

# → 2025 Load Impact Evaluation for Pacific Gas & Electric Company's SmartRate™ Program

Ex-Post and Ex-Ante Load Impacts  
CALMAC ID PGE0514.01

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This work was performed by ICF

Project Manager: Tommy Williams

Project Advisor: William Golemboski

Project Team: Lia Tang

in consultation with Pacific Gas & Electric Company

Robert Kasman

Stephanie Wong

## Abstract

This report documents the load impact evaluation of the residential SmartRate™ program operated by Pacific Gas and Electric (PG&E) for Program Year 2025 (PY2025). The primary goals of this evaluation study include:

- 1) Estimating the ex-post load impacts for PY2025
- 2) Estimating ex-ante load impacts for the programs for years 2026–2036

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 nine and 15 SmartDays™ a year. SmartDays™ can be dispatched year-round but are typically dispatched 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.

ICF estimated hourly ex-post load impacts for each event during 2025 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 PY2025, PG&E dispatched the minimum number of events (nine) between June and September. The estimated aggregate ex-post load impact for an average event day was 4.1 MW.

ICF 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 2026. The estimated aggregate ex-ante load impacts for August Worst Day in 2026 for a PG&E 1-in-2 weather scenario is 4.4 MW during the resource adequacy (RA) window (4 to 9 PM).

## Executive Summary

This report documents the program year 2025 (PY2025) load impact evaluation of the residential SmartRate™ program offered by Pacific Gas & Electric (PG&E), conducted by ICF. The study's key objectives include estimating ex-post and ex-ante load impacts for the residential SmartRate™ program using methods and assumptions consistent with the California Demand Response (DR) Load Impact Protocols (LIP),<sup>1</sup> as follows:

- **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<sup>2</sup> and separately for key customer segments.
- **Estimate Ex-ante load impacts** for the average customer and all customers in aggregate for the resource adequacy (RA) window.<sup>3</sup> We provide estimates for each year over an 11-year<sup>4</sup> time horizon based on PG&E and CAISO's 1-in-2 weather conditions for a typical event day and each monthly system peak day. We provide estimates for both program-specific and portfolio-adjusted<sup>5</sup> scenarios. We also provide estimates by dual program enrollment.

The following sections provide:

- An [overview of the SmartRate™ program](#),
- A review of [participation in the PY2025 program](#),
- Results of the [ex-post load impact analysis](#),
- Results of the [ex-ante load impact analysis](#), and
- Key evaluation [findings and recommendations](#).

## Overview of SmartRate

SmartRate™ is a voluntary residential year-round critical peak pricing program (i.e., no direct load control) that overlays a customer's electric rate. It is designed to lower summer electricity costs while conserving California's power grid. Key aspects of the SmartRate™ program design follow.<sup>6</sup> Customers must opt-in to SmartRate; no customers are defaulted into the program.

**Eligibility.** Residential customers with a SmartMeter on the standard rate (E1), one of five time-of-use (TOU) rates (TOU-B, TOU-C, TOUD, EV2-A, and E-ELEC), or Net Billing Tariff (NBT) rate<sup>7</sup> are eligible to participate in SmartRate™. Participants may be dually enrolled in SmartAC™ or Emergency Load Reduction Program (ELRP) A6. All

### Executive Takeaways

- PY2025 SmartRate delivered ~4.1 MW average event-hour reduction (0.09 kW/customer; 4.6%) across 9 SmartDays
- Impacts were statistically significant and stable across events (typical range ~0.07–0.10 kW/customer)
- Enrollment averaged ~45,242 accounts on event days; participation remained steady through the season
- Ex-ante forecast: ~4.4 MW on Aug 2026 worst day (PG&E 1-in-2) during the RA window
- SmartRate continues to provide predictable peak reduction, with forecasts reflecting known program transitions

<sup>1</sup> Attachment A. Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance, California Public Utilities Commission, Energy Division, April 2008.

<sup>2</sup> I.e., without considering the effects of other demand response programs on the estimated SmartRate™ impacts.

<sup>3</sup> The RA window is 5 PM to 10 PM for March, April and May and 4 PM to 9 PM for all other months.

<sup>4</sup> PG&E has requested a PY2024 back cast as part of the ex-ante impact analysis.

<sup>5</sup> Portfolio level impacts exclude the load impacts from dually enrolled participants attributed to concurrent SmartAC events.

<sup>6</sup> Details on the program design can be found on PG&E's SmartRate™ website: <https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/smartrate.html#accordion-aab9e3dd-d-item-a7aa982cf5>

<sup>7</sup> NBT is a new rate offered by PG&E for residential customers with a Renewable Electrical Generating Facility (REGF)

participants dually enrolled to SmartAC™ enrolled in both programs before October 26th, 2018. Participants dually enrolled in ELRP A6 are residential customers on CARE and FERA rates defaulted onto the ELRP pilot and other customers that may have optionally enrolled. Residential participants that received a payment from the Self-Generation Incentive Program (SGIP)<sup>8</sup> are required to enroll in one of PG&E residential demand response programs, SmartRate being one of the Demand Response programs offered for the incentive recipients. Historically, NEM, i.e. customers with PV solar, have not been eligible for SmartRate™. Beginning PY2025, NEM NBT customers are eligible for SmartRate™ enrollment.

**Price Incentives.** The SmartRate™ programs charges customers more for their consumption from 4 PM to 9 PM on SmartDays™ (\$0.60/kWh) and rewards participants for shifting their consumption away from those hours through the SmartRate Non-High Price credit (\$0.00636/kWh) and the SmartRate Participation Credit (\$0.00167/kWh). The credits apply to non-SmartDays™ too, but only during billing cycles with at least one SmartDay™. All consumption increases and decreases are measured relative to customer-specific baselines.

**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 at the end of the season if their SmartRate™ costs exceed their regular pricing plan.

**SmartDays™ (Events).** The program must dispatch at least nine and no more than 15 SmartDays™ each year. PG&E typically dispatches SmartDays™ during the summer, most often on weekdays, but can dispatch them year-round. High temperatures, CAISO alerts, and other factors, including Public Safety Power Shutoff (PSPS) activity, influence event dispatches. In PY2025, PG&E dispatched the minimum number of events (nine) from June through September, as shown in Table ES-1. Three of these SmartDays™ coincided with SmartAC™ events, though not all Sub-LAPs were dispatched for each event, and hours did not always overlap with the SmartDay™ event windows.

**Notification.** PG&E provides day-ahead notifications via text and/or email by 4 PM the day before a SmartDay™, giving customers time to plan their energy use or shift their demand away from event hours.

The PY2025 program design remained consistent with the design of the PY2024 program, with all major changes from that year carrying forward.

## PY2025 Participation

More than 45,000 unique customers were enrolled in SmartRate™ in the PY2025 season. The rate of participation remained constant across events, with minimal number of customers unenrolling during the summer months. The majority of SmartRate™ participants belonged to the Greater Fresno Area (24.5%) or unknown/other (21.5%) local capacity areas (LCA), as shown in Table ES-2 and Figure ES-1. The total shows the number of participants on an average event day.

Table ES-1 PY2025 SmartDays™

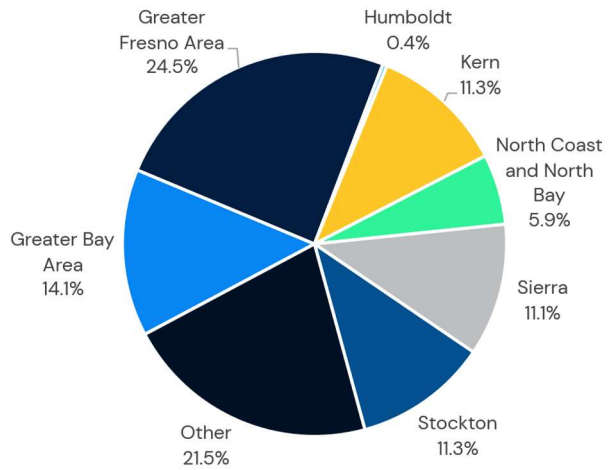
Date	Day of Week
Jul 10	Thursday
Jul 11	Friday
<u>Aug 8</u>	Friday
Aug 21	Thursday
<u>Aug 22</u>	Friday
<u>Sep 4</u>	Thursday
<u>Sep 16</u>	Tuesday
<u>Sep 17</u>	Wednesday
Sep 23	Tuesday
<sup>a</sup> Concurrent SmartAC events days are highlighted gray. SmartAC events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window. <sup>**</sup> Minimum Dispatch Events are <u>underlined</u> .	

<sup>8</sup> SGIP provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs.

Table ES-2 PY2025 Enrollment by LCA

LCA	# Accounts
Greater Bay Area	6,361
Greater Fresno Area	11,092
Humboldt	166
Kern	5,100
North Coast and North Bay	2,679
Sierra	5,038
Stockton	5,101
Other	9,705
<b>Total</b>	<b>45,242</b>

Figure ES-1 PY2025 Enrollment by LCA



As shown in Table ES-3 and Figure ES-2, the majority of SmartRate™ participants are enrolled in the E1 tiered rate, followed by the TOU-C and TOU-D rates. Additional participants are distributed among the Electric Vehicle (EV2-A), and Electric Home (E-ELEC) rates. Notably, 1.8% of participants are on the new NEM NBT rate, while a minimal proportion are enrolled in the TOU-B rate.

Table ES-4 PY2025 Enrollment by Billing Rate

Rate Code	# Accounts
E1	21,276
E-ELEC	928
NEM NBT	812
TOU-B	12
TOU-C	14,220
TOU-D	6,241
EV2-A	1,752
<b>Total</b>	<b>45,242</b>

Figure ES-4 PY2025 Enrollment by Billing Rate

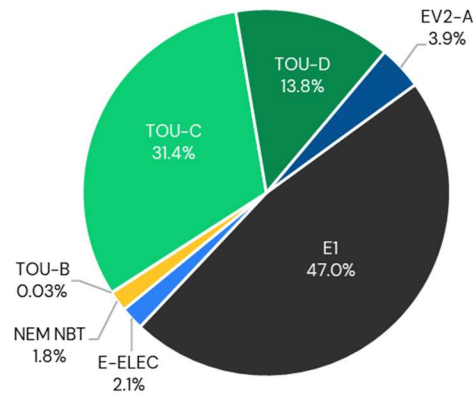


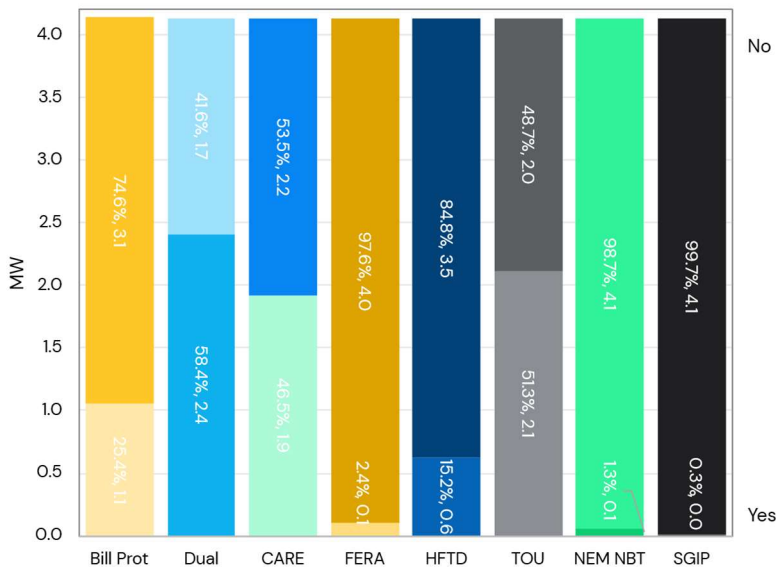
Table ES-4 and Figure ES-3 show the distribution of SmartRate™ participants enrollment and reference load in each segment of interest.

Table ES-7 PY2025 Enrollment by Segment

Segment	Status	# Accounts <sup>a</sup>
Bill Protection	No	33,872
	Yes	11,370
Dual Program Enrollment	SmartRate Only	19,354
	Dual – ELRP A6	22,717
	Dual – SmartAC	3,172
CARE Enrollment	No	24,920
	Yes	20,322
FERA Enrollment	No	44,167
	Yes	1,075
Time-of-Use	No	38,058
	Yes	7,183
High Fire Thread District	No	21,276
	Yes	23,966
NEM NBT	No	44,430
	Yes	812
SGIP	No	44,981
	Yes	260
<b>Total</b>		<b>45,242</b>

<sup>a</sup> Since customers can belong to more than one segment, these counts should not be summed.

Figure ES-2 PY2025 Reference Load by Segment



## Load Impact Evaluation Results

The following sections provide the results of the impact evaluation. In PY2025, SmartRate™ participants reduced their demand by 4.1 MW during the average SmartDay™ event hour, an average of 0.09 kW (4.6%) per customer.

### Ex-Post Load Impact Results

In the subsequent sections, we report the following metrics:

- The number of participants enrolled during each SmartDay™
- The aggregate and per-customer reference load (i.e., what ICF estimated participants would have consumed without the SmartRate™ program)
- The aggregate and per-customer load impacts, both in absolute (MW or kW) terms and as a percentage of the reference load
- The average temperature.

All reported estimates represent the average of the SmartDay™ event window (4–9 PM).

### Ex-Post Results by SmartDay™

Table ES-5 shows the results of the impact evaluation for each PY2025 SmartDay™. SmartRate™ participants reduced their demand by 4.1 MW during the average SmartDay™ event hour, an average of 0.09 kW (4.6%) per customer. Impacts remained consistent across event days, with participants saving between 0.07 kW and 0.10 kW during the average event hour. All impact estimates were statistically significant.

Three of the nine SmartDays™ coincided with SmartAC™ event days. The impacts estimated for these event days reflect the effects of SmartAC™ customers responding to SmartAC™ days in addition to the SmartRate™ price signals.

Table ES-9 Ex-Post Load Impacts by Event

Event Date <sup>a</sup>	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
July 10	43,037	85.9	4.0	2.00	0.09	4.7%	94
July 11	43,062	96.4	4.2	2.24	0.10	4.3%	96
<u>August 8</u>	44,677	97.5	4.4	2.18	0.10	4.5%	97
August 21	45,308	95.0	4.3	2.10	0.09	4.5%	96
<u>August 22</u>	45,391	99.9	4.4	2.20	0.10	4.4%	97
<u>September 4</u>	45,986	80.2	3.4	1.74	0.07	4.3%	86
<u>September 16</u>	46,450	82.9	4.1	1.79	0.09	4.9%	92
<u>September 17</u>	46,531	83.8	4.1	1.80	0.09	4.9%	92
September 23	46,735	87.3	4.2	1.87	0.09	4.8%	94
<b>Average Event Day</b>	<b>45,242</b>	<b>90.0</b>	<b>4.1</b>	<b>1.99</b>	<b>0.09</b>	<b>4.6%</b>	<b>94</b>

<sup>a</sup> Concurrent SmartAC events days are highlighted gray. SmartAC events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.  
 \*\* Minimum Dispatch Events are underlined. PG&E may initiate SmartDay events to meet the annual SmartDay Event Day minimum for a calendar year. These are noted as Minimum Dispatch Events.

### Ex-Post Results by Local Capacity Area

Table ES-6 summarizes the aggregate ex-post results for the average event day for PG&E's eight local capacity areas (LCA). Nearly 25% of all participants belong to the Greater Fresno Area, with slightly less (21%) in the "Other or Unknown" category. These two LCAs combined contributed 49% of the total SmartRate™ impact (2.0 MW).

Table ES-10 Ex-Post Savings by Load Capacity Area

LCA	# Accounts	Reference Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp (°F)
Greater Bay Area	6,361	9.3	0.5	4.9%	84
Greater Fresno Area	11,092	26.4	1.1	4.2%	98
Humboldt	166	0.1	0.0	6.2%	67
Kern	5,100	12.1	0.5	4.3%	99
North Coast and North Bay	2,679	3.4	0.2	6.0%	86
Sierra	5,038	9.4	0.5	4.8%	93
Stockton	5,101	10.7	0.5	4.4%	94
Other	9,705	18.6	0.9	4.9%	95

### Ex-Post Results by Customer Segment

Table ES-7 summarizes ex-post estimates for the average event day for key customer segments. We discuss these findings in more detail in [Section 2](#).

Table ES-11 Ex-Post Savings by Segment

Segment	Status	# Accounts N=45,242	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
			Reference Load	Load Impact	Reference Load	Load Impact		
Bill Protection	No	33,872	66.3	3.1	1.96	0.09	4.6%	94
	Yes	11,370	23.7	1.1	2.08	0.09	4.4%	94
Program Enrollment	SmartRate Only	19,354	36.9	1.7	1.91	0.09	4.7%	93
	Dual – ELRP A6	22,717	47.4	2.0	2.09	0.09	4.3%	94
	Dual – Smart AC	3,172	5.8	0.4	1.83	0.11	6.2%	95
CARE Enrollment	No	24,920	45.2	2.2	1.82	0.09	4.9%	92
	Yes	20,322	44.8	1.9	2.21	0.09	4.3%	95
FERA Enrollment	No	44,167	87.5	4.0	1.98	0.09	4.6%	94
	Yes	1,075	2.6	0.1	2.38	0.09	3.9%	95
High Fire Threat District	No	38,058	79.2	3.5	2.08	0.09	4.4%	94
	Yes	7,183	10.8	0.6	1.51	0.09	5.8%	92
TOU	No	21,276	44.7	2.0	2.10	0.09	4.5%	95
	Yes	23,966	45.4	2.1	1.89	0.09	4.7%	92
NEM NBT	No	44,430	89.2	4.1	2.01	0.09	4.6%	94
	Yes	812	0.9	0.1	1.06	0.07	6.4%	94
SGIP	No	44,981	89.8	4.1	2.00	0.09	4.6%	94
	Yes	260	0.2	0.0	0.84	0.05	6.2%	92

<sup>a</sup> Since customers can belong to more than one segment, values should not be summed across segments.

## Ex-Ante Load Impacts Results

This section summarizes the results of the ex-ante analysis, where ICF used the ex-post models to forecast SmartRate™ impacts through 2036 under multiple weather scenarios. For 2025 and beyond, the resource adequacy (RA) measurement hours are 5 PM – 10 PM in all months except June–October, when the hours are 4 PM – 9 PM.<sup>9</sup> We refer to the RA measurement hours as the RA window. Specifically, we met the following objectives of the ex-ante load impact analysis:

- Develop hourly load impact estimates for the average customer and all customers in aggregate for the RA window.<sup>10</sup>
- Estimate impacts for each year over an 11-year<sup>11</sup> horizon based on PG&E's and CAISO's 1-in-2 weather conditions for each monthly system worst day.
- Provide program-specific ex-ante estimates by forecasting SmartRate™ impacts without considering the effects of dual enrollment in other demand response programs, i.e., assuming no SmartAC™ or ELRP A6 events are dispatched in future years.
- Avoid double-counting impacts attributable to SmartRate™ and other demand response programs by providing portfolio-adjusted estimates, i.e., assuming SmartAC™ and ELRP A6 events are dispatched in future years, if necessary.

As part of the ex-ante evaluation, we worked with PG&E staff to develop the following key approaches and assumptions:

- **ICF used a combined weighted PY2025 and PY2024 ex-post models to forecast the 11-year SmartRate™ per-customer impacts year-round.** The RA window coincides with the SmartRate™ event window only in summer months.
- **PG&E provided an enrollment forecast by customer segment, LCA, and sub-LAP,** which ICF used to aggregate per-customer impacts to the program level. The assumptions used to develop the enrollment forecast are discussed in [Section 3](#).
- **All dually enrolled ELRP A6 customers rejoined the SmartRate™ only group starting in January 2026,** when the ERLP A6 pilot is set to close.
- **All dually enrolled SmartAC™ customers rejoined the SmartRate™ only group starting in January 2029,** when the SmartAC program is set to close at the end of 2028.

## Program-Specific Ex-Ante Impacts

Table ES-8 summarizes the aggregate and per-customer load impact forecasts for SmartRate™ participants on an August Worst Day in 2026. The table includes impact forecasts under the 1-in-2 weather scenarios for both PG&E and CAISO peaks.

We forecasted a higher per-customer impacts for participants dually enrolled in SmartAC™ compared to customers in other segments, as given their technology-supported response, contributing 8% of the aggregate impact (PG&E 1-in-2 weather scenario) despite accounting for only 5% of the total enrollment population.

<sup>9</sup> California Public Utilities Commission (CPUC), Energy Division, Load Impact Protocol (LIP) Filing Guide, Version 6.1 (March 5, 2025), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/load-impact-protocols/final-lip-filing-guide-v61.pdf> (accessed March 20, 2026).

<sup>10</sup> The RA window is 5 PM to 10 PM for all months, except June – October, when the window is 4 PM to 9 PM.

