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2023 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates

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Table of Contents

List of Figures

List of Tables

EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2023. The evaluation produces estimates of the ex-post load impacts for each hour of each CPP event called for PG&E, SCE, and SDG&E in 2023. The evaluation also develops ex-ante load impact forecasts for the programs for 2024 through 2034. The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

ES.1 Resources Covered

California's CPP programs provide participating non-residential customers with lower rates during non-CPP summer season hours and momentary higher rates during CPP periods when an event is called. These dynamic pricing rates are designed to encourage price-responsive demand reductions during the higher-priced critical periods. The programs are similar at the three utilities, though they are referred to by different names (e.g., Peak Day Pricing (PDP) at PG&E). Program provisions vary by utility, including the notification period for events, the specific hours when CPP events can be called, the number and duration of CPP events, and the minimum demand requirements for eligible customers. Note that the analysis of SDG&E's small CPP customers is included in a different study.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2023 by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2023 for each of the utilities' Automated Demand Response (Auto-DR) programs for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2024 through 2034;[1]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

Secondary goals include estimating the effect of event notifications and dual enrollments on load impacts for all three utilities. In addition, for PG&E, we compare the load impacts for other subgroups of interest, such as net energy metered (NEM) customers, Commercial and Industrial (C&I), agricultural, and government rate classes, and customers assigned Business Energy Support (BES)/CRS.

ES.2 Ex-Post Load Impacts

In this evaluation, we estimate CPP ex-post load impacts using two primary methodologies: within-subjects panel models and customer-specific regressions. In both cases, load impact estimates are based on comparisons of event-day loads to non-event

[1] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2023), with the values serving as weather-normalized versions of the ex-post load impacts.

day loads, controlling for weather conditions and day type characteristics (e.g., day of week or month of year). Panel models, which combine customers into a model with common estimates, are used for all but the largest CPP customers. For the largest customers, we estimate customer-specific models to properly account for any idiosyncrasies in their load profiles that may affect their load impact estimates. As requested by each utility, we also studied the load impacts for specific subsets of customers within each size group.

ES.2.1 Summary of Ex-Post Impacts by Utility

Table ES.1 shows the total enrollments, reference loads, aggregate and percentage load impacts, and average event temperatures for all three utilities' programs on the typical event day. PG&E has the highest aggregate load impacts on the typical event day. SCE has the highest enrollment but the lowest percentage load impacts. Though SDG&E has the highest percentage load impacts, it has the lowest enrollment, so the aggregate load impacts are the lowest.

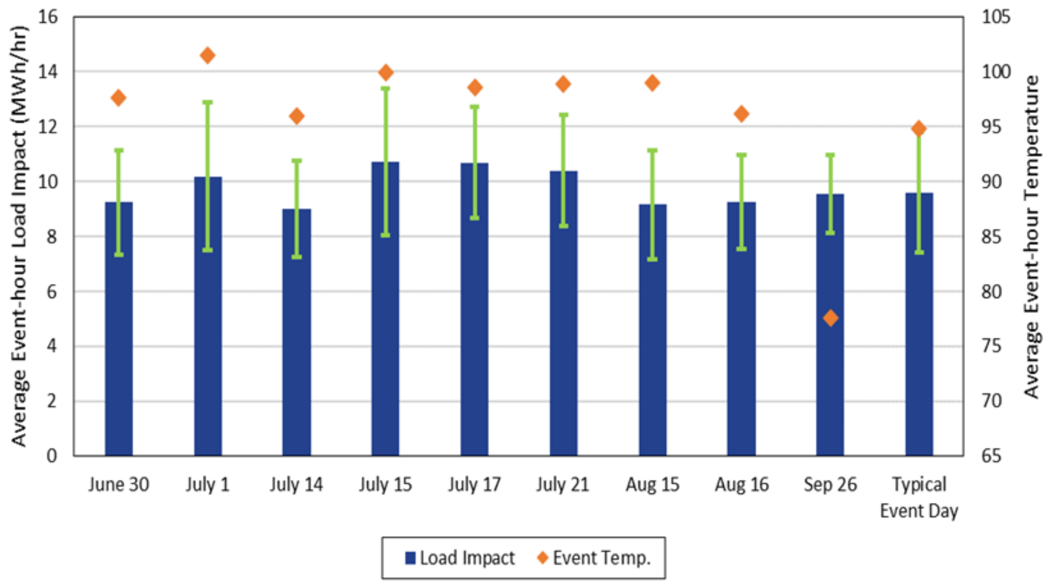
Table ES.1: Ex-Post Impacts by Utility, Typical Event Day

Utility	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
PG&E - PDP	107,258	847	9.6	1.1%	94.8
SCE - CPP	226,193	1,220	7.0	0.6%	87.6
SDG&E - CPP	2,861	139	4.4	3.2%	85.4

