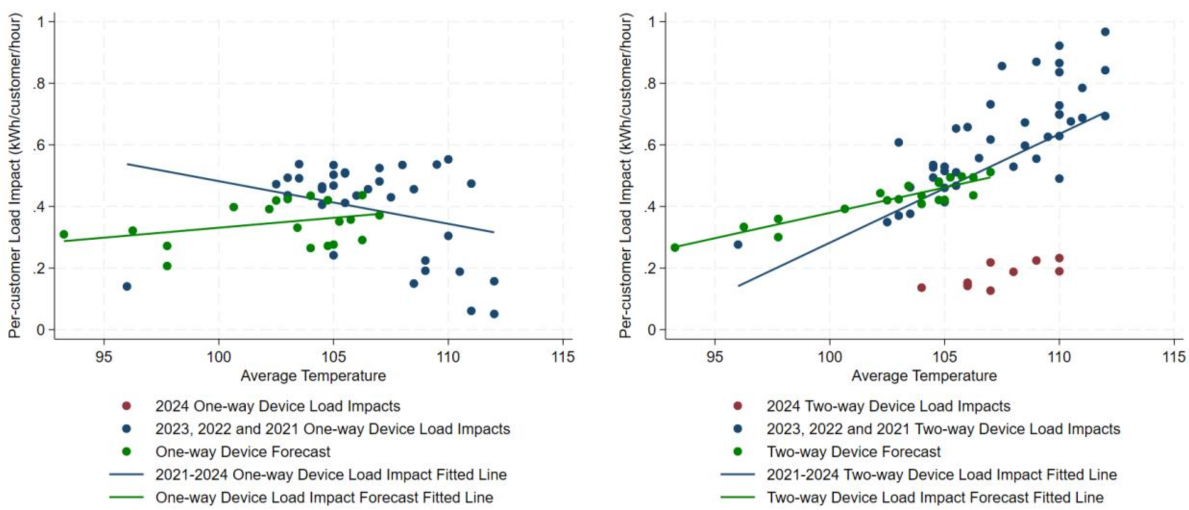


Figure C.5: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNB

[redacted]

Figure C.6: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNC

[redacted]