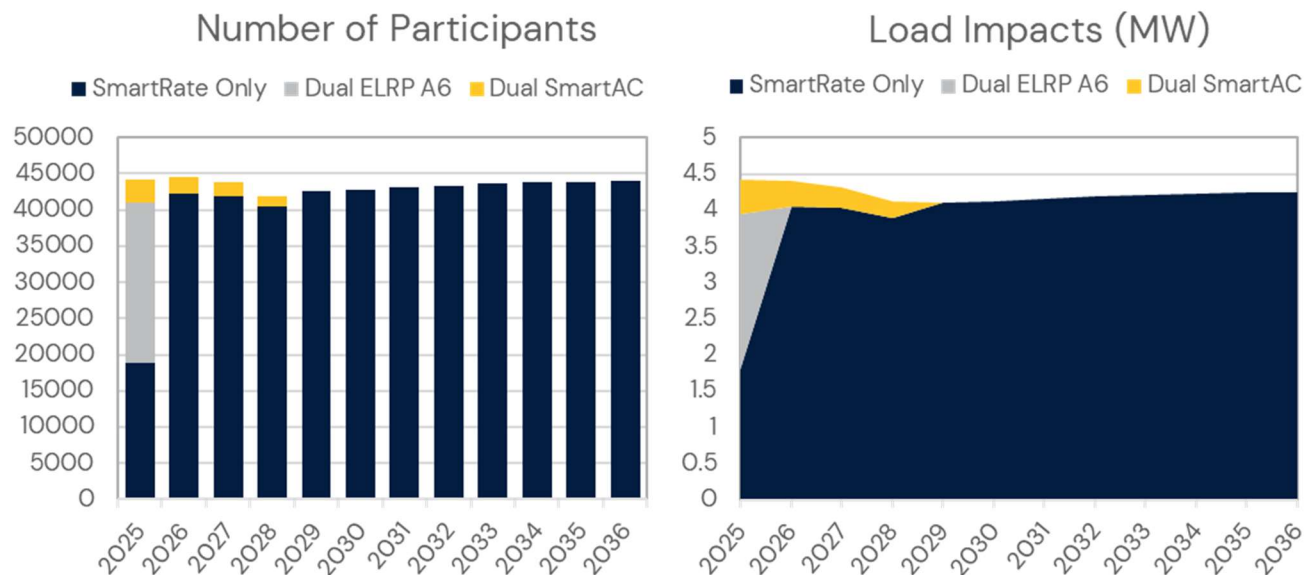
<sup>11</sup> ICF included the PY2025 back cast as part of the ex-ante impact analysis.

Table ES-12 August Worst Day Impacts by Program Enrollment: 2026, RA Window

Program Enrollment	# Accounts	Aggregate Impact (MW)		Per Customer Impact (kW)	
		PG&E Peak	CAISO Peak	PG&E Peak	CAISO Peak
		1-in-2 (95 °F)	1-in-2 (96 °F)	1-in-2 (95 °F)	1-in-2 (96 °F)
SmartRate™ Only	42,168	4.1	4.1	0.10	0.10
Dually Enrolled – SmartAC	2,381	0.4	0.4	0.15	0.15
<b>Total</b>	<b>44,549</b>	<b>4.4</b>	<b>4.5</b>	<b>0.10</b>	<b>0.10</b>

Figure ES-4 shows PG&E’s annual enrollment forecast and the associated aggregated load impact forecasts for the PG&E 1-in-2 weather scenario on an August Worst Day, including the 2025 backcast. Overall, PG&E expects enrollment to decrease through the 11-year horizon without any planned marketing efforts to offset program attrition over time.

Figure ES-6 Enrollment and Impact Forecast: PG&E 1-in-2, August Worst Day, RA Window, 2025 - 2036



### Portfolio-Adjusted Ex-Ante Impacts

The estimated program-specific ex-ante impacts forecast savings of the SmartRate™ program without considering the effects of other demand response programs. To avoid double-counting impacts of dually enrolled customers across all the program ex-ante forecasts, ICF provided portfolio-adjusted forecasts, which follow a portfolio hierarchy structure predetermined by PG&E.

Table ES-9 shows the program and portfolio-adjusted impacts for the PG&E 1-in-2 weather scenario for 2026 for the RA Window. For each program, we used the following assumptions to develop the portfolio-adjusted impacts:

- ICF assumes that, for customers dually enrolled in SmartAC™ and SmartRate™, all load shed observed on SmartRate™ event days is fully attributable to SmartAC™. This shift reflects the recent discovery that the DLC switch is enabled during all SmartRate™ event days, in addition to SmartAC™ event days. Because the

switch is active in both cases, there is no meaningful difference in load response between SmartAC™ only participants and those enrolled in both programs. Therefore, applying a 0% incremental SmartRate™ effect for dually enrolled customers is considered reasonable.<sup>12</sup>

- Since ELRP A6 was sunset after December 2025, ICF did not include ELRP A6 participants in the program or portfolio results.

As discussed, the RA window is from 5 PM to 10 PM for all non-summer months, and 4 PM to 9 PM for summer months<sup>13</sup>, which does not fully coincide with the SmartRate™ event window, which is 4 PM to 9 PM. This leads to slightly lower impacts on these months compared to summer months.

Table ES-13 Program-Level vs. Portfolio-Adjusted Load Impacts: PG&E 1-in-2, Monthly System Worst Day, 2026, RA Window

Month	Program-Level Load Impacts (MW)			Portfolio-Adjusted Load Impacts (MW)		
	SmartRate™ Only	Dually Enrolled SmartAC™	Total	SmartRate™ Only	Dually Enrolled SmartAC™	Total
January	1.90	0.17	2.07	1.90	0.17	2.07
February	1.72	0.15	1.86	1.72	0.15	1.86
March	1.40	0.09	1.49	1.40	0.09	1.49
April	1.70	0.11	1.81	1.70	0.11	1.81
May	2.00	0.13	2.13	2.00	0.00	2.00
June	4.27	0.40	4.67	4.27	0.00	4.27
July	4.19	0.39	4.57	4.19	0.00	4.19
August	4.05	0.35	4.41	4.05	0.00	4.05
September	3.82	0.29	4.11	3.82	0.00	3.82
October	2.50	0.13	2.63	2.50	0.00	2.50
November	1.62	0.11	1.73	1.62	0.11	1.73
December	1.89	0.13	2.03	1.89	0.13	2.03

### Key Findings

ICF identified the following key findings based on the ex-post impact evaluation:

- **The SmartRate™ program continued to successfully drive customers to reduce their demand during SmartDay™ event hours.** During the average event hour, customers delivered savings of 4.1 MW in total (4.6% of reference load consumption). The aggregate impact was lower than in PY2024 (5.2 MW) but the percent impact was slightly higher than in PY2024 (4.4%) reflecting a shift in the reference load due to lower-than-average summer temperatures.
- **SmartRate™ participants experienced lower than average reference loads in 2025.** This phenomenon is most likely a reflection of lower summer temperatures in 2025.

<sup>12</sup> In previous evaluations, ICF ran simulations to predict the incremental effect of dual participation on dual event days finding that SmartRate™ participation will add 18% to the SmartAC™ load impact on dual event days in PY2023 and 2% in PY2024.

<sup>13</sup> Summer months are defined as June, July, August, September, and October.

- **SmartRate™ participants dually enrolled in ELRP A6 showed lower impacts in PY2025 (0.09 kW per customer) than in PY2024 (0.11 kW per customer).** This is likely a reflection of lower temperatures in 2025 compared to 2024.
- **Over 25% of PY2025 SmartRate™ participants qualified for the Bill Protection Guarantee,** a slight increase from the 21% in PY2024 and 19% in PY2023, which aligns with the increased SmartRate™ enrollments over the previous year.
- **Customers with Bill Protection slightly underperformed customers without Bill Protection in PY2025,** delivering impacts of 4.4% (compared to 4.6% For non-bill-protected). This result aligns with expectations, where customers without Bill Protection are more incentivized to save during SmartDays™ than customers with Bill Protection.
- **Participants dually enrolled in SmartAC™ saved an average of 6.2%,** compared to 4.7% for participants enrolled solely in SmartRate™. Customers dually enrolled in ELRP A6 delivered the same percentage demand reductions during the average PY2025 SmartDay™ event hour (4.3%) as they did in PY2024 (4.3%)
- **SmartRate™ enrollment continues shifting from E-1 toward TOU and electrification-oriented rates,** with TOU-C now accounting for 14,220 customers (31%). Higher-usage groups like TOU-D, E-ELEC, and EV2-A show the largest reference loads but the lowest percentage reductions (3.4%–3.5%), while lower-load TOU-C and NBT customers deliver the highest impacts (5.6%–6.4%). E-1 remains the largest segment and continues to provide stable reductions (~4.5%).

ICF identified the following key findings based on the ex-ante impact evaluation:

- **PG&E expects enrollment to fall until 2028 with the phasing out of SmartAC™ and ELRP A6 participants from the program.** Following this decline, PG&E projects an annual growth rate of approximately 0.5% from 2029 through 2036. SmartAC™ dual-enrollments are expected to phase out entirely by 2028, and ELRP A6 customers migrate to SmartRate™-only status following the pilot sunset in November 2025.
- **The SmartRate™ program (before portfolio adjustments) will deliver demand reductions of 4.4 MW in August 2026 under PG&E's 1-in-2 weather conditions.** These demand reductions assume that around 45,000 customers will participate in the PY2026 program and reduce their demand during the average SmartRate™ event hour by 4.4% of their reference load. These impacts include the technology-driven response of SmartAC™ customers responding to concurrent SmartAC™ events. For comparison, the PY2024 ex-ante forecast projected 4.9 MW under the same weather conditions. The lower forecasted aggregate reduction is consistent with PY2025's milder summer temperatures, which contributed to a lower aggregate reference load; applying a similar percentage reduction to a lower baseline results in lower aggregate MW impacts.
- **The PY2025 SmartDays™ experienced lower average event temperatures compared to most weather scenarios but had similar percentage impacts compared to ex-post savings.** Despite having a cooler than average summer, the ex-ante percent savings impacts remained similar to ex-post under the other weather scenarios with temperatures closer to those observed in PY2024. The reference loads across ex-post and ex-ante were the biggest differences across the two analyses with lower reference loads observed in the PY2025 ex-post compared to ex-ante reference loads under the PG&E 1-in-2 weather scenario.
- **The shift in the RA window to later hours in March through May (5 PM to 10 PM) resulted in slightly lower impacts during these months' peaks compared to other non-summer months.** The SmartRate™

event window (4–9 PM) coincides with the RA window in all other months such that no adjustment to the impacts was necessary.

## Recommendations

We provide the following recommendations to PG&E based on findings from the ex-post and ex-ante impacts evaluations:

- **Continue evaluating SGIP and NEM NBT customers enrolled on SmartRate™.** As enrollment in electrification oriented and net billing tariff (NBT) schedules grows, future evaluations should track whether these customers continue to demonstrate the strong percentage impacts observed to date and whether their responsiveness persists as the groups expand. Monitoring these rate classes over time will help determine whether targeted outreach or tailored event messaging could enhance their performance and whether they warrant distinct treatment in ex-ante forecasting.
- **Revisit reference loads in future years** to see if the smaller reference loads were an anomaly in PY2025 or if the finding continues in more “normal weather” years. Because PY2025 SmartDays™ occurred during a cooler than average summer and produced noticeably lower reference loads, future studies should assess whether reference loads normalize under hotter conditions or whether structural changes—such as continued TOU migration, electrification, or energy efficiency—are reducing baseline event hour consumption. Reevaluating reference load trends over multiple program years will improve the accuracy of both ex-post comparisons and ex-ante forecasts.

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# 1 Introduction

This report documents the program year 2025 (PY2025) load impact evaluation of the residential SmartRate™ program offered by Pacific Gas & Electric (PG&E), conducted by ICF. The study's key objectives include estimating ex-post and ex-ante load impacts for the residential SmartRate™ program using methods and assumptions consistent with the California Demand Response (DR) Load Impact Protocols (LIP),<sup>14</sup> as follows:

- **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<sup>15</sup> and separately for key customer segments.
- **Estimate Ex-ante load impacts** for the average customer and all customers in aggregate for the resource adequacy (RA) window.<sup>16</sup> We provide estimates for each year over an 11-year<sup>17</sup> time horizon based on PG&E and CAISO's 1-in-2 weather conditions for a typical event day and each monthly system peak day. We provide estimates for both program-specific and portfolio-adjusted<sup>18</sup> scenarios. We also provide estimates by dual program enrollment.

In this chapter, we provide an overview of the SmartRate™ program, a review of the PY2025 participation, and an overview of the evaluation approach.

## 1.1 Overview of SmartRate™

SmartRate™ is a voluntary residential year-round critical peak pricing program (i.e., no direct load control) that overlays a customer's electric rate. It is designed to lower summer electricity costs while conserving California's power grid. Key aspects of the SmartRate™ program design follow.<sup>19</sup> Customers must opt-in to SmartRate; no customers are defaulted into the program.

**Eligibility.** Residential customers with a SmartMeter on the standard rate (E1), one of five time-of-use (TOU) rates (TOU-B, TOU-C, TOUD, EV2-A, and E-ELEC), or Net Billing Tariff (NBT) rate<sup>20</sup> 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 in ELRP A6 are residential customers on CARE and FERA rates defaulted onto the ELRP pilot and other customers that may have optionally enrolled. Residential participants that received a payment from the Self-Generation Incentive Program (SGIP)<sup>21</sup> are required to enroll in one of PG&E residential demand response programs, SmartRate being one of the Demand Response programs offered for the incentive recipients. Historically, NEM, i.e. customers with PV solar, have not been eligible for SmartRate™. Beginning PY2025, NEM NBT residential customers are eligible for SmartRate™ enrollment.

**Price Incentives.** The SmartRate™ programs charges customers more for their consumption from 4 PM to 9 PM on SmartDays™ (\$0.60/kWh) and rewards participants for shifting their consumption away from those hours through the SmartRate Non-High Price credit (\$0.00636/kWh) and the SmartRate™ Participation Credit (\$0.00167/kWh). The credits apply to non-SmartDays™ too, but only during billing cycles with at least one

<sup>14</sup> Attachment A. Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance, California Public Utilities Commission, Energy Division, April 2008.

<sup>15</sup> I.e., without considering the effects of other demand response programs on the estimated SmartRate™ impacts.

<sup>16</sup> The RA window is 5 PM to 10 PM for March, April and May and 4 PM to 9 PM for all other months.

<sup>17</sup> PG&E has requested a PY2024 back cast as part of the ex-ante impact analysis.

<sup>18</sup> Portfolio level impacts exclude the load impacts from dually enrolled participants attributed to concurrent SmartAC events.

<sup>19</sup> Details on the program design can be found on PG&E's SmartRate™ website: <https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/smartrate.html#accordion-aab9e3ddddd-item-a7aa982cf5>

<sup>20</sup> NBT is a new rate offered by PG&E for customers with a Renewable Electrical Generating Facility (REGF)

<sup>21</sup> SGIP provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs.

SmartDay™. The credits are paid against all hours in the billing period that are not SmartDay™ event hours (4–9pm). If there are multiple SmartDays™ in a single billing period, then the credits are multiplied by the number of SmartDays™ in the billing period. All consumption increases and decreases are measured relative to customer-specific baselines.

**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 at the end of the season if their SmartRate™ costs exceed their regular pricing plan.

**SmartDays™ (Events).** The program must dispatch at least nine and no more than 15 SmartDays™ each year. PG&E typically dispatches SmartDays™ during the summer, most often on weekdays, but can dispatch them year-round. High temperatures, CAISO alerts, and other factors, including Public Safety Power Shutoff (PSPS) activity, influence event dispatches. In PY2025, PG&E dispatched the minimum number of events (nine) from June through September, as shown in Table 1-1 PY2025 SmartDays™. Three of these SmartDays™ coincided with SmartAC™ events, though not all Sub-LAPs were dispatched for each event, and hours did not always overlap with the SmartDay™ event windows.

**Notification.** PG&E provides day-ahead notifications via text and/or email by 5 PM the day before a SmartDay™, giving customers time to plan their energy use or shift their demand away from event hours.

The PY2025 program design remained consistent with the design of the PY2024 program, with all major changes from that year carrying forward.

Table 1-1 PY2025 SmartDays™

Date	Day of Week
Jul 10	Thursday
Jul 11	Friday
<u>Aug 8</u>	<u>Friday</u>
Aug 21	Thursday
<u>Aug 22</u>	<u>Friday</u>
<u>Sep 4</u>	<u>Thursday</u>
<u>Sep 16</u>	<u>Tuesday</u>
<u>Sep 17</u>	<u>Wednesday</u>
Sep 23	Tuesday

<sup>a</sup> Concurrent SmartAC events days are highlighted gray. SmartAC events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.  
 \*\* Minimum Dispatch Events are underlined.

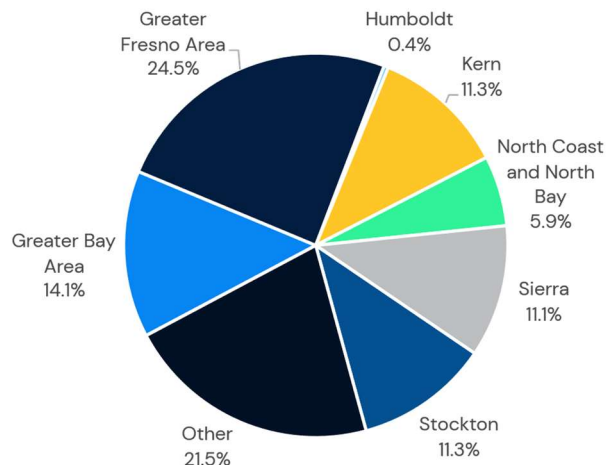
## 1.2 PY2025 Participation

More than 45k unique customers were enrolled in SmartRate™ in the PY2025 season. The rate of participation remained constant across events, with minimal number of customers unenrolling during the summer months. The majority of SmartRate™ participants

Table 1-4 PY2025 Enrollment by LCA

LCA	# Accounts
Greater Bay Area	6,361
Greater Fresno Area	11,092
Humboldt	166
Kern	5,100
North Coast and North Bay	2,679
Sierra	5,038
Stockton	5,101
Other	9,705
<b>Total</b>	<b>45,242</b>

Figure 1-2 PY2025 Enrollment by LCA



belonged to the Greater Fresno Area (24.5%) or unknown/other (21.5%) local capacity areas (LCA), as shown in Table 1-2 and Figure 1-1. The total shows the number of participants on an average event day.

As shown in Table 1-3 and Figure 1-2, the majority of SmartRate™ participants are enrolled in the E1 tiered rate, followed by the TOU-C and TOU-D rates. Additional participants are distributed among the Electric Vehicle (EV2-A), and Electric Home (E-ELEC) rates. Notably, 1.8% of participants are on the new NEM NBT rate.

Table 1-6 PY2025 Enrollment by Billing Rate

Rate Code	# Accounts
E1	21,276
E-ELEC	928
NEM NBT	812
TOU-B	█
TOU-C	14,220
TOU-D	6,241
EV2-A	1,752
<b>Total</b>	<b>45,242</b>

Figure 1-5 PY2025 Enrollment by Billing Rate

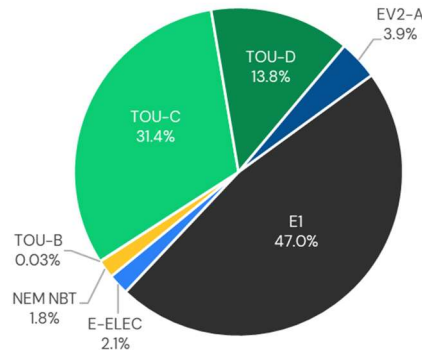


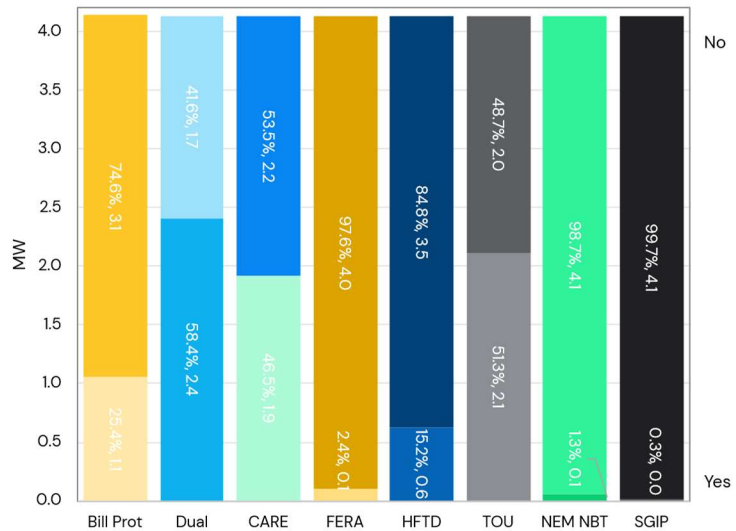
Table 1-4 and Figure 1-3 show the distribution of SmartRate™ participants enrollment and reference load in each segment of interest.

Table 1-9 PY2025 Enrollment by Segment

Segment	Status	# Accounts <sup>a</sup>
Bill Protection	No	33,872
	Yes	11,370
Dual Program Enrollment	SmartRate Only	19,354
	Dual – ELRP A6	22,717
	Dual – SmartAC	3,172
CARE Enrollment	No	24,920
	Yes	20,322
FERA Enrollment	No	44,167
	Yes	1,075
Time-of-Use	No	38,058
	Yes	7,183
High Fire Thread District	No	21,276
	Yes	23,966
NEM NBT	No	44,430
	Yes	812
SGIP	No	44,981
	Yes	260
<b>Total</b>		<b>45,242</b>

<sup>a</sup> Since customers can belong to more than one segment, these counts should not be summed.