ES.2.2 PG&E

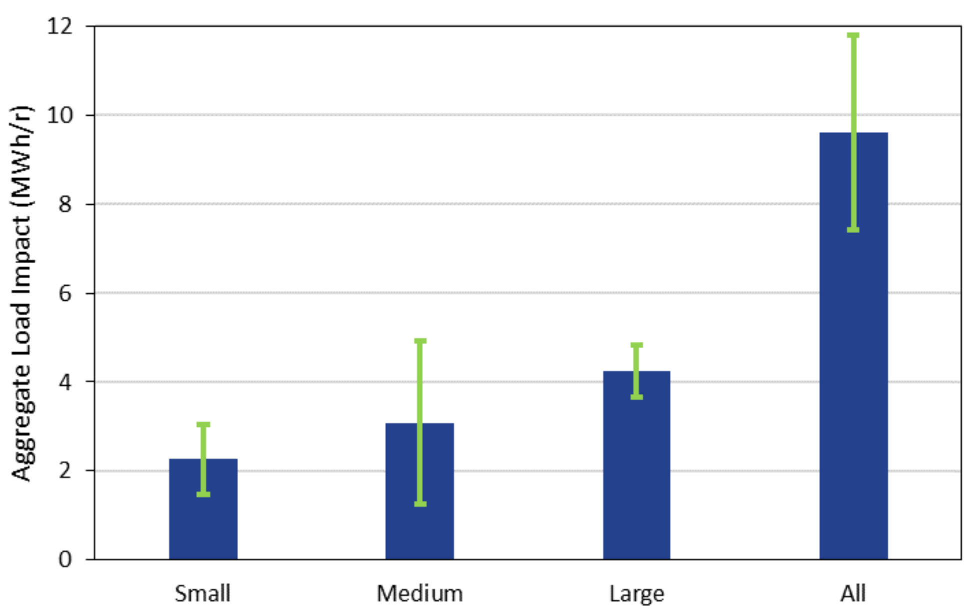
Figure ES.1 shows the estimates of the average event-hour load impacts by event day, along with a 90% confidence interval for all PG&E's PDP customers. These customers achieve statistically significant load reductions on all nine event days as well as on the typical event day. The estimated load reduction for the typical event day is 9.6 MWh/hour, which is a 1.1% load reduction. Figure ES.1 does not provide evidence of a strong relationship between load impacts and average temperatures. For instance, July 1st has the hottest temperature, but the load impact is only the fourth highest. September 26th has the coolest temperature, but the load impact is higher than August 15th and August 16th, which have much higher temperatures.

Figure ES.1: Average Event-Hour Load Impacts by Event, *PG&E All*



All customer size groups had statistically significant load reductions on all nine event days. Figure ES.2 shows the estimates of the average event-hour load impacts on the typical event day by customer size with 90% confidence intervals. The estimated load reduction for the typical event day is 2.3 MWh/hour for small customers, 3.1 MWh/hour for medium customers, and 4.2 MWh/hour for large customers.

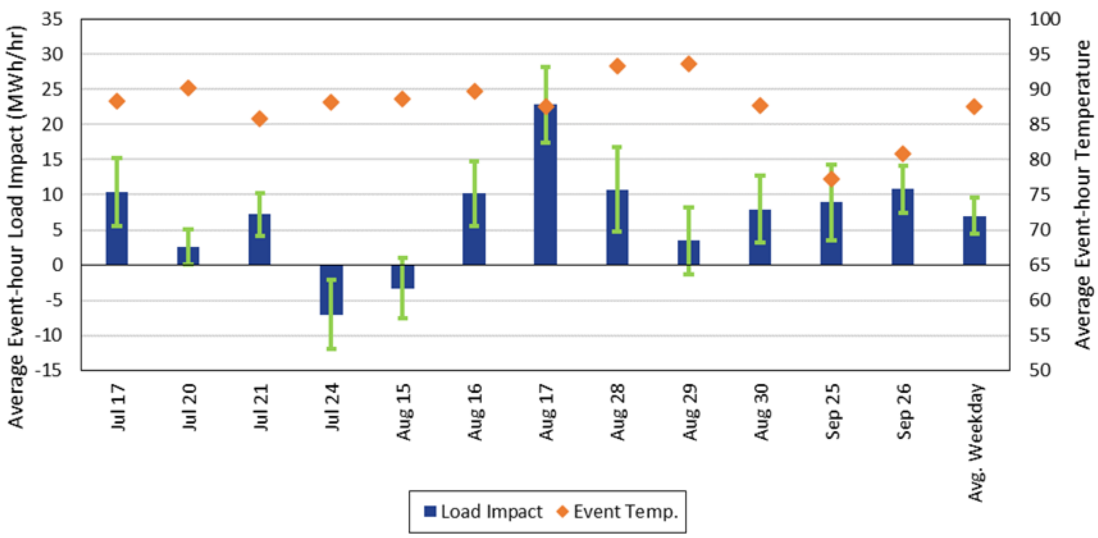
Figure ES.2: Average Event-Hour Load Impacts on Typical Event Day by Size, *PG&E*



ES.2.3 SCE

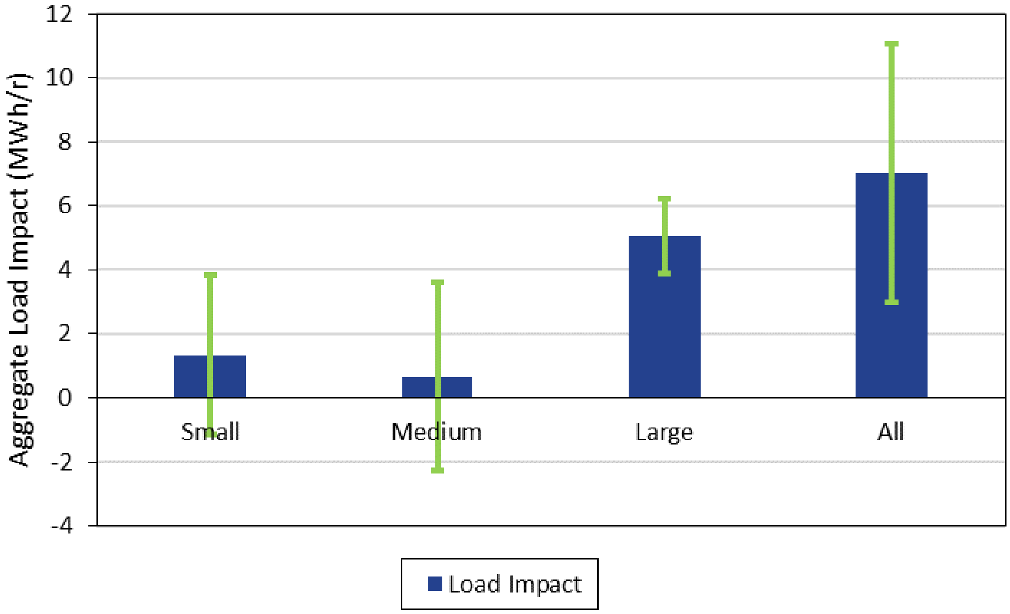
Figure ES.3 shows the ex-post load impacts for all SCE's CPP customers. SCE called twelve weekday events in 2023. Overall, SCE's CPP customers had statistically significant load reductions on nine out of twelve event days. The load impact averaged 7 MWh/hour across all event days, which is a 0.6% load reduction. The range of statistically significant load reductions was 2.6 MWh/hour on July 20th to 22.8 MWh/hour on August 17th. There was, on average, a total of 226,193 CPP customers enrolled during the 2023 events.

