2022 Load Impact Evaluation for Pacific Gas & Electric Company's SmartRate™ Program

EX-POST AND EX-ANTE LOAD IMPACTS
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Confidential information is removed and blacked out. [redacted]

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in consultation with Pacific Gas & Electric Company.

ABSTRACT

This report documents the load impact evaluation of the residential SmartRate™ program operated by Pacific Gas and Electric (PG&E) for Program Year 2022 (PY2022). The primary goals of this evaluation study are to 1) estimate the ex-post load impacts for PY2022 and 2) estimate ex-ante load impacts for the programs for years 2023–2033.

SmartRate™ is a voluntary critical peak pricing program that overlays a customer's electric rate designed to lower summer electricity costs for customers and conserve California's power grid. On SmartDays™, participants are charged $0.60/kWh in addition to their regular rate charges during the peak period (4–9 PM). Participants also receive energy credits for usage other than the peak period during SmartDays™ and all usage on those days within a billing period that is not declared as SmartDays™. During their first full summer season of program enrollment (and any preceding partial season), customers are backed by PG&E's Bill Protection Guarantee that refunds customers if their SmartRate™ costs exceed their regular residential pricing plan. The program dispatches between 9 and 15 SmartDays™ a year. SmartDays™ can be dispatched year-round but is typically called on summer weekdays. PG&E provides customers with day-ahead notification of SmartDays™ via text or email to allow customers to plan for reducing their energy use or shifting their load during event hours.

AEG estimated hourly ex-post load impacts for each event during 2022 using regression analysis of segment-level hourly load, weather, and event data. The estimated load impacts are reported for each event and the average event day. Load impacts are also reported by CAISO local capacity area (LCA), program enrollment, bill protection status, CARE enrollment, billing rate, and high fire-threat district status. In PY2022, PG&E dispatched 13 events occurring between June and September. The estimated aggregate ex-post load impact for an average event day is 4.1 MW.

AEG developed ex-ante load impact forecasts by combining enrollment forecasts provided by PG&E and per-customer load impacts generated from the analysis of current ex-post load impact estimates. The forecast of enrolled service accounts and aggregate ex-ante load impacts presented in the report reflect several program changes expected to occur beginning in 2023. The estimated aggregate ex-ante load impacts for a typical event day in 2023 for a PG&E 1-in-2 weather scenario is 5.89 MW during the resource adequacy (RA) window (4 to 9 PM).

EXECUTIVE SUMMARY

This report documents the load impact evaluation of the residential SmartRate™ program operated by Pacific Gas and Electric (PG&E) for Program Year 2022 (PY2022).

The primary goals of the 2022 load impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each SmartDay™ in PY2022, and
- Estimate hourly ex-ante load impacts for years 2023-2033.

In addition to this study's key objectives, PG&E expressed interest in the Bill Protection Guarantee load impacts and bill impacts.

We present the program description, ex-post analysis, ex-ante analysis, key findings, and recommendations in the following subsections.

Program Description

SmartRate™ is a voluntary critical peak pricing program that overlays a customer's electric rate. It is designed to lower summer electricity costs while conserving California's power grid.

Eligibility. Customers with a SmartMeter and on the following rates: standard rate (E1) and five TOU rates (E6, TOUB, TOUC, TOUD, and EV2A) are eligible to participate in SmartRate™. Participants may be dually enrolled in SmartAC™ or Emergency Load Reduction Program (ELRP A6). All participants dually enrolled to SmartAC™ enrolled in both programs before October 26th, 2018. Participants dually enrolled to ELRP A6 are residential customers on CARE and FERA rates defaulted onto the ELRP pilot.

Charges. Participants are charged $0.60/kWh in addition to their regular rate charges for all usage between 4 PM and 9 PM on each SmartDay™.

Credits. Participants will receive energy credits for usage other than 4 PM to 9 PM during SmartDays™ and all usage on those days within a billing period that are not declared as SmartDays™. These credits only apply for bill periods in which at least one SmartDay™ occurs. The energy credits are multiplied by the number of SmartDays in a bill period.

Bill Protection Guarantee. During their first full summer season (May through October) of program enrollment (and any preceding partial season), customers are backed by PG&E's Bill Protection Guarantee that refunds customers if their SmartRate™ costs are more than their regular residential pricing plan. PG&E would credit the difference on the customer's November bill if they did not save on SmartRate™.

SmartDays™ (Events). The program calls a minimum of 9 and a maximum of 15 SmartDays™ a year. PG&E typically calls SmartDays™ on summer weekdays but may call them year-round. High temperatures, CAISO alerts, and other factors, including Public Safety Power Shutoff (PSPS) activity (to minimize demands on the

Table ES-1 PY2022 SmartDays™

Date	Day of Week
Jun 10	Friday
Jun 27	Monday
Jul 11	Monday
Jul 18	Monday
Jul 21	Thursday
Aug 16	Tuesday
Aug 17	***Wednesday***
Aug 19	Friday
Sep 1	***Thursday***
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* Concurrent SmartAC events (gray highlighted) were called for various combinations of Sub-LAPs and event hours.

* Concurrent ELRP events (bold italicized text) were called at the system-level on the same 4 to 9 PM event window.

customer service center, web, and meteorology teams and avoid unnecessary communications with impacted customers), influence event dispatches. In PY2022, PG&E called thirteen events occurring between June and September. Table ES-1 summarizes the PY2022 SmartDays™, including eight concurrent SmartAC™ events (gray highlighted) and three concurrent ELRP events (***bold italicized*** text). Note that impacts from ELRP A6 dually-enrolled participants on concurrent ELRP events are excluded from this report and are reported under the ELRP evaluation.

Notification. PG&E provides participants with day-ahead notification of SmartDays™ via phone, text, and/or email to allow customers to plan to reduce their energy use or shift their load during event hours.

Program Changes. Changes implemented in PY2022 that impact the SmartRate™ program are as follows:

- PG&E completed its plan to default customers onto the TOU rate, which experienced an overall opt-out rate of 21%.
- The SmartRate™ event window shifted to 4 PM – 9 PM from 2 PM – 7 PM,
- Customers under the EV2A and TOUD rates will be eligible to participate in SmartRate™, and
- PG&E launched the Emergency Load Reduction Program (ELRP) pilot, and residential customers on CARE and FERA rates were defaulted onto ELRP A6. SmartRate™ participants in CARE rates are currently dually enrolled in ELRP A6. The pilot is set to run through October 2025.

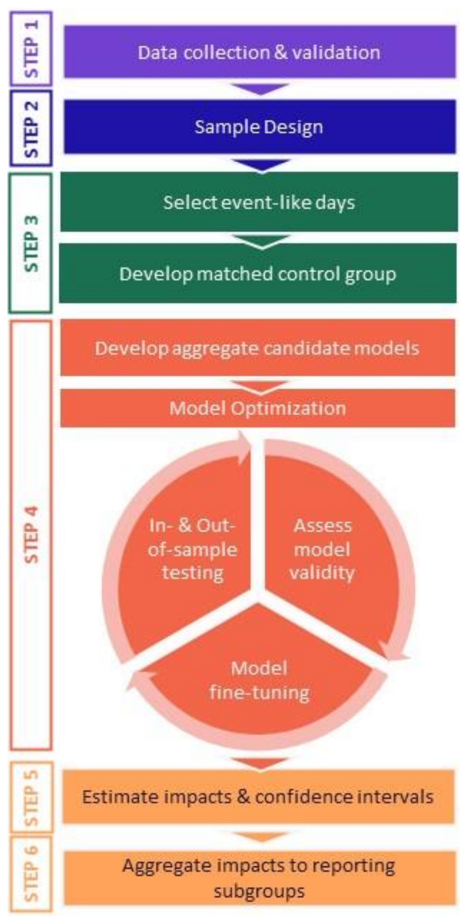
Ex-Post Load Impact Analysis

We present the analysis approach and summary results of the ex-post analysis below.

Ex-Post Analysis Approach. Figure ES-1 to the right outlines our approach to the ex-post analysis. The basic structure is one that we have used in previous California Statewide C&I DR evaluations; however, we implemented several modifications appropriate to a residential DR program:

- We limited the analysis to PY2022 data (June 2022 – September 2022) to estimate PY2022 ex-post impacts. Doing so allowed AEG to treat PY2022 as a unique period, estimating SmartDay™ impacts relative to current conditions.
- We used a segmented analysis approach, dividing the PY2022 participant population into the following five segments: (1) dually enrolled in SmartAC™, (2) dually enrolled in ELRP A6, (3) singly enrolled and under bill protection, (4) singly enrolled, under bill protection, and did not receive notifications, and (5) singly enrolled no longer under bill protection. We performed the sampling, control group matching, and regression analysis separately for each participant segment.

Figure ES-1 Ex-Post Analysis Approach



- We used a simplified version of the optimization process compared to the method used in C&I DR evaluations. The optimization process served as a starting point for our model selection, leveraging automated algorithms, and also played a crucial role in assessing model validity.

Ex-Post Analysis Results. Table ES-2 below summarizes the overall program-level event-hour impacts on each event, including the number of participants enrolled during each SmartDay™, the aggregate reference load and load impacts, the percent impact, and the average temperature. Load impacts as a percent of the reference load were 3.9%, on average, across the ten[1] events. The aggregate load impact was 4.1 MW, on average.

Table ES-2 All Participants: Average Event-Hour Impacts by Event

Event Date	# of Accts	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
Jun 10	42,388	92.1	3.4	2.17	0.08	3.7%	90
Jun 27	42,578	96.9	3.4	2.28	0.08	3.5%	88
Jul 11	42,811	102.2	4.0	2.39	0.09	3.9%	90
Jul 18	42,926	98.3	3.3	2.29	0.08	3.3%	88
Jul 21	43,029	95.6	3.2	2.22	0.07	3.4%	87
Aug 16	43,664	107.1	4.4	2.45	0.10	4.1%	92
Aug 17	***20,941***	***41.7***	***2.9***	***1.99***	***0.14***	***6.9%***	***87***
Aug 19	43,790	99.7	3.4	2.28	0.08	3.4%	88
Sep 1	***20,978***	***45.3***	***3.4***	***2.16***	***0.16***	***7.4%***	***91***
Sep 5	***21,198***	***55.7***	***4.5***	***2.63***	***0.21***	***8.2%***	***99***
Sep 6	44,190	124.6	5.8	2.82	0.13	4.7%	99
Sep 7	44,190	115.3	4.9	2.61	0.11	4.2%	95
Sep 8	44,190	115.0	4.9	2.60	0.11	4.2%	96
Average Event Day	**43,376**	**104.7**	**4.1**	**2.41**	**0.09**	**3.9%**	**91**

Concurrent SmartAC events (gray highlighted cells) called for various combinations of Sub-LAPs and event hours.
Concurrent ELRP A6 events (***bold italicized* text**) called at the system level on the same 4 PM to 9 PM event window.

Figure ES-2 presents the average event-hour ex-post load impacts for each event day for all SmartRate™ participants. These results indicate that participants had statistically significant load reductions on all thirteen SmartDays™, ranging from 2.9 to 5.8 MW.

The components of the figure are as follows:

- Green Bars – the magnitude of the aggregate load impact,
- Striped Bars – concurrent ELRP A6 event, dually enrolled to ELRP A6 participants are excluded from the average event day,
- Gray shading – a concurrent SmartAC™ event,

[1] Three concurrent ELRP events (***bold italicized*** text) are excluded from this analysis and reported in the ELRP LI Evaluation. These events were excluded from the average event day.

- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by the participants during the event hours.

Figure ES-2 All Participants: Ex-Post Load Impacts by Event

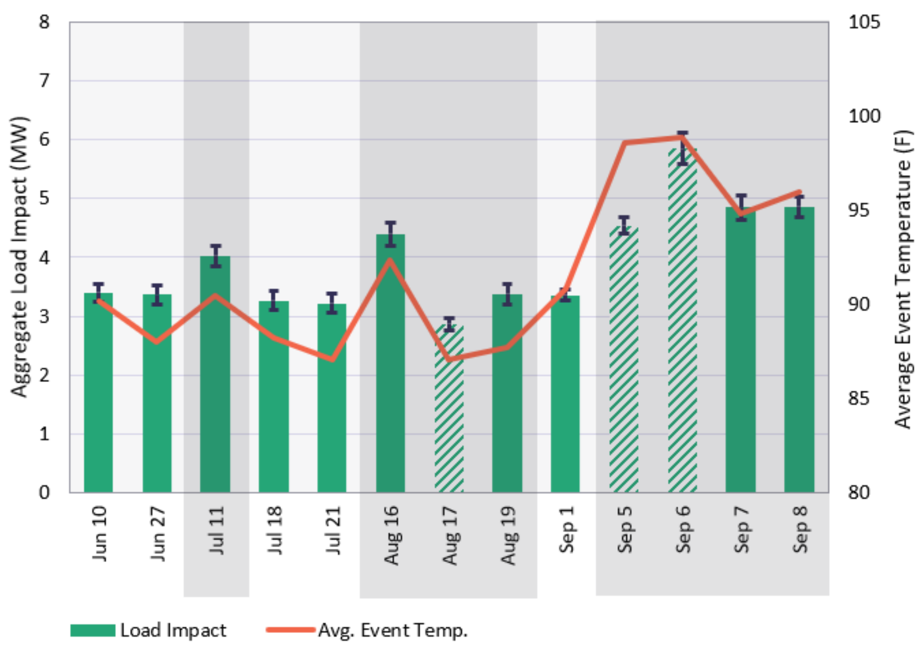


Figure ES-3 presents the total load impact contributions by LCA on an average event day. On average, the Greater Fresno Area and Other/Unknown contribute the most load impacts, with 1.5 MW and 1.6 MW, respectively.

Figure ES-4 presents the per-customer load impacts on an average event day for each subgroup based on status. The black bands correspond to 90 percent confidence intervals around these estimates. Thus, non-overlapping black bands within subgroups indicate statistically significant differences between the subgroup per-customer estimates. In PY2022, we found that all subgroups show statistically significant differences between the subgroup per-customer load impacts.

Figure ES-3 Contributions by LCA on an Average Event

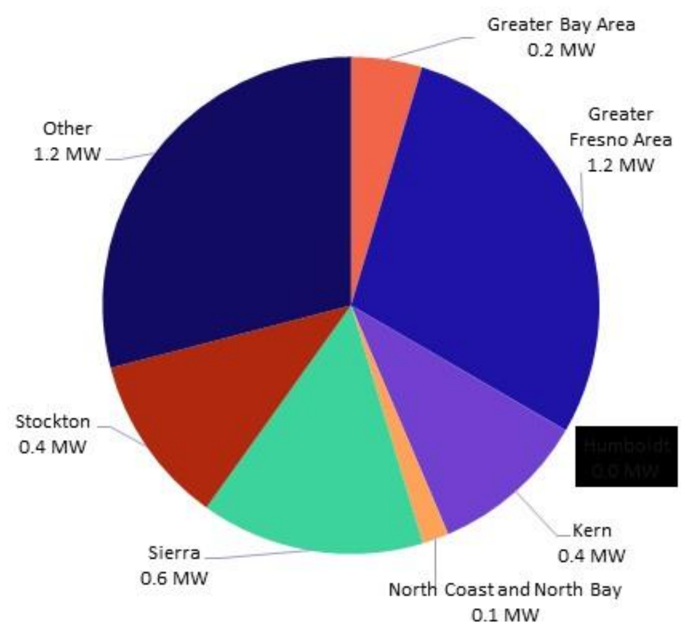
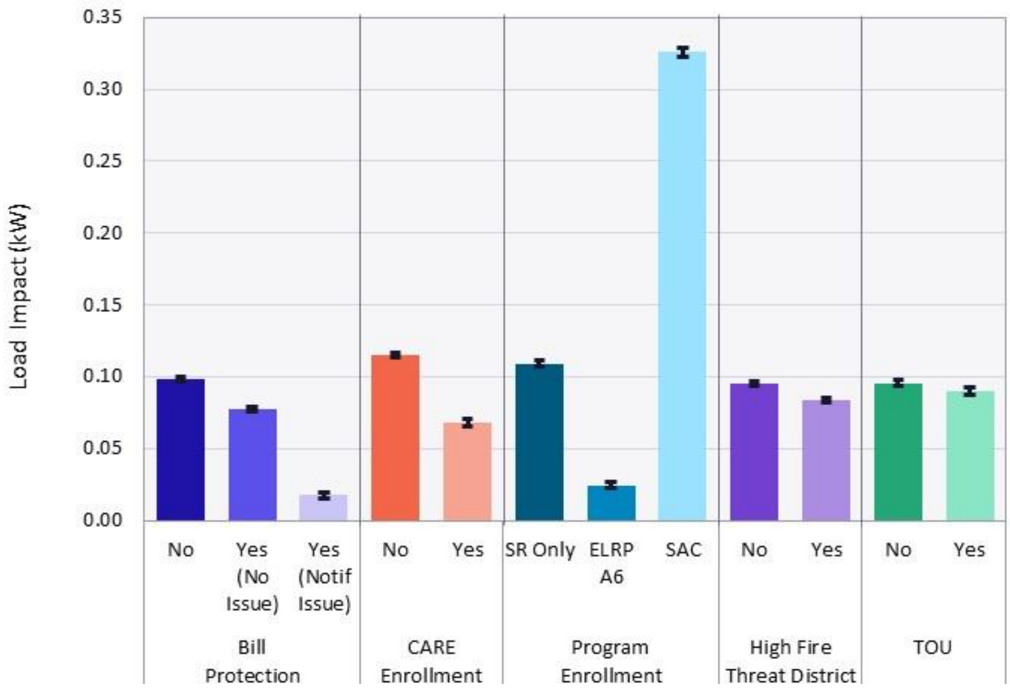


Figure ES-4 By Subgroup: Per-Customer Load Impacts on an Average Event Day



Ex-Post Analysis Key Findings. The ex-post analysis resulted in the following key findings:

- SmartRate™ participants deliver highly weather-sensitive load impacts, showing an increase in load impacts on hotter days with or without technology assistance. The aggregate load impact was 4.1 MW, on average, in the 2022 season.
- Program enrollment affected SmartRate™ program performance in two ways:
  - Participants **dually enrolled in SmartAC™** continue to deliver substantially higher load impacts per customer, with 13.9% average event impacts compared to 4.8% for singly enrolled participants. These higher load impacts can be directly attributed to the SmartAC™ devices, which allow participants to respond to events with minimal to no effort or change in behavior. Since dual enrollment in SmartAC™ is no longer allowed for new participants, the higher load impacts from SmartAC™ devices will slowly decline as natural participant attrition occurs.
  - Participants **dually enrolled in ELRP A6** delivered very low impacts inconsistent with those historically shown by this group, previously singly enrolled in SmartRate™ and primarily CARE customers. The Emergency Load Reduction Program (ELRP) launched in PY2022, automatically enrolling residential customers on CARE or FERA rates and customers receiving Home Energy Reports. PG&E attributes the low performance in this subgroup to overall participant confusion.
    - ELRP A6 defaulted customers were delivered welcome packets to the pilot. However, as there is no precedent on the SmartRate™ and ELRP A6 dual enrollment, no information on their interaction was included in the packet. There are no current plans for additional marketing/education outreach for dually enrolled participants. Discussions are ongoing on this topic.
    - Both SmartRate™ and ELRP send out day-ahead email or text notifications for program events, and the PG&E SmartRate™ call center reported customer calls indicating confusion regarding ELRP notifications received by defaulted customers unaware of ELRP enrollment.

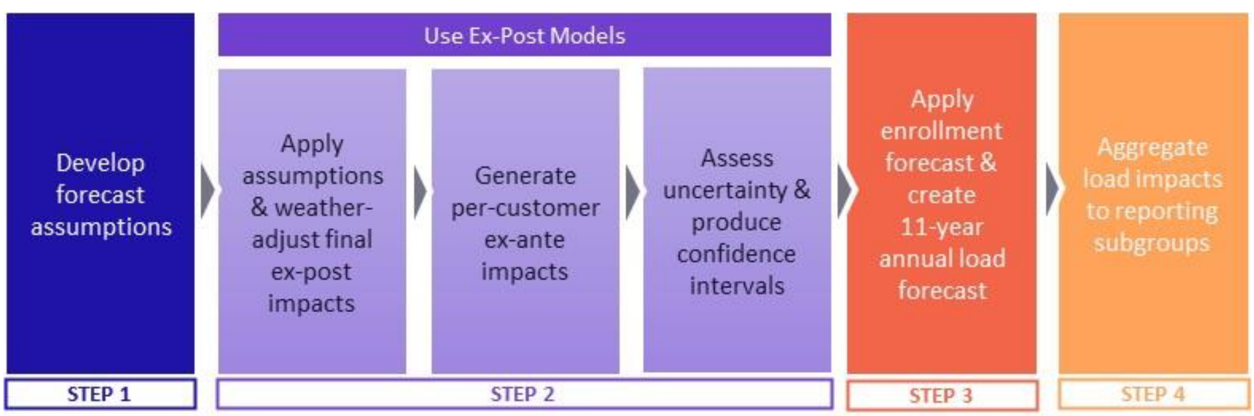
- PY2022 SmartRate™ implementation experience **notification issues** for approximately 5% of the overall population, primarily bill-protected participants.
  - The participants affected by the notification issue exhibited very small, yet statistically significant, load impacts. These findings possibly indicate that a subset of participants receives SmartDay™ alerts through other mediums (i.e., day ahead on the PG&E website or day of on Twitter) besides the official email and text message notifications.
  - Consistent with PY2021 findings, participants under the Bill Protection Guarantee (not affected by notification issues) delivered slightly lower yet comparable per-customer load impacts compared to participants no longer eligible for bill protection (3.5% for bill-protected v. 4.0% for no bill protection). These results are intuitive and expected from the bill-protected group due to one or more of the following: (1) customer "complacency," (2) the first season "learning curve," or (3) the absence of technology-enabled participants in the bill protected group.
- In PY2022, participants with an underlying TOU rate delivered higher load impacts per customer with 4.2% average event impacts compared to 3.8% for participants with an underlying standard rate. These findings are different from PY2021, wherein participants with an underlying standard rate delivered higher load impacts per customer. We attribute this change to the following factors:
  - PG&E completed the TOU defaulting transition in 2022, which increased the share of TOU customers from 23% to 36%.
  - In PY2022, the SmartRate™ peak period became coincident with TOU-B and TOU-C rates (4 to 9 PM). Participants on the TOU-C rate save 5.2% on average, now higher than participants on the standard rate (3.8% on average). The increase in per-customer impacts can be attributed to these customers' overall awareness of the 4 to 9 PM peak period.