Figure 1-8 PY2025 Reference Load by Segment



### 1.3 Load Impact Evaluation

ICF designed the PY2025 SmartRate™ evaluation to meet PG&E's specific research objectives for the program. Table 1-5 briefly describes these analysis steps. The [Detailed Analysis Methods](#) appendix provides more details on the specific approaches.

In outcome, ICF produced Excel workbooks in conformance with the California LIP, referred to as the Table Generators, which were supplied to PG&E separately for ex-post and ex-ante results. These workbooks have been embedded in Appendix A.

Table 1-11 Overview of Evaluation Methods

Step	Description
<b>Define the Participation Population</b>	<p>Starting with the full SmartRate™ participation list, ICF screened out the following customers from the final PY2025 participation population:</p> <ul style="list-style-type: none"> <li>Accounts that went inactive before start of summer (June 1, 2025)</li> <li>Accounts that unenrolled before start of summer</li> <li>Accounts that did not receive any SmartRate event notifications</li> </ul>
<b>Establish the Analysis Sample</b>	<p>ICF further removed accounts from the analysis pool based on the quality of their billing data, mitigating the need for oversampling because of data inadequacies:</p> <ul style="list-style-type: none"> <li>Accounts with zero / negative usage in billing data</li> <li>Accounts without sufficient remaining summer billing data</li> </ul> <p>After defining the final sample frame, ICF selected a random sample of participants for the analysis to avoid having to process and model the entire nearly 46k participant population. We selected ~8,700 participants in total, stratified by the following customer segments:</p> <ul style="list-style-type: none"> <li>Dually enrolled SmartAC™ customers (~1,500 customers)</li> <li>SmartRate™ customers on bill protection (~3,000 customers)</li> <li>SmartRate™ customers not on bill protection (~3,000 customers)</li> <li>SmartRate™ customers on the NEM NBT rate and/or SGIP recipients (battery owners), with or without bill protection (1,113 customers; census)</li> </ul>
<b>Develop a Matched Control Group<sup>22</sup></b>	<p>ICF analyzed SmartRate™ impacts using quasi-experimental methods, creating a control group of nonparticipants similar in energy consuming behavior to participants. We developed the matched control group as follows:</p> <ul style="list-style-type: none"> <li>First, we selected event-like days based on their similarity in weather to PY2025 SmartDays™.</li> <li>Then, we matched eligible nonparticipants to SmartRate™ participants based on their consumption on event-like days using Euclidean distance matching.<sup>23</sup></li> </ul>
<b>Estimate Ex-Post Load Impacts</b>	<p>Using the final subset of participants and the matched control group, we estimated ex-post impacts for the average participant in each customer segment using panel regression difference-in-differences models with customer fixed effects.</p>

<sup>22</sup> Participants in this segment were not matched to an external comparison group due to the prevalence of battery ownership and/or enrollment on the NEM NBT rate, which is strongly associated with photovoltaic (PV) ownership. These characteristics limit the availability of comparable non-participant customers for establishing a counterfactual. Accordingly, impacts for this segment were estimated using a within-group analytical approach.

<sup>23</sup> Euclidean distance matching calculates the distance (i.e., the square-root of the sum of squared differences) between multiple matching variables (e.g., early morning load, on-peak load, etc.) to create a single metric for assessing the quality of each participant-nonparticipant candidate match.

	<p>Subgroup-level results were derived by aggregating customer fixed-effect estimates to establish an “average customer” for the smallest subgrouping and then rolling these results up to the subgroupings of interest. We then calculated program-total demand savings for each PY2025 SmartDay™ event by applying per-customer impacts to the final participant population.</p>
<b>Estimate Ex-Ante Load Impacts</b>	<p>We calculated ex-ante savings for each year, and monthly peak of an 11-year forecast period as follows:</p> <ul style="list-style-type: none"><li>• First, we applied the ex-post regression models to the ex-ante weather scenarios to estimate ex-ante impacts for an average customer in each segment.</li><li>• Then, we calculated program-specific ex-ante savings by applying per-customer impacts to the 11-year enrollment forecast (provided by PG&amp;E).</li><li>• Finally, we developed portfolio-adjusted impacts by applying assumptions to the program-specific ex-ante impacts for the effects of dual-enrollment in other demand repose programs.</li></ul>

## 1.4 Report Organization

The remaining chapters provide the following:

Chapter 2: [Ex-Post Evaluation Results](#)

Chapter 3: [Ex-Ante Impact Analysis](#)

Chapter 4: [Key Findings](#)

Chapter 5: [Recommendations](#)

## 2 Ex-Post Evaluation Results

This chapter provides the results of ICF's ex-post evaluation for PG&E's PY2025 SmartRate™ program. In the subsequent sections, we report the following metrics:

- The number of participants enrolled during each SmartDay™
- The aggregate and per-customer reference load (i.e., what ICF estimated participants would have consumed without the SmartRate™ program)
- The aggregate and per-customer load impacts, both in absolute (MW or kW) and as a percentage of the reference load
- The average temperature.

All reported estimates represent the average of the SmartDay™ event window (4–9 PM).

### 2.1 Overview of PY2025 Ex-Post Impacts

Table 2-1 shows the results of ICF's impact evaluation for each PY2025 SmartDay™. SmartRate™ participants reduced their demand by more than 4 MW during the average SmartDay™ event hour, an average of 0.09 kW (4.6%) per customer. Impacts remained consistent across event days, with participants most often saving between 0.07 kW and 0.10 kW during the average event hour. All impact estimates were statistically significant.

Three of the nine SmartDays™ coincided with SmartAC event days. The impacts estimated for these event days reflect the effects of SmartAC™ customers responding to SmartAC™ days in addition to the SmartRate™ price signals.

Table 2-1 Ex-Post Load Impacts by Event

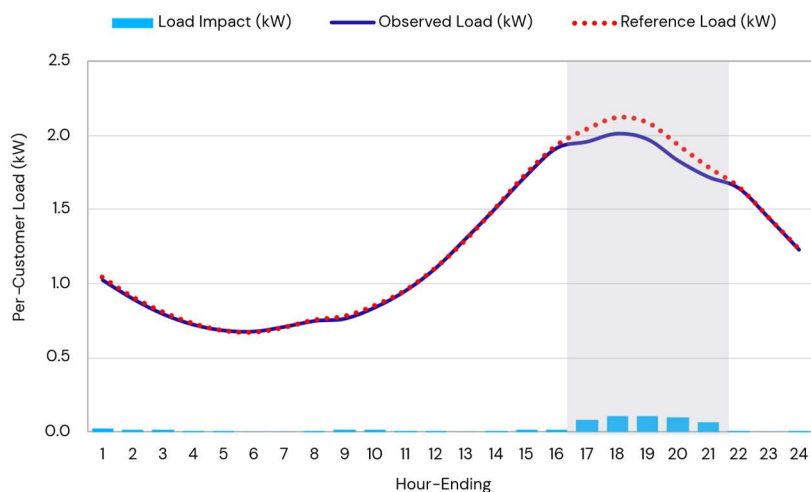
Event Date <sup>a</sup>	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
July 10	43,037	85.9	4.0	2.00	0.09	4.7%	94
July 11	43,062	96.4	4.2	2.24	0.10	4.3%	96
<b>August 8</b>	44,677	97.5	4.4	2.18	0.10	4.5%	97
August 21	45,308	95.0	4.3	2.10	0.09	4.5%	96
<b>August 22</b>	45,391	99.9	4.4	2.20	0.10	4.4%	97
<u>September 4</u>	45,986	80.2	3.4	1.74	0.07	4.3%	86
<u>September 16</u>	46,450	82.9	4.1	1.79	0.09	4.9%	92
<u>September 17</u>	46,531	83.8	4.1	1.80	0.09	4.9%	92
September 23	46,735	87.3	4.2	1.87	0.09	4.8%	94
<b>Average Event Day</b>	<b>45,242</b>	<b>90.0</b>	<b>4.1</b>	<b>1.99</b>	<b>0.09</b>	<b>4.6%</b>	<b>94</b>

<sup>a</sup> Concurrent SmartAC events days are highlighted gray. SmartAC events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.  
 \*\* Minimum Dispatch Events are underlined.

Figure 2-1 shows the per-customer hourly observed loads, estimated reference loads, and estimated load impacts on the average event day. SmartRate™ participants produced a relatively flat event response, reaching the highest impact during the second event hour (Hour Ending 18). The load figures use continuous lines, though the analysis is hourly; therefore, pre-cooling or post-event snapback occurring within a single hour may not be visible, and gaps between lines across hours should be interpreted cautiously.

At the program level, hourly load impacts show 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 2-1 Per-Customer Load Profiles on an Average Event Day



**PY2025 Performance**

- Average SmartDay hourly impact: 4.1 MW of demand reduction during 4–9 PM, equal to 0.09 kW per customer (a 4.6% decrease)
- PY2025 had nine SmartDays (two were minimum dispatch) delivering consistent impacts across events
- The reduction profile was steady throughout the event window, with the largest drop around HE18 and little evidence of program-level pre-cooling or snapback
- SmartRate reliably reduces load during event hours with a response pattern that aligns with a price-only program with limited automation

**2.1.1 Comparisons to Previous Years**

Table 2-2 shows trends in the ex-post load impacts starting in the 2020 program year. Enrollment decreased from 2020 through 2022, followed by a modest increase in SmartRate™ program in PY2023–PY2024 and a subsequent decline in PY2025.

Per-customer load impact in PY2025 is slightly lower than in PY2024, at 0.09kW compared to 0.11kW. The shift in the on-peak window from 2–7 PM to 4–9 PM 2022 onwards likely drove the overall decline observed in PY2022–PY2025 relative to PY2020–PY2021.

Table 2-2 Ex-Post Load Impacts for the Average Event Day Over Time

Program Year	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	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
2023 (4–9 PM)	45,558	108.5	5.2	2.38	0.11	4.7%	92
2024 (4–9 PM)	47,920	119.5	5.2	2.49	0.11	4.4%	96
2025 (4–9 PM)	45,242	90.0	4.1	1.99	0.09	4.6%	94

Notably, the per-customer reference load in PY2025 is lower than in prior years. This pattern appears in both the aggregate and per-customer level. For example, the per-customer reference load in PY2025 is 1.99 kW, compared to 2.49 kW in PY2024, 2.38 kW in PY2023, and 2.41 kW in PY2022. This reduction is likely attributable to lower temperatures and a milder summer with fewer consecutive hot days.

Table 2-3 compares the forecasted PY2024 Ex-Ante (for PY2025) results with the PY2025 Ex-Post performance. The PY2024 Ex-Ante (2025) forecast assumed 43,975 participating accounts, while PY2025 Ex-Post enrollment increased to 45,242 accounts.

Table 2-3 PY2025 Ex-Post vs. PY2024 Ex-Ante (PG&E 1-in-2) Estimate of PY2025

Program Year	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
<b>PY2024 Ex-Ante (2025)</b>	43,975	103.8	4.8	2.36	0.11	4.6%	95
<b>PY2025 Ex-Post</b>	45,242	90.0	4.1	1.99	0.09	4.6%	94

The ex-ante forecast for PY2024 estimated aggregate reference loads of 103.8 MW and an aggregate load impact of 4.8 MW. In contrast, PY2025 Ex-Post results show an aggregate reference load of 90.0 MW and a load impact of 4.1 MW. On a per-customer basis, the PY2024 forecast anticipated a reference load of 2.36 kW and a load impact of 0.11 kW, whereas the PY2025 Ex-Post results indicate a per-customer reference load of 1.99 kW and a load impact of 0.09 kW. Despite differences in absolute loads, the percentage load impact remained consistent at 4.6% in both the forecast and observed results. Average event temperatures were similar across the two data points, with the PY2024 Ex-Ante forecast assuming 95°F in the PG&E 1-in-2 scenario and the PY2025 Ex-Post events averaging 94°F.

**Comparison to Previous Years**

- PY 2025 impacts: 4.1 MW, down from 5.2 MW in PY2024, while the percent reduction increased slightly (4.6% vs. 4.4%).
- PY2025 reference load was lower (e.g., 1.99 kW/customer vs 2.49 in PY2024), consistent with milder summer conditions
- Lower absolute MW impact appears driven by lower baseline load

## 2.2 Ex-Post Savings by Subgroups

This section presents all load impact estimates for each of the following customer segments: LCA, bill protection status, CARE enrollment, dual-program enrollment, high fire-threat district status, and TOU enrollment, along with the distribution of impacts for each segment. In addition to these established subgroupings, this year’s analysis also includes segmentation by FERA enrollment, SGIP (i.e., with or without receiving a SGIP incentive), and NEM NBT status (whether or not participant is on net metering net billing rate, i.e. PV solar customer). All these customer segments are discussed in the subsections that follow.

### 2.2.1 Local Capacity Area

Table 2-4 summarizes the aggregate ex-post results for the average event day for PG&E's eight LCAs. 25% of all participants belong to the Greater Fresno Area, and 21% in the “Other” category. These two LCAs combined contributed 49% of the total SmartRate™ impact (2.0 MW).

Table 2-4 Ex-Post Savings by Load Capacity Area

LCA	# Accounts	Reference Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp (°F)
Greater Bay Area	6,361	9.3	0.5	4.9%	84
Greater Fresno Area	11,092	26.4	1.1	4.2%	98
Humboldt	166	0.1	0.0	6.2%	67

Kern	5,100	12.1	0.5	4.3%	99
North Coast and North Bay	2,679	3.4	0.2	6.0%	86
Sierra	5,038	9.4	0.5	4.8%	93
Stockton	5,101	10.7	0.5	4.4%	94
Other	9,705	18.6	0.9	4.9%	95

Figure 2–2 shows each LCA’s share of the program enrollment, impacts, and reference load. As expected, the LCAs’ shares of impacts align closely with their shares of the enrollment population, showing that customers generally reduced their demand by the same distribution across LCAs. Notably, customers in the Greater Bay Area saved less, on average, compared to other LCAs, while customers in the Greater Fresno Area and Kern tended to save more. This reflects the differences in the temperatures experienced by customers in these LCAs during the average event.

Figure 2–2 LCA-Specific Contributions to Average Event Day Impacts



## 2.2.2 Other Customer Segments

Table 2–5 summarizes ex–post estimates for the average event day for each customer segment described in [PY2025 Participation](#).

Table 2–5 Ex-Post Savings by Segment

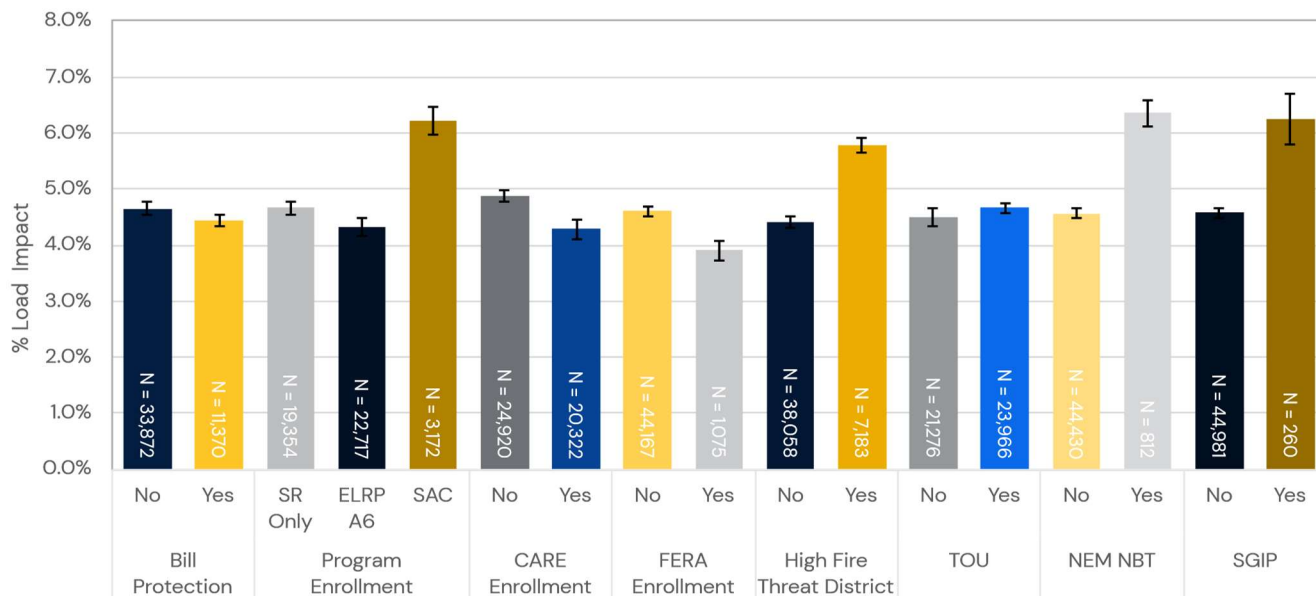
Segment	Status	# Accounts N=45,242	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
			Reference Load	Load Impact	Reference Load	Load Impact		
Bill Protection	No	33,872	66.3	3.1	1.96	0.09	4.6%	94
	Yes	11,370	23.7	1.1	2.08	0.09	4.4%	94
Program Enrollment	SmartRate Only	19,354	36.9	1.7	1.91	0.09	4.7%	93
	Dual – ELRP A6	22,717	47.4	2.0	2.09	0.09	4.3%	94
	Dual – Smart AC	3,172	5.8	0.4	1.83	0.11	6.2%	95
CARE Enrollment	No	24,920	45.2	2.2	1.82	0.09	4.9%	92
	Yes	20,322	44.8	1.9	2.21	0.09	4.3%	95
FERA Enrollment	No	44,167	87.5	4.0	1.98	0.09	4.6%	94
	Yes	1,075	2.6	0.1	2.38	0.09	3.9%	95
High Fire Threat District	No	38,058	79.2	3.5	2.08	0.09	4.4%	94
	Yes	7,183	10.8	0.6	1.51	0.09	5.8%	92
TOU	No	21,276	44.7	2.0	2.10	0.09	4.5%	95

	Yes	23,966	45.4	2.1	1.89	0.09	4.7%	92
NEM NBT	No	44,430	89.2	4.1	2.01	0.09	4.6%	94
	Yes	812	0.9	0.1	1.06	0.07	6.4%	94
SGIP	No	44,981	89.8	4.1	2.00	0.09	4.6%	94
	Yes	260	0.2	0.0	0.84	0.05	6.2%	92

<sup>a</sup> Since customers can belong to more than one segment, values should not be summed across segments.

Figure 2-3 shows each subgroup’s per-customer load impacts on the average event day and corresponding (+/-)90% confidence intervals. Non-overlapping confidence intervals within segments reveal that these customers reduced their demand at statistically different rates, within the same segment(s).

Figure 2-3 Ex-Post Impacts Per Customer for the Average Event Day by Subgroup



<sup>a</sup> Error bars show the 90% confidence interval around estimated impacts.

### 2.2.2.1 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 the implications of PG&E’s Bill Protection Guarantee on load impacts.

25% of PY2025 SmartRate™ participants qualified for the Bill Protection Guarantee, an increase from the 21% in PY2024, which aligns with the steady increased SmartRate™ enrollments over the previous year.

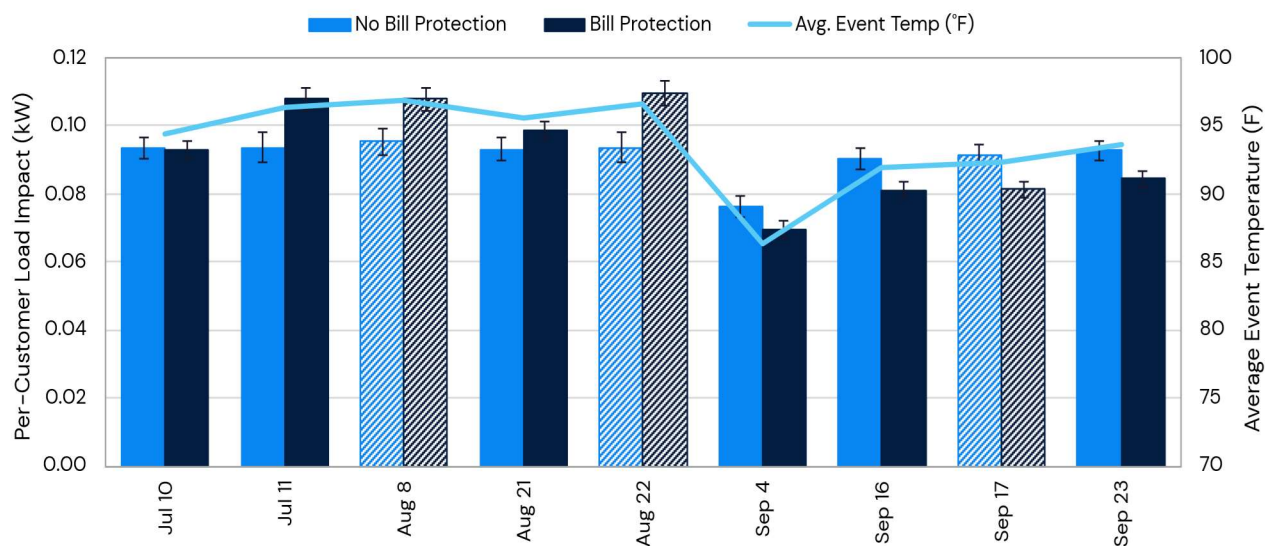
Table 2-6 shows the per-customer reference loads and load impacts by bill protection status on an average event day, while Figure 2-4 provides the impacts estimated for each SmartDay™.