Figure ES.3: Average Event-Hour Load Impacts by Event, *SCE All*



Large customers had statistically significant load reductions on all but one event day (July 24th), ranging from 2 to 10 MWh/hour. The load impact averaged 5.0 MWh/hour across all event days. Medium customers had statistically significant load reductions on three out of twelve event days. The average event day load impact is 0.7 MWh/hour for medium customers but is not statistically significant. For small customers, six events exhibited reductions in usage that are statistically significant. The average non-holiday weekday load impact of 1.3 MWh/hour was not statistically significant for small customers. Figure ES.4 shows the ex-post load impacts on the average weekday by customer size with 90% confidence intervals.

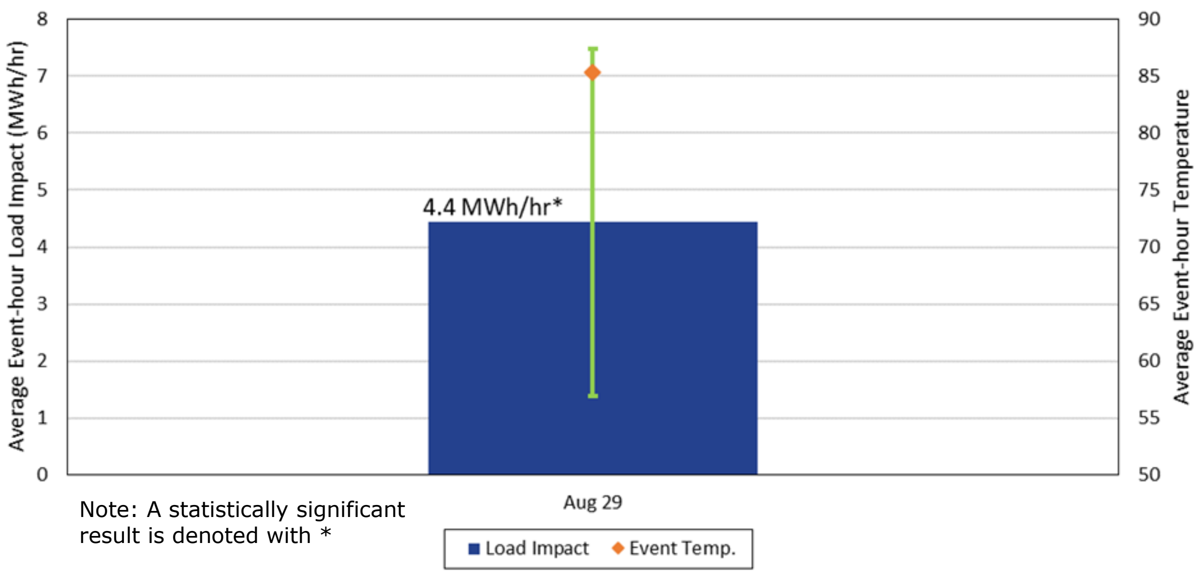
Figure ES.4: Average Event-Hour Load Impacts by Size on Average Weekday, *SCE*



ES.2.4 SDG&E

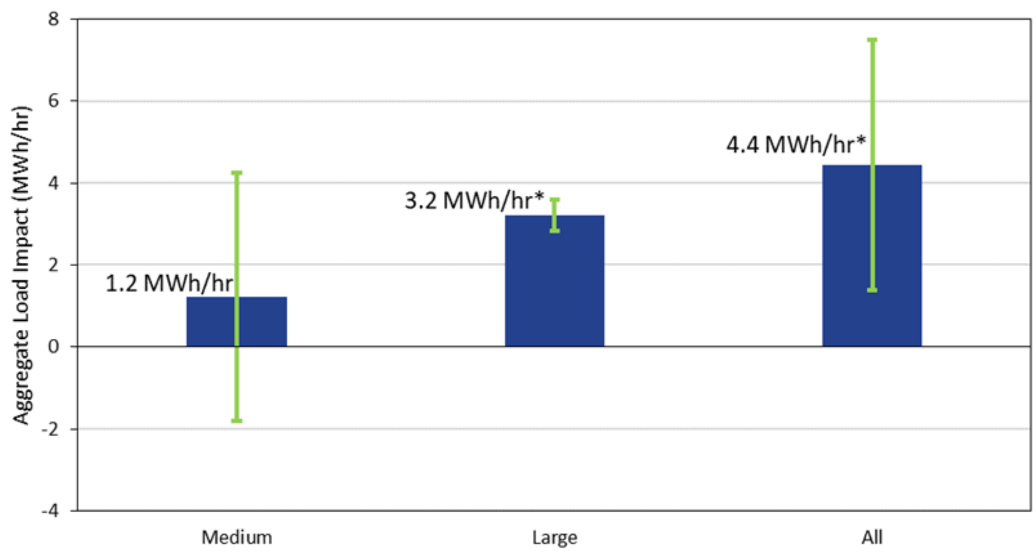
Figure ES.5 shows the ex-post load impact for all SDG&E's CPP customers. Overall, SDG&E's customers had a statistically significant load reduction on the event day. The load impact averaged 4.4 MWh/hour.

Figure ES.5: Average Event-Hour Load Impact, *SDG&E All*



Large customers had a statistically significant load reduction on the event day of 3.2 MWh/hour. Medium customers had a load reduction of 1.2 MWh/hour, though this result is statistically insignificant. Figure ES.6 shows the ex-post load impacts by customer size with 90% confidence intervals.