Figure C.7: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNP

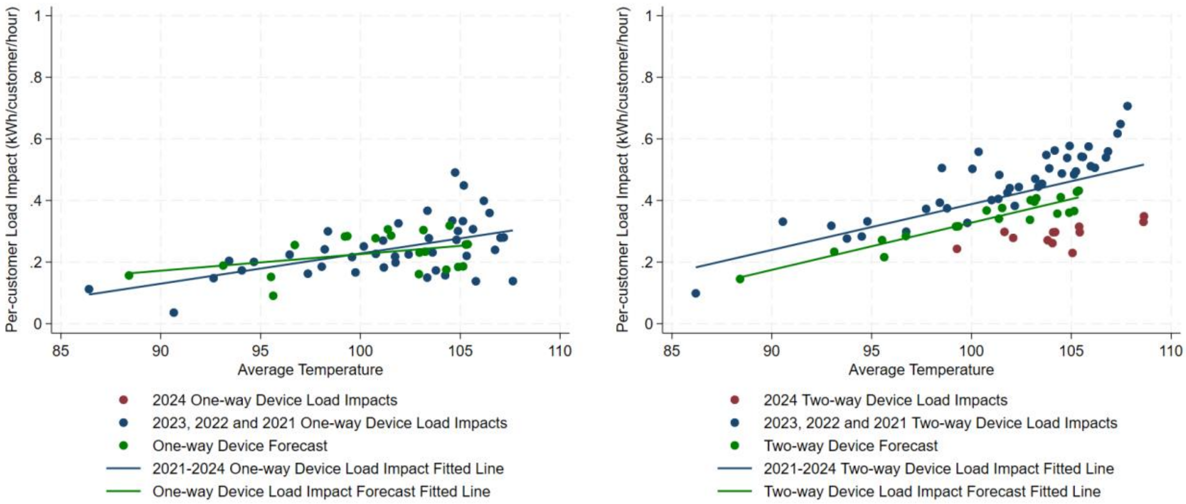


Figure C.8: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGP2

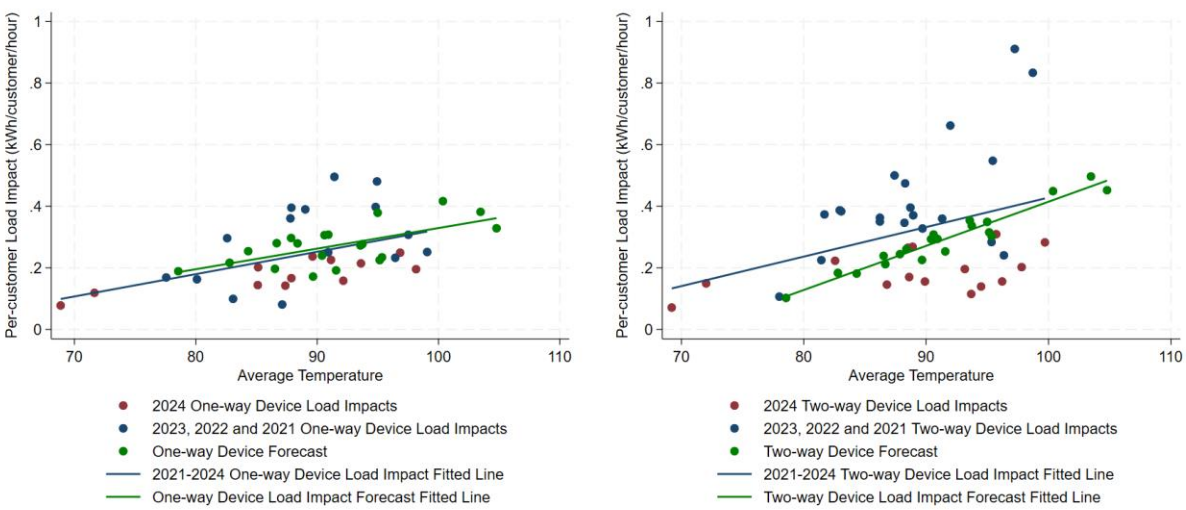


Figure C.9: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGSB

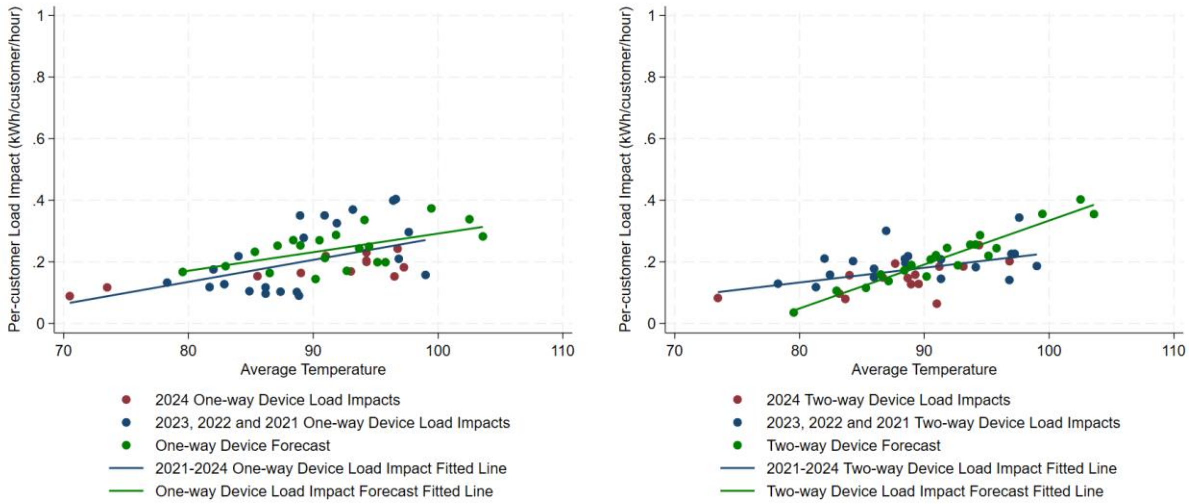


Figure C.10: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGSI

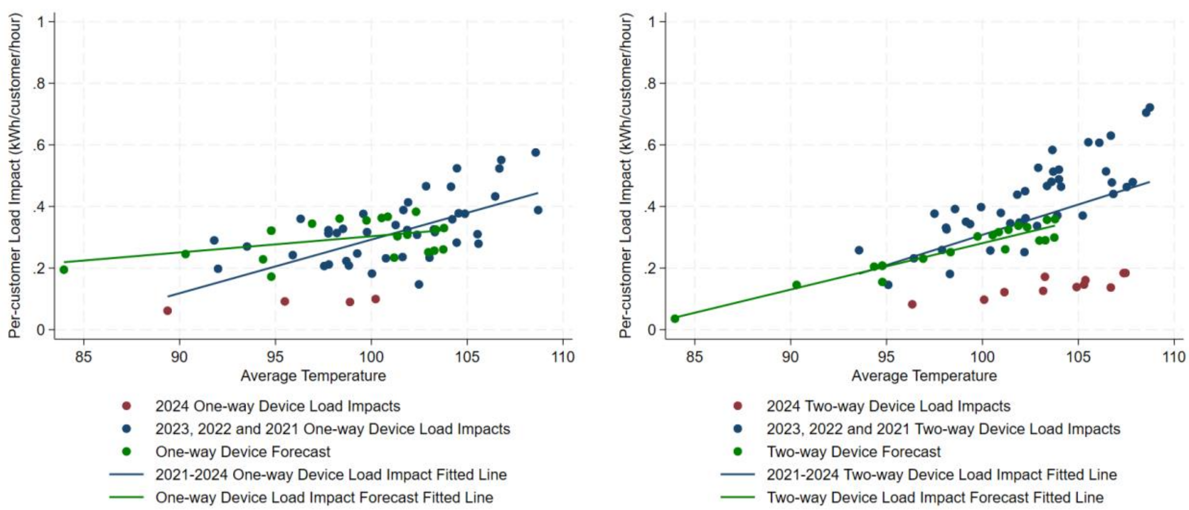


Figure C.11: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGST

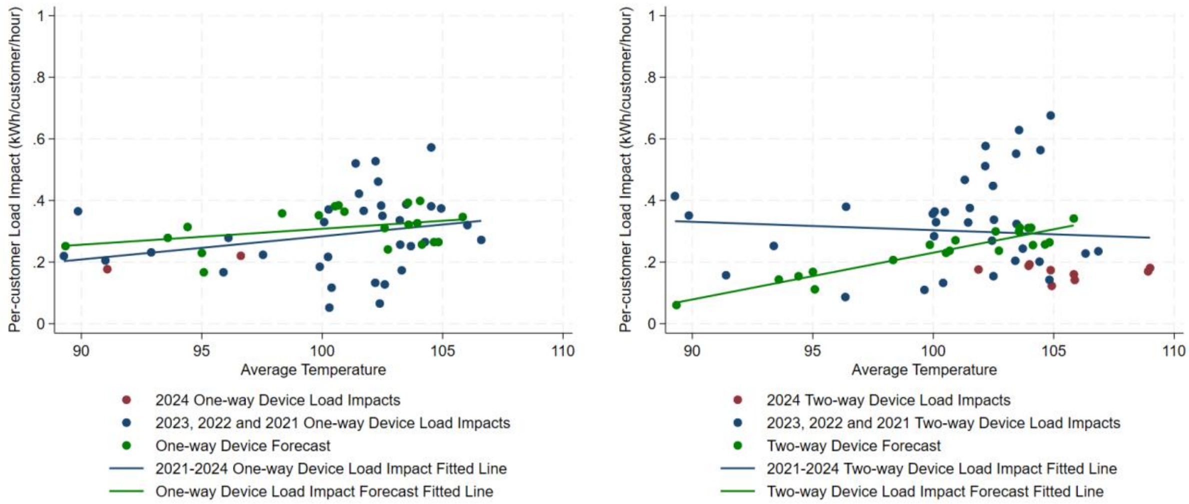
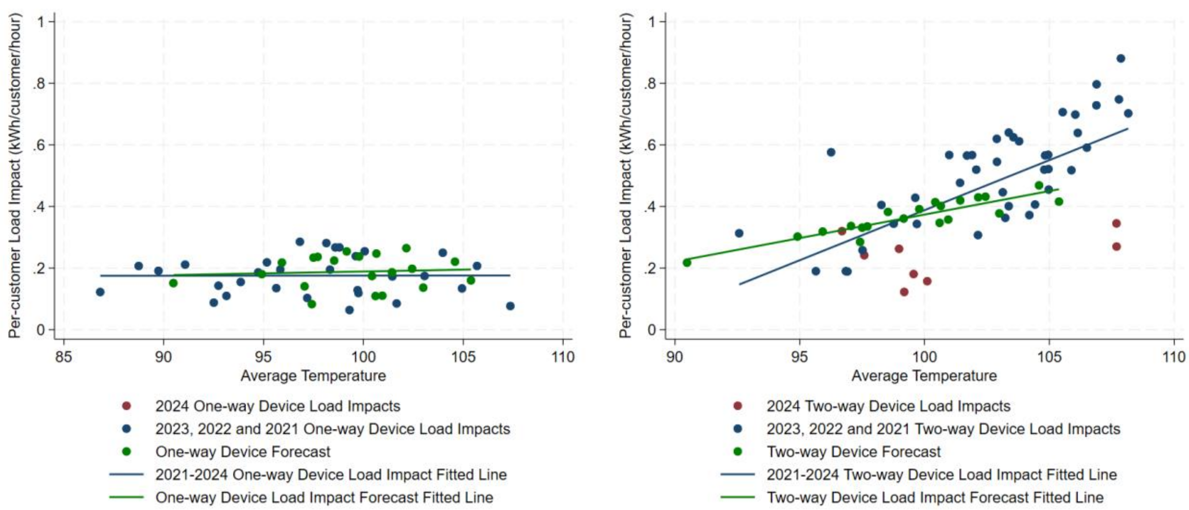