Ex-Ante Load Impact Analysis

We present the analysis approach and summary results of the ex-ante analysis below.

Ex-Ante Analysis Approach. Figure ES-5 summarizes our approach to the ex-ante analysis.

Figure ES-5 Ex-Ante Analysis Approach



We developed appropriate forecast assumptions through continued discussions with PG&E regarding SmartRate™'s approved program changes. The forecast assumptions are as follows:

- **Update participant load impacts based on PY2022 ex-post analysis.** Effective May 2022, the SmartRate™ event window shifted to 4 PM to 9 PM. Prior analyses were based on a 2 PM to 7 PM event window.

- **Exclude load impact estimates from participants affected by the Notification error.** PG&E anticipates the notification issues experienced in PY2022 to be corrected by the implementer.
- **Assume typical event day percent impacts for non-summer months.** Since load impact estimates for non-summer months (outside June through September), we estimated load impacts by applying the hourly percent impacts for a typical event day to the estimated reference loads during non-summer months.
- **The ELRP pilot is set to conclude after October 2025.** Consequently, we used the following assumptions:
  - Participants dually enrolled in ELRP A6 will rejoin the singly enrolled subgroup starting in November 2025.
  - Maintain PY2022 load impacts[2] for participants dually enrolled in ELRP A6 through the remainder of the pilot (October 2025).
  - Over three years, there will be a gradual catch-back period for previous ELRP A6 participants. Beginning November 2025, customers will perform at 50% of the singly enrolled subgroup for one year. In November 2026, load impacts will increase to 75%. In November 2027, the customers will catch up to singly enrolled subgroup levels.
- The portfolio-adjusted forecast used the following assumptions:
  - **Dually enrolled in SmartAC™ – maintained the assumption that 18% load impacts is an incremental effect of SmartRate™ participation.** We assume that 18% of load impacts on concurrent SmartRate™ and SmartAC™ events are attributed to the behavioral impact of SmartRate™ participation.
  - **Dually enrolled in ELRP A6 – included in the portfolio-adjusted forecast through the ELRP pilot implementation.** The impacts from this subgroup are primarily attributed to SmartRate™, while incremental impacts, if any, are attributed to ELRP[3]. We assume participants in this subgroup to perform as they do when called to SmartRate-only events.

Ex-Ante Analysis Results. Figure ES-6 presents side-by-side comparisons of PG&E's annual enrollment and impact forecasts for the PG&E 1-in-2 weather scenario on a typical event day, including the 2022 enrollment and impact "back-cast." The forecast is segmented by program enrollment: singly v. dually enrolled (SmartAC™ and ELRP A6). PG&E expects a decrease in enrollment over time, with no marketing-derived enrollments expected for future years. PG&E forecasts approximately 44k participants in 2022, decreasing to 20k participants in 2033.

At the conclusion of the ELRP pilot (2026), we see a gradual increase in aggregate load impacts despite the expected program attrition. Previous ELRP A6 participants are expected to gradually catch up to singly enrolled participants over three years. Under PG&E 1-in-2 weather conditions, PG&E estimates 5.9 MW in aggregate load impacts during the RA window on a typical event day in 2023 and 5.0 MW in 2033.

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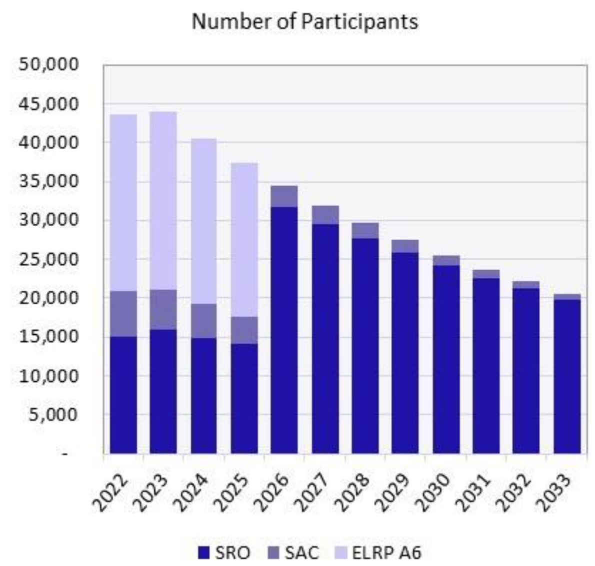
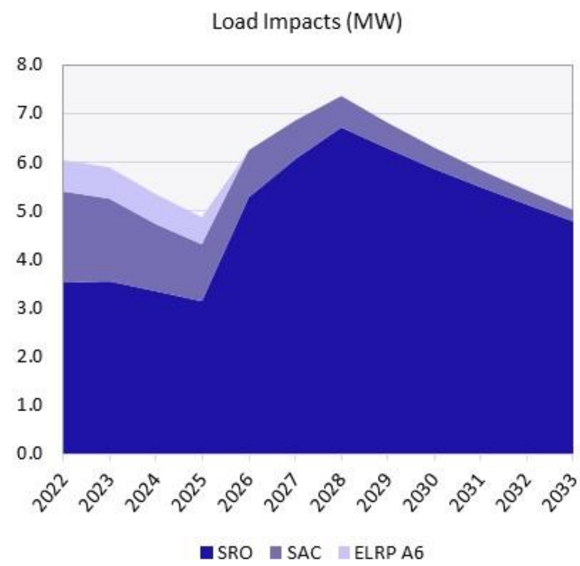
[2] The PY2022 Ex-Post analysis resulted in very low impacts for the participants dually enrolled in ELRP A6. PG&E attributes this to notification issues and participant confusion regarding their default to ELRP and how it may interact with their SmartRate enrollment. ELRP A6 defaulted customers were delivered welcome packets to the pilot, but as there is no precedent on the SmartRate/ELRP A6 dual enrollment no information on their interaction was included in the packet. There are no plans for additional marketing/education outreach for dually enrolled participants as of the filing of this report. Discussions are ongoing on this topic.

[3] Estimated under the ELRP LI evaluation's portfolio-adjusted ex-ante analysis.

Figure ES-6 Enrollment and Impact Forecast: PG&E 1-in-2, Typical Event Day, 2022 - 2033





Ex-Ante Analysis Key Findings. The ex-ante analysis resulted in the following key findings:

- The PY2022 load impacts, excluding participants affected by the notification issues, showed that the first-year learning curve adjustment assumption was unnecessary.
  - In PY2022, SmartRate™ participants, on average, showed 5.4% load impacts after excluding participants affected by the Notification error. This performance is comparable to PY2021's performance at 6.0%.
  - During the PY2021 ex-ante LI analysis, we assumed a 50% decrease in per-customer percent impacts (2022) to account for a first-year "learning curve" and "back to normal" or 100% of 2021 percent impacts from 2023 onwards. In PY2022, SmartRate™ participants, on average, showed 5.4% load impacts after excluding participants affected by the Notification error. This performance is comparable to PY2021's performance at 6.0%.
- The participants dually enrolled in ELRP A6 showed very low per-customer impacts. However, since PG&E does not currently have plans for further marketing/education efforts for this subgroup, we did not assume any adjustments through the expected implementation of the ELRP pilot (through November 2025).
  - At the conclusion of the ELRP pilot, we assume a three-year gradual catch-back period for previous ELRP A6 participants, increasing per-customer load impacts to align with singly enrolled participants by November 2027.
- The event window shift implemented in PY2022 substantially increased the RA window load impacts since the new event window (SmartRate™ peak period) is now coincident with the RA window.
- PG&E continues to forecast a consistent decrease in SmartRate™ enrollment through 2033. This assumption estimates a reduced ex-ante forecast of 5 MW in 2033 for a typical event day under the PG&E 1-in-2 weather conditions.

Recommendations

AEG has the following recommendations for future research and evaluation related to PG&E's residential SmartRate™ program.

- AEG recommends a follow-up analysis of the conservation effect to include current participants with 2019–2023 enrollments. This effort was not pursued in PY2022 due to constraints[4] in the analysis timeline. The follow-up analysis will aim to achieve the following:
  - Further leverage the variation-in-adoption approach using a more extended period of rolling enrollment. This approach will allow for revisiting the data requirements on pre-enrollment data and including more customers in the analysis.
  - Estimate results more applicable to the current population by producing joint averages of the seasonal impacts of bill-protected and post-bill-protected periods.
  - Leverage a larger analysis sample and an extended period to more accurately estimate the COVID effect.
- AEG recommends a more collaborative effort with the ELRP Pilot LI evaluation team through the remainder of the ELRP pilot implementation. The collaboration can align evaluation approaches and further analyze the drop in participant load impacts found in the subgroup.

[4] The ELRP pilot implementation prompted several iterations in both the Ex-Post and Ex-Ante analyses.

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INTRODUCTION

This report documents the program year 2022 (PY2022) load impact evaluation of the residential SmartRate™ program offered by Pacific Gas & Electric (PG&E).

Research Objectives

The study's key objectives are to estimate both ex-post and ex-ante load impacts for the residential SmartRate™ program, consistent with the California Demand Response (DR) Load Impact Protocols (LIP).[5] More specifically,

- **Estimate Ex-post load impacts** for the average customer and all customers in aggregate for each hour of each event day and the average event day. We present all estimates at the program level and separately for each of the following customer segments: program enrollment[6], each local capacity area (LCA), CARE enrollment, bill protection status, rate tariff, and high fire-threat district status, along with the distribution of impacts for each segment.
- **Estimate Ex-ante load impacts** for the average customer and all customers in aggregate for the resource adequacy (RA) window[7]. We provide estimates for each year over an 11-year[8] time horizon based on PG&E's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day. We provide estimates for both program-specific and portfolio-adjusted[9] scenarios. As applicable, we also provide estimates for the following customer segments: size group, LCA, and program enrollment[10].

Additional Research Objectives

In addition to this study's key objectives, PG&E expressed interest in the Bill Protection Guarantee load impacts and bill impacts.

Report Organization

We organize the remainder of this report into the following sections:

- Section 2 describes the SmartRate™ program as PG&E implements it,
- Section 3 describes the methods used to estimate the ex-post and ex-ante load impacts for PY2022,
- Section 4 presents the results of the ex-post load impact analysis,
- Section 5 presents the results of the ex-ante load impact analysis, and
- Section 6 presents the key findings and recommendations.

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[5] *Attachment A. Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance*, California Public Utilities Commission, Energy Division, April 2008.

[6] SmartRate™ only or dual enrollment in SmartAC™ or ELRP A6.

[7] The RA window is 5 PM to 10 PM fpr March and April and 4 PM to 9 PM for all other months.

[8] PG&E has requested a PY2021 back cast as part of the ex-ante impact analysis.

[9] Portfolio level impacts exclude the load impacts from dually enrolled participants attributed to concurrent SmartAC events.

[10] SmartRate™ only or dual enrollment in SmartAC™ or ELRP A6.

2

PROGRAM DESCRIPTION

This section describes the PY2022 SmartRate™ program implementation and any program changes since PY2021. We also present information regarding the PY2022 event days and program enrollment.

Program Implementation

SmartRate™ is a voluntary critical peak pricing program that overlays a customer's electric rate. It is designed to lower summer electricity costs while conserving California's power grid.

Eligibility. Customers with a SmartMeter and on the following rates: standard rate (E1) and five TOU rates (E6, TOUB, TOUC, TOUD, and EV2A) are eligible to participate in SmartRate™. Participants may be dually enrolled in SmartAC™ or Emergency Load Reduction Program (ELRP A6). All participants dually enrolled to SmartAC™ enrolled in both programs before October 26th, 2018. Participants dually enrolled to ELRP A6 are residential customers on CARE and FERA rates defaulted onto the ELRP pilot and other customers that may have optionally enrolled.

Charges. Participants are charged $0.60/kWh in addition to their regular rate charges for all usage between 4 PM and 9 PM on each SmartDay™.

Credits. Participants will receive a SmartRate Non-High Price credit ($0.00636/kWh from 4 PM to 9 PM during SmartDays™ and a SmartRate Participation Credit ($0.00167/kWh)) for usage other than 4 PM to 9 PM during SmartDays™ and all usage on those days within a bill period that are not declared as SmartDays™. These credits are only applicable for bill periods in which at least one SmartDay™ occurs. The SmartRate™ Participation and Program credits are multiplied by the number of SmartDays in a bill period.

Bill Protection Guarantee. During their first full summer season (May through October) of program enrollment (and any preceding partial season), customers are backed by PG&E's Bill Protection Guarantee that refunds customers if their SmartRate™ costs are more than their regular residential pricing plan. PG&E would credit the difference on the customer's November bill if they did not save on SmartRate™.

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Table 2-1 PY2022 SmartDays™

Date	Day of Week
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* Concurrent SmartAC events (gray highlighted) were called for various combinations of Sub-LAPs and event hours.

* Concurrent ELRP events (bold italicized text) were called at the system-level on the same 4 to 9 PM event window.

SmartDays™, including eight concurrent SmartAC™ events (gray highlighted) and three concurrent ELRP events (***bold italicized*** text). Note that impacts from ELRP A6 dually-enrolled participants on concurrent ELRP events are excluded from this report and are reported under the ELRP evaluation.

Notification. PG&E provides participants with day-ahead notification of SmartDays™ via text and/or email to allow customers to plan to reduce their energy use or shift their load during event hours.

Program Changes

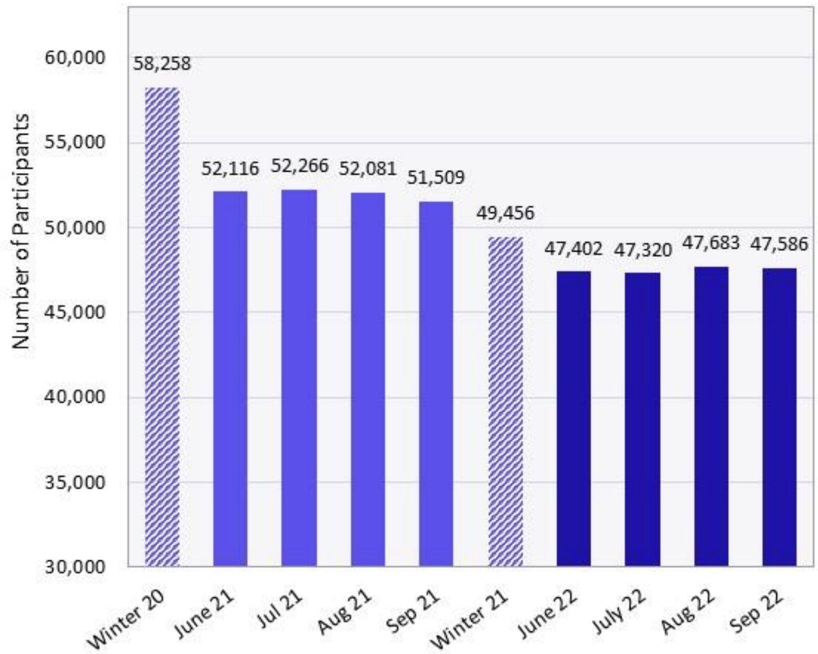
Changes implemented in PY2022 that impact the SmartRate™ program are as follows:

- PG&E completed its plan to default customers onto the TOU rate, which experienced an overall opt-out rate of 21%.
- The SmartRate™ event window shifted to 4 PM – 9 PM from 2 PM – 7 PM,
- Customers under the EV2A and TOUD rates will be eligible to participate in SmartRate™, and
- PG&E launched the Emergency Load Reduction Program (ELRP) pilot, and residential customers on CARE and FERA rates were defaulted onto ELRP A6. SmartRate™ participants in CARE rates are currently dually enrolled in ELRP A6. The pilot is set to run through October 2025.

PY2022 Participation

A total of 49,547 unique customers participated in at least one SmartDay™ in the PY2022 season. The SmartRate™ program saw an average of 670 new enrollments and 531 de-enrollments each month, showing a slight increase in participation throughout the season. However, the SmartRate™ program has seen a steady rate of attrition over the last three years, which PG&E attributes participant attrition to customers moving onto CCAs or ineligible rates, both ineligible to participate in SmartRate™ and the lack of marketing efforts for the program. Figure 2-1 compares the monthly enrollment between PY2021 and PY2022.

Figure 2-1 SmartRate™ Monthly Enrollment

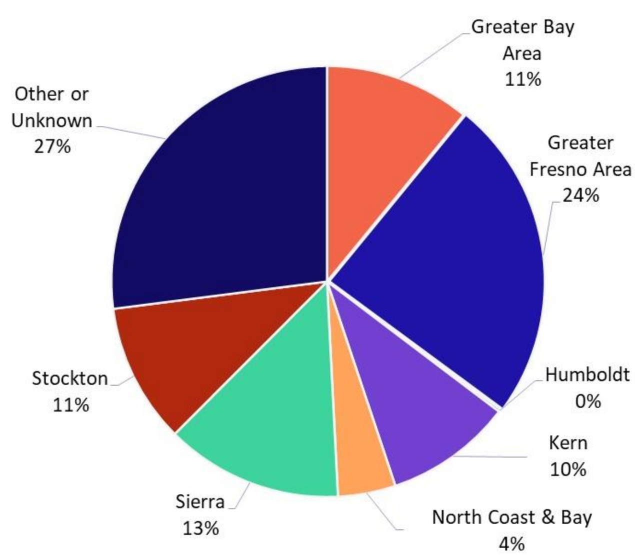


Next, we present the enrollment distribution of SmartRate™ participants in each of PG&E's eight local capacity areas (LCA). As shown in Table 2-2 and Figure 2-2, the Greater Fresno Area has the largest share of enrollment at 24%. Notably, 27% of participants are categorized as "Other or Unknown."

Table 2-2 Enrollment by LCA

LCA	# of Accounts
Greater Bay Area	5,402
Greater Fresno Area	11,991
Humboldt	97
Kern	4,734
North Coast and North Bay	2,134
Sierra	6,590
Stockton	5,190
Other or Unknown	13,409

Figure 2-2 Enrollment by LCA

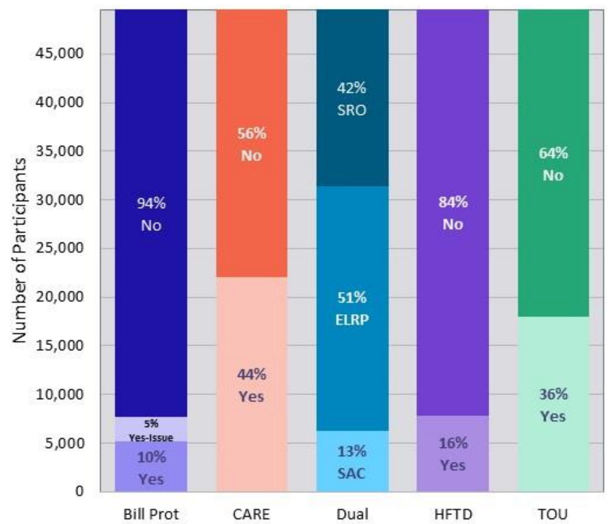


Finally, we present the enrollment distribution of SmartRate™ participants in each subgroup of interest: bill protection status, CARE enrollment, program enrollment, high fire-threat district, and TOU enrollment. The dually enrolled group makes up a significantly larger share of the overall population at 62% in PY2022 compared to 14% in PY2021, driven by the launch of the ELRP program in PY2022. In PY2022, SmartRate™ experienced notification issues, and a small subgroup (5%) of participants, primarily bill-protected participants, did not receive event notifications. The rest of the customer subgroups remain comparable to PY2021. Table 2-3 and Figure 2-3 show the counts and distributions of unique participants by subgroup.

Table 2-3 Enrollment by Subgroup

Subgroup	Status	# Accts
Bill Protection	No	38,031
	Yes (No Issue)	3,967
	Yes (Notif Issue)	1,378
CARE Enrollment	No	23,625
	Yes	19,751
Program Enrollment	SmartRate Only	15,023
	Dual - ELRP A6	22,604
	Dual - SmartAC	5,748
High Fire Threat District	No	36,533
	Yes	6,842
TOU	No	28,651
	Yes	14,725

Figure 2-3 Enrollment by Subgroup



3

STUDY METHODS

This section presents an overview of AEG's approach to the ex-post load impact analysis, the ex-ante load impact analyses, and the conservation effect analysis.

Ex-Post Load Impact Analysis

In the following subsections, we present our approach and describe each step in detail.