Figure ES.6: Average Event-Hour Load Impacts by Size, *SDG&E*



ES.3 Ex-Ante Load Impacts

Ex-ante estimates are based on ex-post results with the reference loads simulated to represent the range of weather and day types required by the Protocols.

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

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

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

We conducted this process for each utility, size group (under 20 kW, 20 to 200 kW, and over 200 kW), and LCA. The load impacts are provided for the years 2024 through 2034 for various day types (monthly system peak days) and weather scenarios (utility-specific and CAISO peaking conditions in both 1-in-2 and 1-in-10 scenarios).

ES.3.1 Summary of Ex-ante Load Impacts by Utility

Table ES.2 shows the enrollment forecasts and aggregate load impacts in program years 2024 and 2034 for all three utilities' programs during the RA window on a typical event day. In program year 2024, the utilities forecast 20.0 MW of total load reduction during the RA window, and PG&E has the highest load impacts. In program year 2034, the total forecasted load reduction on a typical event day is 18.2 MW. SCE has the highest load impacts due to an increase in enrollments, while PG&E and SDG&E have lower load impacts than 2024 due to a decline in enrollments.

Table ES.2: Ex-Ante Impacts by Utility: Utility 1-in-2, Typical Event Day

Utility	PY 2024 Enrollment	PY 2024 Load Impact (MW)	PY 2034 Enrollment	PY 2034 Load Impact (MW)
PG&E - PDP	103,659	9.0	75,213	7.4
SCE - CPP	225,082	7.8	244,641	8.4
SDG&E - CPP	2,570	3.2	2,470	2.5
All	**331,311**	**20.0**	**322,324**	**18.2**

ES.3.2 PG&E

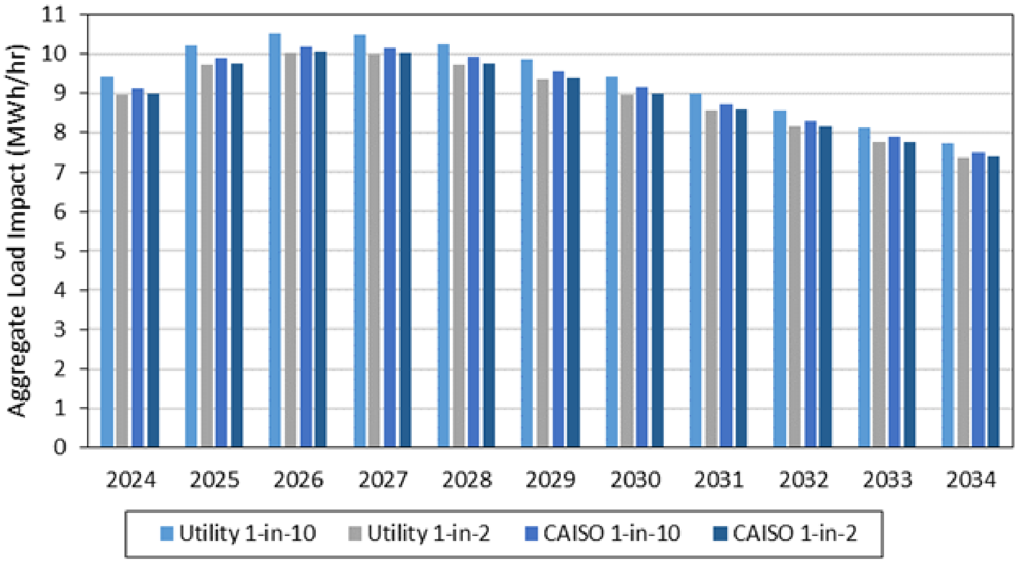
Table ES.3 presents enrollments, aggregate and pre-customer reference loads, and load impacts from 2024 to 2034 under PG&E 1-in-2 weather conditions. Figure ES.7 summarizes the aggregate load impacts associated with each weather scenario (1-in-2 and 1-in-10 PG&E and CAISO weather conditions). The results reflect the Typical Event Day load impacts during the Resource Adequacy (RA) window from 4 to 9 p.m. at August enrollments. The aggregate load impacts increase from 9.0 MWh/hour to 10.0 MWh/hour from 2024 to 2026 and decline to 7.4 MWh/hour in 2034. The main driver of the change in aggregate load impacts is change in enrollments.[2] There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Table ES.3: Typical Event Day Load Impacts, Utility 1-in-2, *PG&E All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	103,659	779.7	9.0	7.5	0.086
2025	107,798	841.9	9.7	7.8	0.090
2026	108,494	865.7	10.0	8.0	0.092
2027	106,575	859.5	10.0	8.1	0.094
2028	102,975	835.6	9.7	8.1	0.095
2029	98,474	801.2	9.4	8.1	0.095
2030	93,634	763.2	9.0	8.2	0.096
2031	88,763	724.2	8.6	8.2	0.096
2032	84,029	685.6	8.1	8.2	0.097
2033	79,509	649.2	7.8	8.2	0.098
2034	75,213	613.9	7.4	8.2	0.098

[2] The per-customer load impacts change slightly over the years due to changes in customer composition.

Figure ES.7: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *PG&E All*



ES.3.3 SCE

Table ES.4 presents enrollments, aggregate and pre-customer reference loads, and load impacts from 2024 to 2034 under SCE 1-in-2 weather conditions. Figure ES.8 summarizes the aggregate load impacts associated with each weather scenario (1-in-2 and 1-in-10 PG&E and CAISO weather conditions). The results reflect the average weekday event day impacts during the RA window from 4 to 9 p.m. at August enrollments. 2034. The main driver of the change in aggregate load impacts is change in enrollments.[3]

Enrollment is forecast to increase by about 2% for each size group until 2028; whereafter, it will be steady for the remainder of the forecast. Therefore, the aggregate load impacts increase from 7.8 MWh/hour to 8.4 MWh/hour from 2024 to 2028 and remain constant until 2034. Ex-ante load impacts are negatively correlated with weather for specific customer size and LCA categories. Therefore, load impacts are smaller for weather scenarios with hotter temperatures. The load impacts for 1-in-10 scenarios are lower than 1-in-2 scenarios. The highest load impacts for each year occur under CAISO 1-in-2 weather conditions.