Table 2-6 By Bill Protection: Ex-Post Savings on an Average SmartDay™

Event Date	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
No Bill Protection	33,872	66.3	3.1	1.96	0.09	4.6%	94
Bill Protection	11,370	23.7	1.1	2.08	0.09	4.4%	94

Both groups show some correlation between impacts and temperatures. Participants under the Bill Protection guarantee consistently generated higher per-customer impacts on all event days. The difference in impacts between the two groups is even greater on hotter days, indicating a higher correlation between impacts and temperatures for the bill-protected group.

Figure 2-4 Bill Protection: Ex-Post Savings on each SmartDay™



<sup>a</sup> Concurrent SmartAC™ events days are striped. SmartAC™ events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.

<sup>b</sup> Error bars show the 90% confidence interval around estimated impacts.

In total, customers with bill protection contributed 25% of total SmartRate™ MW impacts during the average SmartDay™ event hour.

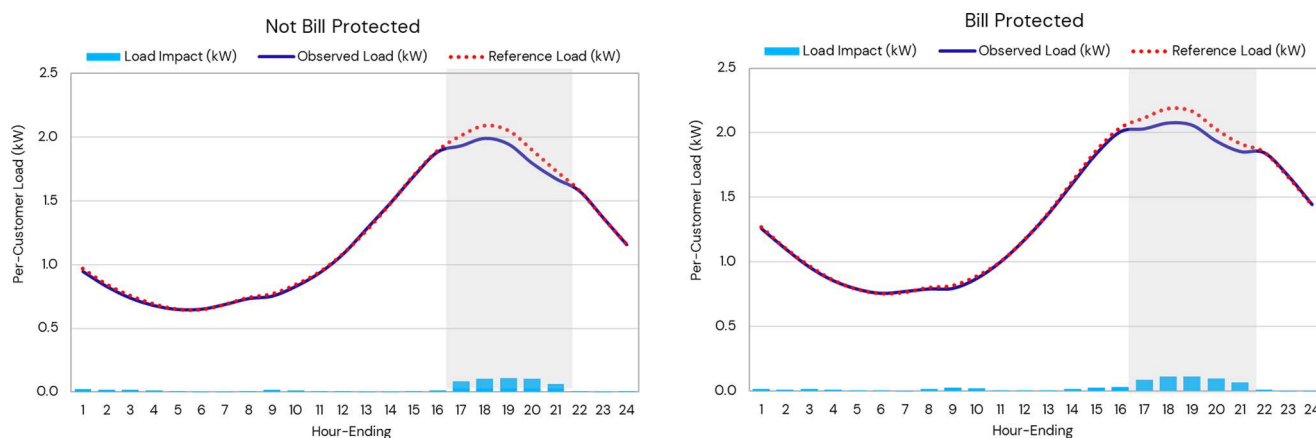
Figure 2-5 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day based on bill protection status. ICF modeled these customer segments separately, based on the assumption that customers would respond differently depending on whether they were guaranteed protection on their bills when participating. We observed the following:

**Bill Protection**

- ~25% of participants qualified for bill protection (up from ~21% in prior year)
- Bill-protected customers delivered slightly lower impacts (4.4% vs 4.6%) than non-protected customers
- Bill protection may modestly dampen incentives to respond, but differences are small

- Customers in both segments did not meaningfully shift load to hours outside the event window. A slight snapback effect was observed immediately following the event.
- The two customer segments exhibit different baseline consumption patterns in the absence of an event, both in overall magnitude and in the general shape of the reference load.
- The Bill Protected segment demonstrates a slightly higher reference load, particularly after HE18, with a flatter load shape later in the day. In contrast, the Not Bill Protected segment shows a more pronounced peak and a steeper decline following the peak period.
- The shape of customer impacts differs between the two segments. Participants without Bill Protection achieved their highest load reductions during the second hour of the event window (HE18).
- Participants with Bill Protection achieved their highest reductions in the third hour (HE19). Differences in impact magnitudes are visible in the relative bar heights.

Figure 2-5 Bill Protection: Per-Customer Load Profiles on an Average Event Day



### 2.2.2.2 Dual Program Enrollment

Next, we present the implications of SmartRate™ customers dual enrolling in PG&E’s other demand response programs. Participants may be dually enrolled in SmartAC™ or Emergency Load Reduction Program (ELRP A6):

- The SmartAC™ program installs devices on participants’ air conditioner (AC) units that allow PG&E to remotely reduce the units’ capacities during both SmartAC™ and SmartRate™ events.
- The ELRP pilot is a statewide initiative that targets various customer segments and end uses for incremental load reductions. PG&E automatically enrolled residential CARE and FERA rates as well as participants of PG&E’s Home Energy Reports (HER) program into the pilot. Customers not in these segments may opt-in to the program.

In PY2025, dually enrolled participants comprised 57% of all SmartRate™ participants and contributed 59% of total MW impacts during the average SmartDays™ event hour.

Table 2-7 reveals differences in the magnitude of per-customer load impacts among these three segments:

- Dual SmartAC™ customers generated the highest percentage load impacts, with 0.11 kW, or 6.2% of their reference load.
- Customers dually enrolled to SmartAC™ respond to price signals via a switch; hence they generate a higher impact than those without this automated response capability.
- SmartRate™ only customer achieved savings of 0.09 kW per customer, or 4.7% of their reference load, compared to 0.09 kW (4.3% of reference load) for their dually enrolled ELRP A6 counterparts.

- Customers dually enrolled in ELRP A6 delivered the same percentage demand reductions during the average PY2025 SmartDay™ event hour (4.3%) as they did in PY2024 (4.3%).

Table 2-7 By Dual-Program Enrollment: Ex-Post Savings on an Average SmartDay™

Event Date	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
SmartRate™ Only	19,354	36.9	1.7	1.91	0.09	4.7%	93
Dual – ELRP A6	22,717	47.4	2.0	2.09	0.09	4.3%	94
Dual – SmartAC™	3,172	5.8	0.4	1.83	0.11	6.2%	95

The remainder of this section explores the effect of SmartRate™ for SmartAC™ and ERLP A6 dual participants.

### 2.2.2.2.1 Dual-Enrollment in SmartAC™

The SmartAC™ program calls emergency-based and Sub-LAP-level events lasting between one and six hours per day. Customers enrolled in the SmartAC™ program have a switch installed on their air conditioning (AC) unit (including heat pumps), which allows PG&E to remotely signal cooling equipment to run below maximum output.

During SmartDays™, PG&E also remotely controls participants' cooling equipment via the SmartAC™ switch such that 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 PY2025 analysis results are consistent with this segment’s historical performance, except for PY2024, in which the reduction of savings was potentially attributed to an issue with the dispatch signals.

Historically, participants dually enrolled in SmartAC™ have achieved significantly higher savings, often more than double that of participants in other groups. This year, participants dually enrolled in SmartAC™ saved an average of 6.2%, compared to 4.7% for participants enrolled solely in SmartRate™ (See Table 27)

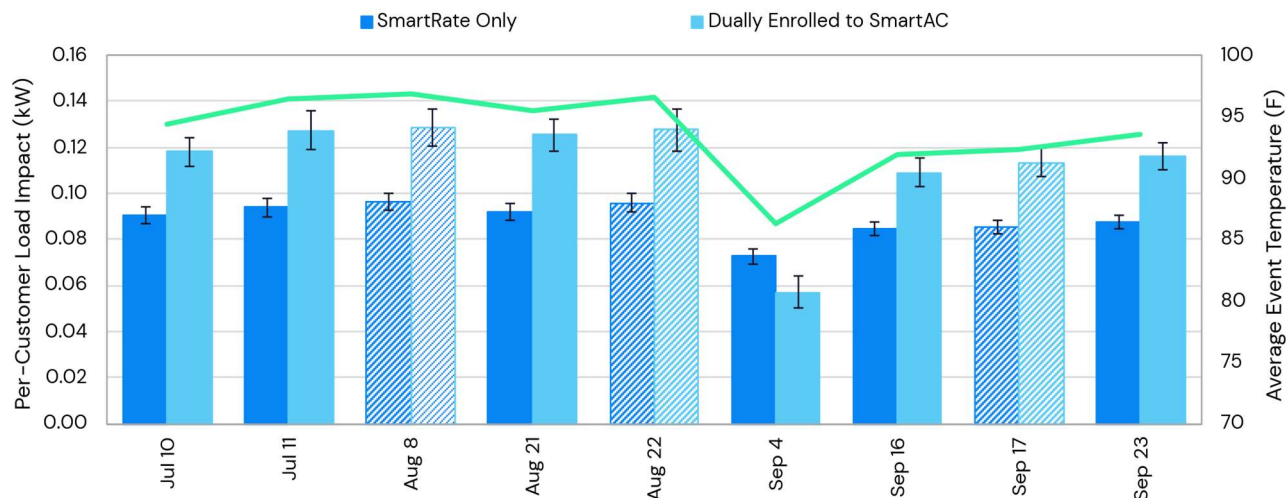
Figure 2-6 shows the per-customer ex-post load impacts for each event day for SmartRate™-only and dually enrolled participants. We observed the following:

- As discussed, participants dually enrolled in SmartAC™ exhibit higher per-customer load impacts compared to singly enrolled participants, as their response to events is supported and automated by PG&E’s control of their AC units.
- Both dually enrolled to SmartAC™ and SmartRate™ Only group show correlation between impacts and correlations. Except for the mild September 4 event day, participants dually enrolled to SmartAC™ exhibit higher average event impacts compared to the SmartRate™ Only participants.

**Program Enrollment**

- Dual-enrolled customers comprised ~57% of participants and contributed ~59% of total MW impacts
- SmartAC duals show the highest % impacts (~6.2%) vs SmartRate-only (~4.7%) and ELRP A6 dual (~4.3%)
- Technology-enabled response (SmartAC switch) yields higher reductions than price-only response

Figure 2-6 SmartAC™ Enrollment: Ex-Post Savings on each SmartDay™

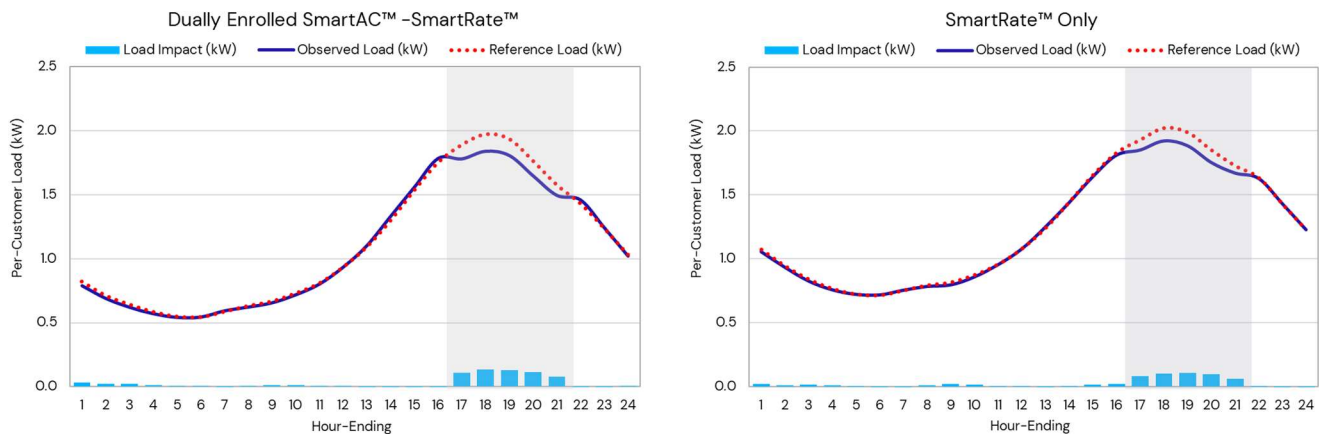


<sup>a</sup> Concurrent SmartAC events days are striped. SmartAC™ events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.  
<sup>b</sup> Error bars show the 90% confidence interval around estimated impacts.

Figure 2-7 on the following page compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for participants of SmartRate™ only and those dually enrolled in SmartAC™.

- SmartRate™-only customers did not substantially shift their load to hours outside the event window in either segment, except for some snapback immediately following the event. In contrast, dually enrolled SmartAC™ customers exhibited some (albeit minor) pre-cooling effects and snapback usage patterns, typical of technology-enabled participants.
- The average SmartAC™ dual-enrolled customer had a similar reference load consumption than the average SmartRate™-only customer, which is different than with previous years, in which SmartAC™ dual-enrolled customer tend to have a higher reference load. While AC saturations are likely high in PG&E's territory, the requirement that homes have central cooling to be eligible for the SmartAC™ program could lead this group to consume slightly more, on average.
- The shape of customer impacts is similar in both segments, despite the difference in pre-cooling and snapback for SmartAC™. Both groups achieved the highest impact in the second hour (HE18) of the event window—this coincides with the peak of their reference load, i.e., when customers have the greatest capacity to reduce their consumption.

Figure 2–7 SmartAC™ Dual-Enrollment: Per-Customer Load Profiles on an Average Event Day



**2.2.2.2.2 Dual-Enrollment in ELRP A6**

ELRP is a five-year pilot implemented statewide in 2021 that encourages customers to reduce their demand during times of high stress on the electrical grid. Specifically, it was designed as a last-resort option for curtailing load during grid emergencies. The ELRP A6 pilot is set to conclude after 2025. Other program characteristics follow.

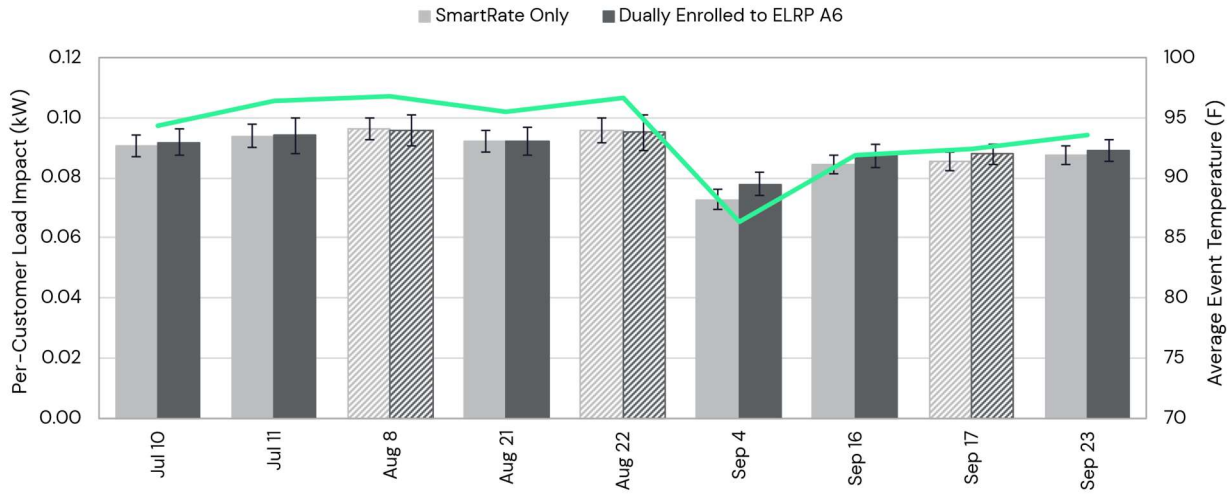
- Events can be dispatched from May through October during the 4–9 PM hours, seven days a week. They are triggered based on the day-ahead CAISO system conditions or day-of grid emergencies.
- Customers receive \$2/kWh in bill credits for responding to dispatched events based on individual customer baseline calculations. They are not penalized for non-response or increasing consumption relative to the calculated baseline.
- Customers receive day-ahead notification of events most often via email, though they can sign up to receive text notifications.
- Per CPUC Decision, PG&E automatically enrolled residential customers on CARE or FERA rates within their territory, as well as participants of PG&E’s HER program, into the pilot. Customers not in these segments may opt-in to the program, including customers in PG&E’s SmartRate™ program.

No ERLP A6 events were dispatched in PY2025.

Figure 2–8 shows the per-customer ex-post load impacts for each event day for SmartRate™-only customers and those dually enrolled in ELRP A6. We observed the following:

- The 90% confidence intervals (shown by the error bars) suggest that some of the observed differences in impacts across SmartDays™ are statistically significant.
- As shown in the graph below, the impacts for these two groups were very comparable for every event day with a range of 0.07 kW to 0.10 kW.
- Like PY2023 and PY2024, there were also no ELRP A6 event dispatched in PY2025.

Figure 2–8 ELRP A6 Dual-Enrollment: Ex-Post Savings on each SmartDay™

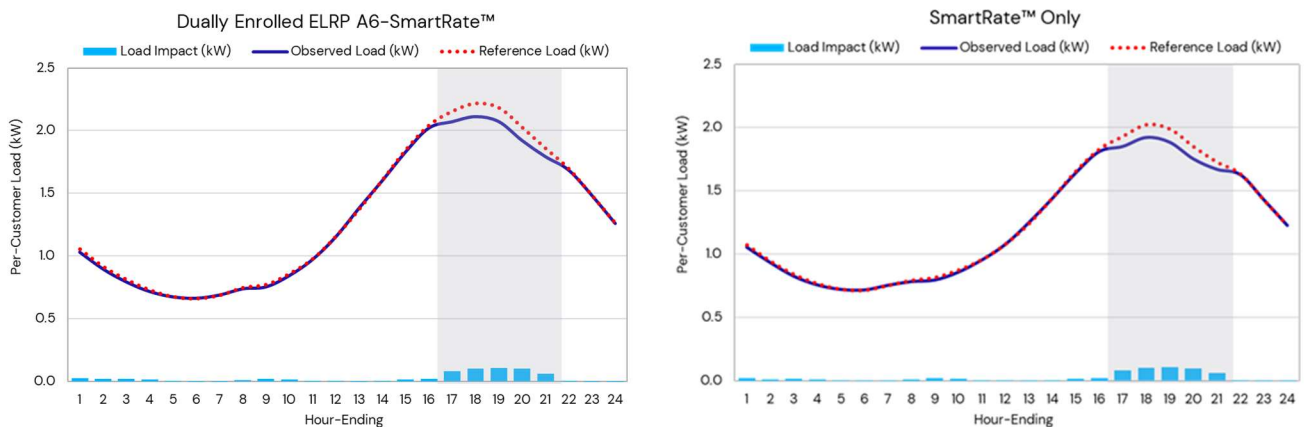


<sup>a</sup> Concurrent SmartAC events days are striped. SmartAC™ events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.  
<sup>b</sup> Error bars show the 90% confidence interval around estimated impacts.

Figure 2–9 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for participants of SmartRate™ only and those dually enrolled in ELRP A6.

- Customers did not substantially shift their load to hours outside the event window in either segment, except for some snapback immediately following the event.
- The average ELRP A6 dual-enrolled customer had slightly higher reference load consumption than the average SmartRate™-only customer, consistent with previous years. Because customers on CARE comprise much of the ELRP A6 dual-enrollment segment, it is likely a less efficient group.
- The shape of customer impacts is similar in both segments, with the highest impacts achieved in the second hour (HE18) of the event window—this generally coincides with the peak of their reference load, i.e., when customers have the greatest capacity to reduce their consumption. The small difference in the magnitudes of impacts is highlighted here, with differences between the size of the bars being difficult to distinguish.

Figure 2–9 ELRP A6 Dual-Enrollment: Per-Customer Load Profiles on an Average Event Day



### 2.2.2.3 CARE Enrollment

Before CARE customers were defaulted in the ELRP A6 pilot, CARE and non-CARE performed similarly during SmartRate™ events. However, defaulting CARE customers into ELRP A6 severely impacted the average performance of this segment in PY2022. Table 2-8 shows that while some effects of the initial default still linger, CARE customers performed a lot better in PY2025, delivering impacts of 4.3% (compared to 2.6% in PY2022). This is very close to the average non-CARE customer, who achieved reductions of 4.9%. Because CARE customers had higher reference loads compared to non-CARE customers, both segments delivered roughly the same impact on a per-customer kW basis.

Table 2-8 By CARE Status: Ex-Post Savings on an Average SmartDay™

CARE Status	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
Non-CARE Customer	24,920	45.2	2.2	1.82	0.09	4.9%	92
CARE Customer	20,322	44.8	1.9	2.21	0.09	4.3%	95

### 2.2.2.4 FERA Enrollment

Table 2-9 summarizes ex-post load impacts for FERA and non-FERA customers on an average SmartDay™.

PY2025 marks the first time that FERA enrollment status has been examined within the SmartRate™ Evaluation Report. Because FERA participation remains relatively small, only about 1,075 customers in the population, results should be interpreted with appropriate caution. –

Overall, customers not enrolled in FERA achieved average percentage load reductions of 4.6%, compared to 3.9% for FERA participants. Although the percentage impacts differ slightly, both groups delivered similar per-customer kW reductions (0.09 kW). This similarity is largely attributable to the higher reference loads observed among FERA customers (2.38 kW compared to 1.98 kW for non-FERA customers).

Given the limited size of the FERA segment and its introduction as a newly tracked low-income category, these results provide an initial baseline for understanding the performance of FERA customers in SmartRate™ moving forward.