Overview of the Ex-post Analysis

Figure 3-1 Ex-Post Analysis Approach

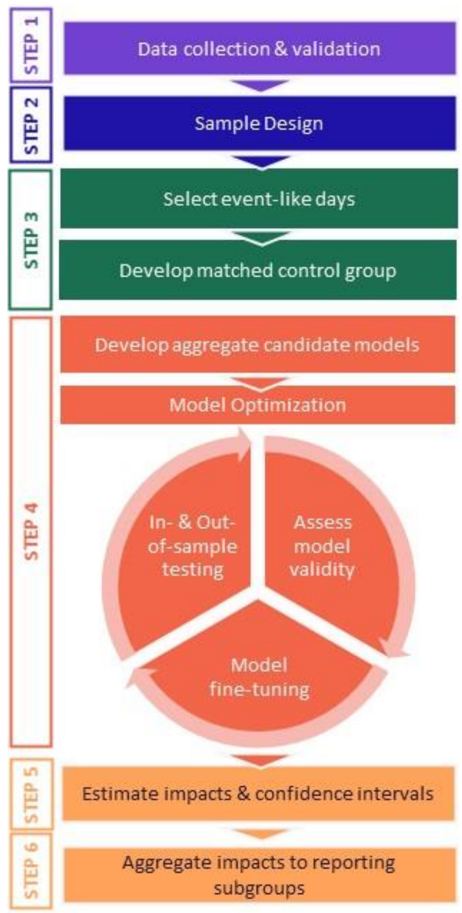


Figure 3-1 outlines our approach to the ex-post analysis. We've used this basic structure in previous California Statewide C&I DR evaluations. However, we modified the approach to be more appropriate for a residential DR program, simplifying and streamlining the approach to leverage efficiencies from established methods and algorithms without over-complicating the modeling process. For each step outlined in the figure, we applied the following modifications that make our approach unique to the SmartRate™ program. We discuss each step in detail in subsequent sections.

Data Collection. We used strictly PY2022 data (June 2022 – September 2022) to estimate PY2022 ex-post impacts. Doing so allowed AEG to treat PY2022 as a unique period, estimating the impacts of SmartRate™ relative to current conditions.

Participant Sample Development. PY2022 has approximately 49k unique participants in the SmartRate™ program. **We used a sampling approach to limit the data required to perform the analysis.** We used a segmented sampling approach aligned with the matched control group and regression modeling approach. AEG used the following five segments:

- Dually enrolled in SmartAC™ (1),
- Dually enrolled in ELRP A6 (2),
- Singly enrolled in SmartRate™:
  - Under bill protection (3),
  - Under bill protection and did not receive notifications (4), and
  - No longer under bill protection (5).

Matched Control Group Development. We used the same segmented approach in matched control group development and stratified using weather stations within each segment. AEG requested an eligible control pool with a 1:10 participant-to-control pool ratio, proportionately selected based on the weather station distribution.

Develop Candidate Regression Models. We estimated aggregate models using the same segmented approach. The purpose of segmentation is to minimize variation in the models. For example, we expect segmenting by program enrollment to be the best approach since technology-enabled participants (SmartAC™ participants) have inherently different load profiles.

Model Optimization and Selection Process. We used a simplified version of the optimization process relative to the method used in C&I DR evaluations. The SmartRate™ program used only five model segments, each needing around five candidate models. Thus, the optimization process served as a starting point for our model selection, leveraging automated algorithms developed for previous C&I DR evaluations. The optimization process also played a key role in assessing model validity to justify our confidence in our impact estimates.

Obtaining Impact Estimates and Confidence Intervals. While the methodology for obtaining estimates is relatively straightforward, **we leveraged algorithms developed in previous CA Statewide DR evaluations.** This approach promoted efficiency, especially since our algorithms were explicitly designed to address the requirements in the CPUC LI Protocols.

Step 1. Data Collection and Validation

Data Collection. We collected the data items (listed below) from PG&E and constructed a database that houses the data collected to perform the analysis. The database served as the foundation for the data validation process.

- SmartRate™ participant and eligible control group customer information: DR program enrollment (SmartRate™, SmartAC™, and ELRP A6), LCA indicator, CARE status, bill protection status, notification status, high fire-threat district status, and weather station indicator,
- Billing data: tariff, billed consumption, billed amount, and program credits,
- Participant and eligible control group hourly interval data that has undergone standard billing VEE processes during the appropriate program periods,
- Outage or PSPS day data,
- Hourly weather data for the appropriate program periods by weather station,
- SmartRate™, SmartAC™, and ELRP A6 event data,

Data Validation. We reviewed the data received from PG&E to make sure it corresponded to the data request and was complete. We also validated all interval data using algorithms we developed to detect issues such as zero intervals, missing intervals, peaks, valleys, and erroneous intervals.

Step 2. Sample Development

In the interest of efficiency, AEG utilized a sampling approach to limit the data requested and received. Since regression models were estimated at the segment level, the sample was designed based on this segmentation. We pulled a sample of 3,000 customers from each of the following segments:

- Participants dually enrolled in SmartAC™,
- Participants dually enrolled in ELRP A6,
- Participants singly enrolled in SmartRate™ and under the Bill Protection Guarantee,
- Participants singly enrolled in SmartRate™, under the Bill Protection Guarantee, and are affected by the Notification error,

- All other participants (i.e., singly enrolled in SmartRate™, no longer under the Bill Protection Guarantee, and not affected by the Notification error).

Step 3. Matched Control Group Development

Event-like Day Selection. The selection of comparable non-SmartDays™ or event-like days is essential to several evaluation activities. These days are used in the matched control group development and the out-of-sample testing in model optimization and validation. In matched control group development, these event-like days served as the basis for matching participants to non-participants by ensuring that matched customers consume energy similarly on days comparable to event days. In out-of-sample testing, we used event-like days to test the predictive abilities of each model as part of our model optimization process, employed regardless of the analysis design.

The event-like days included thirteen days comparable to called SmartDays™ in terms of weather, day of the week, and month of the year. We use these days to match treatment customers to control customers with similar usage on event-like days, assuming similar usage on SmartDays™. Due to the social and economic circumstances constantly changing due to the COVID-19 pandemic, we selected the event-like days within the same year.

We used a Euclidean distance metric (similar to what we describe below) to select days as similar as possible to actual SmartDays™ using multiple weather-based criteria.[11]

Matched Control Group. We used a Stratified Euclidean Distance Matching (SEDM) technique to create the matched control group. The necessary steps are as follows.

Step 1: Define the populations (participant and non-participant) and the periods (treatment and pre-treatment[12]). Within each sample segmentation, we assigned both customer populations into categorical strata or filters. This stratification ensured that customers with similar usage characteristics were matched to one another, capturing some of the unobservable attributes that affect how customers use energy. For SmartRate™ participants, we used weather station assignment and CARE status as filters.

Step 2: Perform the one-to-one match based on the hourly demand data of event-like days. We used a Euclidean distance metric to determine how close each participant is to a potential match. The Euclidean distance is the square root of the sum of the squared differences between the matching variables.

We used an ED metric to determine the similarity in load shapes on event-like days between each treatment customer and eligible control customer, assessing the similarity in usage patterns using the following four demand variables: early morning (HE6-HE9), morning (HE10-HE13), on-peak window (HE15-HE19), and late evening (HE23-HE24). The Euclidean distance for this set of variables is as follows:

$$ED = \sqrt{\begin{array}{c}(early\ morning_{Ti} - early\ morning_{Ci})^2 + (morning_{Ti} - morning_{Ci})^2 \\ + (onpeak_{Ti} - onpeak_{Ci})^2 + (late\ evening_{Ti} - late\ evening_{Ci})^2\end{array}}$$

After calculating the distance metric for each possible combination of participant and control customer, the control customer with the smallest distance is matched to each participant without replacement. We can then

[11] We used weather variables in the Euclidean distance metrics calculation to select event-like days and developed a metric specific to PG&E SmartRate™. We discuss each metric used in the Model Validity Appendix.

[12] We define the treatment periods as the event days and the pre-treatment period as the event-like days.

select the closest matches[13] for each of our participants, creating a one-to-one match of control customers to participants. Once the matching process is complete, we validate the match using the appropriate t-tests and visual inspection of the event-like day load shapes.

Step 4. Regression Analysis

Develop Candidate Regression Models. AEG estimated hourly regression models, which allowed us to estimate the impact of SmartDays™ independently in each hour. For all 24 fitted models, we used the same set of independent variables and referred to them as one model. This approach allowed us to estimate seasonality[14] independently but consistently for each hour of the day.

In general, we think of regression models consisting of building blocks, which, in turn, are made up of one or more explanatory variables. The blocks can be generally categorized into either "baseline" variables or "impact" variables. They could consist of a single variable (e.g., cooling degree hours (CDH)) or a group of variables (e.g., days of the week). The baseline portion of the model explains variation in usage unrelated to DR events, while the impact portion explains the variation in usage related to a DR event[15]

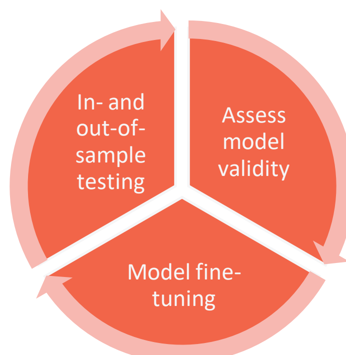
The building blocks were combined in various ways to create a set of candidate models representing a wide variety of customers and their impacts. We used our judgment and experience and worked closely with PG&E to develop an initial set of 5 to 10 models.

Optimization and Model Selection Process. Our optimization process included the validation of the hourly segment regression models and was designed to:

- Accurately predict the actual participant load on SmartDays™, and
- Accurately predict the reference load, or what customers would have used on SmartDays™ in the absence of an event.

After fitting each candidate model to a segment, we selected the best model through a three-part optimization process, consisting of the following steps: (1) In-sample and out-of-sample testing; (2) assessing model validity; and (3) model fine-tuning. Each step of the three-part cycle is described below.

Figure 3-2 Optimization Process



In-Sample and Out-of-Sample Testing

We used in-sample tests to show how well each model performs on the actual SmartDays™, helping us understand how well the model matched the actual load. We used out-of-sample tests to show how well each of the candidate models predicts a customer's load on non-SmartDays™ that were as similar as possible to actual SmartDays™, giving us an estimate of how well each model predicts the reference load.

- **To perform the in-sample test**, we fit each candidate model to the entire data set. The results of these fitted models predict the usage on SmartDays™. Then we assessed the accuracy and bias of the predictions

[13] The closest match is defined by a control customer with an ED with the smallest distance to a participant's ED. If two or more participants share the same closest match, the participant that is "worst off" will "win" its closest match. This is determined by checking the ED's for the second closest matches for each participant.

[14] An example of seasonality would be using weekday v. weekend indicators in all hourly models. This means that we are assuming all hours have weekday v. weekend usage patterns, but the magnitude, i.e., coefficient estimate, of the weekday v. weekend usage patterns are unique to each hour.

[15] Any unexplained variation will end up in the error term.

by calculating the mean absolute percent error (MAPE)[16] and mean percent error (MPE)[17], respectively. We refer to these metrics as the in-sample MAPE and MPE.

- **To perform the out-of-sample test**, we first identified event-like days as several days similar to SmartDays™. We used the same event-like days used in matched control group development for efficiency and consistency. After identifying the event-like days, we removed them from the analysis dataset and fit the candidate models to the remaining data. We used the results of these fitted models to predict the usage on event-like days. Lastly, we assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, respectively. Similarly, we refer to these metrics as the out-of-sample MAPE and MPE.

These two tests result in several in-sample and out-of-sample metrics. Recall that the tests' goal is to find the best model for each segment in terms of its ability to predict each segment's reference load and actual load. Therefore, we combined the two tests into a single metric. The metric used is defined as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + (0.1 * |MPE_{in}|) + (0.1 * |MPE_{out}|)$$

We computed the metric for each segment and candidate model combination and then selected the best model by choosing the specification with the smallest overall metric.

Assessing Model Validity

After selecting the best model for each segment, AEG assessed model validity at the program level by calculating the weighted average MAPE and MPE at the program level. We describe the steps in more detail and go over analysis metrics in the Model Validity Appendix.

Model Fine-Tuning

We also used visual inspection of the results as a simple but highly effective tool. We looked for specific aspects of the segment-level predicted and reference load shapes to determine how well the models performed during the inspection. We used observations from these inspections to edit the model specifications obtained from the optimization process. For example:

- We checked that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely little effect from the event. Significant differences can indicate a problem with the reference load over or underestimating usage in the absence of the rate.
- We closely examined the reference load for odd increases or decreases in the load, indicating an effect not properly captured in the model.
- We also looked for bias both visually and mathematically. Identification of bias and its source allowed us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

Step 5. Estimate Load Impacts and Confidence Intervals by Reporting Subgroup

For each of the five model segments, the final model selected is the following:

$$kwh_{it} = \beta_0 + \beta_1 trt_i + \beta_b(\delta_t + CDH_t + AvgLoad_i) + \beta_a EVNT_i(1 + CDH_t + SR\_SAC_{it} + SAC_{it}) + \varepsilon_{it}$$

Where:

kwh_{it} is the consumption of customer i in hour t.

[16] The mean absolute percent error (MAPE) is defined as: $MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right|$

[17] The mean percent error (MPE) is defined as: $MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h}$

βs are the model intercept and the coefficient estimates.

trt_i is a dummy variable indicating that a customer i is a SmartRate™ participant.

δ_t is a vector of seasonal indicators, i.e., month and day of the week.

CDH_t represents the cooling degree hours for hour t.

$AvgLoad_i$ represents the average hourly load for a specified window[18] for customer i.

$EVNT_i$ is a dummy variable indicating a SmartDay™[19] for customer i.

SR_SAC_{it} is a dummy variable indicating a simultaneous SmartAC™ event for customer i on hour t.

SAC_{it} is a dummy variable indicating a SmartAC™ event for customer i on hour t.

ε_{it} is the error for participant i in time t.

To illustrate a simplified process of estimating the impacts from the final model for a single subgroup, we simplify the model above to be the following:

$$kwh_{it} = \beta_0 + \beta_1 trt_i + \beta_b(base_{it}) + \beta_a EVNT_i(impact_{it}) + \varepsilon_{it}$$

Where, $base_{it} = \delta_t + CDH_t + AvgLoad_i$ and $impact_{it} = 1 + CDH_t + +SR\_SAC_{it} + SAC_{it}$.

In the simplified example above, trt_i and $base_{it}$ make up the baseline blocks of the model, and explain variation in kwh_{it} unrelated to demand response events. The remaining variables, $EVNT_i(impact_{it})$, make up the impact blocks and explain the variation in kwh_{it} related to a SmartDay™.[20] An hourly model like the equation above can be equivalently estimated as one model with hourly dummy variables or as 24 separate hourly models.

This type of time-series data is likely both autocorrelated and heteroskedastic. To address autocorrelation, we use two techniques: (1) estimate 24 separate models for each hour to remove autocorrelation from hour to hour, and (2) incorporate seasonal indicators to minimize autocorrelation. To address heteroskedasticity, we use the Huber-White robust error correction.

We used the model above to estimate the load impacts using the steps outlined below. Although we fitted models at the segment level, we estimated the impacts for every combination of reporting subgroups required in the CPUC LI Protocols: program enrollment, each local capacity area (LCA), CARE enrollment, bill protection status, notification status, rate tariff, and high fire-threat district status.

- **Predicted Load.** First, we obtained the predicted load $\widehat{kwh_{it}}$ on each hour and SmartDay™ based on the specification defined in the equation above.
- **Reference Load.** Next, we used the estimated coefficients and the baseline portion of the model to predict what this customer would have used on each day and hour if there had been no events.
- **Load Impact.** We calculated the difference between the reference load (based on the baseline blocks) and the predicted load (based on the baseline + impact blocks) on each SmartDay™.

To avoid confusion between the observed load and the predicted load, we re-estimated the reference load as the sum of the observed load and the estimated load impact.

[18] The specified window can be one or more of the following: HE10-HE13, HE23-HE24

[19] For ELRP A6 participants, this indicator includes SmartDays™, concurrent SmartDay™ and ELRP events, and ELRP-only events. This indicator makes the assumption that there is no incremental impacts attributed to ELRP participation.

[20] Any unexplained variation will end up in the error term.

Because the impacts are statistical estimates, establishing a range or confidence interval around the estimates is essential, resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each segment.

Step 6. Aggregate Load Impacts to Reporting Subgroups

We estimated the load impacts for each combination of customer subgroups required in the CPUC LIP. This resulted in a per-customer estimate for each combination of customer segments, which was easily aggregated to each reporting subgroup by calculating a sum product using the number of participants within each combination.

To estimate statistical certainty for each reporting subgroup, we can assume that the estimates are independent across participants, and consequently, estimates are independent across modeling segments. Thus, the variance of the sum is the sum of the variances. We can follow this approach to obtain the confidence intervals for each reporting subgroup.

Ex-Ante Load Impact Analysis

In the following subsections, we present our approach and describe each step in detail.

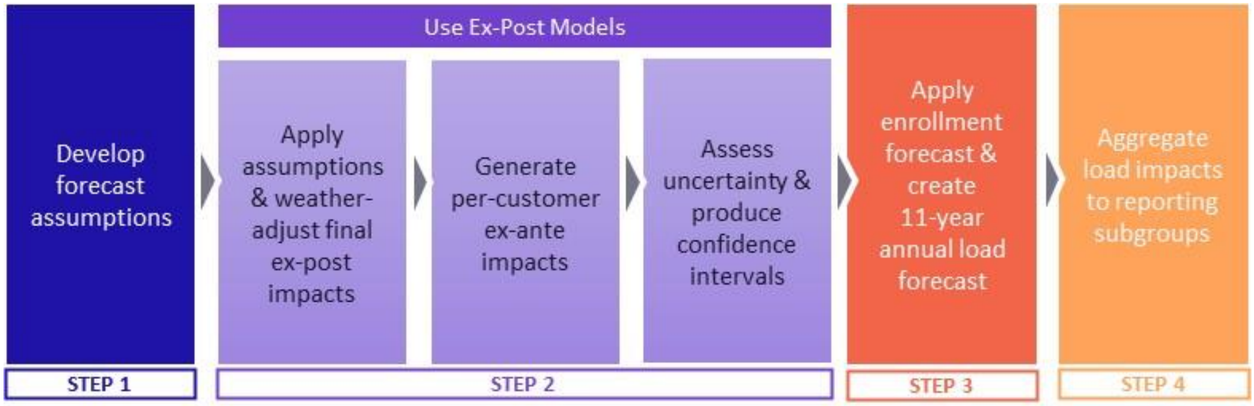
Overview of the Ex-ante Analysis

This section discusses our approach to the ex-ante load impact analysis. We designed the PY2022 ex-ante load impact analysis to meet each of the objectives listed below, all objectives to be provided at the program level.

- To develop hourly load impact estimates for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM),
- To estimates for each year over an 11-year[21] time horizon based on PG&E's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day, and
- To provide estimates for both program-specific and portfolio-adjusted scenarios.

Figure 3-3 shows our approach, and we discuss each step of the analysis.

Figure 3-3 Ex-Ante Analysis Approach



[21] PG&E has requested a PY2022 back cast as part of the ex-ante impact analysis.

Step 1. Develop Forecast Assumptions

We collected the data items (listed below) from each IOU for the ex-ante LI analysis:

- Monthly peak day and typical event day hourly weather for PG&E and CAISO 1-in-2 weather year and 1-in-10 weather year, and
- Eleven-year enrollment forecast data by LCA and program enrollment[22].

We developed appropriate forecast assumptions through continued discussions with PG&E regarding SmartRate™'s approved program changes. We summarize the forecast assumptions below and then discuss the methods used to develop these assumptions.

- **Update participant load impacts based on PY2022 ex-post analysis.** Effective May 2022, the SmartRate™ event window shifted to 4 PM to 9 PM. Prior analyses were based on a 2 PM to 7 PM event window.
- **Exclude load impact estimates from participants affected by the Notification error.** PG&E anticipates the notification issues experienced in PY2022 to be corrected by the implementer.
- **Assume typical event day percent impacts for non-summer months.** Since load impact estimates for non-summer months (outside June through September), we estimated load impacts by applying the hourly percent impacts for a typical event day to the estimated reference loads during non-summer months.
- **The ELRP pilot is set to conclude after October 2025.** Consequently, we used the following assumptions:
    - Participants dually enrolled in ELRP A6 will rejoin the singly enrolled subgroup starting in November 2025.
    - Maintain PY2022 load impacts[23] for participants dually enrolled in ELRP A6 through the remainder of the pilot (October 2025).
    - Over three years, there will be a gradual catch-back period for previous ELRP A6 participants. Beginning November 2025, customers will perform at 50% of the singly enrolled subgroup for one year. In November 2026, load impacts will increase to 75%. In November 2027, the customers will catch up to singly enrolled subgroup levels.
- The portfolio-adjusted forecast used the following assumptions:
    - **Dually enrolled in SmartAC™ – maintained the assumption that 18% load impacts is an incremental effect of SmartRate™ participation.** We assume that 18% of load impacts on concurrent SmartRate™ and SmartAC™ events are attributed to the behavioral impact of SmartRate™ participation.
    - **Dually enrolled in ELRP A6 – included in the portfolio-adjusted forecast through the ELRP pilot implementation.** The impacts from this subgroup are primarily attributed to SmartRate™, while incremental impacts, if any, are attributed to ELRP[24]. We assume participants in this subgroup to perform as they do when called to SmartRate-only events.

[22] SmartRate™ only or dual enrollment in SmartAC™ or ELRP A6.

[23] The PY2022 Ex-Post analysis resulted in very low impacts for the participants dually enrolled in ELRP A6. PG&E attributes this to notification issues and participant confusion regarding their default to ELRP and how it may interact with their SmartRate enrollment. ELRP A6 defaulted customers were delivered welcome packets to the pilot, but as there is no precedent on the SmartRate/ELRP A6 dual enrollment no information on their interaction was included in the packet. There are no plans for additional marketing/education outreach for dually enrolled participants as of the filing of this report. Discussions are ongoing on this topic.