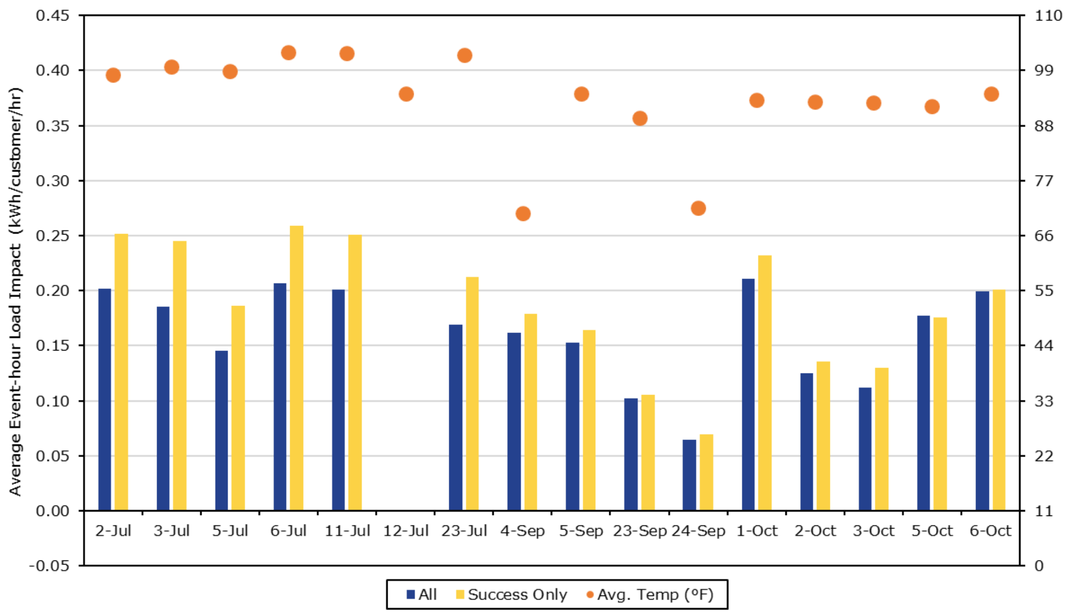
Figure C.12: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGZP



Appendix D. Dispatch Issues of Two-Way Devices

In 2024, PG&E was able to identify two-way devices that were not successfully dispatched for the events.[30] On average, about 23% of two-way devices had dispatch issues for each sub-LAP. The lower per-customer load impacts in 2024 as compared to previous years are partly explained by this dispatch issues. Figure D-1 shows the comparison of per-customer load impacts between all devices that were supposed to be dispatched versus those that were successfully dispatched by each event date.[31] By eliminating two-way devices that failed to dispatch, the per-customer load impacts are higher.

Figure D.1: Load Impacts for All vs. Successfully Dispatched Devices by Events in 2024



[30] PG&E identified two-way devices with a "not ready" status. These devices cannot be dispatched in events. Reasons for the "not ready" status include: the meter associated with the device is inoperable, the device cannot be found in the system, the device cannot communicate with the system that manages two-way devices, or the device is unreachable.

[31] Since there is no "return loop" for one-way devices, PG&E is not able to determine whether an individual one-way device is successfully dispatched. In this comparison, all one-way devices were still included as successfully dispatched devices.