Table 2-9 By FERA Status: Ex-Post Savings on an Average SmartDay™

FERA Status	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
Non-FERA Customer	44,167	87.5	4.0	1.98	0.09	4.6%	94
FERA Customer	1,075	2.6	0.1	2.38	0.09	3.9%	95

### 2.2.2.5 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 PY2025 SmartRate™ participants were located within high fire-threat districts and they contributed 15% of total MW impacts.

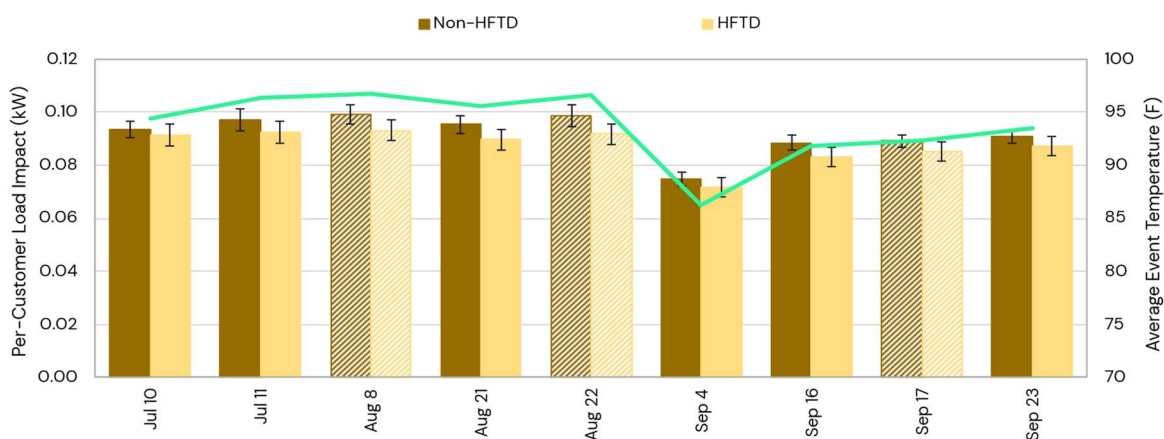
Table 2-10 shows the per-customer reference loads and load impacts by high fire-threat district status on an average event day, while Figure 2-10 provides the impacts estimated for each SmartDay™. On average, we see slightly higher load impacts as a percentage of reference loads for customers in high fire-threat districts (5.8%) compared to customers residing outside of these areas (4.4%), which reflects the substantially lower average customer consumption (reference load) estimated for the high fire-threat district participants.

However, customers delivered similar impacts on a per-customer kW basis on the average event day and consistently across event days. While customers not in a high fire-threat district saved similarly to other, hotter event days, customers in high fire-threat districts produced much smaller impacts on this milder day.

Table 2-10 By High Fire-Threat District Status: Ex-Post Savings on an Average SmartDay™

High Fire-Threat District Status	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
Non-High Fire-Threat District	38,058	79.2	3.5	2.08	0.09	4.4%	94
High Fire-Threat District	7,183	10.8	0.6	1.51	0.09	5.8%	92

Figure 2-10 High Fire-Threat District: Ex-Post Savings on each SmartDay™



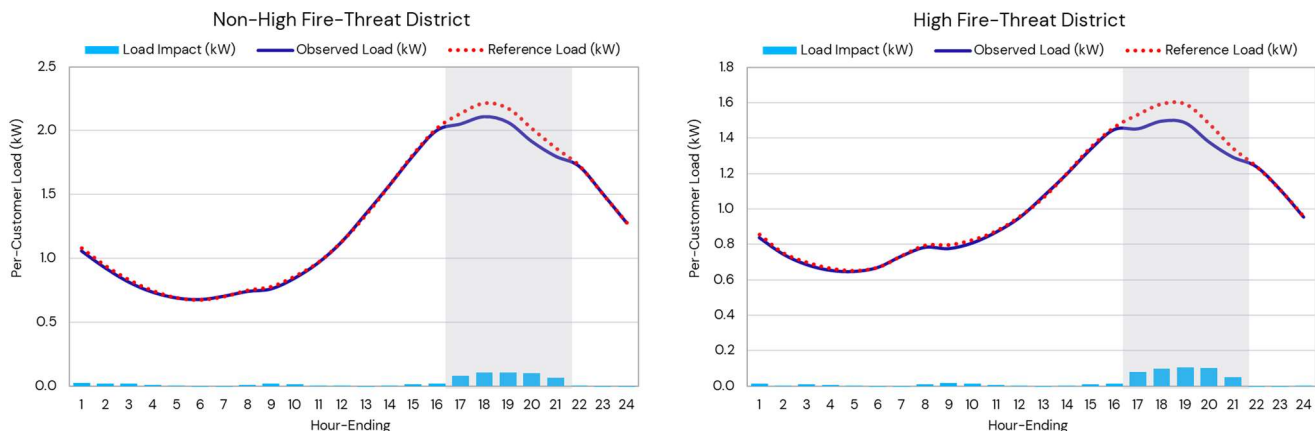
<sup>a</sup> Concurrent SmartAC events days are striped. SmartAC™ events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.

<sup>b</sup> Error bars show the 90% confidence interval around estimated impacts.

Figure 2-11 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for participants belonging to high fire-threat districts and those residing elsewhere.

- Like with other segments, customers did not substantially shift their load to hours outside the event window in either segment.
- The average customer living in a high fire-threat district had much lower reference load consumption than the average customer belonging to other areas, consistent with previous years. Despite this, customers generated similar impacts on a per-customer kW basis, as shown by the size of the bars (shaded in blue) displaying load impacts at the bottom of the charts.
- The shape of customer impacts is also similar in both segments, with the highest impacts achieved in the second hour (HE18) of the event window. This coincides somewhat with the peak of their reference loads, i.e., when customers have the greatest capacity to reduce their consumption.

Figure 2-11 High Fire-Threat District: Per-Customer Load Profiles on an Average Event Day



### 2.2.2.6 Billing Rate and Time-of-Use

SmartRate™ is currently available to customers on the tiered rate (E1) and five TOU rates. Starting in 2021, PG&E began defaulting residential customers onto the TOU-C rate in monthly waves. With TOU-C now the default rate, the share of TOU customers is increasing over time. Consequently, the share of E1 rate enrollment in SmartRate™ remains high as a percentage, at 47% in PY2025, compared to 77% before the defaulting transition that began in 2021. The TOU periods for the different rates are as follows:

- TOU-B (Opt-in customers): Peak pricing on weekdays from 4 to 9 PM. (The TOU-B rate was closed in October 2025 and enrolled customers were transitioned to TOU-D.)
- 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.
- EV2-A (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.
- E-ELEC (Electric Home Rate Plan): Peak pricing every day from 4 to 9 PM with partial peak pricing every day from 3 to 4 PM and 9 PM to 12 AM.

Table 2-11 presents per customer reference loads and load impacts by rate schedule on an average SmartDay™. Figure 2-12 provides the corresponding event-level impacts for TOU vs non-TOU. Across all rates, customers reduced load between 3.4% and 6.4% of their reference load during the average SmartDay™ hour, with one very small rate group (TOU-B; n = 12) exhibiting a higher but statistically unstable percentage reduction.

PG&E’s transition toward TOU pricing continues to shape SmartRate™ enrollment patterns.

- Tiered Rate:
  - **E-1:** The tiered E-1 rate remains the largest segment, with 21,276 customers, down from 26,016 last year.
- Time-of-Use Rate:
  - **TOU-C:** Enrollment in TOU-C, the default TOU rate, increased from 12,656 to 14,220 customers, now representing 31.4% of all SmartRate™ participants.
  - **TOU-D:** Participation in TOU-D also increased, rising from 4,639 to 6,241 customers, consistent with ongoing adoption of TOU rates among higher-use households.

- **TOU-B:** Participation in TOU-B has dropped from 1,634 to just [REDACTED]
- Electrification-oriented rate options likewise expanded.
- **E-ELEC:** Enrollment in E-ELEC increased from 757 to 928 customers,
- **EV2-A:** while EV2-A grew from 1,218 to 1,752, reflecting continued growth in electric vehicle adoption.
- **NEM NBT:** This year also marks the first inclusion of NEM NBT rate, with 812 customers participating in SmartRate™.

As in prior years, the rate groups serving higher-consumption households (E-ELEC, TOU-D, EV2-A) exhibited larger per-customer reference loads. For instance, TOU-D customers averaged 2.61 kW, compared to 1.58 kW for TOU-C and 2.10 kW for E-1. Despite these higher loads, these groups delivered some of the lowest percentage reductions (3.4%–3.5%), a pattern consistent with higher-usage households already shifting load outside the event window under TOU pricing.

Conversely, TOU-C customers, who had among the lowest per-customer reference loads—achieved one of the highest percentage reductions (5.6%), similar to last year’s 5.8%. The new NBT group also showed high percentage impacts (6.4%), though the findings should be interpreted with care due to its relatively small sample size.

E-1 customers continued to demonstrate stable performance, delivering an average reduction of 0.09 kW (4.5%), consistent with long-term SmartRate™ results.

### Rates Insight

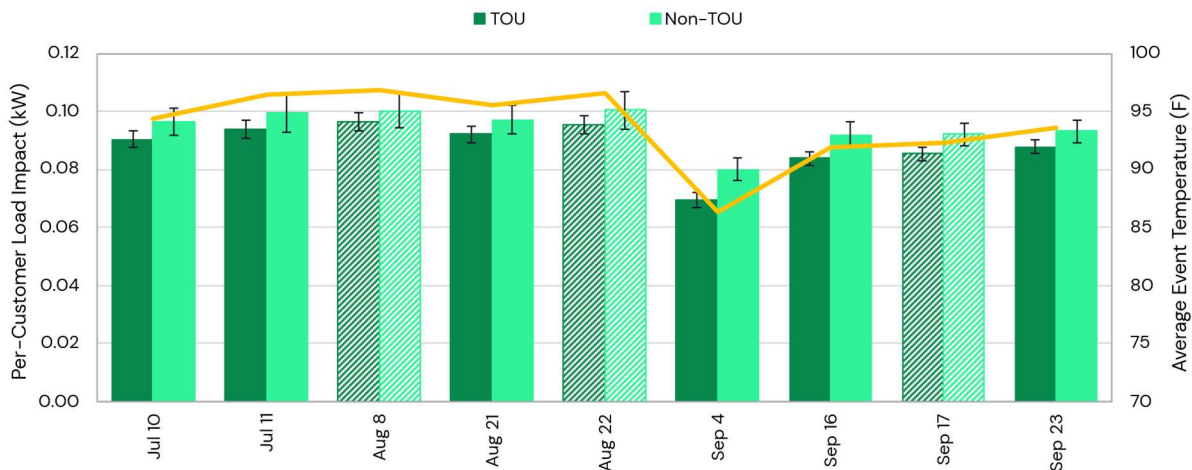
- Enrollment continues shifting from E1 toward TOU/electrification rates (TOU-C now a large share)
- First year inclusion of the NEM NBT rate
- Higher-usage rate groups (TOU-D, E-ELEC, EV2-A) have higher reference loads but lower reductions (~3.4%–3.5%); TOU-C and NBT show higher reductions (~5.6%–6.4%)
- As TOU adoption expands, segment-level forecasting should continue reflecting behavioral + load-shape differences by rate.

Table 2-11 Billing Rate: Ex-Post Savings on an Average SmartDay™

Billing Rate	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
E-1	21,276	44.7	2.0	2.10	0.09	4.5%	95
E-ELEC	928	2.4	0.1	2.58	0.09	3.4%	93
NBT	812	0.9	0.1	1.06	0.07	6.4%	94
<b>TOU-B</b>	<b>12</b>	<b>0.0</b>	<b>0.0</b>	<b>0.40<sup>24</sup></b>	<b>0.07</b>	<b>18.4%</b>	<b>82</b>
TOU-C	14,220	22.5	1.3	1.58	0.09	5.6%	92
TOU-D	6,241	16.3	0.6	2.61	0.09	3.5%	93
EV2-A	1,752	3.3	0.1	1.86	0.08	4.5%	90

<sup>24</sup> TOU-B rate was discontinued, as of October 2025, customers of the rate were transitioned to TOU-D. Low reference load likely due to low participation count.

Figure 2-12 TOU: Ex-Post Savings on each SmartDay™



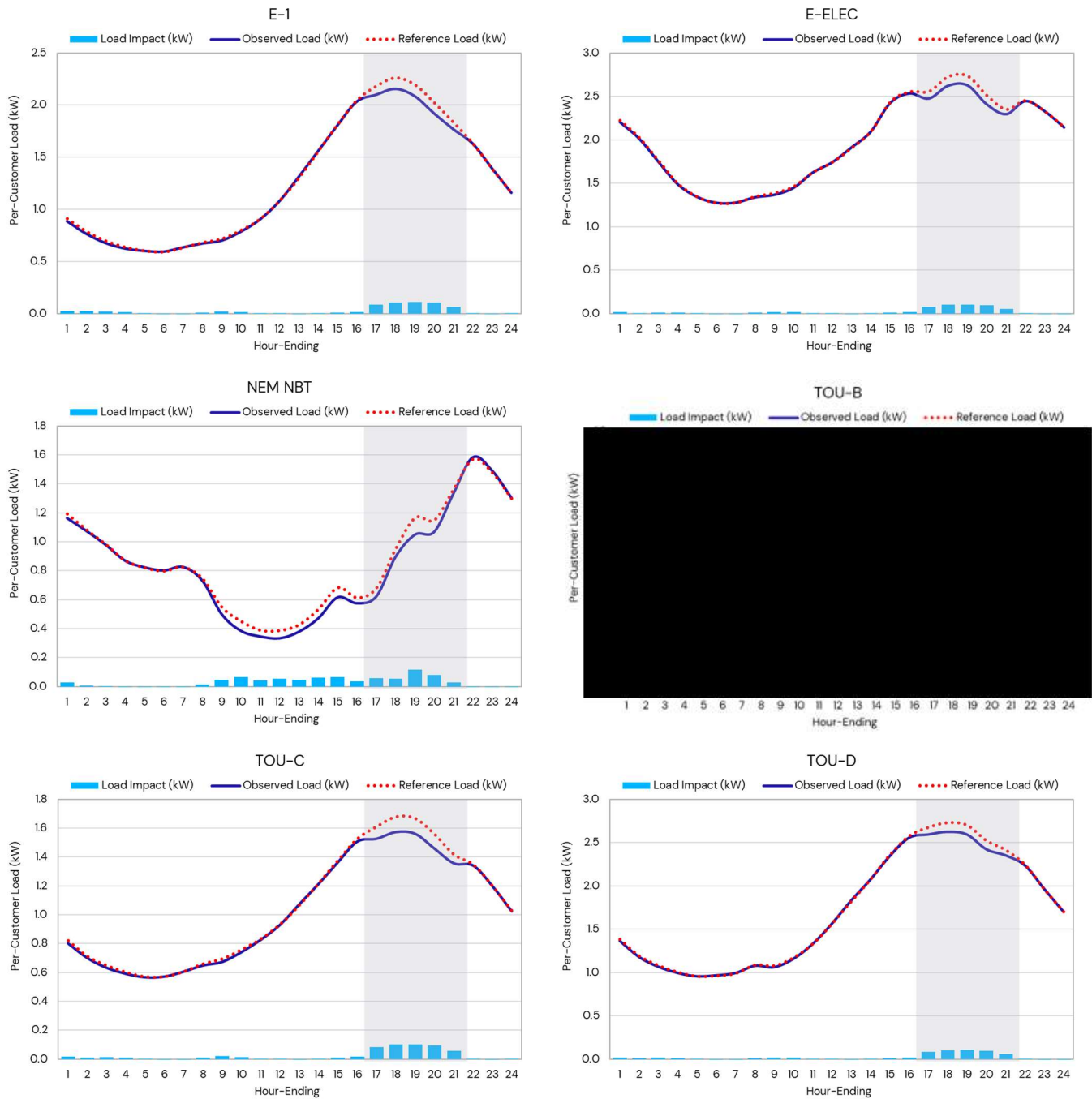
<sup>a</sup> Note: Concurrent SmartAC events days are striped. SmartAC events were dispatched for specific Sub-LAPs and event hours that did not always coincide with the SmartRate™ event window.

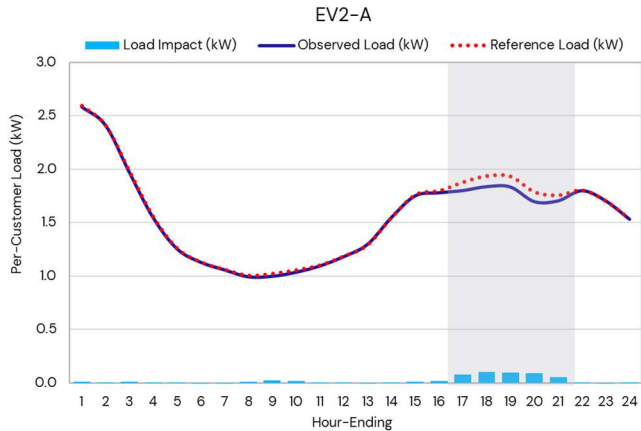
<sup>b</sup> Error bars show the 90% confidence interval around estimated impacts.

Figure 2-13 compares the per-customer hourly reference loads, observed loads, and estimated load impacts on the average event day for participants on each of the six billing rates eligible for SmartRate™ participation.

- The reference loads indicate clear differences in average customer size across the billing rates. E-ELEC, TOU-B, and TOU-D appear to include larger-consuming customers than the other rate groups. This pattern is broadly consistent with the roles of these rates, where TOU-D generally serves higher-usage households and E-ELEC and TOU-B tend to attract customers with electric vehicles or electrified homes.
- Differences in the estimated per-customer load impacts are reflected in the relative bar heights, with customers on E-1 and TOU-C showing some of the larger modeled reductions during the event window.
- The modeled shapes of customer impacts look similar across the standard and TOU rate groups, with the largest reductions occurring in the second hour of the event window (HE18). This timing aligns with the point where reference loads generally peak, when customers may have more load available to reduce.
- The NEM NBT and TOU-B groups show the most irregular impact shapes. For NEM NBT, this may reflect behind-the-meter generation—most customers appear to have solar, and some may have storage—which produces atypical net load patterns. The pattern for TOU-B is likely influenced by the very small sample size (n = 12). EV2-A shows a distinct early-morning peak, which is consistent with a rate design that encourages overnight EV charging.

Figure 2-13 Billing Rate: Per-Customer Load Profiles on an Average Event Day





### 2.2.2.7 SGIP Status

PY2025 is the first year that SmartRate™ participants with Self-Generation Incentive Program (SGIP) systems are reported as a distinct segment in this evaluation. SGIP has historically supported a range of distributed energy technologies—including CHP, fuel cells, solar PV, and wind—but for residential customers in this context, SGIP participation primarily indicates the presence of battery storage, either standalone or paired with PV. SGIP recipients are required to enroll in a demand response program, and SmartRate™ is one of the eligible options.

As shown in Table 2–12, the SGIP segment remains relatively small, with 260 customers compared to 44,981 customers without SGIP systems. While the group is still emerging, these PY2025 results provide a useful early indication of how storage-enabled households may respond to SmartRate™ events going forward.

On average SmartDay™ events, customers without SGIP systems delivered a 4.6% reduction from a per-customer reference load of 2.00 kW, corresponding to a 0.09 kW load impact. Customers with SGIP systems show a smaller per-customer impact in absolute terms—0.05 kW—primarily because they have lower reference loads (0.84 kW). However, on a percentage basis, SGIP customers exhibited an estimated 6.2% reduction, which is higher than the non-SGIP group. Given the small sample size and the diversity of underlying technologies, these results should be interpreted cautiously but will serve as a useful baseline for assessing SGIP customer performance in future years.

**SGIP Performance**

- First year segmenting SGIP (battery-associated) participants; small group (~260) but shows higher impacts (~6.2%) with lower reference load
- Storage-enabled customers may show distinct response patterns; continue tracking as this cohort grows.

Table 2–12 By SGIP Status: Ex-Post Savings on an Average SmartDay™

SGIP	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
<b>No SGIP</b>	44,981	89.8	4.1	2.00	0.09	4.6%	94
<b>SGIP</b>	260	0.2	0.0	0.84	0.05	6.2%	92

### 3 Ex-Ante Evaluation Results

This section summarizes the results of the ex-ante analysis, where ICF used the ex-post models to forecast SmartRate™ impacts through 2036 under multiple weather scenarios. For 2025 and beyond, the resource adequacy (RA) measurement hours are 5 PM – 10 PM in all months except June–October, when the hours are 4 PM – 9 PM.<sup>25</sup> We refer to the RA measurement hours as the RA window. Specifically, we met the following objectives of the ex-ante load impact analysis:

- Develop hourly load impact estimates for the average customer and all customers in aggregate for the RA window.<sup>26</sup>
- Estimate impacts for each year over an 11-year<sup>27</sup> horizon based on PG&E's and CAISO's 1-in-2 weather conditions for each monthly system worst day.
- Provide program-specific ex-ante estimates by forecasting SmartRate™ impacts without considering the effects of dual-enrollment in other demand response programs, i.e., assuming no SmartAC™ or ELRP A6 events are dispatched in future years.
- Avoid double-counting impacts attributable to SmartRate™ and other demand response programs by providing portfolio-adjusted estimates, i.e., assuming SmartAC™ or ELRP A6 events are dispatched in future years, if necessary.