[24] Estimated under the ELRP LI evaluation's portfolio-adjusted ex-ante analysis.

Portfolio-Adjusted Load Impacts for Participants Dually Enrolled in SmartAC™

Portfolio-adjusted load impacts exclude the load impacts from dually enrolled participants attributed to concurrent SmartAC™ events. In other words, SmartAC™ takes precedence over SmartRate™. The dually enrolled customer load impacts are removed in the portfolio-adjusted scenarios to avoid double counting. However, we assume a portion of the load impacts for dually-enrolled customers on concurrent event days is attributable to SmartRate™ because those customers exhibit higher impacts on SmartDays™ than on SmartAC™-only event days. We believe the incremental impact is due to a price response over and above the effect of the SmartAC™ switch.

In PY2022, we maintained the PY2019 assumption that 18% of load impacts on concurrent SmartRate™ and SmartAC™ events is an incremental effect of enrollment to SmartRate™ due to constraints[25] in the analysis timeline. However, a simple check using PY2022 data found that participants dually enrolled in SmartAC™ showed:

- 13% load impacts, on average, on SmartDays™ June 10th, June 27th, July 18th, July 21st, and September 1st.
- 15% load impacts, on average, on concurrent system-level SmartAC™ events September 5th, September 6th, September 7th, and September 8th. None of these days had a full 4 PM to 9 PM concurrent event window.
- The resulting incremental SmartRate™ impact is 16%. Given that none of these days have a full concurrent 4 PM to 9 PM event, this estimate is an underestimation. We maintained the 18% assumption from previous years.

Step 2. Use Ex-Post Regression Models

We used the ex-post hourly regression models to apply developed forecast assumptions and predict weather-adjusted impacts for each weather scenario. This step produced a set of impacts under each of the different weather scenarios required by the CPUC LIP, typical event day, and monthly peak for both PG&E and CAISO 1-in-2 and 1-in-10 weather years. To do this, we carried out the following steps:

- **Weather-Adjust Impacts and Apply Forecast Assumptions.** We assembled an input dataset using the weather scenarios required in the CPUC LIP and estimated weather-adjusted reference loads and load impacts using the ex-post hourly regression models. We made appropriate adjustments based on the assumptions listed above.
- **Generate Per-Customer Ex-Ante Load Impacts.** After applying all forecast assumptions, we develop per-customer estimates (reference loads and load impacts) for the 11-year forecast period. These per-customer estimates will be multiplied against the enrollment forecast to develop the 11-year load impact forecast.
- **Assess Uncertainty and Produce Confidence Intervals.** Similar to the ex-post analysis, it is vital to establish a confidence interval around the estimates resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each subgroup.

Step 3. Create 11-Year Annual Forecast

Per-customer ex-ante load impacts for each combination of reporting subgroups required in the CPUC LIP were multiplied to program enrollment forecasts to create an annual forecast of load impacts over the next 11 years. We also estimated a "back-cast," which consisted of weather-adjusted ex-post estimates of the current program

[25] The ELRP pilot implementation prompted several iterations in both the Ex-Post and Ex-Ante analyses.

year. PG&E provided an 11-year enrollment forecast, while the "back-cast" used actual program year enrollment counts.

Step 4. Aggregate Load Impacts to Reporting Subgroups

Once ex-ante load impact forecasts have been predicted for each combination of reporting subgroups, for each of the required weather scenarios, we aggregated the load impacts and generated per-customer average impacts for each CPUC LIP required reporting subgroup.

To estimate statistical uncertainty for each reporting subgroup, we can assume that the estimates are independent across participants, and consequently, estimates are independent across subgroups. Thus, the variance of the sum is the sum of the variances. We can follow this approach to obtain the confidence intervals for each reporting subgroup.

4

EX-POST ANALYSIS RESULTS

This section presents the PY2022 ex-post load impacts for PG&E's Residential SmartRate™ Program.

Summary of Load Impacts

Table 4-1 below summarizes the overall program level estimates for each PY2022 SmartDay™. All reported estimates represent the average of the SmartDay™ peak period or event window. We include the number of participants enrolled during each SmartDay™, the aggregate and per-customer reference load and load impacts, the percent impacts relative to the reference load, and the average temperature.

In PY2022, SmartRate™ implemented a new on peak period, 4 PM to 9 PM (previously 2 PM to 7 PM). Load impacts as a percent of the reference load were 3.9% on average, which is lower than in previous years. We discuss this further in a subsequent subsection.

Three concurrent ELRP events (***bold italicized*** text) are excluded from this analysis and reported in the ELRP LI Evaluation. These events were excluded from the average event day.

Table 4-1 All Participants: Ex-Post Load Impacts by Event

Event Date	# of Accts	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
Jun 10	42,388	92.1	3.4	2.17	0.08	3.7%	90
Jun 27	42,578	96.9	3.4	2.28	0.08	3.5%	88
Jul 11	42,811	102.2	4.0	2.39	0.09	3.9%	90
Jul 18	42,926	98.3	3.3	2.29	0.08	3.3%	88
Jul 21	43,029	95.6	3.2	2.22	0.07	3.4%	87
Aug 16	43,664	107.1	4.4	2.45	0.10	4.1%	92
Aug 17	***20,941***	***41.7***	***2.9***	***1.99***	***0.14***	***6.9%***	***87***
Aug 19	43,790	99.7	3.4	2.28	0.08	3.4%	88
Sep 1	***20,978***	***45.3***	***3.4***	***2.16***	***0.16***	***7.4%***	***91***
Sep 5	***21,198***	***55.7***	***4.5***	***2.63***	***0.21***	***8.2%***	***99***
Sep 6	44,190	124.6	5.8	2.82	0.13	4.7%	99
Sep 7	44,190	115.3	4.9	2.61	0.11	4.2%	95
Sep 8	44,190	115.0	4.9	2.60	0.11	4.2%	96
Average Event Day	**43,376**	**104.7**	**4.1**	**2.41**	**0.09**	**3.9%**	**91**

Concurrent SmartAC events (gray highlighted cells) called for various combinations of Sub-LAPs and event hours.
Concurrent ELRP A6 events (***bold italicized*** **text**) called at the system level on the same 4 PM to 9 PM event window.

Figure 4-1 presents the aggregate ex-post load impacts for each event day for all SmartRate™ participants:

- Green Bars – the magnitude of the aggregate load impact,

- Striped Bars – concurrent ELRP A6 event, dually enrolled to ELRP A6 participants are excluded from the average event day,
- Gray shading – a concurrent SmartAC™ event,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by the participants during the event hours

These results indicate that participants had statistically significant load reductions on all PY2022 SmartDays™, ranging from 2.9 to 5.8 MW. These results also demonstrate weather sensitivity, with the green bars moving up/down with the orange line. The aggregate load impact was 4.1 MW on average.

Figure 4-1 All Participants: Aggregate Load Impacts by Event

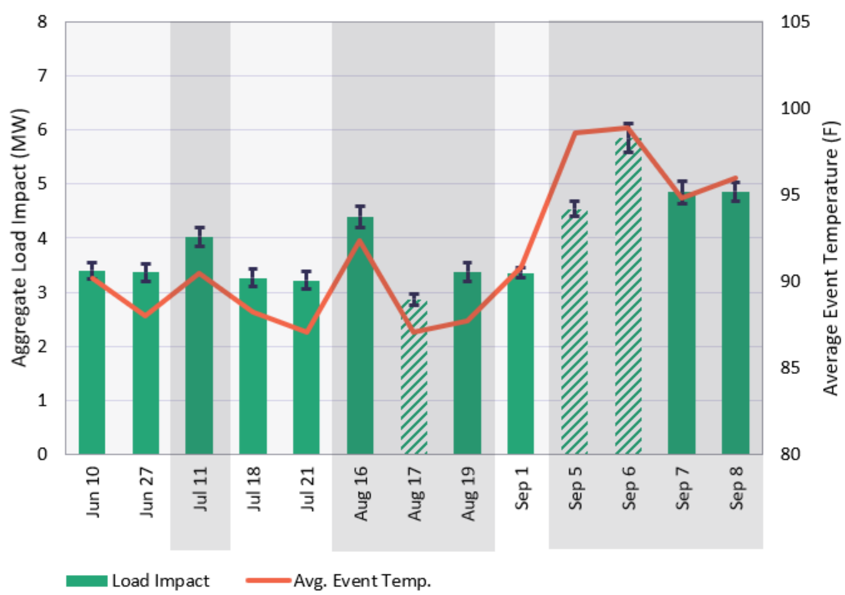
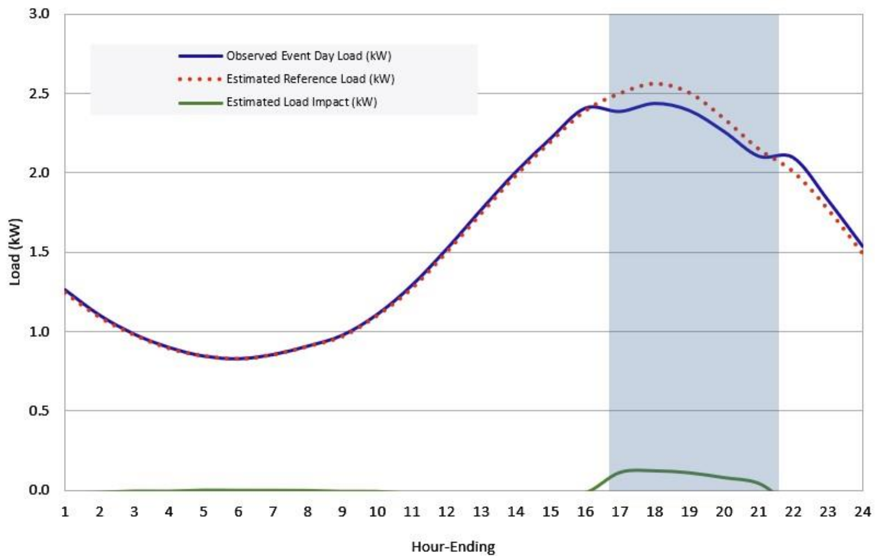


Figure 4-2 shows the per-customer hourly observed loads, estimated reference loads, and estimated load impacts on the average event day. On average, SmartRate™ participants have a relatively flat event response, reaching the highest impact during the second event hour (HE18). At the program level, hourly load impacts show very minimal signs of pre-cooling or post-event snapback. This response is typical of programs where participants do not have a technology-enabled device to assist in event response. We will discuss this more in a subsequent section on the impacts of dual enrollment in SmartAC™.

Figure 4-2 All Participants: Per-Customer Load Profiles on an Average Event Day



Comparison of Ex-Post Impacts

This section discusses how the PY2022 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Table 4-2 presents the ex-**post load impacts over time**. In this comparison, we see the following:

- Consistent with previous years, PG&E's SmartRate™ program continues to experience an overall decrease in program enrollments, and consequently aggregate load impacts. PG&E attributes participant attrition to customers moving onto CCAs or ineligible rates, both ineligible to participate in SmartRate™ and the lack of marketing efforts for the program.
- Per-customer load impacts also decreased, which we attribute to the following:
    - The implementation of a new on peak period (4 PM to 9 PM) may have prompted a "learning curve" as participants adjust their behavior to the new window.
    - Participants dually enrolled in ELRP A6 delivered very low impacts, which PG&E attributes to notification issues, contributing to participant confusion.
    - Notification issues affected a small subgroup (5%) of participants that did not receive event notifications
- The average customer usage (per-customer reference load) decreased, likely due to the change in participant population and event window shift.

Table 4-2 Current v. Previous Ex-Post, Average Event Day

Year	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
2020 (2-7 PM)	64,752	153.8	12.3	2.38	0.19	8.0%	96
2021 (2-7 PM)	51,489	125.1	7.3	2.43	0.14	5.8%	95
2022 (4-9 PM)	**43,376**	**104.7**	**4.1**	**2.41**	**0.09**	**3.9%**	**91**

Table 4-3 presents the **PY2022 ex-post load impacts compared to prior (PY2022) ex-ante estimates**. In this comparison, we see the following:

- Participant attrition is at a higher rate than anticipated, with the average number of accounts at 43k instead of the forecasted 45k.
- Per-customer load impacts (3.9%) performed better than the prior ex-ante forecast (3.1%), which assumed a 50% decrease in load impacts during the first year of the event window shift to account for the "learning curve" as participants adjust their behavior to the new event window.
- The average customer usage (per-customer reference load) is higher, suggesting that the COVID effect persists. We can interpret this as the "new normal," or the COVID effect is decreasing at a much slower rate than initially expected.
- PY2022 enrolled customers, on average, experienced temperatures slightly milder than 1-in-2 weather conditions.

Table 4-3 Current Ex-Post (Average Event Day) v. Prior Ex-Ante (PG&E 1-in-2, Typical Event Day, 2022)

Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Prior Ex-Ante	44,915	102.4	3.2	2.28	0.07	3.1%	96
Ex-Post 2022	**43,376**	**104.7**	**4.1**	**2.41**	**0.09**	**3.9%**	**91**

Distribution of Program Impacts

This section presents all load impact estimates for each of the following customer subgroups: LCA, bill protection status, CARE enrollment, program enrollment[26], high fire-threat district status, notification status, and TOU enrollment, along with the distribution of impacts for each subgroup.

Impacts by Local Capacity Area

Table 4-4 summarizes the aggregate ex-post results for the average event day for PG&E's eight LCAs. The table includes the number of enrolled customers, the estimated reference loads, the estimated load impacts, the percent impacts relative to the reference load, and the average event temperature.

[26] SmartRate™ only or dual enrollment in SmartAC™ or ELRP A6.

Enrollments are concentrated in the Greater Fresno Area, with 25% of all participants. However, the largest subgroup of customers (28%) is in the "Other or Unknown" category. These two LCAs have the largest share of load impacts and together contribute 2.3 MW.

Table 4-4 By LCA: Aggregate Load Impacts on an Average Event Day

LCA	# of Accts	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Greater Bay Area	4,215	7.2	0.2	2.6%	80
Greater Fresno Area	10,797	30.2	1.2	3.9%	100
Humboldt	30	[redacted]	[redacted]	[redacted]	71
Kern	4,273	12.8	0.4	3.2%	103
North Coast and North Bay	1,455	2.2	0.1	3.1%	87
Sierra	5,881	13.3	0.6	4.5%	95
Stockton	4,729	11.2	0.4	4.0%	94
Other or Unknown	11,994	27.6	1.2	4.3%	95

In Figure 4-3, we present the share of the total enrollment, impacts, and reference load by LCA. This figure demonstrates that the share of impacts is similar to the share of enrollment, resulting from minor differences between each LCA's per-customer impacts.

Figure 4-3 By LCA: Contributions on an Average Event Day

Impacts by Other Subgroups

Next, we look at load impacts for other subgroups of interest. Table 4-5 summarizes ex-post estimates for the average event day for each of the following subgroups: bill protection status, CARE enrollment status, program enrollment, high fire-threat district status, and TOU enrollment. The table includes the number of enrolled customers, the aggregate and per-customer reference loads and load impacts, the percent impacts relative to the reference load, and the average event temperature.

Table 4-5 By Subgroup: Ex-Post Load Impacts on an Average Event Day

Subgroup	Status	# of Accts	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Bill Protection	No	38,031	92.4	3.7	2.43	0.10	4.0%	92
	Yes (No Issue)	3,967	8.7	0.3	2.19	0.08	3.5%	91
	Yes (Notification Issue)	1,378	3.5	0.0	2.57	0.02	0.7%	92
CARE Enrollment	No	23,625	53.7	2.7	2.27	0.12	5.1%	90
	Yes	19,751	51.0	1.3	2.58	0.07	2.6%	93
Program Enrollment	SmartRate Only	15,023	34.0	1.6	2.26	0.11	4.8%	90
	Dual - ELRP A6	22,604	57.2	0.5	2.53	0.02	1.0%	92
	Dual - SmartAC	5,748	13.5	1.9	2.35	0.33	13.9%	93
High Fire Threat District	No	36,533	92.0	3.5	2.52	0.10	3.8%	92
	Yes	6,842	12.7	0.6	1.85	0.08	4.5%	90
TOU	No	28,651	72.8	2.7	2.54	0.10	3.8%	92
	Yes	14,725	31.9	1.3	2.17	0.09	4.2%	92

Figure 4-4 presents the total load impact contributions based on status within each subgroup on an average event day. As expected, the share of aggregate load impacts is mostly driven by the share of enrollment for each subgroup. For example, participants on non-TOU rates make up 64% of total enrollment and contribute to 67% of total MW impacts, despite having lower per-customer load impacts compared to participants on TOU rates. For reference, Figure 2-3 shows the enrollment distributions by subgroup. In subsequent sections, we also discuss each subgroup's overall contribution to the program.

Figure 4-5 presents each subgroup's per-customer load impacts on an average event day. The black bands correspond to 90 percent confidence intervals around these estimates. Thus, non-overlapping black bands within subgroups indicate statistically significant differences between the subgroup per-customer estimates. In PY2022, all subgroups show statistically significant differences between the subgroup per-customer load impacts. We discuss these differences in subsequent sections.

Figure 4-4 Load Impact Distributions by Subgroup

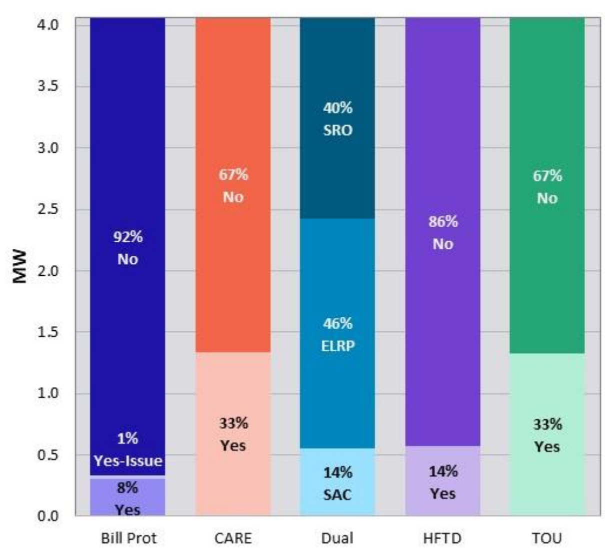
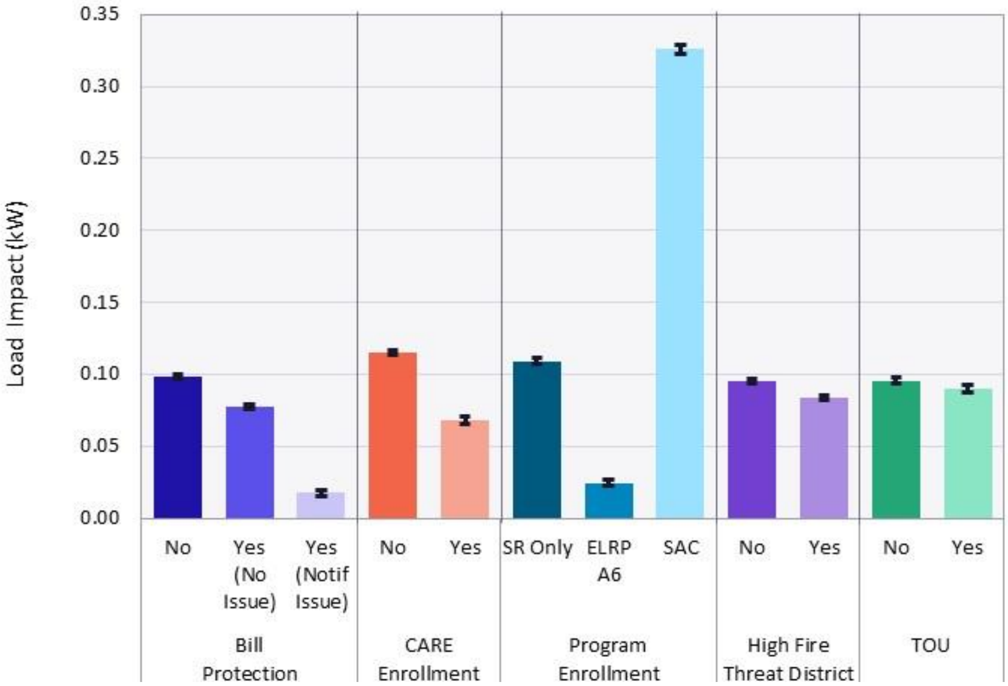


Figure 4-5 By Subgroup: Per-Customer Load Impacts on an Average Event Day



Bill Protection Guarantee

During their first full summer season (May through October) of program enrollment (and any preceding partial season), customers are backed by PG&E's Bill Protection Guarantee that refunds customers if their SmartRate™ costs are more than their regular residential pricing plan. PG&E would credit the difference on the customer's November bill if they did not save on SmartRate™. This section explores any implications of PG&E's Bill Protection Guarantee on load impacts.

Around 12% of PY2022 SmartRate™ participants qualify for the Bill Protection Guarantee, a slight increase from 10% in PY2021, which suggests the SmartRate™ new enrollments are higher in PY2022. During the PY2022 implementation, SmartRate™ experienced notification issues, primarily affecting participants under the Bill Protection Guarantee. Around 26% of bill-protected participants were affected by notification issues. The bill-protected group contributed, on average, 8% of total SmartRate™ MW impacts. Table 4-6 presents the per-customer reference loads and load impacts by bill protection status on an average event day.