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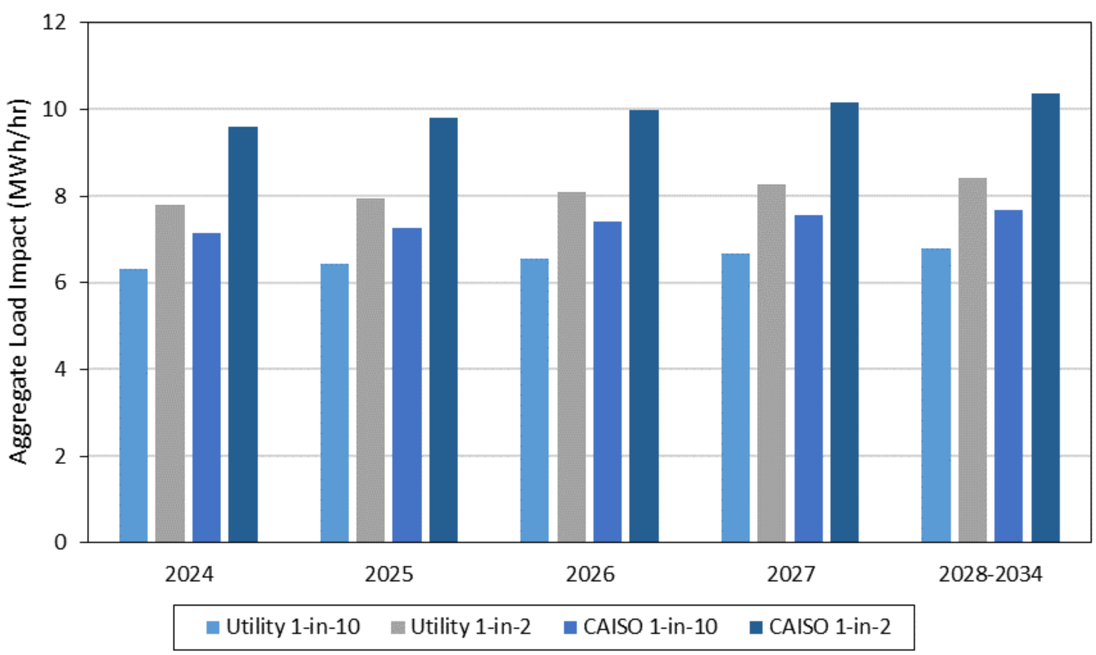
[3] The per-customer load impacts change slightly over the years due to changes in customer composition.

Table ES.4: Typical Event Day Load Impacts, Utility 1-in-2, *SCE All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	225,082	1,269.8	7.8	5.6	0.035
2025	229,973	1,297.4	8.0	5.6	0.035
2026	234,862	1,324.8	8.1	5.6	0.035
2027	239,751	1,352.3	8.3	5.6	0.034
2028	244,641	1,379.6	8.4	5.6	0.034
2029	244,641	1,379.6	8.4	5.6	0.034
2030	244,641	1,379.6	8.4	5.6	0.034
2031	244,641	1,379.6	8.4	5.6	0.034
2032	244,641	1,379.6	8.4	5.6	0.034
2033	244,641	1,379.6	8.4	5.6	0.034
2034	244,641	1,379.6	8.4	5.6	0.034

Figure ES.8: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE All*



ES.3.4 SDG&E

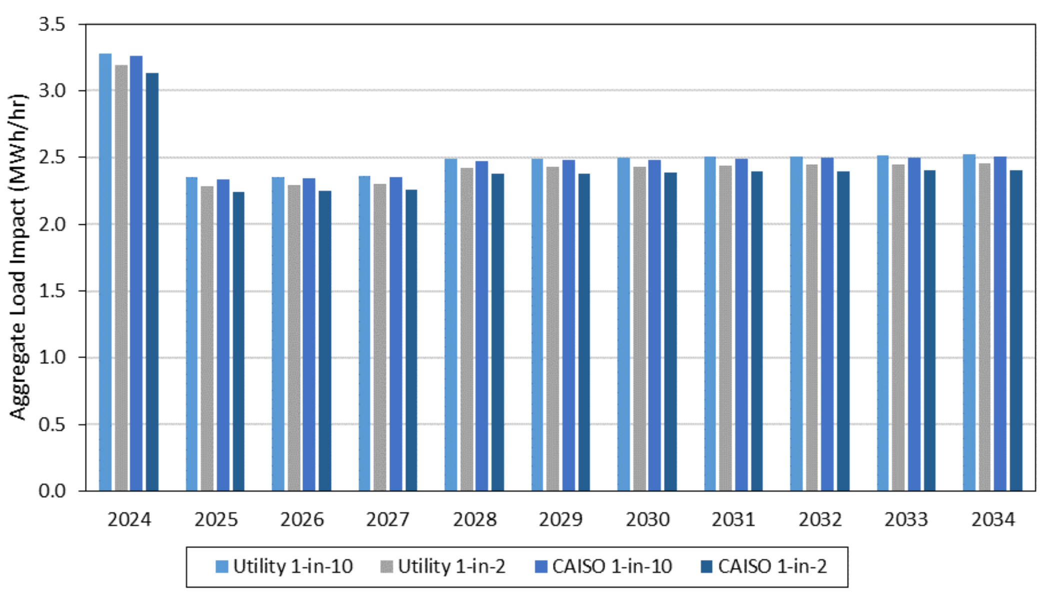
Table ES.5 presents enrollments, aggregate and pre-customer reference loads, and load impacts from 2024 to 2034 under SDG&E 1-in-2 weather conditions. Figure ES.9 summarizes the aggregate load impacts associated with each weather scenario (1-in-2 and 1-in-10 PG&E and CAISO weather conditions). The results reflect the average weekday event day impacts during the RA window from 4 to 9 p.m. at August enrollments.