As part of the ex-ante evaluation, ICF worked with PG&E staff to develop the following key approaches and assumptions:

- **ICF used a combined weighted PY2025 and PY2024 ex-post models to forecast the 11-year SmartRate™ per-customer impacts year-round.** The RA window coincides with the SmartRate™ event window in only in summer months. ICF shifted impacts to align with the reference loads estimated during these hours.
- **For all participant combinations that were also assessed in the 2024 ex-post SmartRate™ evaluation,** ICF applied a weighted average of the ex-post results of the PY2024 and PY2025 evaluations to form the ex-ante results in 2025.<sup>28</sup>
- **PG&E provided an enrollment forecast by customer segment, LCA, and sub-LAP,** which ICF used to aggregate per-customer impacts to the program level.
- **All dually enrolled ELRP A6 customers rejoined the SmartRate™ only group starting in January 2026,** when the ERLP A6 pilot is set to close.
- **All dually enrolled SmartAC™ customers rejoined the SmartRate™ only group starting in January 2029,** when the SmartAC™ program is set to close.

#### Enrollment Forecast Assumptions:

PG&E's current enrollment assumptions for SmartRate™ and related programs include the following:

- SmartRate™ participation increases by 0.8% in 2026, followed by an average annual decline of –3% from 2026–2028, which contrasts with PY2022–PY2024 trends.
- After 2028, enrollment is expected to increase by 1.4% in 2029 and then grow at an average rate of 0.5% annually through 2036.

<sup>25</sup> CPUC Energy Division, LIP Filing Guide v6.1 (March 5, 2025)

<sup>26</sup> The RA window is 5 PM to 10 PM for all months, except June – October, when the window is 4 PM to 9 PM.

<sup>27</sup> ICF included the PY2025 back cast as part of the ex-ante impact analysis.

<sup>28</sup> The main exceptions to this were SGIP and NEM NBT participants who were only assessed in the 2025 evaluation.

- Based on PY2025 proportions, 25% of customers are expected to transition from bill-protected to non-bill-protected status.
- ELRP A6 enrollment remains constant until the program sunsets in November 2025, after which customers migrate to single-enrolled SmartRate™ status.
- SmartAC™ dual enrollments are expected to be fully phased out of SmartRate™ by the end of 2028.

### 3.1 Program-Specific Ex-Ante Impacts

Table 3-1 summarizes the aggregate and per-customer load impact forecasts for SmartRate™ participants on an August Worst Day in 2026. The table includes impact forecasts under the 1-in-2 weather scenarios for both PG&E and CAISO peaks.

We forecasted high per-customer impacts for participants dually enrolled in SmartAC™ compared to the SmartRate™ Only group, contributing nearly 8% of the aggregate impact (PG&E 1-in-2 weather scenario) despite accounting for only 5% of the total enrollment population – a finding likely due to a technology-enhanced response.

Table 3-1 Typical Event Day Impacts by Program Enrollment: 2026, RA Window

Program Enrollment	# Accounts	Aggregate Impact (MW)		Per Customer Impact (kW)	
		PG&E Peak	CAISO Peak	PG&E Peak	CAISO Peak
		1-in-2 (95 °F)	1-in-2 (96 °F)	1-in-2 (95 °F)	1-in-2 (96 °F)
<b>SmartRate™ Only</b>	42,168	4.1	4.1	0.10	0.10
<b>Dually Enrolled – SmartAC™</b>	2,381	0.4	0.4	0.15	0.15
<b>Total</b>	<b>44,549</b>	<b>4.4</b>	<b>4.5</b>	<b>0.10</b>	<b>0.10</b>

Figure 3-1 shows PG&E’s annual enrollment forecast and the associated aggregated load impact forecasts for the PG&E 1-in-2 weather scenario on a typical event day, including the 2025 backcast. Overall, PG&E expects enrollment to decrease through the 11-year horizon without any planned marketing efforts to offset program attrition over time.

We see the effects of the ELRP A6 pilot ending in both forecasts as these customers transition back into the SmartRate™ only segment. ICF assumed that ELRP A6 participants would maintain their impacts through December 2025. Additionally, SmartAC™ dual participants are expected to phase out by the end of 2028, as only customers enrolled prior to October 26, 2018 can be on both programs simultaneously. Customers who are dually enrolled in both SmartAC™ and SmartRate™ will remain in that status until the conclusion of the 2028 event season, after which they’ll transition to being singly enrolled in SmartRate™.

Figure 3-1 Enrollment and Impact Forecast: PG&E 1-in-2, August Worst Day, 2025 – 2036, RA Window

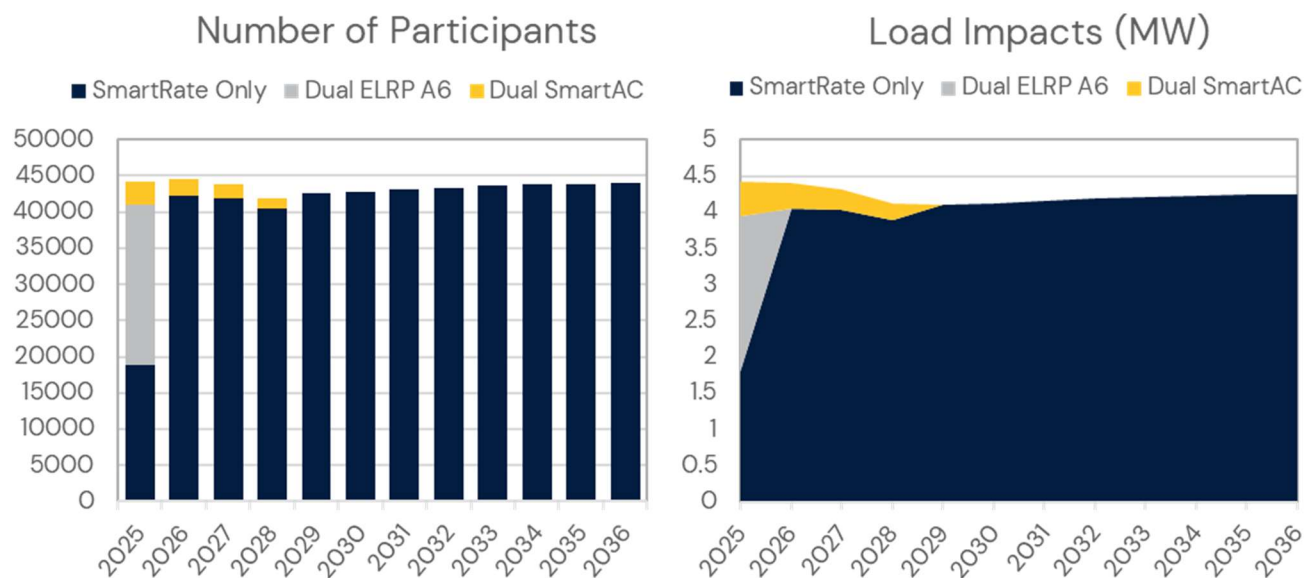


Table 3-2 shows the per-customer load impacts estimated during the RA window for PG&E 1-in-2 monthly peak days in 2026 for each of the program enrollment segments. Load impact estimates for RA window are required for non-summer months (October – May) even though PG&E only calls summer-month events. We estimated load impacts for non-summer months by applying the hourly percentage impacts for a typical event day during the SmartRate™ event window to the estimated impacts during non-summer months.<sup>29</sup>

Table 3-2 Per-Customer Load Impacts on PG&E 1-in-2 Monthly Peak Days, 2026, RA Window

Month	SmartRate™ Only Impacts		Dually Enrolled – SmartAC™ Impacts		Overall	
	kW	%	kW	%	kW	%
January	0.04	3.5%	0.04	4.6%	0.04	3.5%
February	0.03	3.4%	0.03	4.5%	0.03	3.4%
March	0.03	3.4%	0.03	4.6%	0.03	3.4%
April	0.04	3.4%	0.04	4.7%	0.04	3.5%
May	0.05	3.5%	0.05	5.0%	0.05	3.6%
June	0.10	4.3%	0.16	7.7%	0.10	4.5%
July	0.10	4.2%	0.16	7.4%	0.10	4.4%
August	0.10	4.2%	0.15	7.3%	0.10	4.4%
September	0.09	4.3%	0.12	6.8%	0.09	4.4%
October	0.06	4.5%	0.06	5.3%	0.06	4.6%
November	0.03	3.4%	0.03	4.5%	0.03	3.4%
December	0.04	3.4%	0.04	4.6%	0.04	3.5%

<sup>29</sup> Non-summer months baselines are estimates using a separate regression model.

Note that the SmartRate™ event window (4–9 PM) coincides with the RA window only in summer months<sup>30</sup>, whereas the RA window spans 5 PM to 10 PM for the rest of the year. This shift in hours results in slightly lower impacts during these months' peaks, compared to other non-summer months.

## 3.2 Portfolio-Adjusted Ex-Ante Impacts

The estimated program-specific ex-ante impacts forecast savings of the SmartRate™ program without considering the effects of other demand response programs. To avoid double-counting impacts for dually enrolled customers across all the program ex-ante forecasts, ICF provided portfolio-adjusted forecasts, which follow a portfolio hierarchy structure predetermined by PG&E.

Table 3-3 shows the program and portfolio-adjusted impacts for the PG&E 1-in-2 weather scenario for 2026. For each program, we used the following assumptions to develop the portfolio-adjusted impacts:

- ICF assumes that, for customers dually enrolled in SmartAC™ and SmartRate™, all load shed observed on SmartRate™ event days is fully attributable to SmartAC™. This shift reflects the recent discovery that the DLC switch is enabled during all SmartRate™ event days, in addition to SmartAC™ event days. Because the switch is active in both cases, there is no meaningful difference in load response between SmartAC™ only participants and those enrolled in both programs. Therefore, applying a 0% incremental SmartRate™ effect for dually enrolled customers is considered reasonable.<sup>31</sup>
- Since ELRP A6 was sunset after December 2025, ICF did not include ELRP A6 participants in the program or portfolio results.

Table 3-3 Program-Level vs. Portfolio-Adjusted Load Impacts: PG&E 1-in-2, Monthly System Worst Day, 2026, RA Window

Month	Program-Level Load Impacts (MW)			Portfolio-Adjusted Load Impacts (MW)		
	SmartRate™ Only	Dually Enrolled SmartAC™	Total	SmartRate™ Only	Dually Enrolled SmartAC™	Total
January	1.57	0.11	1.68	1.57	0.11	1.68
February	1.42	0.09	1.51	1.42	0.09	1.51
March	1.40	0.09	1.49	1.40	0.09	1.49
April	1.70	0.11	1.81	1.70	0.11	1.81
May	2.00	0.13	2.13	2.00	0.00	2.00
June	4.27	0.40	4.67	4.27	0.00	4.27
July	4.19	0.39	4.57	4.19	0.00	4.19
August	4.05	0.35	4.41	4.05	0.00	4.05
September	3.82	0.29	4.11	3.82	0.00	3.82
October	2.50	0.13	2.63	2.50	0.00	2.50
November	1.33	0.07	1.40	1.33	0.07	1.40
December	1.56	0.09	1.65	1.56	0.09	1.65

<sup>30</sup> Summer months are defined as June, July, August, September, and October.

<sup>31</sup> In previous evaluations, ICF ran simulations to predict the incremental effect of dual participation on dual event days finding that SmartRate™ participation will add 18% to the SmartAC™ load impact on dual event days in PY2023 and 2% in PY2024.

### 3.3 Current Ex Ante Compared to Current Ex Post and Previous Ex Ante

Table 3-4 compares the current (PY2025) ex-post estimates with the current ex-ante estimates (before portfolio adjustments), which demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios.

The PY2025 SmartDays™ experienced lower average event temperatures compared to both weather scenarios. Ex-ante impacts were larger than ex-post under the other weather scenarios as reference loads were lower than expected due to milder summer temperatures in 2025. Therefore, in higher temperature scenarios, all impacts and reference loads will be higher. Impacts as percentages of the estimated reference load correlated with temperatures as expected, though remained similar to those observed during the PY2025 season.

Table 3-4 Current Ex-Post (PY2025 Average Event Day) and Current Ex-Ante (PY2025 August Worst Day, 2025), 4 to 9 PM

Estimate	Scenario	Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact		
Current Ex-Post	Program Average	1.99	0.09	4.6%	94
Current Ex-Ante (backcast)	PG&E 1-in-2	2.17	0.10	4.6%	95
	CAISO 1-in-2	2.22	0.10	4.6%	96

Table 3-5 compares the previous (PY2024) and current (PY2025) ex-ante forecast for 2026, showing how current program performance affected the load impact forecast from the previous year.

ICF estimated higher load impacts (4.4 MW) than the previous forecast (4.9 MW) under PG&E's 1-in-2 weather conditions for PY2026. This decrease is likely driven by milder actual temperatures in PY2025 which partially contributes to the ex-post models used for the ex-ante forecast.

The SmartAC™ ex-ante impact is expected to be slightly lower in PY2025 (7.3%) compared to the PY2024 (7.9%) for PY2026. Additionally, the overall percentage impact is the same this year compared to PY2024 (4.4% vs. 4.4% forecasted in PY2024 ex-ante for PY2026).

Table 3-5 Previous and Current Ex-Ante, PG&E 1-in-2, Typical Event Day/August Worst Day, 2026, 4 to 9 PM

Segment	# Accounts	Aggregate (MW)		Per Customer (kW)		% Load Impact	Avg. Event Temp (°F)
		Reference Load	Load Impact	Reference Load	Load Impact		
<b>Previous (PY2024) Ex-Ante, August Worst Day, 2026</b>							
SmartRate™ Only	40,880	103.5	4.2	2.53	0.10	4.1%	95
Dually Enrolled – SmartAC™	3,620	8.2	0.6	2.25	0.18	7.9%	96
<b>Total</b>	<b>44,500</b>	<b>111.7</b>	<b>4.9</b>	<b>2.51</b>	<b>0.11</b>	<b>4.4%</b>	<b>95</b>
<b>Current (PY2025) Ex-Ante, August Worst Day, 2026</b>							
SmartRate™ Only	42,168	95.7	4.1	2.27	0.10	4.2%	95
Dually Enrolled – SmartAC™ <sup>a</sup>	2,381	4.8	0.4	2.02	0.15	7.3%	96
<b>Total</b>	<b>44,549</b>	<b>100.5</b>	<b>4.4</b>	<b>2.26</b>	<b>0.10</b>	<b>4.4%</b>	<b>95</b>

## 4 Key Findings

ICF identified the following key findings based on the ex-post impact evaluation:

- **The SmartRate™ program continued to successfully drive customers to reduce their demand during SmartDay™ event hours.** During the average event hour, customers delivered savings of 4.1 MW in total (4.6% of reference load consumption). The aggregate impact was lower than in PY2024 (5.2 MW) but the percent impact was slightly higher than in PY2024 (4.4%) reflecting a shift in the reference load due to lower-than-average summer temperatures.
- **SmartRate™ participants experienced lower than average reference loads in 2025.** This phenomenon is most likely a reflection of lower summer temperatures in 2025 and has been documented in other PG&E program evaluations as well.
- **SmartRate™ participants dually enrolled in ELRP A6 showed lower impacts in PY2025 (0.09 kW per customer) than in PY2024 (0.11 kW per customer).** This is likely a reflection of lower temperatures in 2025 compared to 2024.
- **Over 25% of PY2025 SmartRate™ participants qualified for the Bill Protection Guarantee,** a slight increase from the 21% in PY2024 and 19% in PY2023, which aligns with the increased SmartRate™ enrollments over the previous year.
- **Customers with Bill Protection slightly underperformed customers without Bill Protection in PY2025,** delivering impacts of 4.4% (compared to 4.6% For non-bill-protected). This result aligns with expectations, where customers without Bill Protection are more incentivized to save during SmartDays™ than customers with Bill Protection.
- **Participants dually enrolled in SmartAC™ saved an average of 6.2%,** compared to 4.7% for participants enrolled solely in SmartRate™. Customers dually enrolled in ELRP A6 delivered the same percentage demand reductions during the average PY2025 SmartDay™ event hour (4.3%) as they did in PY2024 (4.3%)
- **SmartRate™ enrollment continues shifting from E1 toward TOU and electrification-oriented rates,** with TOU-C now accounting for 14,220 customers (31%). Higher usage groups like TOU-D, E-ELEC, and EV2-A show the largest reference loads but the lowest percentage reductions (3.4%–3.5%), while lower load TOU-C and NBT customers deliver the highest impacts (5.6%–6.4%).

ICF identified the following key findings based on the ex-ante impact evaluation:

- **Overall enrollment over the next 11 years is expected to remain relatively flat,** as projected increases offset planned phase-outs. PG&E forecasts a decline through 2028 as SmartAC™ and ELRP A6 participants exit the program. Beginning in 2029, enrollment is projected to grow at approximately 0.5% annually through 2036. SmartAC™ dual enrollments are expected to be fully phased out by 2028, and ELRP A6 customers will migrate to SmartRate™-only status following the pilot sunset in November 2025.
- **The SmartRate™ program (before portfolio adjustments) will deliver demand reductions of 4.4 MW in August 2026 under PG&E's 1-in-2 weather conditions.** These demand reductions assume that around 45,000 customers will participate in the PY2026 program and reduce their demand during the average SmartRate™ event hour by 4.4% of their reference load. These impacts include the technology-driven response of SmartAC™ customers responding to concurrent SmartAC™ events. For comparison, the PY2024 ex-ante forecast projected 4.8 MW under the same weather conditions. The lower forecasted aggregate reduction is consistent with PY2025's milder summer temperatures, which contributed to a lower aggregate reference load; applying a similar percentage reduction to a lower baseline results in lower aggregate MW impacts.

- **The PY2025 SmartDays™ experienced lower average event temperatures compared to most weather scenarios but had similar percentage impacts compared to ex-post savings.** Despite having a cooler than average summer, the ex-ante percent savings impacts remained similar to ex-post under the other weather scenarios with temperatures closer to those observed in PY2024. The reference loads across ex-post and ex-ante were the biggest differences across the two analyses with lower reference loads observed in the PY2025 ex-post compared to ex-ante reference loads under the PG&E 1-in-2 weather scenario.
- **The shift in the RA window to later hours in non-summer months (5 PM to 10 PM) resulted in slightly lower impacts during these months' peaks compared to summer months.** The SmartRate™ event window (4-9 PM) coincides with the RA window in summer months such that no adjustment to the impacts was necessary.

## 5 Recommendations

ICF provides the following recommendations to PG&E based on findings from the ex-post and ex-ante impacts evaluations:

- **Continue evaluating SGIP and NEM NBT customers enrolled on SmartRate™.** As enrollment in electrification-oriented and net billing tariff (NBT) schedules grows, future evaluations should track whether these customers continue to demonstrate the strong (%) impacts observed to-date, and whether their responsiveness persists as the groups expand. Monitoring these rate classes over time will help determine whether targeted outreach or tailored event messaging could enhance their performance, and whether they warrant distinct treatment in ex-ante forecasting.
- **Revisit reference loads in future years to see if the smaller reference loads were an anomaly in PY2025 or if the trend continues in more “normal weather” years.** Because PY2025 SmartDays™ occurred during a cooler-than-average summer and produced noticeably lower reference loads, future studies should assess whether reference loads normalize under hotter conditions, or whether structural changes—such as continued TOU migration, electrification, or energy efficiency—are reducing baseline event hour consumption. Reevaluating reference load trends over multiple program years will improve the accuracy of both ex-post comparisons and ex-ante forecasts.

## A | Table Generators

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2a. PGE\_2025\_SmartRate\_Ex\_Post\_PUBLIC

2b. PGE\_2025\_SmartRate\_Ex\_Ante\_PUBLIC

## B | Detailed Analysis Methods

This appendix describes ICF's approach to estimating ex-post and ex-ante savings from the SmartRate™ program.

### Steps Used to Define the Participant Population and Analysis Sample

Table B-1 shows the steps ICF took to determine the final PY2025 participant population and define the pool of customers eligible for the ex-post analysis. The eligible analysis pool defines the sample frame from which we selected a representative sample of participants for the ex-post analysis. Estimating impacts based on a sample of participants increased the efficiency of the analysis while still producing robust results. The specific steps follow.

**Stratify the PY2025 Participant Population.** We stratified the participant population by the customer segments shown in Table B-1, which group customers by the following based on expected differences in per-customer impacts:

- **Bill Protection Status.** Previous evaluations have shown that customers with bill protection generate lower impacts than those without bill protection, likely because of (1) complacency due to the absence of cost impacts, and (2) learning for new participants who have yet to change their behavior adequately in response to events.
- **Dual-Enrollment Status.** Previous evaluations have also shown that customers dually enrolled in SmartAC™ and ELRP A6 generate different impacts than customers enrolled only in SmartRate™.
  - The SmartAC™ program installs devices on participants' air conditioner (AC) units that allow PG&E to remotely reduce the units' capacities during both SmartAC™ and SmartRate™ events.
  - The ELRP pilot is a statewide initiative that targets various customer segments and end uses for incremental load reductions. PG&E automatically enrolled residential CARE, FERA, and HER customers into the pilot, though customers not in these segments may opt-in to the program.
  - There were no ELRP A6 events in PY2022 – PY2025. Previous results indicates that participants dually enrolled in ELRP A6 exhibited similar event impacts to the SmartRate™-only group. As a result, we combined the dually enrolled ELRP A6 group with the SmartRate™-only group for modeling purposes.
- **Other.** Participants on the NEM NBT rate and SGIP customers became newly eligible for SmartRate™ in PY2025. These groups tend to have more variable and atypical load patterns due to self-generation or battery storage systems, which differ from the load shapes observed among the rest of the participant cohort.