Table 4-6 By Bill Protection Status: Per-Customer Load Impacts on an Average Event Day

Subgroup	# of Accts	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)	% Load Impact	Avg. Event Temp.
No Bill Protection	38,031	2.43	0.10	3.7	4.0%	92
Bill Protection (No Issue)	3,967	2.19	0.08	0.3	3.5%	91
Bill Protection (Notification Issue)	1,378	2.57	0.02	<0.1	0.7%	92

Excluding bill-protected participants affected by the notification issue, we saw results consistent in previous years. We see slightly lower per-customer load impacts for the bill-protected group compared to the not-bill-protected group. We attribute these differences to the following typical expectations from the Bill Protection Guarantee:

- Customer "complacency" due to the absence of cost impacts,
- The first season "learning curve" where participants have yet to adjust their behaviors to respond to events adequately, and
- The absence of technology-enabled participants in the bill-protected group since dual enrollment in SmartAC™ is closed to new customers.

The participants affected by the notification issue exhibited very small, yet statistically significant, load impacts. These findings possibly indicate that a subset of participants receives SmartDay™ alerts through other mediums (i.e., day ahead on the PG&E website or day of on twitter) besides the official email and text message notifications.

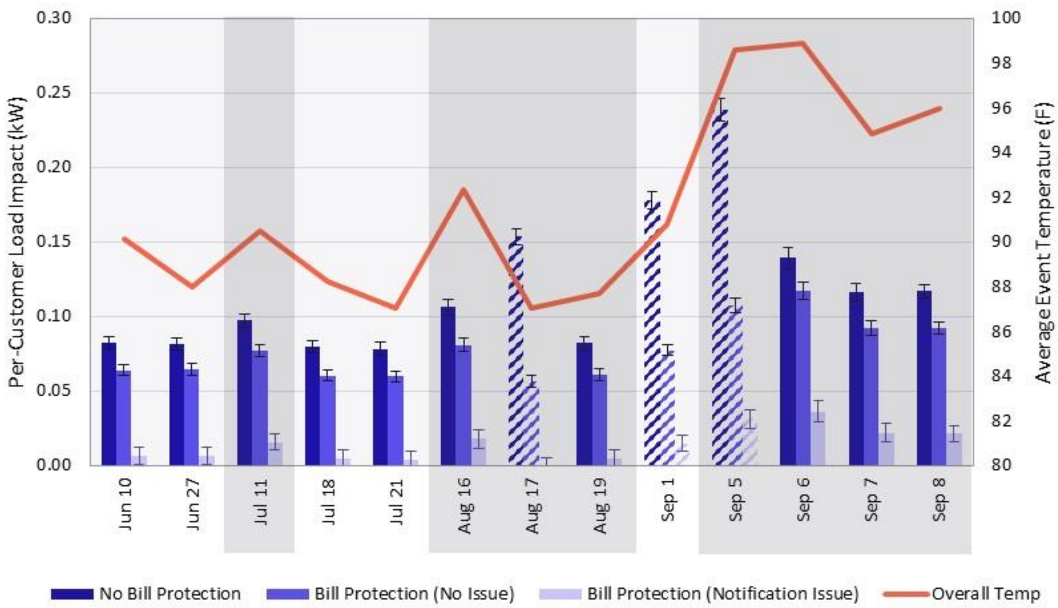
Figure 4-6 presents the share of the total enrollment, impacts, and reference load by bill protection status.

Figure 4-6 By Bill Protection Status: Contributions on an Average Event Day

Figure 4-7 presents the per-customer ex-post load impacts for each event day based on bill protection status:

- Dark, medium, and light blue bars – the magnitude of the per-customer load impacts for no bill protection, bill-protected without issues, and bill-protected with notification issues, respectively,
- Striped Bars – concurrent ELRP A6 event and excluded from the average event day,
- Gray shading – concurrent SmartAC™ event,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by all participants during the event hours.

Figure 4-7 By Bill Protection Status: Per-Customer Load Impacts by Event

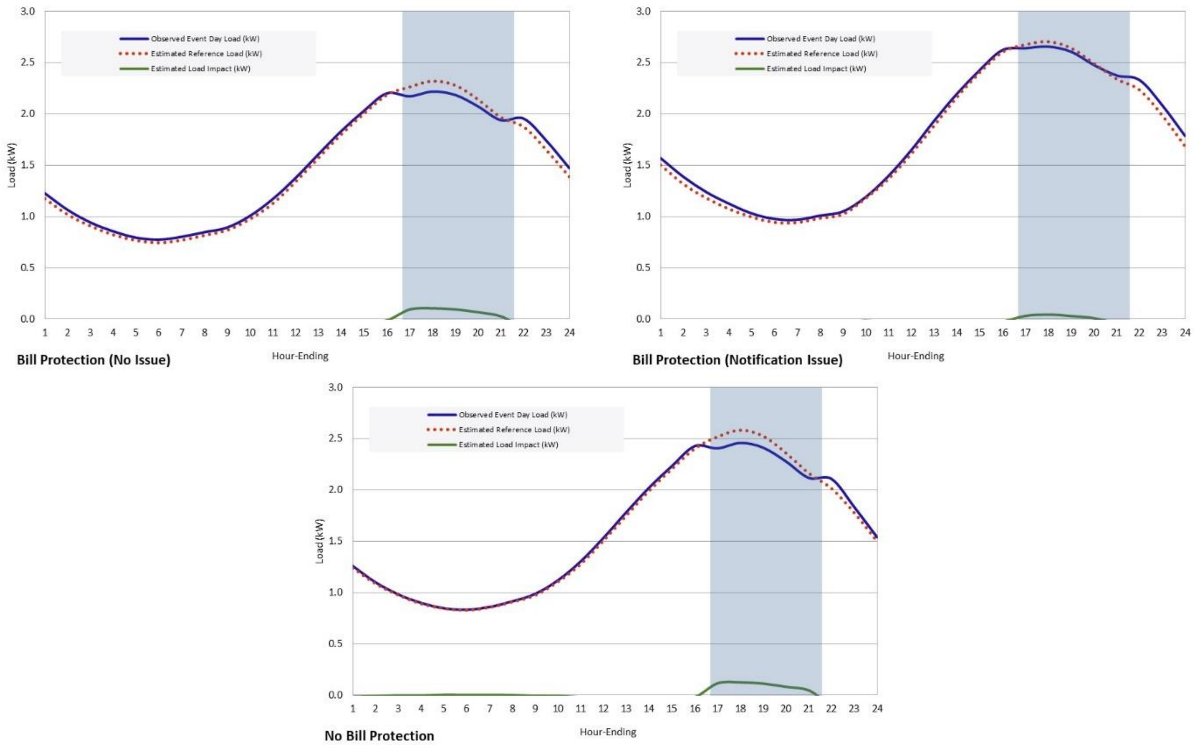


From Figure 4-7, we can observe the following:

- The bill-protected participants affected by the notification issue exhibited very small, but on average statistically significant, load impacts compared to bill-protected participants without notification issues.
- Consistent with previous years, participants under the Bill Protection Guarantee (no issue) have slightly lower per-participant impacts compared to continuing SmartRate™ participants.
- Both groups show some correlation between impacts and temperatures.

Figure 4-8 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day based on bill protection status. Note that these subgroups were included in three separate modeling subgroups based on the assumption that these three subgroups have significant differences in load impacts or program response.

Figure 4-8 By Bill Protection Status: Per-Customer Load Profiles on an Average Event Day



From Figure 4-8, we can observe the following:

- All subgroups show minimal impact outside the event window, indicating consistent load reductions without shifting load into non-event hours.
- Participants under bill protection (no issue) have lower average usage than continuing participants.
- The magnitude difference in per-customer load impacts is clearly shown in these comparison figures.

Program Enrollment

Next, we present the implications of program enrollment. In PY2022, dually enrolled participants make up approximately 65% of the SmartRate™ participants, contributing, on average, 60% of total MW impacts. Participants may be dually enrolled in SmartAC™ or Emergency Load Reduction Program (ELRP A6).

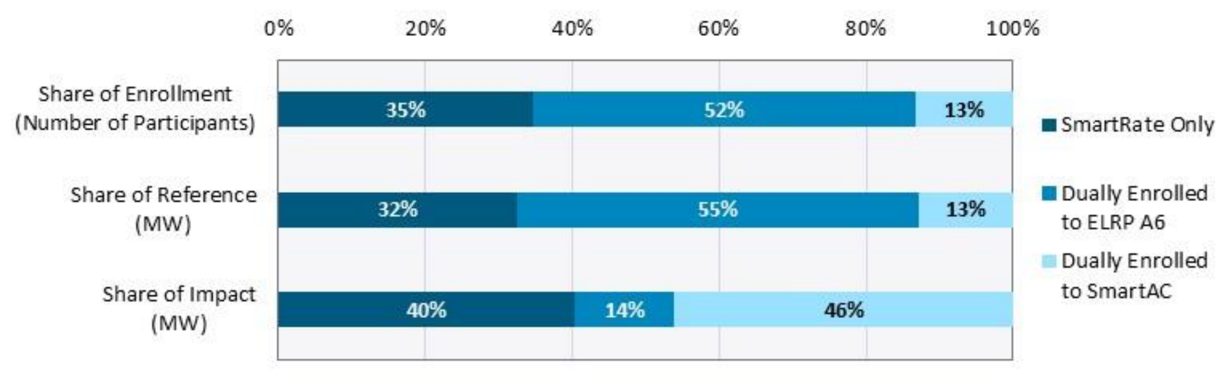
Table 4-7 presents the per-customer reference loads and load impacts by program enrollment on an average event day. Comparing the results from these three subgroups shows that the key difference is the magnitude of per-customer load impacts. Consistent with previous years, participants dually enrolled in SmartAC™, on average, show high levels of per-customer percent impacts (13.9%). New to PY2022, participants dually enrolled in ELRP A6 show an average of very low per-customer percent impacts (1.0%).

Table 4-7 By Program Enrollment: Per-Customer Load Impacts on an Average Event Day

Subgroup	# of Accts	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)	% Load Impact	Avg. Event Temp.
SmartRate Only	15,023	2.26	0.11	1.6	4.8%	90
Dually Enrolled - ELRP A6	22,604	2.53	0.02	0.5	1.0%	92
Dually Enrolled - SmartAC	5,748	2.35	0.33	1.9	13.9%	93

Figure 4-9 presents the share of the total enrollment, impacts, and reference load by program enrollment. This figure demonstrates that each program enrollment's effect on per-customer performance impacts overall contributions to the SmartRate™ program. Consistent with previous years, SmartAC™ dual enrollment contributes significantly with 46% of aggregate load impacts despite having only 13% of total enrollments. On the other hand, ELRP A6 dual enrollment contributes only 14% of aggregate load impacts despite having 52% of total enrollments.

Figure 4-9 By Program Enrollment: Contributions on an Average Event Day



We further discuss the implications of both SmartAC™ and ELRP A6 below.

Dual Enrollment in ELRP A6

The Emergency Load Reduction Program (ELRP) is a pilot program implemented statewide for various customer segments and end-use interventions. The purpose of the pilot is to provide incremental load reduction and open participation to customers beyond those already enrolled in traditional supply-side demand response programs. Events are triggered based on the day-ahead CAISO system conditions or day-of grid emergencies. The ELRP pilot is set to conclude after October 2025.

Participants in Residential ELRP will be incentivized to reduce consumption during event hours (4 to 9 PM) by providing a $2.00 bill credit for each kilowatt-hour of energy reduced during an event. The reduction will be calculated based on an individual customer baseline. There is no penalty for participants that increase their load relative to the baseline.

Per the CPUC Decision, PG&E automatically enrolled residential customers on CARE or FERA rates within their territory. PG&E was also instructed to default an additional group, customers who receive PG&E's Home Energy Reports. Customers not in these segments may opt-in to the program. For PG&E, customers can be dually enrolled in SmartRate™.

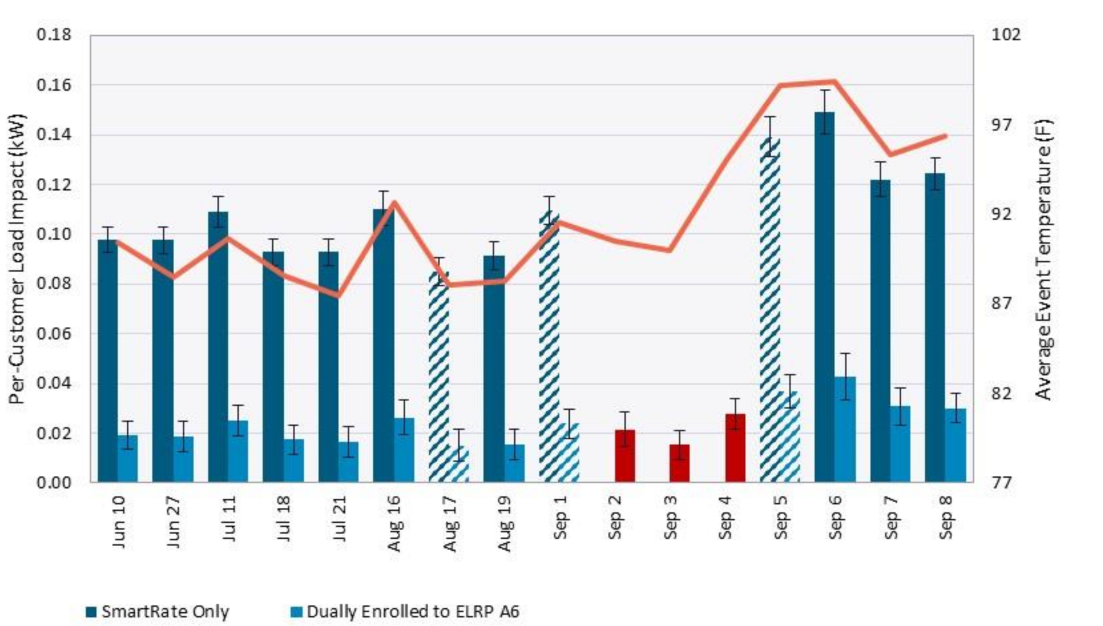
For each event, customers will receive a day-ahead notification. An email notification was sent to all default and opt-in customers for whom PG&E has contact information, while text notifications were sent to those who signed up for them.

The ex-post analysis on dual enrollment in ELRP A6 indicated very low impacts inconsistent with those historically shown by this group, previously singly enrolled in SmartRate™ and primarily CARE customers. PG&E attributes this to overall participant confusion. Both SmartRate™ and ELRP send out day-ahead email or text notifications for program events, and the PG&E SmartRate™ call center reported customer calls indicating confusion regarding ELRP notifications received by defaulted customers unaware of ELRP enrollment. ELRP A6 defaulted customers were delivered welcome packets to the pilot. However, as there is no precedent on the SmartRate/ELRP A6 dual enrollment, no information on their interaction was included in the packet. There are no current plans for additional marketing/education outreach for dually enrolled participants. Discussions are ongoing on this topic.

Figure 4-10 presents the per-customer ex-post load impacts for each event day for singly and dually enrolled participants:

- Dark and medium blue bars – the magnitude of the per-customer load impacts for singly enrolled and dually enrolled in ELRP A6, respectively,
- Striped Bars – concurrent ELRP A6 event and excluded from the average event day,
- Red bars – ELRP-only events,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by all participants during the event hours.

Figure 4-10 By ELRP A6™ Enrollment: Per-Customer Load Impacts by Event

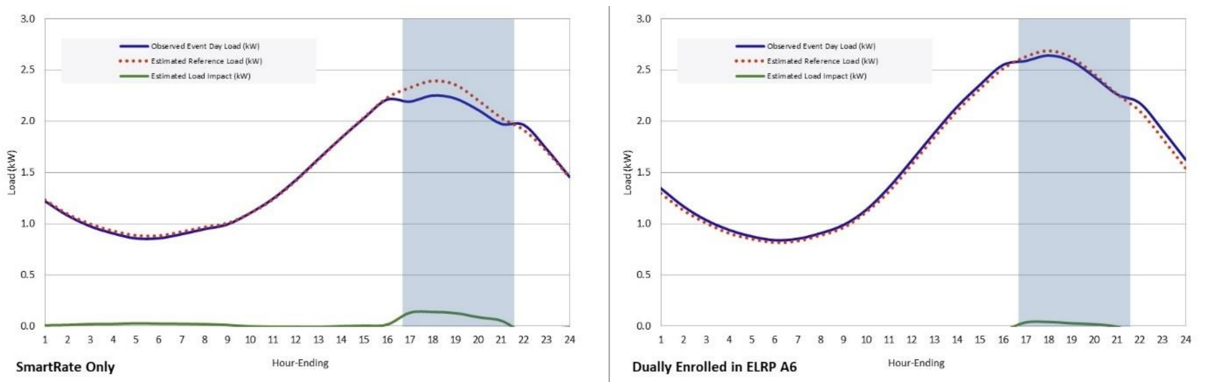


From Figure 4-10, we observe the following:

- As mentioned above, the participants dually enrolled in ELRP A6 exhibited very low per-customer load impacts compared to singly enrolled participants. Historically, this subgroup exhibited load impacts comparable to the singly enrolled subgroup. Note that these participants were previously singly enrolled in SmartRate™ and primarily CARE customers.
- The dually enrolled participants showed consistent load impacts on all three types of events experienced: SmartDays™ (solid bars), SmartDays™ concurrent with ELRP (striped bars), and ELRP-only events (red bars). These results indicate no incremental impacts[27] can be attributed to either program.
- Not as apparent due to the difference in magnitude, but both subgroups show some correlation between impacts and temperatures.

Figure 4-11 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for singly and dually enrolled participants.

Figure 4-11 By ELRP A6™ Enrollment: Per-Customer Load Profiles on an Average Event Day



From Figure 4-11, we can observe the following:

- Both subgroups show minimal impacts outside the event window, indicating consistent load reductions without shifting load into non-event hours.
- The magnitude difference in per-customer load impacts is clearly shown in these comparison figures.

ELRP Pilot Effect on CARE Customers

Previous LI evaluations provided little discussion around CARE customers since historical performance showed no statistically significant differences between CARE and non-CARE load impacts. Defaulting CARE customers into ELRP A6 impacted the average performance of this subgroup, which now exhibits much lower percent impacts (2.6%) compared to non-CARE customers (5.1%). Table 4-10 presents the per-customer reference loads and load impacts by CARE enrollment on an average event day.

[27] We discuss this further under the portfolio adjusted ex-ante impacts in Section 5.

Table 4-8 By CARE Enrollment: Per-Customer Load Impacts on an Average Event Day

Subgroup	# of Accts	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)	% Load Impact
Non-CARE Customers	23,625	2.27	0.12	2.7	5.1%
CARE Customers	19,751	2.58	0.07	1.3	2.6%

To further demonstrate that this change in CARE customer performance was driven by ELRP A6 defaulting, Table 4-9 compares the CARE and non-CARE performance of singly and dually enrolled participants. Participants' program enrollment shows minor differences in percent impacts between CARE and non-CARE customers. However, the large share (86%) of CARE customers are dually enrolled in ELRP A6 drove the overall CARE performance lower than historical performance.

Table 4-9 By CARE Enrollment and Program: Customer Counts & Percent Impacts on an Average Event Day

Program Enrollment	Non-CARE Customers		CARE Customers	
	# of Accts	% Impact	# of Accts	% Impact
SmartRate Only	14,510	4.9%	513	3.8%
Dually Enrolled - SmartAC	3,450	13.9%	2,298	13.8%
Dually Enrolled - ELRP A6	5,665	0.6%	16,939	1.1%

Dual Enrollment in SmartAC™

The SmartAC™ program calls emergency-based and Sub-LAP-level events, lasting between one and six hours daily. Customers enrolled in the SmartAC™ program have a device installed on their air conditioner (AC), allowing PG&E to remotely signal AC units to run at a lower capacity. During SmartDays™, PG&E also remotely controls participants' AC Units via the SmartAC™ devices. In other words, dually enrolled participants receive the same experience on both SmartAC™ events and SmartDays™. All dually enrolled participants enrolled in both programs before October 26th, 2018. Dual enrollment is not currently available to new participants.

The PY2022 analysis showed results consistent with this subgroup's historical performance. On average, participants dually enrolled in SmartAC™ save 13.9% compared to 4.8% for singly enrolled participants. These differences in magnitude can be directly attributed to the SmartAC™ devices, which allow participants to respond to events with minimal to no impact on customer behavior.

Figure 4-12 presents the per-customer ex-post load impacts for each event day for singly and dually enrolled participants:

- Dark and light blue bars – the magnitude of the per-customer load impacts for singly enrolled and dually enrolled in SmartAC™, respectively,
- Striped Bars – concurrent ELRP A6 event and excluded from the average event day,
- Gray shading – concurrent SmartAC™ event,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by all participants during the event hours.

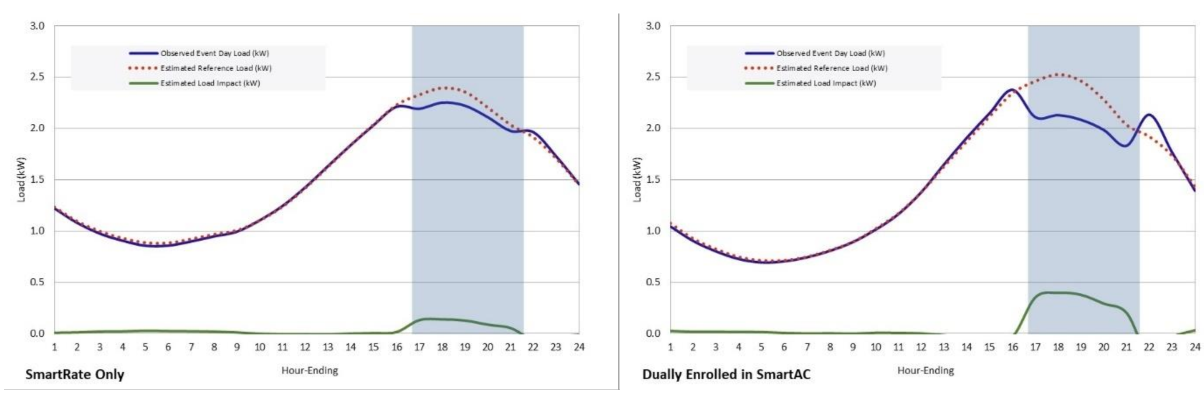
Figure 4-12 By SmartAC™ Enrollment: Per-Customer Load Impacts by Event

From Figure 4-12, we observe the following:

- As previously discussed, participants dually enrolled in SmartAC™ exhibit higher per-customer load impacts compared to singly enrolled participants. These results are consistent with historical performance.
- Both groups show some correlation between impacts and temperatures.
- As in previous years, higher impacts on SmartDays™ with concurrent SmartAC™ events indicate that dually enrolled participants have an incremental impact[28] attributed to SmartRate™ in addition to impacts attributed to SmartAC™ devices.