SDG&E anticipates the total number of customers to decrease sharply until 2025 and thereafter to increase at a pace of about 0.5% each year. Per-customer load impacts vary across years due to changes in customer composition. Aggregate load impacts decrease from 3.2 MWh/hour to 2.3 MWh/hour from 2024 to 2025 due to both the decrease of enrollments and lower per-customer load impacts. Aggregate load impacts increase slightly after 2025 because of forecasted enrollments. The load impacts of the 1-in-10 scenarios are slightly higher than 1-in-2 scenarios because of hotter temperatures and reference loads.

Table ES.5: Typical Event Day Load Impacts, Utility 1-in-2, *SDG&E All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	2,570	102.6	3.2	39.9	1.243
2025	2,365	87.0	2.3	36.8	0.967
2026	2,380	87.5	2.3	36.8	0.964
2027	2,393	87.8	2.3	36.7	0.961
2028	2,405	88.7	2.4	36.9	1.007
2029	2,417	89.1	2.4	36.9	1.004
2030	2,427	89.3	2.4	36.8	1.002
2031	2,438	89.9	2.4	36.9	1.000
2032	2,449	90.3	2.4	36.9	0.998
2033	2,460	90.6	2.4	36.8	0.996
2034	2,470	91.0	2.5	36.8	0.994

Figure ES.9: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E All*



The load impacts of both large and medium customers decrease until 2025 and subsequently increase slightly over time following the trend in enrollments. For both large and medium customers, the largest load impacts occur for the SDG&E 1-in-10 weather year, while the lowest load impacts occur during the CAISO 1-in-2 weather year.

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2023. The evaluation produces estimates of the ex-post load impacts for each hour of each of the utilities' CPP events called in 2023, and it develops ex-ante load impact forecasts of the programs for 2024 through 2034.

California's non-residential CPP programs provide participating customers with lower rates during non-CPP summer season hours and momentary higher rates during CPP event hours when events are called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher-priced critical periods. Customers should benefit financially from the lower rates for electricity consumed outside of the CPP periods. However, new customers to the program are afforded bill protection for the first twelve months after enrollment to ensure that their energy costs on CPP do not exceed their pre-CPP costs while they learn how to respond to the program incentives.

PG&E, SCE, and SDG&E (henceforth the Joint Utilities) have implemented CPP as the default service for their non-residential customers (customers have the option to choose a different rate). PG&E began defaulting their large commercial and industrial (C&I) customers (over 200 kW) onto their CPP rates, called Peak Day Pricing (PDP), in 2010. Although PG&E began defaulting small and medium business (SMB) customers onto PDP in late 2014, they later delayed the process in anticipation of a change in TOU pricing periods and have since resumed defaulting customers onto PDP. SCE began defaulting their large C&I customers onto CPP rates in 2010 and their SMB customers in 2019. SDG&E began defaulting their large C&I customers onto CPP rates in 2009 and their SMB customers in 2018. SDG&E's small business CPP customer performance is analyzed in a separate evaluation and, therefore, will not be included in this evaluation. The Joint Utilities had the following enrollments in CPP on the typical event day in 2023:

Table 1.1: Enrollment by Group Included in the Study

Size Group	PG&E	SCE	SDG&E
Large (Over 200kW)	1,321	1,691	316
Medium (20 to 199kW)	16,807	21,207	2,545
Small (Under 20kW)	89,130	203,294	Excluded

Among the CPP tariffs offered by the Joint Utilities, there are a number of common rate design elements but also some significant differences. PG&E and SDG&E provide a Capacity Reservation option that protects a portion of a customer's load from the CPP rate during events. PG&E only provides this option to its largest C&I and Agricultural customers, while SDG&E offers it to all non-residential customers above 20 kW. Customers on the CPP tariffs offered by the Joint Utilities are also eligible to participate in Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (Auto-DR) programs. The following table summarizes some of the program provisions that vary by utility:

Table 1.2: Event Hours and Allowed Number of Events by Utility

Program Characteristic	PG&E	SCE	SDG&E
Event hours	4 to 9 p.m.	4 to 9 p.m.	4 to 9 p.m.
Events / year	9 to 15	12 to 15	Maximum of 18
Days	All	All	All
Notification	Day ahead, by 4 p.m.	Day ahead, by 3 p.m.	Day ahead, by 3 p.m.

1.1 Project Goals

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2023 by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2023 for each of the utilities' Automated Demand Response (Auto-DR) programs for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2024 through 2034;[4]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

Secondary goals include estimating the effect of event notifications on load impacts and comparing the load impacts for other subgroups of interest for PG&E, such as net energy metered (NEM) customers, Commercial & Industrial (C&I), agricultural, and government rate classes, and customers assigned Business Energy Support (BES)/CRS. The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

[4] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2023), with the values serving as weather-normalized versions of the ex-post load impacts.

1.2 PY2023 Event Days

Table 1.3 summarizes the CPP events for the Joint Utilities. PG&E called nine events, SCE twelve events, and SDG&E one event. The bolded event days occurred on weekends.

Table 1.3: PY2023 CPP Event Dates by Utility

Date	Day of Week	PG&E	SCE	SDG&E
6/30/2023	Friday	X		
7/1/2023	**Saturday**	**X**		
7/14/2023	Friday	X		
7/15/2023	**Saturday**	**X**		
7/17/2023	Monday	X	X	
7/20/2023	Thursday		X	
7/21/2023	Friday	X	X	
7/24/2023	Monday		X	
8/15/2023	Tuesday	X	X	
8/16/2023	Wednesday	X	X	
8/17/2023	Thursday		X	
8/28/2023	Monday		X	
8/29/2023	Tuesday		X	X
8/30/2023	Wednesday		X	
9/25/2023	Monday		X	
9/26/2023	Tuesday	X	X	

1.3 Report Organization

The report is organized as follows:

- Section 2 describes the evaluation methods used in the study.
- Section 3 contains PG&E's load impact results.
- Section 4 contains SCE's load impact results.
- Section 5 contains SDG&E's load impact results.
- Section 6 provides recommendations.
- Appendices describe the results of our model validation process and contain electronic versions of the required Protocol table generators.