**Establish the PY2025 Participant Population.** Starting with the full SmartRate™ participation list, ICF screened out customers who went inactive or unenrolled before the first PY2025 event. Some segments experienced higher drop rates than others, but overall, fewer than four percent of customers were dropped from the final SmartRate™ participant pool.

**Exclude Participants after Data Validation.** Next, we used the participant billing data to screen participants for inclusion in the analysis pool. These steps dropped customers with erroneous usage (zero or negative reads), and then customers without any remaining usable billing data. The final sample frame only included customers we expected to have usable data, mitigating the need for oversampling due to data quality issues.

**Select an Analysis Sample.** The final step included sampling customers for the analysis. Previous program year evaluations have shown that sample sizes of 3,000 participants were sufficient for detecting significant program effects on event days for most segments.

For participants dually enrolled in SmartAC™, smaller sample sizes have yielded precise estimates of savings, likely driven by the technology-enabled response to events and higher magnitude of impacts. Conversely, ICF included the population of bill-protected segments because these participants will likely have small impacts, making them more difficult to detect.

A census sample mitigated the risk of not detecting significant impacts where they exist. For the “Other” Segment, it consists of participants newly eligible for SmartRate™, including customers on NEM NBT rate, and customers with SGIP incentives, or both.

Table B-1 Participation and Analysis Pool Attrition

Step	Bill-Protected		Non-Bill Protected			Total
	SmartRate™ Only & DE ELRP A6	Other	SmartRate™ Only & DE ELRP A6	Dual-Enrolled SmartAC™	Other	
<b>Starting Participant List</b>	<b>13,293</b>	<b>1,326</b>	<b>31,011</b>	<b>3,165</b>	<b>1,016</b>	<b>49,811</b>
Drop inactive account before start of summer (June 1, 2025)	13,293 100.0%	1,174 88.5%	31,011 100.0%	3,165 100.0%	736 72.4%	49,379 99.1%
Drop accounts unenrolled before start of summer	13,293 100.0%	1,155 87.1%	31,011 100.0%	3,165 100.0%	708 69.7%	49,332 99.0%
Drop accounts with no SmartRate™ event participation	13,293 100.0%	1,155 70.1%	31,011 100.0%	3,165 100.0%	708 26.4%	49,332 97.7%
Drop accounts with ineligible rates and account status	13,272 99.8%	918 69.2%	30,951 99.8%	3,162 99.9%	220 21.7%	48,523 97.4%
<b>Final PY2025 Participant Population</b>	<b>13,272</b>	<b>918</b>	<b>30,951</b>	<b>3,162</b>	<b>220</b>	<b>48,523</b>
Drop accounts with zero / negative usage in billing data	13,236 99.6%	917 69.2%	30,893 99.6%	3,160 99.8%	205 20.2%	48,411 97.2%
<b>Final Analysis Sample Frame</b>	<b>13,236</b>	<b>917</b>	<b>30,893</b>	<b>3,160</b>	<b>205</b>	<b>48,411</b>
<b>Sampled for Analysis</b>	<b>3,000</b>	<b>917</b>	<b>3,000</b>	<b>1,500</b>	<b>205</b>	<b>8,622</b>

## Develop a Matched Control Group

ICF analyzed SmartRate™ impacts using quasi-experimental methods by creating a control group of nonparticipants similar in energy consuming behavior to participants. We developed the matched control group by first selecting event-like days and then matching eligible nonparticipants to SmartRate™ participants based on their consumption on the event-like days. Details follow.

### Select Event-Like Days

As an event-based program, SmartRate™ does not actively encourage customers to change their energy-consuming behavior outside of SmartDays™. Therefore, we matched participants to eligible non-participants based on their similarity in consumption during specific days in PY2025 that were not dispatched for events,

i.e., event-like days. We used Euclidean distance metrics to select event-like days based on their similarity to dispatched SmartDays™ in weather, day of the week and month of the year.<sup>32</sup>

### Match Control Customers to SmartRate Participants

ICF developed a pool of non-participants to estimate what consumption for SmartRate™ participants would have been absent from the program. We used a stratified Euclidean distance matching approach to select control customers similar to participants in their energy consumption as follows.

First, ICF stratified participants and non-participants by weather station and whether they belonged to a CARE rate. We assumed that customers within these strata would behave more similarly than customers across strata, and by matching participants to non-participants within strata would help capture some of the unobservable attributes that affect the way customers use energy.

Next, we performed a one-to-one match (i.e., one non-participant to each sampled participant) within each stratum based on customers' energy consumption on the selected event-like days.

We used a Euclidean distance metric to assess the quality of each match:

$$ED_{ij} = \sqrt{(early\ morning_i - early\ morning_j)^2 + (late\ morning_i - late\ morning_j)^2 + (onpeak_i - onpeak_j)^2 + (late\ evening_i - late\ evening_j)^2}$$

where:

- $ED$  = The Euclidean distance value for each participant  $i$  with candidate control customer  $j$ .
- $early\ morning_{i,j}$  = The average consumption during hours ending 6 to 9 (i.e., the early morning load) across event-like days for participant  $i$  or candidate control customer  $j$ .
- $late\ morning_{i,j}$  = The average consumption during hours ending 10 to 13 (9 AM to 1 PM, i.e., the late morning load) across event-like days for participant  $i$  or candidate control customer  $j$ .
- $onpeak_{i,j}$  = The average consumption during hours ending 15 to 19 (2 PM to 7 PM, the SmartRate™ event window) across event-like days for participant  $i$  or candidate control customer  $j$ .
- $late\ evening_{i,j}$  = The average consumption during hours ending 23 to 24 (10 PM to 12 AM, i.e., the late evening load) across event-like days for participant  $i$  or candidate control customer  $j$ .

After calculating the Euclidean distance metric for each combination of participant and candidate control customer, we selected the candidate control customer that minimized the Euclidean distance for each participant. We performed the matching without replacement, meaning that control customers could only be matched once to a participant. In cases where a control customer was matched more than once, we selected the next-best matches for some participants. We assessed the final matches using t-tests and visual inspections of the load shapes on the event-like days.

<sup>32</sup> We included three weather variables in the Euclidean distance metrics calculation to select similar non-event days: (1) daily maximum temperature; (2) daily minimum temperatures; and (3) average daily temperature. We combined the metrics into a single Euclidean distance metric by the following equation:

$$ED = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2 + (MinTemp_{event} - MinTemp_{non-event})^2 + (MeanTemp_{event} - MeanTemp_{non-event})^2}$$

## Estimate Ex-Post Load Impacts

Using the final sample of participants and the matched control group, we estimated ex-post impacts for the average participant in each of the following customer segments using panel regression difference-in-differences models with customer fixed effects:

- Dually enrolled in SmartAC™
- Singly enrolled in SmartRate™ or dually enrolled in ELRP A6 on bill protection
- Singly enrolled in SmartRate™ or dually enrolled in ELRP A6 not on bill protection
- NEM NBT and/or SGIP customers enrolled in SmartRate™ or dually enrolled in ELRP A6 on bill protection or not on bill protection

We selected the final models and estimated load impacts from the SmartRate™ program as follows.

### Model Selection and Validation

ICF 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 control for seasonal and other effects independently but consistently for each hour of the day.

We tested several difference-in-difference models that each controlled for non-programmatic changes to consumption, including:

- **Customer-variant** differences in consumption through customer fixed effects, and
- **Time-variant** differences in consumption driven by weather and other factors exogenous to the program through variables like month indicators and cooling degree hours (CDH).

We validated the candidate sets of models through in-sample and out-of-sample testing to ensure that the selected model accurately predicted actual participant load on SmartDays™ and on event-like days as follows.

- To perform the **in-sample (IS) test**, we assessed each candidate model's ability to predict actual participant consumption on SmartDays™. The ideal model predicted consumption that closely followed actual observed participant consumption in the hours pre- and post-event and during the on-peak hours. We used several metrics of accuracy and bias to assess each model's predictive ability, including the mean absolute percent error (MAPE) and mean percent error (MPE).
- To perform the **out-of-sample (OOS) test**, we estimated candidate model coefficients on a data set that excluded the event-like days used for developing the matched control group. Then, we used the candidate models to predict consumption on the event-like days. This OOS test helped us assess the ability of each model to predict what participants would have consumed on SmartDays™ in the absence of the program. We similarly calculated the MAPE and MPE of each candidate model to assess the accuracy and bias of its predictions.

The best model will produce MAPE and MPE values close to zero. In selecting the final model, we considered the results of the IS and OOS tests and selected the final model for each segment that minimized the following metric:

$$metric_{ic} = (0.4 \times MAPE_{IS}) + (0.4 \times MAPE_{OOS}) + (0.1 \times |MPE_{IS}|) + (0.1 \times |MPE_{OOS}|)$$

Results of the model validation are provided in Appendix C. For each of the model segments, we selected the following model:

$$kWh_{it} = \beta_0 + \beta_1 Part_i + \beta_b(\delta_{mt} + Weekend_t + CDH_t + CDH_{t-1} + Avg.Load_{ih}) + \beta_\tau Event_{it}(1 + CDH_t + CDH_{t-1} + SR-SAC_{it} + SAC_{it}) + \varepsilon_{it}$$

where:

$kWh_{it}$	=	The consumption of customer $i$ during time period $t$ .
$\beta_0$	=	The average per-customer consumption across all customers and time periods, i.e., the model intercept coefficient estimate.
$\beta_1$	=	The average per-customer consumption across all SmartRate™ participants and time periods.
$Part_i$	=	A variable indicating that customer $i$ is a SmartRate™ participant (1 = participant, 0 = control customer).
$\beta_b$	=	Model coefficient estimates for the baseline variables that explain variability in consumption unrelated to the SmartRate™ program.
$\delta_{mt}$	=	A set of variables indicating that time period $t$ is in month of the year $m$ (June, July, August, or September).
$Weekend_t$	=	A variable indicating whether time period $t$ is a weekend day (1 = weekend, 0 = weekday).
$CDH_t$	=	A set of variables for the cooling degree hours in time period $t$ calculated for base temperatures of 70 °F and 90 °F.
$CDH_{t-1}$	=	A set of variables for the cooling degree hours in the previous time period ( $t - 1$ ) calculated for base temperatures of 70 °F and 90 °F.
$Avg.Load_{ih}$	=	A variable for the average load of customer $i$ for a specified window $h$ (HE5-7, HE10-13, and HE23-24).
$\beta_\tau$	=	Model coefficient estimates for the impact variables that explain variability in consumption related to the SmartRate™ program or time period $t$ being a SmartDay™.
$Event_{it}$	=	A variable indicating that time period $t$ is a SmartDay™ that was dispatched for participant $i$ .
$SR-SAC_{it}$	=	A variable indicating that time period $t$ for dual-enrolled SmartAC™ participant $i$ was dispatched for both a SmartRate™ and SmartAC™ event.
$SAC_{it}$	=	A variable indicating that time period $t$ for dual-enrolled SmartAC™ participant $i$ was dispatched for a SmartAC™ event.

ICF estimated separate hourly models and included monthly indicator variables to minimize hour-to-hour and seasonal autocorrelation and then used Huber-White robust clustered standard errors to account for heteroskedasticity.

## Load Impact Estimates

We used the final model to estimate per-customer impacts for each SmartDay™ for each of the reporting subgroups required by the California Load Impact Protocols, including load capacity area (LCA), bill protection status, CARE status, dual program enrollment, billing rate, and high fire-threat district status. Specifically for each, we calculated the following:

- **Predicted Load.** The model-predicted estimates of participant consumption in each hour of the SmartDays™.

- **Reference Load.** The estimate of what participant consumption would have been during the SmartDays™ absent the SmartRate™ program, i.e., the counterfactual consumption.
- **Load Impact.** The difference between the predicted and reference loads showing the estimated program impacts on consumption in each hour of the SmartDays™.

After estimating per-customer impacts, ICF calculated program-total demand savings for each PY2025 SmartDay™ by applying per-customer impacts to the final participant population. We estimated confidence intervals around per-customer load impacts, program total impacts, and impacts by subgroup.

## Estimate Ex-Ante Load Impacts

ICF used the ex-post regression models to estimate SmartRate™ per-customer impacts under multiple weather scenarios (PG&E and CAISO 1-in-2) from 2026 through 2036 for the typical event day and for each monthly system worst days. Due to the unusually mild weather during the 2025 program year, ICF incorporated ex-post results from 2024 to better reflect conditions typical of an average weather season. We estimated separate ex-ante impacts for each reporting subgroup required by the California Load Impact Protocols. We also estimated ex-ante impacts for the 2025 program year (i.e., backcast ex-ante estimates) to see what impacts would have been under the different weather scenarios.

The resource adequacy window coincides with the SmartRate™ event window in all months of the year except for March, April, and May, when it spans 5 PM to 10 PM. ICF shifted impacts to align with the reference loads estimated during these hours.

## C | Model Validity

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As discussed in the Detailed Analysis Methods ([Appendix B](#)), ICF selected and validated regression models for each of the following customer segments:

- Dually enrolled in SmartAC™
- Singly enrolled in SmartRate™ or dually enrolled in ELRP A6 on bill protection
- Singly enrolled in SmartRate™ or dually enrolled in ELRP A6 not on bill protection
- NEM NBT and/or SGIP customers enrolled in SmartRate™ or dually enrolled in ELRP A6 on bill protection or not on bill protection

Details on the model selection and validation process can be found in [Appendix B](#). Here we present the results of that process for the PY2025 evaluation, specifically for:

- Selecting the event-like days
- Developing the matched control group
- Selecting and validating the final regression model

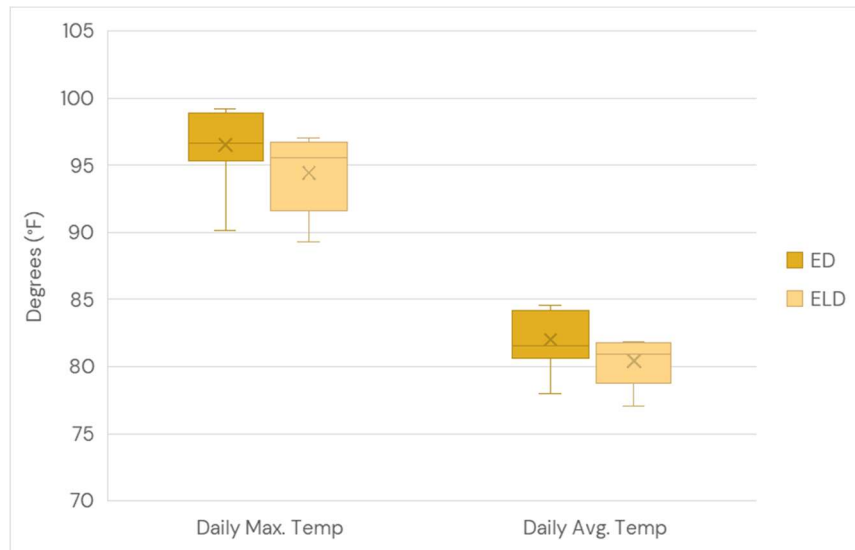
### Event-Like Day Selection

As discussed in the Detailed Analysis Methods appendix, ICF used event-like days to:

- Match participants to eligible non-participants
- Assess the performance of regression models

We used Euclidean distance matching to select several days in 2025 that were similar to SmartDays™ in maximum, minimum, and average daily temperatures. Figure C-1 compares the distributions of the average and maximum daily temperature on event days and the selected event-like days. The event-like days experienced lower temperatures than days dispatched for events, as expected. The milder temperatures in 2025 led to fewer eligible event-like days since most events were dispatched during most of the higher temperature days. However, temperatures were similar enough that the selected event-like days served as adequate event-day proxies for developing a matched control group and validating regression model performance.

Figure C-1 Daily Temperatures of Event Days v. Event-Like Days



## Matched Control Group Development

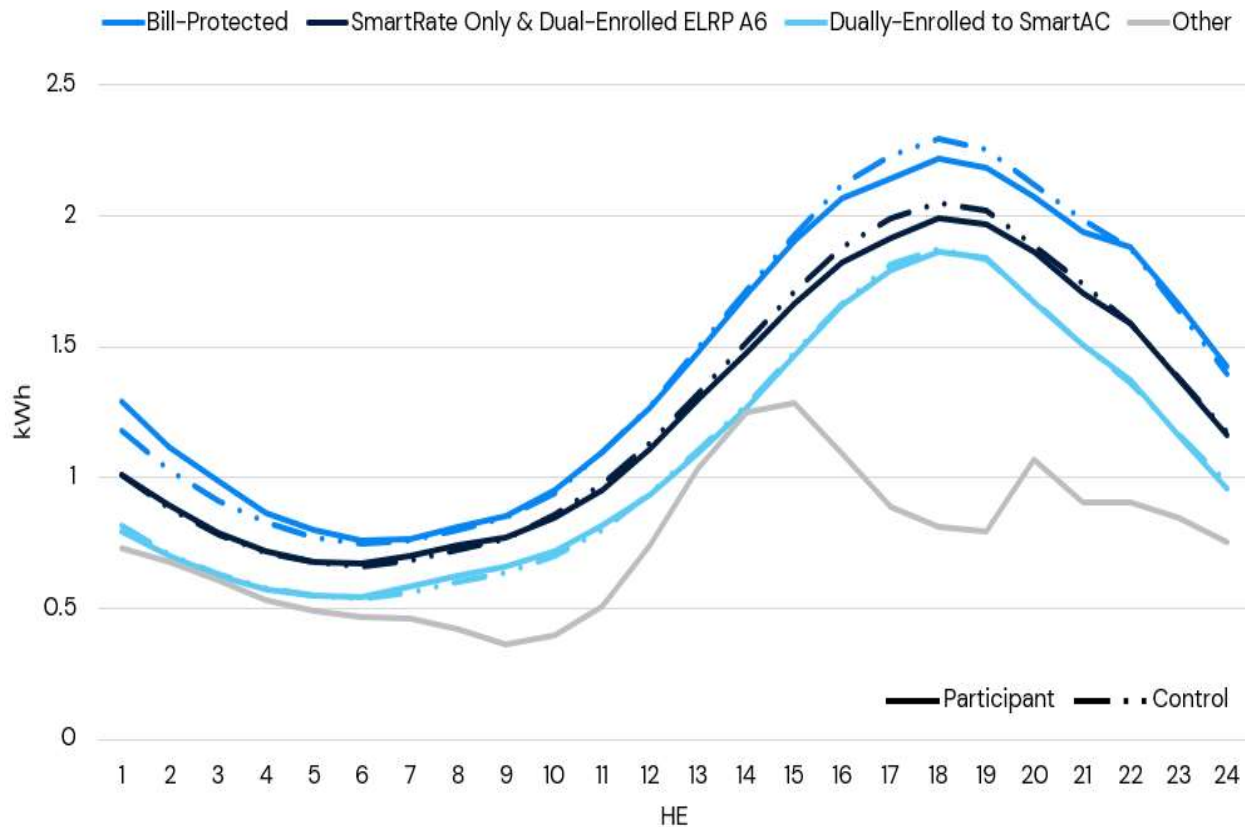
ICF developed a pool of non-participants to estimate what consumption for SmartRate™ participants would have been absent the program. We used a stratified Euclidean distance matching approach to select control customers similar to participants in their energy consumption as follows:

- First, ICF stratified participants and non-participants by weather station, billing rate, and whether they belonged to CARE. We assumed that customers within these strata would behave more similarly than customers across strata, and by matching participants to non-participants within strata would help capture some of the unobservable attributes that affect the way customers use energy.
- Next, we performed a one-to-one match (i.e., one non-participant to each sampled participant) within each stratum based on customers' energy consumption on the selected event-like days. We used a Euclidean distance metric to assess the quality of each match.<sup>33</sup>

Figure C-2 shows the consumption for the average participant and matched control customer for each hour of the average event-like day, by customer segment. In general, the load profiles align within segments, particularly during the on-peak hours (4-9 PM), indicating that the control group behaves similarly to the participants in energy consumption on days when events were not dispatched.

<sup>33</sup> Control matching was not performed for the "Other" Segment, which includes NEM NBT rate participants and SGIP incentive recipient, because their load profiles differ significantly from the non-participants, who generally lack batteries or self-generation.

Figure C-2 Average Load of Participant v. Matched Control on Event-Like Days



## Final Model Selection and Validation

For each customer segment, ICF tested several hourly difference-in-difference regression models that each controlled for non-programmatic changes to consumption.