Figure 4-13 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for singly and dually enrolled participants.

Figure 4-13 By SmartAC™ Enrollment: Per-Customer Load Profiles on an Average Event Day



[28] We discuss this further under the portfolio adjusted ex-ante impacts in Section 5.

Public

From Figure 4-13, we can observe the following:

- Singly enrolled participants show minimal impacts outside the event window, indicating consistent load reductions without shifting load into non-event hours.
- On the other hand, dually enrolled participants have small pre-cooling and large snapback usage patterns, typical of technology-enabled participants.
- And again, the magnitude difference in per-customer load impacts is clearly shown in these comparison figures.

High Fire-Threat District

High fire-threat districts refer to areas with a higher risk of power line fires igniting and spreading rapidly. These high fire-threat areas are chosen by several maps approved on an interim basis. Each interim map covers a different part of California and uses its own method for identifying high fire-threat areas, showing consistency and potential enforcement issues. Around 16% of PY2021 SmartRate™ participants are located within high fire-threat districts. This group contributed, on average, 14% of total MW impacts.

Table 4-10 presents the per-customer reference loads and load impacts by high fire-threat district status on an average event day. On average, we see slightly higher load impacts as a percent of reference loads (4.5% v. 3.8%) despite having substantially lower average customer usage for the high fire-threat district participants.

Table 4-10 By High Fire-Threat District Status: Per-Customer Load Impacts on an Average Event Day

Subgroup	# of Accts	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)	% Load Impact	Avg. Event Temp.
Non Fire-Threat	36,533	2.52	0.10	3.5	3.8%	92
High Fire-Threat District	6,842	1.85	0.08	0.6	4.5%	90

Figure 4-14 presents the share of the total enrollment, impacts, and reference load by high fire-threat district status.

Figure 4-14 By High Fire-Threat District Status: Contributions on an Average Event Day

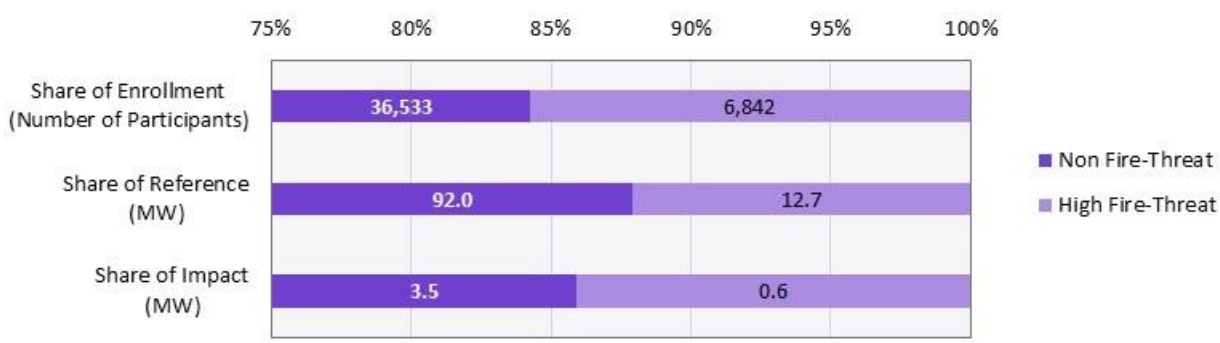
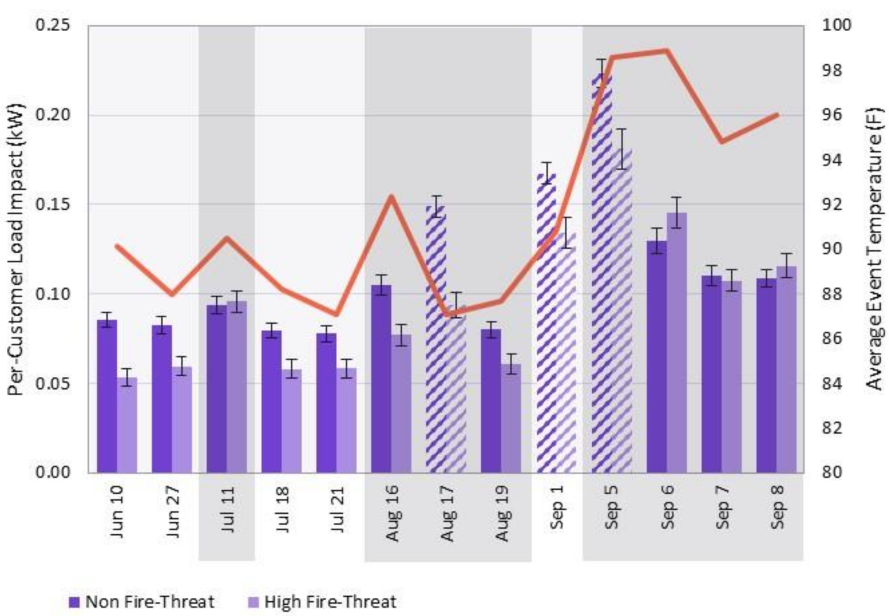


Figure 4-15 presents the per-customer ex-post load impacts for each event day based on high fire-threat district status:

- Dark and light purple bars – the magnitude of the per-customer load impacts for non-high-fire threat and high-fire threat participants, respectively,
- Striped Bars – concurrent ELRP A6 event and excluded from the average event day,
- Gray shading – concurrent SmartAC™ event,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by all participants during the event hours.

Figure 4-15 By High Fire-Threat District Status: Per-Customer Load Impacts by Event

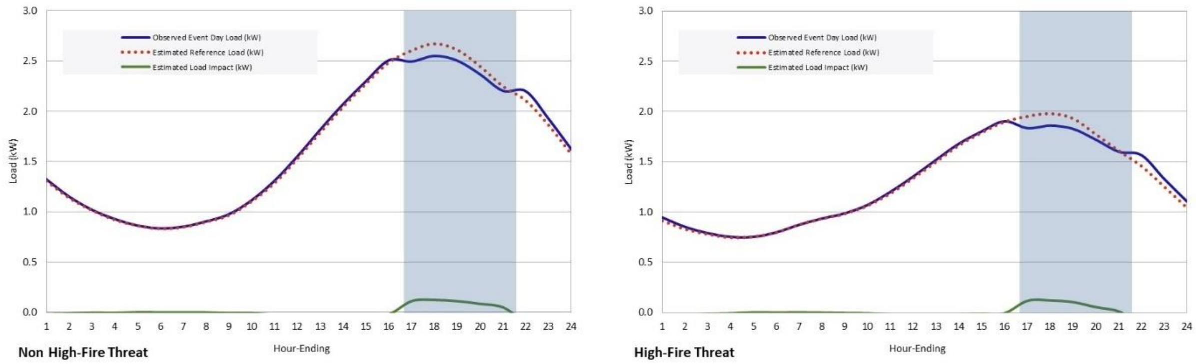


From Figure 4-15, we can observe the following:

- Between the two subgroups, we see statistically significant differences in the per-customer load impacts on nine out of thirteen PY2022 SmartDays™.
- Both groups show some correlation between impacts and temperatures, with the highest impacts on September 5th and 6th.

Figure 4-16 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day based on high fire-threat district status.

Figure 4-16 By High Fire-Threat District Status: Per-Customer Load Profiles on an Average Event Day



From Figure 4-16, we can observe the following:

- Both groups show a presence of technology-enabled participants with slight indications of snapback usage patterns.
- Participants in high fire-threat districts have lower average usage than the rest of the participants.

TOU Enrollment

SmartRate™ is currently available to customers on the following rates: standard rate (E1) and five TOU rates (E6, TOUB, TOUC, TOUD, and EV2A). Starting in 2021, Residential customers are defaulting onto the TOU rate in waves of around 250k customers per month. PG&E completed this transition in 2022, wherein PG&E experienced an overall opt-out rate of 21%. As a result, the share of standard rate enrollment remains high at 66%, compared to 77% before the defaulting transition.

For reference, the TOU periods of the different rates mentioned above are as follows.

- **E6 (Grandfathered customers):** Peak pricing on weekdays from 1 to 7 PM, partial peak pricing on weekdays from 10 AM to 1 PM and 7 to 9 PM, and partial peak pricing on weekends from 5 to 8 PM.
- **TOU-B (Opt-in customers):** Peak pricing on weekdays from 4 to 9 PM.
- **TOU-C (Defaulted customers):** Peak pricing every day from 4 to 9 PM.
- **TOU-D (Opt-in customers):** Peak pricing on weekdays from 5 to 8 PM.
- **EV2A (Home charging electric vehicle customers):** Peak pricing every day from 4 to 9 PM, partial peak pricing every day from 3 to 4 PM and 9 PM to 12 AM.

Table 4-11 presents the per-customer reference loads and load impacts by billing rate on an average event day. When we compare the results between the different rates, we can see differences in the magnitude of both the reference load and load impacts.

Public

Table 4-11 By Billing Rate: Per-Customer Load Impacts on an Average Event Day

Billing Rate	# of Accts	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)	% Load Impact	Avg. Event Temp.
E1	28,651	2.54	0.10	2.7	3.8%	92
E6	884	1.23	0.09	0.1	7.0%	90
TOU-B	2,484	3.36	0.07	0.2	2.0%	91
TOU-C	10,680	1.89	0.10	1.0	5.2%	89
TOU-D	595	3.45	0.06	<0.1	1.6%	95
EV2A	82	[redacted]	[redacted]	[redacted]	[redacted]	93

Participants on the E6 rate save, on average, save 7% relative to their reference loads. This rate is an older rate likely with long-term behavioral impacts, and this group of participants has lower average customer usage.

On the other hand, participants on the TOU-B and TOU-D rates save 2% on average, and participants on the EV2A rate save [redacted] on average, all lower compared to 3.8% for participants on the standard rate. These differences are likely attributable to the shifting behavior of the TOU participants. Participants on a TOU rate are already shifting some portion of their usage outside the on-peak window on all summer weekdays, which overlaps with the SmartDay™ event window.

Interestingly, participants on the TOU-C rate save 5.2% on average, consistent with PY2021 levels (5.8%) but now higher than participants on the standard rate. However, it is worth noting that PY2022 is the first year that TOU-C and SmartRate™ have coincident on-peak periods (4 to 9 PM). Also, the standard rate participants are the customers who opted out of the TOU defaulting, which could indicate other behavioral factors contributing to the decline in average load impacts.

Figure 4-17 presents the share of the total enrollment, impacts, and reference load by billing rate.

Figure 4-17 By Billing Rate: Contributions on an Average Event Day

Figure 4-18 presents the per-customer ex-post load impacts for each event day based on TOU enrollment:

- Dark and light green bars – the magnitude of the per-customer load impacts for standard rate and TOU rate participants, respectively,
- Striped Bars – concurrent ELRP A6 event and excluded from the average event day,

- Gray shading – concurrent SmartAC™ event,
- Black bands – 90 percent confidence intervals around these estimates, and
- Orange line – the average temperatures experienced by all participants during the event hours.

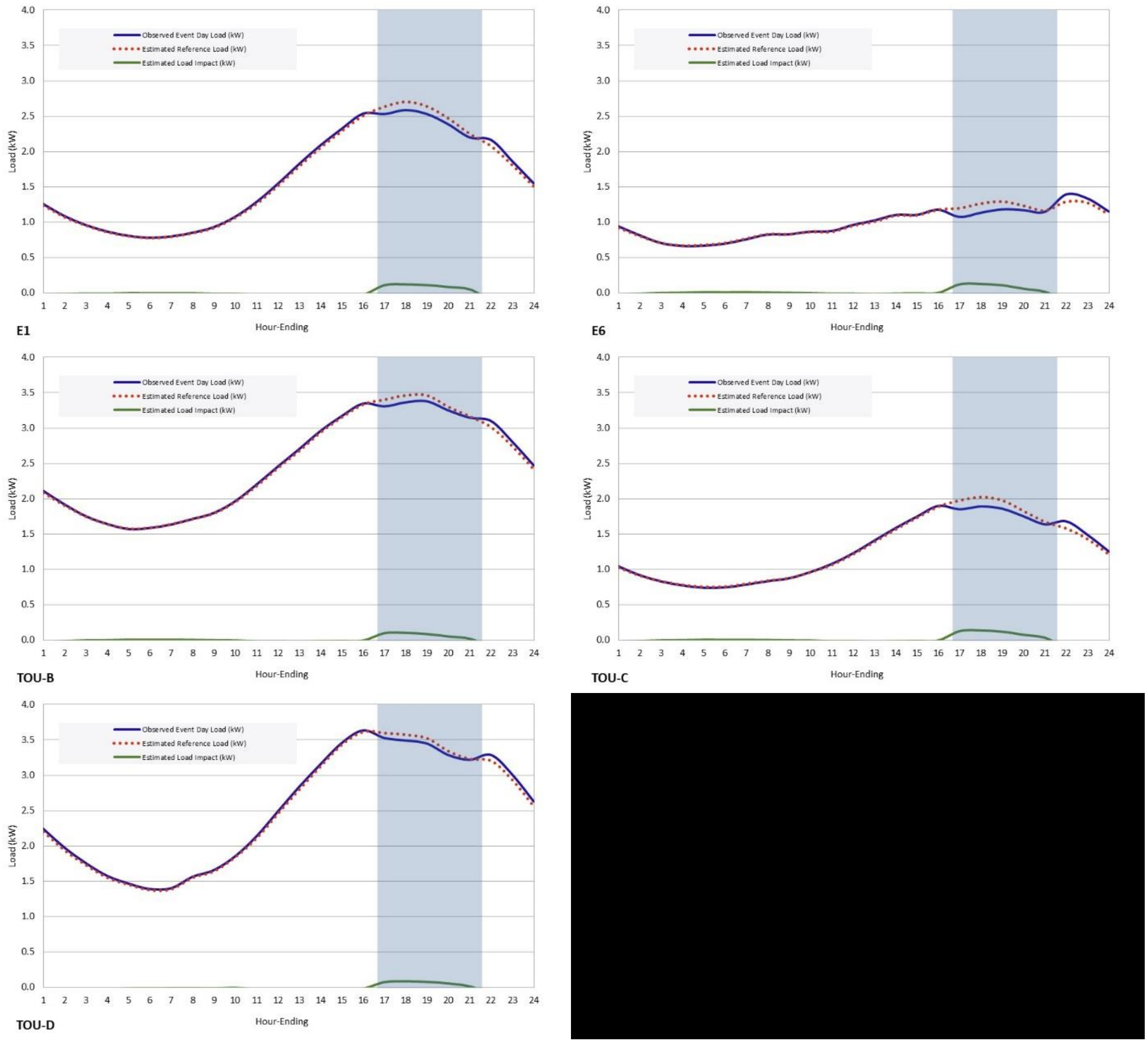
Figure 4-18 By TOU Enrollment: Per-Customer Load Impacts by Event

From Figure 4-18, we can observe the following:

- Standard rate participants show slightly higher per-participant load impacts compared to the collective TOU rate participants, but the difference is not statistically significant.
- All subgroups show some correlation between impacts and temperatures, with the highest impacts on September 5th and 6th.

Figure 4-19 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day by billing rate.

Figure 4-19   By Billing Rate: Per-Customer Load Profiles on an Average Event Day



From Figure 4-19, we can observe the following:

- The differences in customer size (per-customer reference loads) is clearly shown in these comparison figures, with larger customers on average from the following rates: E1, TOU-B, and TOU-D.
- The differences in per-customer load impacts is also significant with participants in E1, E6, and TOU-C rates showing the highest load reductions.
- The TOU subgroups show significant flattening during the on-peak periods relative to the standard rate group, again likely attributable to daily shifting behavior in response to the TOU rate.

5

EX-ANTE ANALYSIS RESULTS

This section presents the ex-ante analysis results, including the load impact forecasts for the 1-in-2 and 1-in-10 weather conditions for PG&E and CAISO. First, we present a summary of the ex-ante load impact forecast. Next, we discuss each forecast assumption and demonstrate how each assumption affects the forecast. Finally, we discuss the ex-ante load impacts relative to current ex-post load impacts and previous ex-ante forecasts.

The objectives of the ex-ante load impact analysis are the following:

- To develop hourly load impact estimates for the average customer and all customers in aggregate for the resource adequacy (RA) window[29]
- To estimates for each year over an 11-year[30] time horizon based on PG&E's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day, and
- To provide estimates for both program-specific and portfolio-adjusted scenarios.

Effective May 2022, the SmartRate™ event window has shifted to 4 to 9 PM, making the SmartRate™ event coincident with the RA window.

Summary of Load Impacts

Table 5-1 summarizes the aggregate and per-customer load impact forecasts for SmartRate™ participants on a typical event day in 2023. The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios for both PG&E and CAISO peaks.

As noted in the ex-post analysis, participants dually enrolled in SmartAC™ show higher per-customer load impacts compared to the other subgroups. Participants dually enrolled in ELRP A6 show lower per-customer load impacts. Participants dually enrolled in ELRP A6 make up most of SmartRate™ enrollment from 2022 through November 2025, since SmartRate™ CARE participants are defaulted in ELRP A6. This subgroup makes up 59% of SmartRate™enrollment but contributes only approximately 11% of the aggregate impact.

Table 5-1 Typical Event Day Enrollment and Impacts by Program Enrollment: 2023

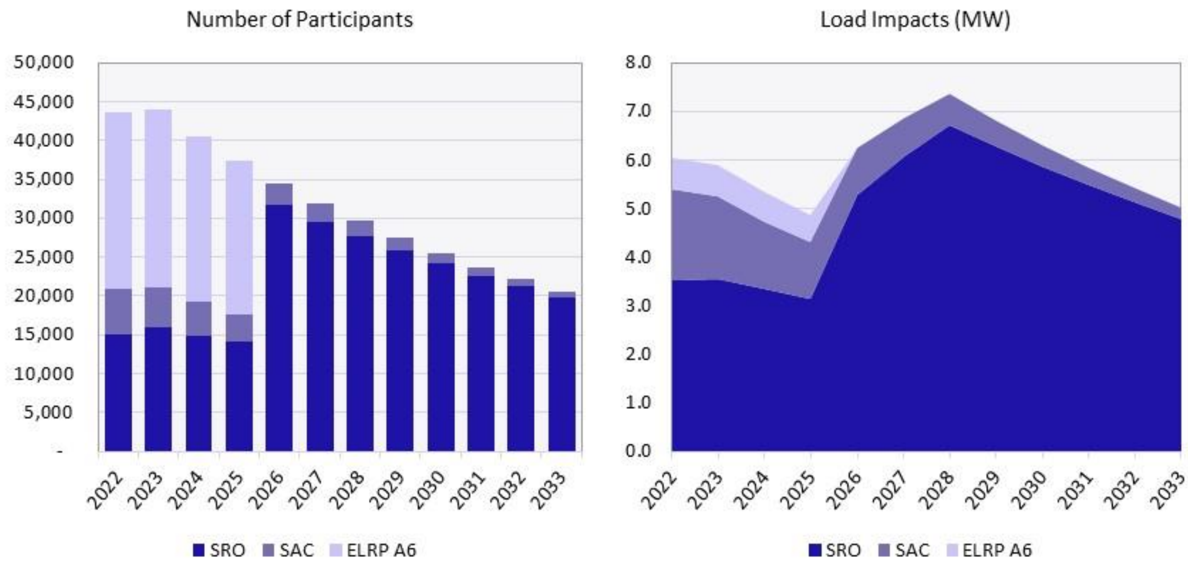
Program Enrollment	# of Accts	Aggregate Impact (MW)				Per-Customer Impact (kW)			
		PG&E Peak		CAISO Peak		PG&E Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
SmartRate Only	15,869	3.55	4.28	3.68	3.82	0.22	0.27	0.23	0.24
Dually Enrolled - SmartAC	5,235	1.69	1.97	1.73	1.78	0.32	0.38	0.33	0.34
Dually Enrolled - ELRP A6	22,837	0.64	0.87	0.72	0.73	0.03	0.04	0.03	0.03
Total	**43,941**	**5.89**	**7.12**	**6.13**	**6.32**	**0.13**	**0.16**	**0.14**	**0.14**

[29] The RA window is 5 PM to 10 PM fpr March and April and 4 PM to 9 PM for all other months.

[30] PG&E has requested a PY2022 back cast as part of the ex-ante impact analysis.

Figure 5-1 presents side-by-side comparisons of PG&E's annual enrollment and load impact forecasts for the PG&E 1-in-2 weather scenario on a typical event day, including the 2022 enrollment and impact "back-cast." The forecast is broken down by program enrollment: singly versus dually enrolled. PG&E expects a decrease in enrollment over time, with no marketing-derived enrollments expected for future years.