2 STUDY METHODOLOGY

The CPP ex-post load impact evaluation uses two methodologies: within-subjects panel models and customer-specific regressions, consistent with the previous evaluation. In both cases, load impact estimates are based on comparisons of event-day loads to non-event day loads, controlling for weather conditions and day type characteristics (e.g., day of week or month of year). Panel models, which combine customers into a model with common estimates, are used for all but the largest CPP customers. For the largest customers, we estimate customer-specific models to properly account for any idiosyncrasies in their load profiles that may affect their load impact estimates.

Ex-ante estimates are based on ex-post load impacts, with the reference loads simulated to represent the range of weather and day types required by the Protocols. Details for the ex-post and ex-ante analyses are provided below.

2.1 Ex-post Load Impact Evaluation

The objectives of the ex-post impact evaluation are described in Section 1.1. This section describes the data and specific methods that we use to meet the objectives, including a discussion of the estimation of uncertainty-adjusted load impacts and distributions of load impacts.

2.1.1 Data

Analyses that address each of the load impact objectives require the following types of data:

- *Customer* information for CPP customers (e.g., date of enrollment and de-enrollment, enrollment dates for other DR programs, LCA, climate zone, weather station, NAICS code, size category);
- Monthly usage from billing data for a 12-month period (used to validate the interval data);
- Billing-based *interval load data* on event and event-like non-event days;
- Billing-based *interval load data* for a sample of customers for a 12-month period (e.g., October 2022 through September 2023), used to simulate ex-ante reference loads;
- *Weather data* (i.e., hourly temperatures and other weather variables for each applicable weather station);
- *Program event data* (i.e., CPP and other demand response (DR) program event dates).

2.1.2 Event-Like Non-Event Day Selection

We select a set of event-like non-event days to best approximate the weather and day types associated with the event days. Weather conditions are assessed using CPP customer-weighted average temperatures across each utility's service territory. This ensures that the weather used in the analysis reflects the conditions faced by the program participants rather than the entire system. Non-event days are selected to closely match the hourly weather profile of event days based on the Euclidean distance between the hourly temperatures on event and non-event days.[5] When selecting days, we exclude event days for other DR programs in which CPP customers may be dually enrolled and ensure that days are selected from a range of time periods (rather than just a series of consecutive dates).

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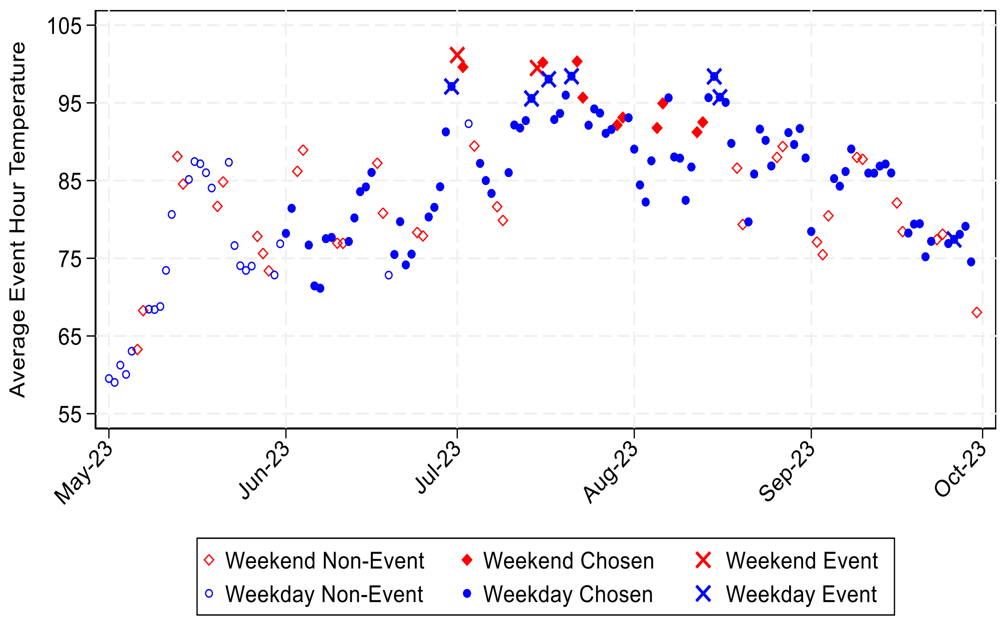
[5] The Euclidean distance is calculated using the following formula (h refers to hour):

$$Distance_{Evt,Non-evt} = \sqrt{(T_{Evt,h=1} - T_{Non-evt,h=1})^2 + (T_{Evt,h=2} - T_{Non-evt,h=2})^2 \ldots + (T_{Evt,h=24} - T_{Non-evt,h=24})^2}$$

Figure 2.1 through Figure 2.3 display the average event-hour temperature for all weekdays, weekends, and holidays between May and September 2023, for the Joint Utilities. Weekdays are represented in blue, while weekends and holidays are represented in red. The event days (represented by "X" markers) between June and August were among the hottest days during 2023.[6] The selected non-event days (represented by filled-in markers) have comparable temperatures to event days.