We validated the candidate sets of models through in-sample and out-of-sample testing to ensure that the selected model accurately predicted actual participant load on SmartDays™ and on event-like days as follows:

- To perform the **in-sample (IS) test**, we assessed each candidate model's ability to predict actual participant consumption on SmartDays™.
- The ideal model predicted consumption that closely followed actual observed participant consumption in the hours pre- and post-event and during the on-peak hours.
- We used several metrics of accuracy and bias to assess each model's predictive ability, including the mean absolute percent error (MAPE) and mean percent error (MPE).
- To perform the **out-of-sample (OOS) test**, we estimated candidate model coefficients on a data set that excluded the event-like days used for developing the matched control group.
- Then, we used the candidate models to predict consumption on the event-like days.
- This test helped us assess the ability of each model to predict what participants would have consumed on SmartDays™ in the absence of the program.
- We similarly calculated the MAPE and MPE of each candidate model to assess the accuracy and bias of its predictions.

Table C-1 shows the weighted average MAPE and MPE for each segment's final set of models. Close-to-zero values indicate low levels of bias (MPE) and accurate predictions (MAPE). The out-of-sample values (all under 2.0%, except for "Other" Segment) show that the models performed well on new data, i.e., data not used to train the initial models. The in-sample values are all closer to zero as expected (i.e. all under 2.0%, except for "Other" Segment), and show that models predicted customers' actual consumption on SmartDays™ accurately with minimal bias.

The MPE and MAPE for the "Other" model segment are notably higher than those for the other segments because this group includes NBT and SGIP customers, many of whom have solar panels and/or battery storage; as a result, their energy usage patterns are more irregular and harder to predict compared to customers in other segments.

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

Model Segment	Out-of-Sample		In-Sample	
	MPE	MAPE	MPE	MAPE
Bill protection	1.72%	1.30%	1.96%	0.64%
Dually enrolled in SmartAC™	2.08%	1.67%	1.88%	0.19%
Singly enrolled in SmartRate™ or Dually enrolled in ELRP A6	1.68%	1.29%	1.72%	0.31%
Other	5.11%	3.50%	6.49%	-1.02%

Figure C-3 and Figure C-4 show the average participant's actual consumption (solid lines) and predicted consumption (dotted lines) on event-like days and on dispatched SmartDays™ by customer segment. We see that the predicted consumption closely aligns with the actual consumption, indicating that the regression models should produce accurate and unbiased reference loads, i.e., estimates of what participant consumption would have been on dispatched SmartDays™.

Figure C-3 Actual and Predicted Loads: Event-Like Days (Out-of-Sample Test)

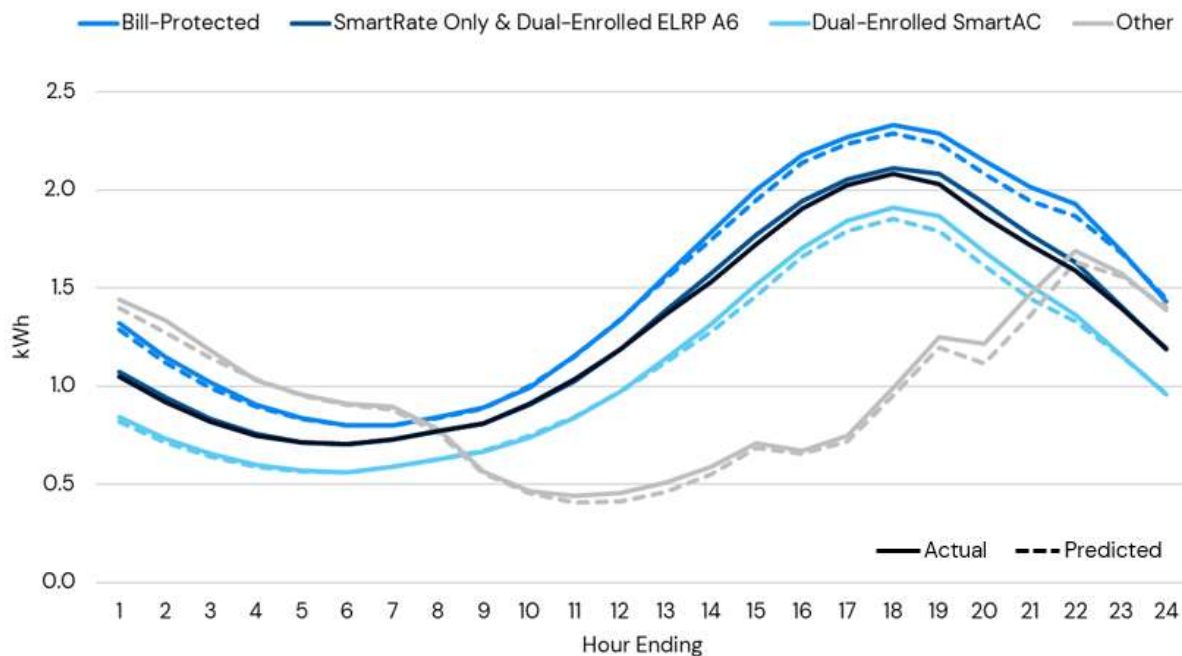
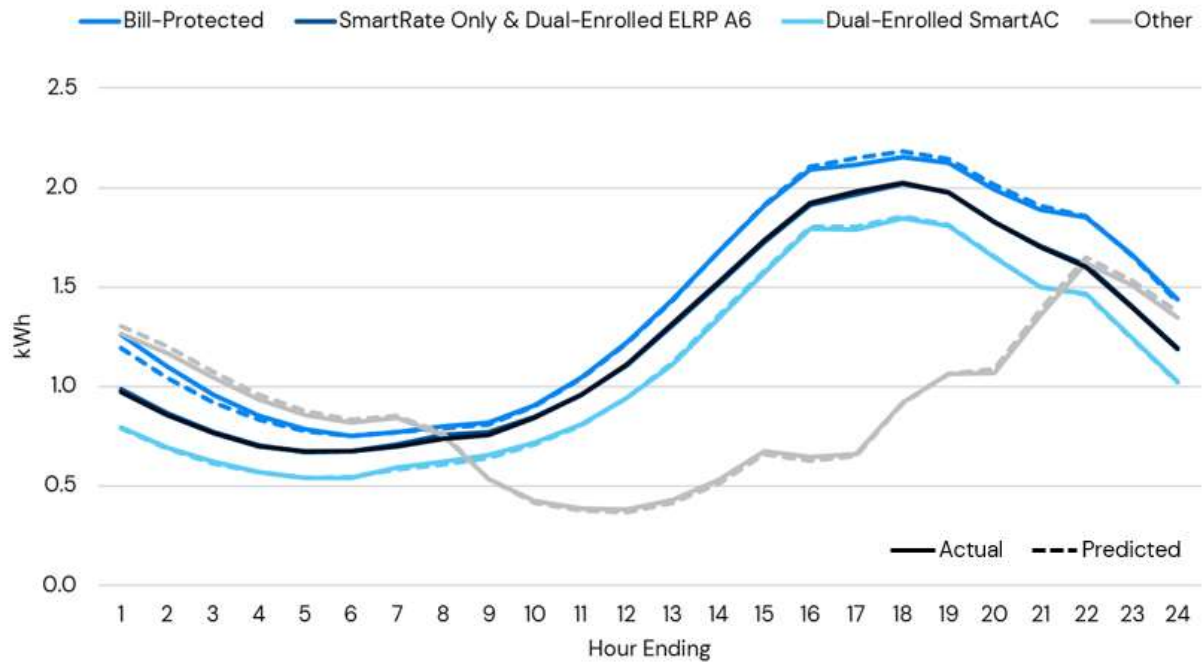


Figure C-4 Actual and Predicted Loads: Event Days (In-Sample Test)



## D | Bill Impact Analysis

As part of the SmartRate™ evaluation, ICF investigated the impact of the program on customers' energy bills. In aggregate, residential customers participating in SmartRate™ earned net bill savings of about \$225,000 in 2025. As discussed in [Chapter 1](#), SmartRate™ provides customers with incentives for shifting their consumption away from the on-peak period on SmartDays™ and non-SmartDays™ during billing cycles when PG&E dispatched at least one SmartDay™. PG&E also offers new participants its Bill Protection Guarantee, which would refund them during their first full season (and previous partial season) if their SmartRate™ costs exceeded their regular residential pricing plan. Bill Protection credits appear on customers' November bills if needed.

Importantly, bill credits should not be interpreted as a direct proxy for event load shifting or load shedding. PG&E noted that credits and load impacts do not necessarily correlate depending on customers' load profiles, customers may receive positive or negative credits even without shifting, and may also receive positive or negative credits even after shifting or shedding load. This chapter therefore reports bill impacts as the financial outcome of participation, while event performance is evaluated separately using load impact methods.

ICF gathered billing data from PG&E covering the May 2025 through November 2025 bills, which included program-specific credits and charges for all PY2025 SmartRate™ participants. ICF analyzed the data to understand the impact on the program's customer bills. Consistent with previous analyses, ICF defined participants as customers who enrolled between June 1, 2025, and September 30, 2025, and participated in at least one SmartDay™. We then excluded customers with fewer than three months of billing data between May and September 2025, leaving ICF a working sample of 39,680 out of the 45,242 unique PY2025 participants for the bill impact analysis.

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

### Overview of Billing Impacts

Table D-1 summarizes overall bill impacts for the PY2025 SmartRate™ bill analysis sample over the May–November 2025 billing period. The table presents the distribution of customers with bill decreases, bill increases, and no change under SmartRate™ and reports the average bill change (\$) for each outcome category. The average participant saved \$4.88 on their energy bill during the SmartRate™ season. Bill savings increased from previous years (\$1.39 in PY2024 and \$2.22 in PY2023), which may be driven by the milder weather experienced by customers during the 2025 summer season compared to previous years.

#### Customer Billing Snapshot

- Bill analysis used May–Nov billing data; working sample ~39,680 of 45,242 participants after billing-data screens.
- Average participant saved ~\$4.88 during the season (higher than PY2024/PY2023 per report)
- Most participants saw decreased bills (~63%) while ~37% increased; near-zero “no change”
- Bill credits are not a direct proxy for load impacts; load shape can yield credits without event response (and vice versa)

Table D-1 Bill Impacts for All Participants

Enrollment Status	Impact	Count of Participants	% of Enrollment Status	Average Bill Change per Season
SmartRate™ Only	Decreased Bill	11,125	68%	-\$15.75
	Increased Bill	5,247	32%	\$12.63
	No Change	18	<1%	\$0.00
	<b>All</b>	<b>16,390</b>	<b>100%</b>	<b>-\$6.65</b>
Dually Enrolled in SmartAC™	Decreased Bill	1,523	51%	-\$12.85
	Increased Bill	1,438	49%	\$13.96
	No Change	1	<1%	\$0.00
	<b>All</b>	<b>2,962</b>	<b>100%</b>	<b>\$0.17</b>
Dually Enrolled in ELRP A6	Decreased Bill	12,506	62%	-\$14.56
	Increased Bill	7,819	38%	\$12.40
	No Change	3	<1%	\$0.00
	<b>All</b>	<b>20,328</b>	<b>100%</b>	<b>-\$4.19</b>
All	Decreased Bill	25,154	63%	-\$14.98
	Increased Bill	14,504	37%	\$12.64
	No Change	22	<1%	\$0.00
	<b>All</b>	<b>39,680</b>	<b>100%</b>	<b>-\$4.88</b>

### Bill Protection Guarantee

25% of participants qualified for the Bill Protection Guarantee during the PY2025 SmartRate™ season, slightly higher than the PY2024 participant population (21%). Since SmartAC™ no longer enrolls new customers, no one dual enrolled in SmartAC™ was under bill protection in PY2025.

Table D-2 Participant Distribution by Bill Protection Status

Enrollment Status	Protection Status	Count of Participants	% of Enrollment Status	Average Bill Change per Season
SmartRate™ Only	Unprotected	11,340	69.19%	-\$6.04
	Protected	5,050	30.81%	-\$8.02
	<b>All</b>	<b>16,390</b>	<b>100.00%</b>	<b>-\$6.65</b>
Dually Enrolled in SmartAC™	Unprotected	2,958	100.00%	\$0.17
	<b>All</b>	<b>2,958</b>	<b>100.00%</b>	<b>\$0.17</b>
Dually Enrolled in ELRP A6	Unprotected	17,004	83.65%	-\$3.58
	Protected	3,324	16.35%	-\$7.28
	<b>All</b>	<b>20,328</b>	<b>100.00%</b>	<b>-\$4.19</b>
All	Unprotected	31,302	78.89%	-\$4.12
	Protected	8,378	21.11%	-\$7.72
	<b>All</b>	<b>39,680</b>	<b>100.00%</b>	<b>-\$4.88</b>

Table D-2 shows the SmartRate™ bills impacts for customers by dual-enrollment status and bill protection status, while Table D-3 and Table D-4 show the proportions of customers with and without bill protection whose bills increased or decreased because of SmartRate™. Consistent with the previous evaluations,

customers with bill protection saved slightly more on their average energy bills than customers without bill protection. Overall, 69% of customers with bill protection experienced decreased energy bills, compared to 62% of customers without bill protection.

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

Enrollment Status	Impact	Count of Participants	% of Enrollment Status	Average Bill Change per Season
SmartRate™ Only	Decreased Bill	3,472	68.75%	-\$16.64
	Increased Bill	1,560	30.89%	\$11.09
	No Change	18	0.36%	\$0.00
	<b>All</b>	<b>5,050</b>	<b>100.00%</b>	<b>-\$8.02</b>
Dually Enrolled in ELRP A6	Decreased Bill	2,266	68.17%	-\$16.23
	Increased Bill	1,055	31.74%	\$11.92
	No Change	3	0.09%	\$0.00
	<b>All</b>	<b>3,324</b>	<b>100.00%</b>	<b>-\$7.28</b>
All	Decreased Bill	5,740	68.51%	-\$16.48
	Increased Bill	2,617	31.24%	\$11.42
	No Change	21	0.25%	\$0.00
	<b>All</b>	<b>8,378</b>	<b>100.00%</b>	<b>-\$7.72</b>

Among participants with Bill Protection, 68.51% (5,740 of 8,378) experienced decreased bills and 31.24% (2,617 customers) experienced increased bills, with very few customers showing no change. Average decreases for Bill-protected customers were similar across SmartRate™-only and dually enrolled ELRP A6 participants (–\$16.64 and –\$16.23, respectively), while average bill increases were modest at \$11.09 for SmartRate™-only customers and \$11.92 for dually enrolled ELRP A6 customers. On an overall basis, Bill-protected customers saw average seasonal savings of \$8.02 for SmartRate™-only and \$7.28 for dually enrolled ELRP A6 participants, indicating that the guarantee cohort tended to experience net bill reductions.

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

Enrollment Status	Impact	Count of Participants	% of Enrollment Status	Average Bill Change per Season
SmartRate™ Only	Decreased Bill	7,653	67.49%	-\$15.35
	Increased Bill	3,687	32.51%	\$13.28
	<b>All</b>	<b>11,340</b>	<b>100.00%</b>	<b>-\$6.04</b>
Dually Enrolled in SmartAC™	Decreased Bill	1,521	51.42%	-\$12.87
	Increased Bill	1,436	48.55%	\$13.97
	No Change	1	0.03%	\$0.00
	<b>All</b>	<b>2,958</b>	<b>100.00%</b>	<b>\$0.17</b>
Dually Enrolled in ELRP A6	Decreased Bill	10,240	60.22%	-\$14.19
	Increased Bill	6,764	39.78%	\$12.48
	<b>All</b>	<b>17,004</b>	<b>100.00%</b>	<b>-\$3.58</b>
All	Decreased Bill	19,414	62.02%	-\$14.54
	Increased Bill	11,887	37.98%	\$12.91
	No Change	1	0.00%	\$0.00

Enrollment Status	Impact	Count of Participants	% of Enrollment Status	Average Bill Change per Season
	<b>All</b>	<b>31,302</b>	<b>100.00%</b>	<b>-\$4.12</b>

For participants without Bill Protection (Table D-4), 62.02% (19,414 of 31,302) had decreased bills and 37.98% (11,887 customers) had increased bills. Average bill decreases were somewhat smaller than for Bill-protected customers (-\$15.35 for SmartRate™-only and -\$14.19 for dually enrolled ELRP A6 customers), while average bill increases were somewhat larger (\$13.28 and \$12.48, respectively). Dually enrolled SmartAC™ participants without Bill Protection were close to bill-neutral on average, with roughly equal shares of bill decreases (51.42%) and increases (48.55%) and a small net increase of \$0.17 per year. Across all non-Bill-protection enrollment groups combined, participants without the guarantee experienced average yearly bill savings of \$4.12, compared with \$7.72 for customers under Bill Protection, reinforcing the pattern that Bill-protected customers tended to achieve slightly greater net bill savings under SmartRate™.

### Billing Impacts by Other Subgroups

Table D-5 shows the average bill impacts by Local Capacity Area. Across LCAs, most customers saved on their energy bills by participating in SmartRate™, with the most significant reductions experienced by participants in Humboldt. Customers in Stockton experienced slight increases in their energy bills.

Table D-5 Bill Impacts by Local Capacity Area

LCA	Count of Participants	% of Population	Average Bill Change per Season
Greater Bay Area	5,624	14.17%	-\$4.70
Greater Fresno Area	9,621	24.25%	-\$4.44
Humboldt	144	0.36%	-\$13.02
Kern	4,364	11.00%	-\$7.29
North Coast and North Bay	2,390	6.02%	-\$8.83
Sierra	8,617	21.72%	-\$4.29
Stockton	4,342	10.94%	-\$4.36
Other	4,578	11.54%	-\$3.01
<b>All</b>	<b>39,680</b>	<b>100.00%</b>	<b>-\$4.88</b>

Table D-6 presents bill impacts by CARE participation. Both CARE and non-CARE customers commonly saw their bills decrease under SmartRate™, and each group realized average bill savings over the season. Non-CARE customers were somewhat more likely to experience bill reductions and tended to achieve slightly larger average savings than CARE customers. At the same time, a substantial portion of CARE participants also benefited financially, suggesting that SmartRate™ delivered bill savings across income levels, with somewhat stronger effects among non-CARE customers.

Table D-6 Bill Impacts by CARE Status

CARE Status	Impact	Count of Participants	% of CARE Status	Average Bill Change per Season
Non-CARE	Decreased Bill	14,420	65.66%	-\$15.24
	Increased Bill	7,530	34.29%	\$13.31
	No Change	11	0.05%	\$0.00
	<b>All</b>	<b>21,961</b>	<b>100.00%</b>	<b>-\$5.45</b>
CARE	Decreased Bill	10,734	60.58%	-\$14.63
	Increased Bill	6,974	39.36%	\$11.91
	No Change	11	0.06%	\$0.00
	<b>All</b>	<b>17,719</b>	<b>100.00%</b>	<b>-\$4.18</b>

Table D-7 shows the average bill impacts achieved by customers across billing rates. Customers on the standard E1 rate were close to bill-neutral on average, with bill decreases and increases occurring in similar proportions. In contrast, customers on time-of-use rates—particularly the default TOU-C and the opt-in TOU-D options—were more likely to experience bill reductions and tended to realize larger average savings. Participants on EV-oriented and whole-home electric rates, such as EV2-A and E-ELEC, saw especially strong bill savings, with a large majority of these customers experiencing decreased bills. Customers on the net billing solar tariff (NEM NBT) also generally benefited from SmartRate™, with most realizing bill reductions and net seasonal savings. Overall, customers on more dynamic or electrification-oriented rates tended to fare better under SmartRate™ than those on the standard tiered rate.

Table D-7 Bill Impacts by Billing Rate

Billing Rate	Impact	Count of Participants	% of Rate Population	Average Bill Change per Season
E1 (Standard)	Decreased Bill	10,201	53.49%	-\$12.20
	Increased Bill	8,864	46.48%	\$12.76
	No Change	5	0.03%	\$0.00
	<b>All</b>	<b>19,070</b>	<b>100.00%</b>	<b>-\$0.59</b>
TOU-B (Opt-in)	Decreased Bill	█	█	█
	Increased Bill	█	█	█
	No Change	█	█	█
	<b>All</b>	█	█	█
TOU-C (Defaulted)	Decreased Bill	8,818	71.87%	-\$12.29
	Increased Bill	3,440	28.04%	\$11.89
	No Change	12	0.10%	\$0.00
	<b>All</b>	<b>12,270</b>	<b>100.00%</b>	<b>-\$5.50</b>
TOU-D (Opt-in)	Decreased Bill	3,789	68.84%	-\$21.05
	Increased Bill	1,710	31.07%	\$13.78
	No Change	5	0.09%	\$0.00
	<b>All</b>	<b>5,504</b>	<b>100.00%</b>	<b>-\$10.21</b>
EV2-A (Home Charging EV)	Decreased Bill	1,305	87.58%	-\$29.23
	Increased Bill	185	12.42%	\$12.95
	No Change	0	0%	n/a

Billing Rate	Impact	Count of Participants	% of Rate Population	Average Bill Change per Season
	<b>All</b>	<b>1,254</b>	<b>100%</b>	<b>-\$23.21</b>
E-ELEC (Electric Home Rate Plan)	Decreased Bill	633	77.86%	-\$31.11
	Increased Bill	180	22.14%	\$11.18
	No Change	0	0%	n/a
	<b>All</b>	<b>813</b>	<b>100.00%</b>	<b>-\$21.74</b>
NEM NBT (Net Billing Solar)	Decreased Bill	405	76.70%	-\$15.90
	Increased Bill	123	23.30%	\$10.70
	No Change	0	0%	n/a
	<b>All</b>	<b>528</b>	<b>100.00%</b>	<b>-\$9.71</b>



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