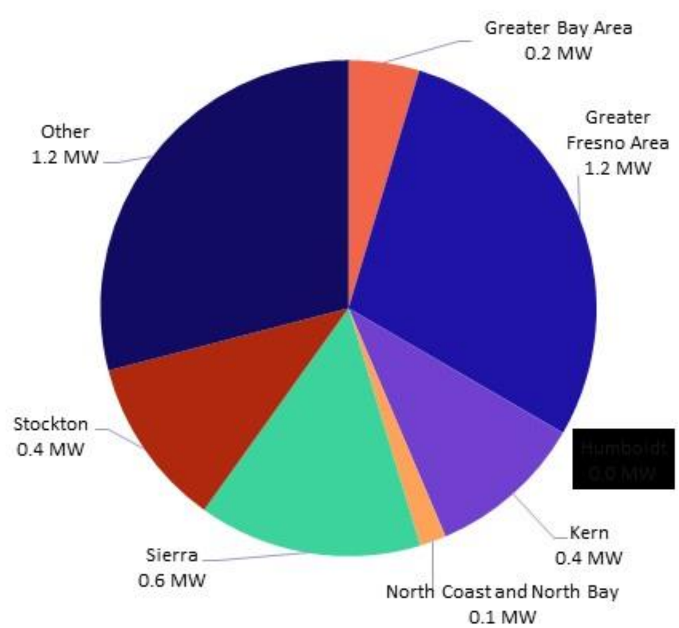
Figure 5-1 Enrollment and Impact Forecast: PG&E 1-in-2, Typical Event Day, 2022 – 2033



The ELRP pilot is expected to run through October 2025. We forecast participants dually enrolled in ELRP A6 will rejoin the singly enrolled subgroup after the conclusion of the pilot implementation. Starting November 2025, we assume the per-customer load impacts of previous ELRP A6 participants to gradually increase (over three years) to match the per-customer load impacts of singly enrolled participants. Under PG&E 1-in-2 weather conditions, PG&E estimates 5.9 MW in aggregate load impacts during the RA window on a typical event day in 2023.

Figure 5-2 shows the distribution of estimated typical event day load impacts by LCA, shown for the 2023 forecast under the PG&E 1-in-2 weather conditions. The LCA distribution of load impacts is similar to what we see in the ex-post analysis since PG&E does not expect any substantial changes in participant enrollment by LCA.

Figure 5-2 By LCA: PG&E 1-in-2 Typical Event Day Aggregate Load Impacts, 2023



Forecast Assumptions

This section discusses the forecast assumptions and presents the corresponding implications on the ex-ante load impact forecast.

Per-Customer Load Impacts

Effective May 2022, the SmartRate™ event window shifted to 4 to 9 PM, making the SmartRate™ event coincident with the RA window. During the PY2021 ex-ante LI analysis, we assumed a 50% decrease in per-customer percent impacts (2022) to account for a first-year "learning curve" and "back to normal" or 100% of 2021 percent impacts from 2023 onwards.

For the PY2022 ex-ante LI analysis, we used the following assumptions:

- **Updated participant load impacts based on PY2022 ex-post analysis.** Effective May 2022, the SmartRate™ event window shifted to 4 PM to 9 PM. Prior analyses were based on a 2 PM to 7 PM event window.
- **Excluded load impact estimates from participants affected by the Notification error.** PG&E anticipates the notification issues experienced in PY2022 to be corrected by the implementer.

Table 5-2 compares the results of the PY2021 and PY2022 ex-ante LI analyses. We show the SmartRate™ event window per-customer load impacts for PG&E 1-in-2 typical event day scenarios in forecast years 2021 through 2023. The comparison shows that the 50% "learning curve" adjustment assumption was unnecessary. In PY2022, SmartRate™ participants, on average, showed 5.4% load impacts after excluding participants affected by the Notification error. This performance is comparable to PY2021 performance at 6.0%.

Table 5-2 Per-Customer Load Impacts on PG&E 1-in-2 Typical Event Day, 2021, 2022, 2023

Forecast Year	Program Enrollment	PY2021 Ex-Ante Analysis		PY2022 Ex-Ante Analysis	
		Per-Cust Impact (kW)	% Impact	Per-Cust Impact (kW)	% Impact
2021 (2-7pm)	SmartRate Only	0.11	4.7%	-	-
	Dually Enrolled - SmartAC	0.33	15.0%	-	-
	Total	**0.14**	**6.0%**	-	-
2022 (4-9pm)	SmartRate Only	0.06	2.4%	0.23	11.1%
	Dually Enrolled - SmartAC	0.16	7.6%	0.32	15.4%
	Dually Enrolled - ELRP A6	-	-	0.03	1.2%
	Total	**0.07**	**3.1%**	**0.12**	**5.4%**
2023 (4-9pm)	SmartRate Only	0.11	4.8%	0.22	10.7%
	Dually Enrolled - SmartAC	0.31	15.2%	0.32	15.4%
	Dually Enrolled - ELRP A6	-	-	0.03	1.2%
	Total	**0.14**	**6.3%**	**0.13**	**6.0%**

Since load impact estimates are required for non-summer months (outside June through September), we estimated load impacts by applying the hourly percent impacts for a typical event day to the estimated reference loads during non-summer months. Consistent with previous years' assumptions, we **assumed typical event day percent impacts for non-summer months.** Table 5-3 presents the RA window per-customer load impacts for PG&E 1-in-2 monthly peak days in 2023 by program enrollment.

Table 5-3 Per-Customer Load Impacts on PG&E 1-in-2 Monthly Peak Days, 2023

Month	SmartRate Only		Dually Enrolled – SAC		Dually Enrolled – ELRP A6	
	Impact (kW)	% Impact	Impact (kW)	% Impact	Impact (kW)	% Impact
January	0.11	10.5%	0.14	15.2%	0.01	1.0%
February	0.11	10.4%	0.13	15.2%	0.01	1.0%
March	0.06	6.0%	0.09	10.1%	<0.01	<0.1%
April	0.08	6.1%	0.11	9.9%	<0.01	0.1%
May	0.17	10.8%	0.22	15.4%	0.02	1.2%
June	0.25	11.5%	0.36	16.2%	0.03	1.4%
July	0.24	11.2%	0.34	15.8%	0.03	1.3%
August	0.22	10.5%	0.32	15.0%	0.03	1.0%
September	0.19	9.8%	0.28	14.4%	0.02	0.8%
October	0.12	10.6%	0.15	15.3%	0.01	1.1%
November	0.10	10.5%	0.12	15.2%	0.01	1.0%
December	0.11	10.4%	0.14	15.2%	0.01	1.0%

The March and April RA window is from 5 PM to 10 PM, which is not fully coincident with the SmartRate™ event. Thus we see slightly lower impacts on these months compared to other non-summer months.

Emergency Load Reduction Program Pilot

In 2022, PG&E launched the Emergency Load Reduction Program (ELRP) pilot. Residential customers on CARE and FERA rates have defaulted onto ELRP A6. SmartRate™ participants in CARE rates are currently dually enrolled in ELRP A6. The ELRP pilot is set to conclude after October 2025. Consequently, we used the following assumptions:

- Participants dually enrolled in ELRP A6 will **rejoin the singly enrolled subgroup starting in November 2025**.
- **Maintain PY2022 load impacts for participants dually enrolled in ELRP A6 through the remainder of the pilot.** The PY2022 Ex-Post analysis resulted in very low impacts for the participants dually enrolled in ELRP A6. PG&E attributes this to overall participant confusion. Both SmartRate™ and ELRP send out day-ahead email or text notifications for program events. The PG&E call center reported customer calls indicating confusion regarding ELRP notifications received by defaulted customers unaware of ELRP enrollment. Though discussions are ongoing, there are no current plans for additional marketing/education outreach for dually enrolled participants.
- **Over three years, there will be a gradual catch-back period for previous ELRP A6 participants**:
  - Beginning November 2025, customers will perform at 50% of the singly enrolled subgroup for one year.
  - In November 2026, load impacts will increase to 75%.
  - In November 2027, the customers will catch up to singly enrolled subgroup levels.

Figure 5-3 shows the enrollment forecast for this subgroup, which expects a decrease in enrollment over time similar to other subgroups. Table 5-4 shows the per-customer load impacts for this subgroup through the forecast duration. Participants have 1.2% load impacts, on average, while dually enrolled in ELRP A6. At the conclusion of the ELRP Pilot, per-customer load impacts are expected to gradually increase back to load impacts comparable to singly enrolled participants. For reference, singly enrolled participants have 10.7% load impacts, on average, through the forecast duration.

Figure 5-3 ELRP A6 Enrollment Forecast

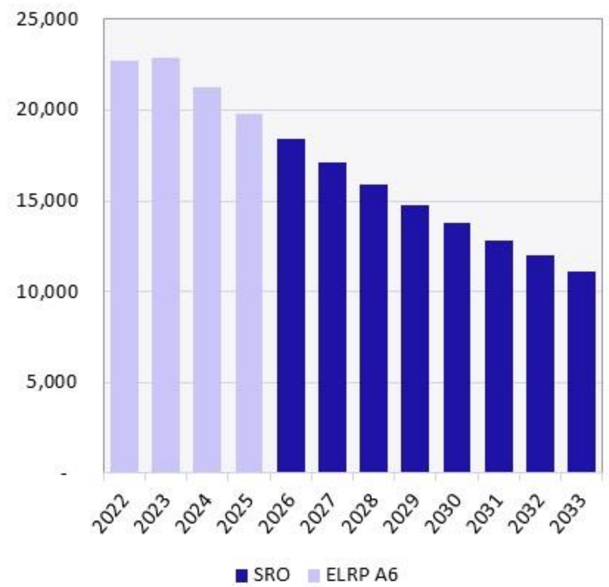


Table 5-4 ELRP A6 Per-Customer Load Impacts on PG&E 1-in-2 Typical Event Days

Year	Impact (kW)	% Impacts
2022	0.03	1.2%
2023	0.03	1.2%
2024	0.03	1.2%
2025	0.03	1.2%
2026	0.13	5.3%
2027	0.19	8.0%
2028	0.26	10.7%
2029	0.26	10.7%
2030	0.26	10.7%
2031	0.26	10.7%
2032	0.26	10.7%
2033	0.26	10.7%

Portfolio-Adjusted Load Impacts

Section 3 discusses our approach to determine the portfolio-adjusted impact forecast. Portfolio-adjusted load impacts exclude the load impacts from dually enrolled participants attributed to concurrent SmartAC™ and ELRP events. In other words, both SmartAC™ and ELRP take precedence over SmartRate™. The dually enrolled customer load impacts are removed in the portfolio-adjusted scenarios to avoid double counting. For each program, we used the following assumptions:

- **Dually enrolled in SmartAC™ – maintained the assumption that 18% load impacts is an incremental effect of SmartRate™ participation.** We assume that 18% of load impacts on concurrent SmartRate™ and SmartAC™ events are attributed to the behavioral impact of SmartRate™ participation because those customers exhibit higher impacts on concurrent program events than on single program event days. In other words, during events when both SmartRate™ and SmartAC™ programs are called to respond, we are estimating that 18% of impacts can be attributed to SmartRate™, i.e., the incremental effect of the SmartRate™ price incentive.
- **Dually enrolled in ELRP A6 – included in the portfolio-adjusted forecast through the ELRP pilot implementation.** The impacts from this subgroup are primarily attributed to SmartRate™, while incremental impacts, if any, are attributed to ELRP[31]. We assume participants in this subgroup to perform as they do when called to SmartRate-only events.

Table 5-5 shows the program and portfolio-adjusted impacts for the PG&E 1-in-2 weather scenario for 2023.

[31] Estimated under the ELRP LI evaluation's portfolio-adjusted ex-ante analysis.

Table 5-5 Program Level vs. Portfolio-Adjusted Load Impacts: PG&E 1-in-2, Monthly Peak Day, 2023

Month	Program Level Load Impacts (MW)				Portfolio-Adjusted Load Impacts (MW)			
	SmartRate™ Only	Dual SmartAC™	Dual ELRP A6	Total	SmartRate™ Only	Dual SmartAC™	Dual ELRP A6	Total
January	1.82	0.80	0.24	**2.86**	1.82	0.14	0.24	**2.20**
February	1.78	0.77	0.23	**2.79**	1.78	0.14	0.23	**2.15**
March	1.00	0.49	0.01	**1.49**	1.00	0.11	0.01	**1.11**
April	1.28	0.60	0.03	**1.91**	1.28	0.09	0.03	**1.40**
May	2.72	1.19	0.48	**4.39**	2.72	0.21	0.48	**3.41**
June	4.00	1.93	0.81	**6.74**	4.00	0.35	0.81	**5.15**
July	3.83	1.83	0.75	**6.41**	3.83	0.33	0.75	**4.91**
August	3.45	1.66	0.57	**5.68**	3.45	0.30	0.57	**4.33**
September	2.99	1.43	0.41	**4.82**	2.99	0.26	0.41	**3.65**
October	1.93	0.75	0.30	**2.98**	1.93	0.14	0.30	**2.36**
November	1.54	0.60	0.20	**2.34**	1.54	0.11	0.20	**1.85**
December	1.75	0.69	0.23	**2.66**	1.75	0.12	0.23	**2.10**

The March and April RA window is from 5 PM to 10 PM, which is not fully coincident with the SmartRate™ event. Thus we see slightly lower impacts on these months compared to other non-summer months.

Comparison of Ex-Ante Impacts

This section discusses how the PY2022 ex-ante load impacts compare to:

- PY2022 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and
- PY2021 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

Table 5-6 compares **the current ex-post estimates with the current ex-ante estimates**. This comparison shows the average estimates for the PY2022 SmartRate™ event window (4 to 9 PM). For reference, we included the average event day estimate that excludes participants affected by the PY2022 Notification issues, which consists of the participants included in the ex-ante analysis.

As mentioned above, we demonstrate the effect of adjusting the impacts and reference loads to reflect the various weather scenarios required in the analysis. We observe the following:

- The PY2022 SmartDays™ experienced cooler average event temperatures compared to all weather scenarios. The ex-ante impacts under all weather scenarios are higher (4.0% v. 6-7%, on average).
- SmartRate™ participants exhibit a positive correlation to weather, showing an increase in both per-customer reference load and load impacts with hotter weather.

Table 5-6 Current Ex-Post (Average Event Day) and Current Ex-Ante (Typical Event Day, 2021), 4 to 9 PM

Estimate		# Enrolled	Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact		
Current Ex-Post	Program Average	43,376	2.41	0.09	3.9%	91
	Excludes Notification Issues	41,998	2.41	0.10	4.0%	91
Current Ex-Ante	PG&E 1-in-2	43,557	2.26	0.14	6.1%	96
	PG&E 1-in-10	43,557	2.47	0.17	6.7%	100
	CAISO 1-in-2	43,557	2.26	0.14	6.4%	97
	CAISO 1-in-10	43,557	2.32	0.15	6.4%	97

Table 5-7 compares **the previous ex-ante forecast to the current ex-ante forecast, both for the forecast year 2023**. A couple of key observations include the following:

- The enrollment forecast was slightly updated to account for the higher attrition rate seen in PY2022. Last year, PG&E forecasted 2022 to have approximately 45k participants, while that forecast is down to approximately 44k participants this year.
- The load impact estimates were updated according to PY2022 findings, indicating that PY2021 assumption of a 50% "learning curve" reduction due to the event window shift was unnecessary.

Table 5-7 Previous and Current Ex-Ante, PG&E 1-in-2, Typical Event Day, 2022, 4 to 9 PM

Estimate	Subgroup	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante	SmartRate™ Only	38,399	88.8	2.1	2.31	0.06	2.4%	96
	Dually Enrolled - SmartAC™	6,516	13.7	1.0	2.10	0.16	7.6%	96
	Total	**44,915**	**102.4**	**3.2**	**2.28**	**0.07**	**3.1%**	**96**
Current Ex-Ante	SmartRate™ Only	15,869	33.0	3.5	2.08	0.22	10.7%	94
	Dually Enrolled - SmartAC™	5,235	11.0	1.7	2.10	0.32	15.4%	97
	Dually Enrolled – ELRP A6	22,837	54.8	0.6	2.40	0.03	1.2%	97
	Total	**43,941**	**98.9**	**5.9**	**2.25**	**0.13**	**6.0%**	**96**

6

KEY FINDINGS AND RECOMMENDATIONS

This section presents the evaluation key findings and recommendations for future research.

Key Findings

The **ex-post analysis** resulted in the following key findings:

- SmartRate™ participants deliver highly weather-sensitive load impacts, showing an increase in load impacts on hotter days with or without technology assistance. The aggregate load impact was 4.1 MW, on average, in the 2022 season.
- Program enrollment affected SmartRate™ program performance in two ways:
  - Participants **dually enrolled in SmartAC™** continue to deliver substantially higher load impacts per customer, with 13.9% average event impacts compared to 4.8% for singly enrolled participants. These higher load impacts can be directly attributed to the SmartAC™ devices, which allow participants to respond to events with minimal to no effort or change in behavior. Since dual enrollment in SmartAC™ is no longer allowed for new participants, the higher load impacts from SmartAC™ devices will slowly decline as natural participant attrition occurs.
  - Participants **dually enrolled in ELRP A6** delivered very low impacts inconsistent with those historically shown by this group, previously singly enrolled in SmartRate™ and primarily CARE customers. The Emergency Load Reduction Program (ELRP) launched in PY2022, automatically enrolling residential customers on CARE or FERA rates and customers receiving Home Energy Reports. PG&E attributes the low performance in this subgroup to overall participant confusion.
    - ELRP A6 defaulted customers were delivered welcome packets to the pilot. However, as there is no precedent on the SmartRate™ and ELRP A6 dual enrollment, no information on their interaction was included in the packet. There are no current plans for additional marketing/education outreach for dually enrolled participants. Discussions are ongoing on this topic.
    - Both SmartRate™ and ELRP send out day-ahead email or text notifications for program events, and the PG&E SmartRate™ call center reported customer calls indicating confusion regarding ELRP notifications received by defaulted customers unaware of ELRP enrollment.
- PY2022 SmartRate™ implementation experience **notification issues** for approximately 5% of the overall population, primarily bill-protected participants.
  - The participants affected by the notification issue exhibited very small, yet statistically significant, load impacts. These findings possibly indicate that a subset of participants receives SmartDay™ alerts through other mediums (i.e., day ahead on the PG&E website or day of on Twitter) besides the official email and text message notifications.
  - Consistent with PY2021 findings, participants under the Bill Protection Guarantee (not affected by notification issues) delivered slightly lower yet comparable per-customer load impacts compared to participants no longer eligible for bill protection (3.5% for bill-protected v. 4.0% for no bill protection). These results are intuitive and expected from the bill-protected group due to one or more of the following: (1) customer "complacency," (2) the first season "learning curve," or (3) the absence of technology-enabled participants in the bill protected group.

- In PY2022, participants with an underlying TOU rate delivered higher load impacts per customer with 4.2% average event impacts compared to 3.8% for participants with an underlying standard rate. These findings are different from PY2021, wherein participants with an underlying standard rate delivered higher load impacts per customer. We attribute this change to the following factors:
  - PG&E completed the TOU defaulting transition in 2022, which increased the share of TOU customers from 23% to 36%.
  - In PY2022, the SmartRate™ peak period became coincident with TOUB-B and TOU-C rates (4 to 9 PM). Participants on the TOU-C rate save 5.2% on average, now higher than participants on the standard rate (3.8% on average). The increase in per-customer impacts can be attributed to these customers' overall awareness of the 4 to 9 PM peak period.

The **ex-ante analysis** resulted in the following key findings:

- The PY2022 load impacts, excluding participants affected by the notification issues, showed that the first-year learning curve adjustment assumption was unnecessary.
  - In PY2022, SmartRate™ participants, on average, showed 5.4% load impacts after excluding participants affected by the Notification error. This performance is comparable to PY2021's performance at 6.0%.
  - During the PY2021 ex-ante LI analysis, we assumed a 50% decrease in per-customer percent impacts (2022) to account for a first-year "learning curve" and "back to normal" or 100% of 2021 percent impacts from 2023 onwards.
- The participants dually enrolled in ELRP A6 showed very low per-customer impacts. However, since PG&E does not currently have plans for further marketing/education efforts for this subgroup, we did not assume any adjustments through the expected implementation of the ELRP pilot (through November 2025).
  - At the conclusion of the ELRP pilot, we assume a three-year gradual catch-back period for previous ELRP A6 participants, increasing per-customer load impacts to align with singly enrolled participants by November 2027.
- The event window shift implemented in PY2022 substantially increased the RA window load impacts since the new event window (SmartRate™ peak period) is now coincident with the RA window.
- PG&E continues to forecast a consistent decrease in SmartRate™ enrollment through 2033. This assumption estimates a reduced ex-ante forecast of 5 MW in 2033 for a typical event day under the PG&E 1-in-2 weather conditions.

Recommendations

AEG has the following recommendations for future research and evaluation related to PG&E's residential SmartRate™ program.

- AEG recommends a follow-up analysis of the conservation effect to include current participants with 2019–2023 enrollments. This effort was not pursued in PY2022 due to constraints[32] in the analysis timeline. The follow-up analysis will aim to achieve the following:

[32] The ELRP pilot implementation prompted several iterations in both the Ex-Post and Ex-Ante analyses.

- Further leverage the variation-in-adoption approach using a more extended period of rolling enrollment. This approach will allow for revisiting the data requirements on pre-enrollment data and including more customers in the analysis.
- Estimate results more applicable to the current population by producing joint averages of the seasonal impacts of bill-protected and post-bill-protected periods.
- Leverage a larger analysis sample and an extended period to more accurately estimate the COVID effect.

- AEG recommends a more collaborative effort with the ELRP Pilot LI evaluation team through the remainder of the ELRP pilot implementation. The collaboration can align evaluation approaches and further analyze the drop in participant load impacts found in the subgroup.

A

TABLE GENERATORS

SmartRate™ Ex-Post Table Generator

SmartRate™ Ex-Ante Table Generator

B

MODEL VALIDITY

We selected and validated segment-level regression models during our optimization process. Participants are grouped based on segments presented in Section 3:

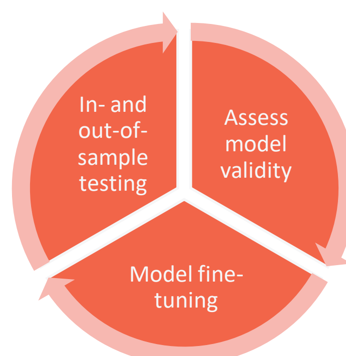
- Dually enrolled in SmartAC™ (1),
- Dually enrolled in ELRP A6 (2),
- Singly enrolled in SmartRate™:
  - Under bill protection (3),
  - Under bill protection and did not receive notifications (4), and
  - No longer under bill protection (5).

The segment-level models are designed to be able to:

- Accurately predict the actual participant load on event days (addressed by in-sample testing), and
- Accurately predict the reference load or participant usage on event days in the absence of an event (addressed by out-of-sample testing).

As described in Section 2, we selected each segment's best model through a three-part optimization process, consisting of the following steps: (1) In-sample and out-of-sample testing; (2) assessing model validity; and (3) model fine-tuning.

Figure B-1 Optimization Process



This section presents metrics related to our optimization process, specifically:

- Selection of event-like days used for out-of-sample testing, and
- Metrics from in-sample and out-of-sample tests from the final models of the ex-post analysis, and
- Comparison load graphs.

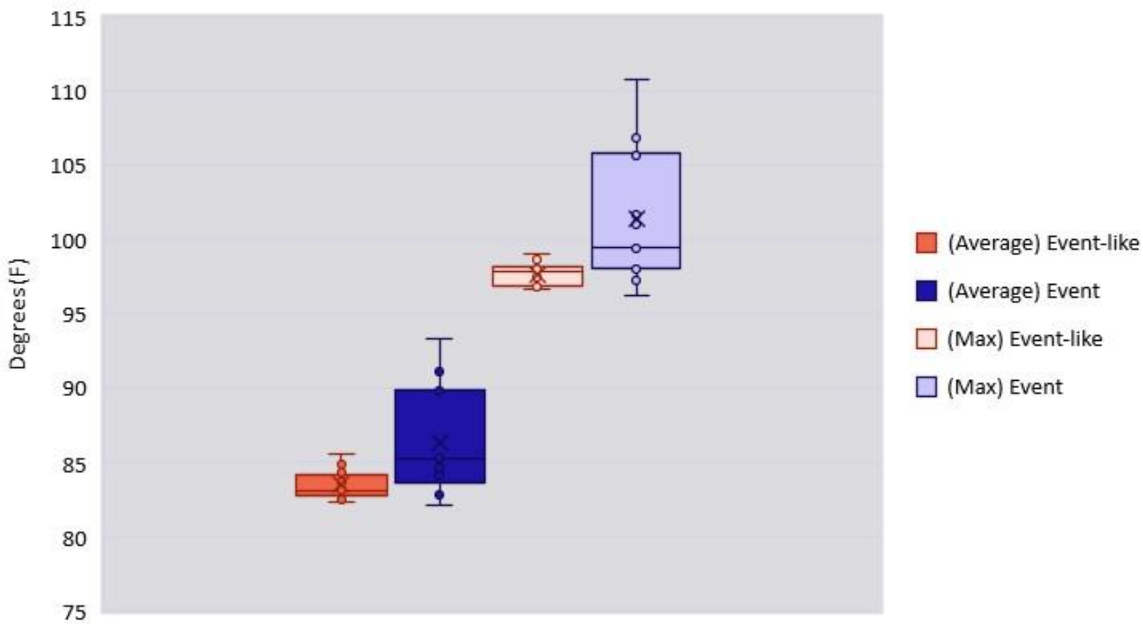
Selecting Event-Like Days

To select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. We calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables to determine how close event day temperature is to a potential event-like day. Any number of relevant variables could be included in the Euclidean distance. This program year included four weather variables in the Euclidean distance metrics calculation to select similar non-event days: early morning (HE6-HE9), morning (HE10-HE13), on-peak window (HE15-HE19), and late evening (HE23-HE24). The Euclidean distance for this set of variables is as follows:

$$ED = \sqrt{\begin{array}{c}(early\ morning_{Ti} - early\ morning_{Ci})^2 + (morning_{Ti} - morning_{Ci})^2 \\ + (onpeak_{Ti} - onpeak_{Ci})^2 + (late\ evening_{Ti} - late\ evening_{Ci})^2\end{array}}$$

In Figure B-2, we compare the distributions of the average and maximum daily temperature of event days and event-like days. We show a single program level comparison because these dates were chosen at the program level, i.e., all subgroups have the same set of event and event-like dates.

Figure B-2 Daily Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

Next, we present the metrics produced by our optimization process for in-sample and out-of-sample testing. To perform each test, we used the following approach:

- **In-sample test.** We fitted each candidate model to the entire data set and used the results of these fitted models to predict the usage on SmartDays™. Then we assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE) and mean percent error (MPE), respectively. We refer to these metrics as the in-sample MAPE and MPE.
- **Out-of-sample test.** We fitted each candidate model to the data set excluding event-like days, and used the results of these fitted models to predict the usage on event-like days. We similarly assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, which we refer to as the out-of-sample MAPE and MPE.

These two tests result in several in-sample and out-of-sample metrics. Recall that the tests' goal is to find the best model for each segment in terms of its ability to predict each segment's reference load and actual load. Therefore, we combined the two tests into a single metric. The metric used is defined as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + \ (0.1 * |MPE_{in}|) + (0.1 * |MPE_{out}|)$$

Where,

$$MAPE = \frac{100\%}{n} \sum_{h=1}^{n} \left| \frac{Actual_h - Estimate_h}{Actual_h} \right|, \qquad MPE = \frac{100\%}{n} \sum_{h=1}^{n} \frac{Actual_h - Estimate_h}{Actual_h}$$

Once we have a single metric for each segment and candidate model combination, we select the best model for each segment by choosing the model specification with the smallest overall metric. The optimization process metrics are shown in the following tables and figures.

Table B-1 presents the weighted average MAPE and MPE for each segment's final set of models. We see very small MPE values (all under ±3%), which indicate a relatively low level of bias. All segments have low MAPE values, all under 7%.

Table B-1 Weighted Average MAPE and MPE by Model Segment

Model Segment	Out-of-Sample		In-Sample	
	MAPE	**MPE**	**MAPE**	**MPE**
Dually Enrolled - SmartAC	5.96%	-1.74%	4.87%	2.25%
Dually Enrolled - ELRP A6	4.55%	-0.62%	3.68%	1.33%
Bill Protected (No Issue)	4.47%	-0.86%	3.75%	1.51%
Bill Protected (Notification Issue)	6.45%	-2.99%	3.63%	1.59%
SmartRate Only	3.78%	0.77%	4.30%	2.16%

Visual inspection can be a simple but highly effective tool. Figure B-3 and Figure B-4 present the average predicted loads (dotted lines) and actual loads (solid lines) from the in-sample and out-of-sample tests by subgroup. During the inspection, we looked for specific aspects of the predicted and reference load shapes to tell us how well the models performed. For example:

- We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely little effect from the event. Large differences can indicate a problem with the reference load, either over- or under-estimating usage in the absence of the event.
- We closely examined the reference load for odd increases or decreases in load, indicating an effect not correctly captured in the models. If we found such an increase or decrease, we investigated the cause and attempted to control for the effect in the models.
- We also looked for bias, both visually and mathematically. Bias is the consistent over- or under-prediction of the actual load. We may see temperature-related bias, under-predicting on hot days, and over-predicting on cool days. We have also seen time-based bias, over-predicting at the beginning and under-predicting at the end of the year. Identifying bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

The figures below show predicted loads very close to the actual loads. This tells us that, on average, the regression models do a good job estimating what customer loads would be like on event-like days and event days and therefore can produce very accurate reference loads.

Figure B-3 Actual and Predicted Loads: Event-like Days

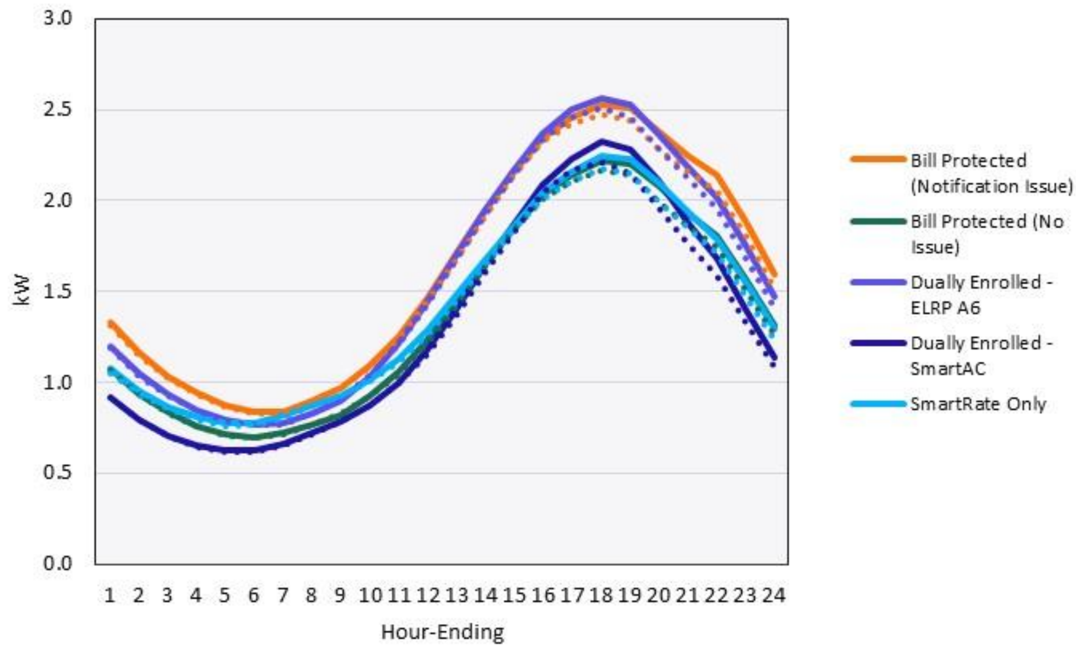
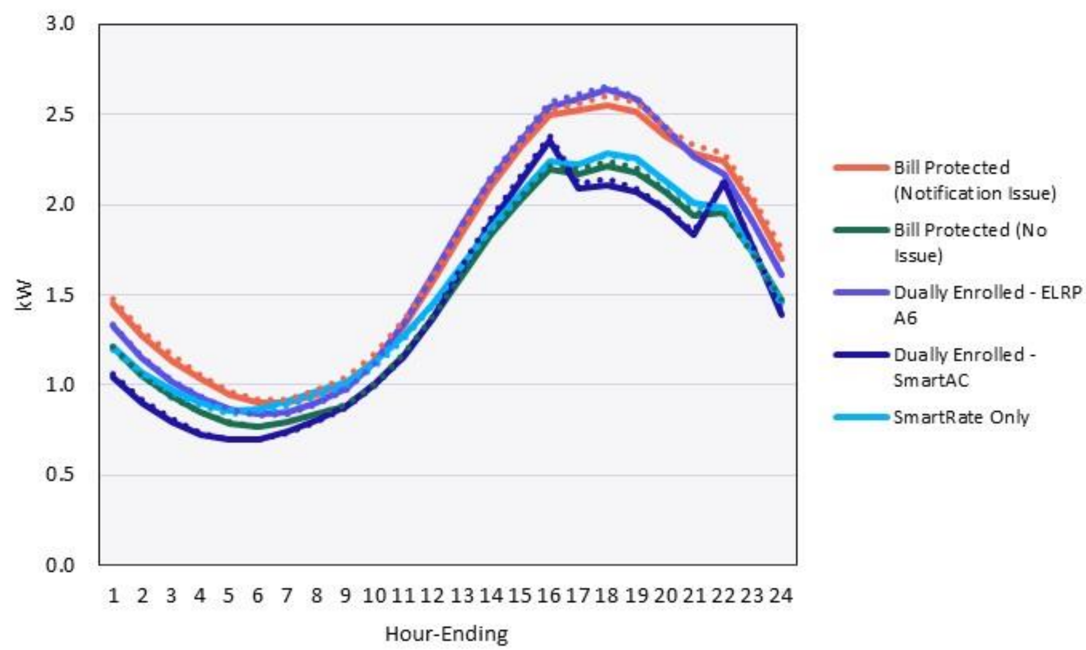


Figure B-4 Actual and Predicted Loads: Event Days



C

BILL IMPACT ANALYSIS

PG&E provided billing data with program-specific credits and charges for all PY2022 SmartRate™ participants[33]. This data included billing impacts for May 2022 through November 2022 billing periods.

During their first full summer season of program enrollment (and any preceding partial season), customers are backed by PG&E's Bill Protection Guarantee that refunds customers if their SmartRate™ costs exceed their regular residential pricing plan. PG&E would credit the difference on the customer's November bill if they did not save on SmartRate™.

AEG analyzed the data to understand the impact on the program's customer bills. Consistent with the PY2020-21 analyses, AEG included customers defined as PY2022 participants and had at least three months of billing data between May and September 2022, leaving AEG a working sample of 43,666 out of the 49,547 unique PY2022 participants.

The following sections discuss the findings of the bill impact analysis.

Overview of Billing Impacts

The table below presents the average billing impacts in PY2022. Across all 43,666 participants, the average participant saved $7.14. PY2022's per-participant bill savings decreased substantially from previous years with $45.89 in PY2021 and $20.81 in PY2020 in average savings.

Table C-1 Bill Impacts for All Participants

Enrollment Status	Impact	Count of Participants	% of Population	Average Bill Change
SmartRate™ Only	Decreased Bill	9,493	22%	-$30.16
	Increased Bill	5,551	13%	$23.61
	All SR Only	**15,044**	**34%**	**-$10.32**
Dually Enrolled in SmartAC™	Decreased Bill	3,466	8%	-$26.64
	Increased Bill	2,406	6%	$20.90
	All Dual SAC	**5,872**	**13%**	**-$7.16**
Dually Enrolled In ELRP A6	Decreased Bill	12,657	29%	-$26.31
	Increased Bill	10,091	23%	$21.67
	No Change	2	<1%	$0.00
	All Dual ELRP A6	**22,750**	**52%**	**-$5.03**
All	Decreased Bill	25,616	58%	-$27.78
	Increased Bill	18,048	42%	$22.16
	No Change	2	<1%	$0.00
	All	**43,666**	**100%**	**-$7.14**

[33] Defined as participants enrolled between June 1, 2022 and September 30, 2022 and participated in at least one SmartDay™.

Bill Protection Guarantee

Overall, 12% of PY2022 participants qualified for the Bill Protection Guarantee during the PY2022 SmartRate™ season, which is slightly higher compared to PY2021 with 10% of participants with bill protection. Dual enrollment in SmartAC™ is not currently available to new participants.

Table C-2 Participant Distribution by Bill Protection Status

Enrollment Status	Protection Status	Count of Participants	% of Enrollment Status	% of Population
SmartRate™ Only	Unprotected	12,401	82%	28%
	Protected	2,643	18%	6%
	All SR Only	**15,044**	**100%**	**34%**
Dually Enrolled In SmartAC™	Unprotected	5,872	100%	13%
	Protected	0	0%	0%
	All Dual SAC	**5,872**	**100%**	**13%**
Dually Enrolled in ELRP A6	Unprotected	20,288	90%	47%
	Protected	2,462	10%	5%
	All Dual ELRP A6	**22,750**	**100%**	**52%**
All	Unprotected	38,561	88%	88%
	Protected	5,105	12%	12%
	All	**43,666**	**100%**	**100%**

The 5,105 participants eligible for the Bill Protection Guarantee saw overall average bill savings across the PY2022 season of $15.75 per participant, a significant decrease from $45.50 in PY2021. This drop in average savings is attributed to two factors:

- In PY2022, 23% of bill-protected participants were affected by a notification issue, i.e., they did not receive email/text notifications. These customers, on average, saw a small $5.32 per-participant bill savings.
- Overall, 43% of participants under bill protection saw an increase in their billing total (29% with no issues and 14% with notification issues). These participants saw an average increase of $26.47 in their billing total, also a significant increase from $7.52 in PY2021. Since these participants are eligible for a refund under the Bill Protection Guarantee, this would be equivalent to the average refund received by protected participants at the end of the PY2021 season.

Table C-3 Bill Impacts for Participants under the Bill Protection Guarantee

Notification Issue	Impact	Count of Participants	% of Bill Protected	Average Bill Change
Received Notifications	Decreased Bill	2,453	48%	-$48.07
	Increased Bill	1,502	29%	$29.06
	All No Issue	**3,955**	**77%**	**-$18.78**
No Notifications	Decreased Bill	462	9%	-$44.26
	Increased Bill	688	14%	$20.83
	All Notif Issue	**1,150**	**23%**	**-$5.32**

Notification Issue	Impact	Count of Participants	% of Bill Protected	Average Bill Change
All	Decreased Bill	2,915	57%	-$47.47
	Increased Bill	2,190	43%	$26.47
	All	**5,105**	**100%**	**-$15.75**

Billing Impacts by Participant Segment

This section presents billing impacts for other participant segments.

A comparison to participants under the Bill Protection Guarantee, the table below presents the billing impacts for participants enrolled in SmartRate™ for more than a full summer and no longer eligible for the Bill Protection Guarantee. Within this segment, 59% of participants experienced a reduction in their billing total, and the average reduction was significantly lower than participants under bill protection ($25.25 versus $47.47).

Table C-4 Bill Impacts for Participants without the Bill Protection Guarantee

Enrollment Status	Impact	Count of Participants	% of Population	Average Bill Change
SmartRate™ Only	Decreased Bill	7,959	20%	-$26.59
	Increased Bill	4,442	12%	$22.66
	All SR Only	**12,401**	**32%**	**-$8.95**
Dually Enrolled in SmartAC™	Decreased Bill	3,466	9%	-$26.64
	Increased Bill	2,406	6%	$20.90
	All Dual SAC	**5,872**	**15%**	**-$7.16**
Dually Enrolled In ELRP A6	Decreased Bill	11,276	29%	-$23.88
	Increased Bill	9,010	24%	$21.21
	No Change	2	<1%	$0.00
	All Dual ELRP A6	**20,288**	**53%**	**-$3.85**
All	Decreased Bill	22,701	59%	-$25.25
	Increased Bill	15,858	41%	$21.57
	No Change	2	<1%	$0.00
	All	**38,561**	**100%**	**-$6.00**

The following table presents the average billing impacts by LCA. Each LCA shows an average reduction in billing totals, with the most significant reduction experienced by participants in Humboldt. The smallest reductions were seen in the "Other" LCA.

Table C-5 Bill Impacts by LCA

LCA	Count of Participants	% of Population	Average Bill Change
Greater Bay Area	4,313	10%	-$6.04
Greater Fresno Area	10,773	25%	-$10.28
Humboldt	46	<1%	[redacted]
Kern	4,276	10%	-$14.24
North Coast and North Bay	1,585	4%	-$12.36
Sierra	5,887	13%	-$5.20
Stockton	4,758	11%	-$1.50
Other	12,026	28%	-$4.63
All	**43,664**	**100%**	**-$7.14**

The following table presents average billing impacts by CARE enrollment. Customers on CARE status experienced slightly higher billing reductions, on average, compared to non-CARE customers.

Table C-6 Bill Impacts by CARE Status

CARE Status	Impact	Count of Participants	% of Population	Average Bill Change
Non-CARE	Decrease Bill	14,768	33%	-$29.85
	Increase Bill	9,048	21%	$23.59
	All Non-CARE	**23,816**	**54%**	**-$9.54**
CARE	Decrease Bill	10,848	25%	-$24.97
	Increase Bill	9,000	21%	$20.73
	No Change	2	<1%	$0.00
	All CARE	**19,850**	**46%**	**-$4.25**

Finally, the following table presents average billing impacts by billing rate. Notably, customers on the TOU-B and TOU-D (Opt-in) billing rates experienced substantially higher billing reductions compared to other rates with $45.41 and $52.92 average reductions, respectively.

Table C-7 Bill Impacts by Billing Rate

Billing Rate	Impact	Count of Participants	% of Population	Average Bill Change
E1 (Standard)	Decrease Bill	14,660	33%	-$24.63
	Increase Bill	14,015	32%	$22.57
	No Change	2	<1%	$0.00
	All E1	**28,677**	**66%**	**-$1.56**
E6 (TOU)	Decrease Bill	804	2%	-$25.75
	Increase Bill	167	<1%	$21.36
	All E6	**971**	**2%**	**-$17.65**
TOU-B (Opt-in)	Decrease Bill	1,962	4%	-$45.41
	Increase Bill	658	2%	$23.48

	All TOU-B	**2,620**	**6%**	**-$28.11**
TOU-C (Defaulted)	Decrease Bill	7,787	18%	-$27.94
	Increase Bill	2,939	7%	$20.14
	All TOU-C	**10,726**	**25%**	**-$14.77**
TOU-D (Opt-in)	Decrease Bill	340	1%	-$52.92
	Increase Bill	255	1%	$19.95
	All TOU-D	**595**	**1%**	**-$21.69**
EV2A (Home Charging EV)	Decrease Bill	63	<1%	[redacted]
	Increase Bill	14	<1%	[redacted]
	Al EV2A	**77**	**<1%**	[redacted]

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