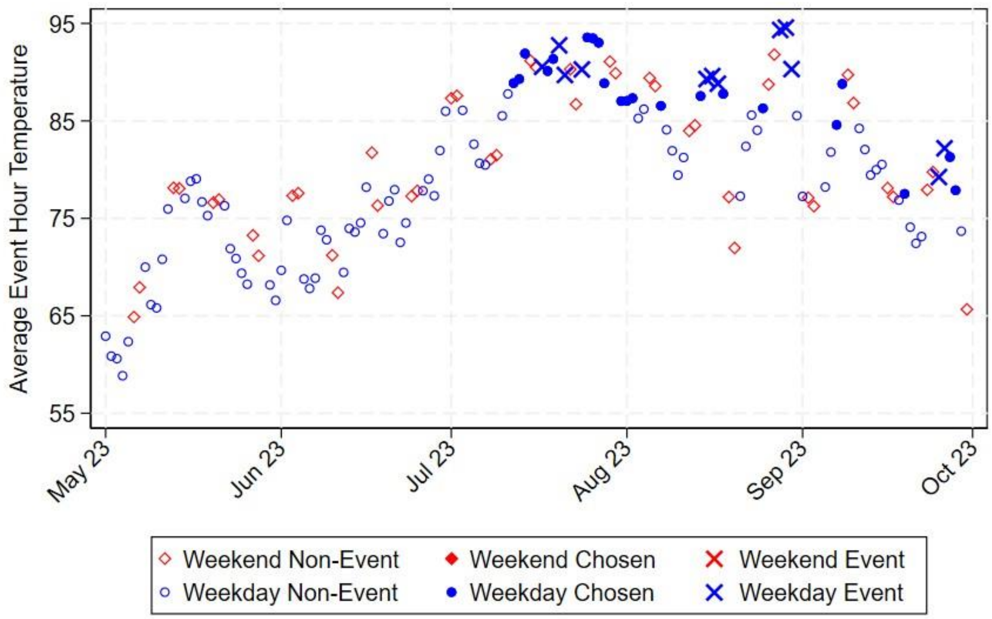
Figure 2.1: Average Event-Hour Temperatures, *PG&E*



Note: Averaged over event hours HE 17-21

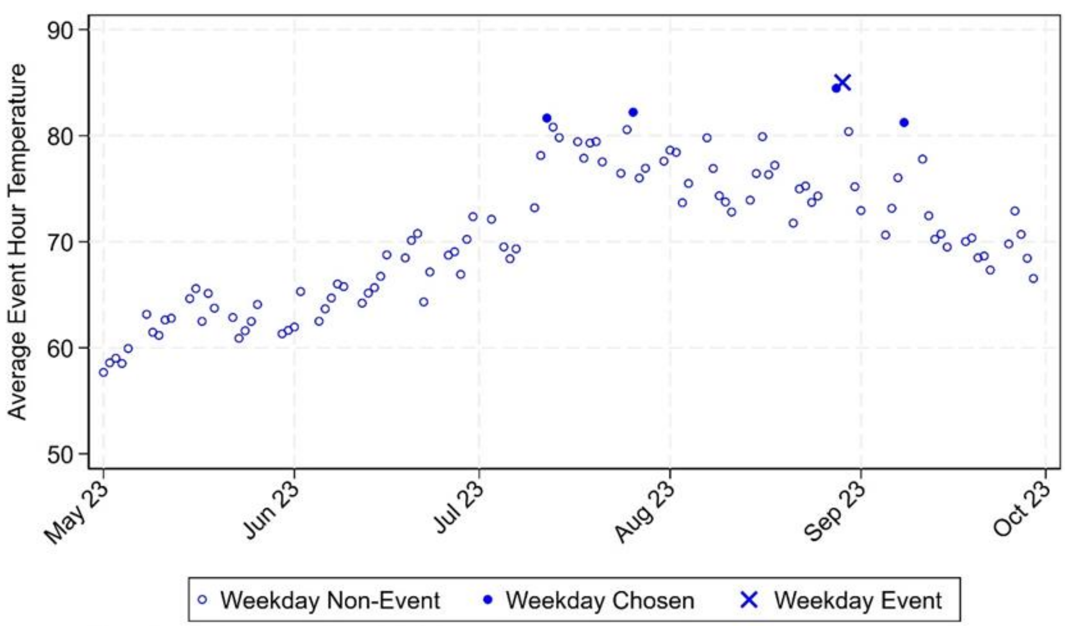
[6] The September event days had cooler temperatures than the other event days. For PG&E, all weekdays between June and September (except holidays and holiday-like days) are selected as proxy days for the September 26th event to reflect the lower event-day temperatures. Similarly for SCE, event-like non-event days with relatively lower temperatures were selected as proxies for the two September event days.

Figure 2.2: Average Event-Hour Temperatures, *SCE*



Note: Averaged over event hours HE 17-21

Figure 2.3: Average Event-Hour Temperatures, *SDG&E*



Note: Averaged over event hours HE 17-21

2.1.3 Model Validation Process

We estimate ex-post hourly load impacts using regression equations applied to hourly load data. The regression equation models hourly load as a function of a set of variables designed to control for factors affecting consumers' hourly demand levels, such as:

- Seasonal and hourly time patterns (e.g., month, day-of-week, and hour, plus various hour/day-type interactions);
- Weather, including hour-specific weather coefficients;
- Event variables. A series of indicator variables that account for each hour of each event day, allowing for estimates of load impacts for every hour of each event day.[7]

We employ both panel and customer-specific regressions, with the latter applied only to the largest customers (differentiated based on average hourly usage during event hours on non-event days). For SCE, we select the top 5% of large customers for customer-specific regressions, which allows us to control for idiosyncratic load profiles of the largest customers separately. For PG&E and SDG&E, we use customer-specific regressions for all large customers. Table 2.1 below provides the classification of customers by regression approach. The usage level, displayed in parentheses, provides an approximation of the size threshold between panel and customer-specific regressions.

Table 2.1: Panel and Customer-Specific Regression Groups

Utility	Size	Panel	Customer-Specific
PG&E	Large	None	All
	Medium	All	None
	Small	All	None
SCE	Large	95% (<600 kWh/hour)	5% (≥ 600 kWh/hour)
	Medium	All	None
	Small	All	None
SDG&E	Large	None	All
	Medium	All	None

We test a variety of weather variables to determine which set best explains usage on event-like non-event days. To determine which variables to include in the model, we go through a model selection and validation process. Model variations are evaluated according to the ability to predict usage on event-like non-event days.

Panel model specifications are evaluated for each utility and customer size. For the customer-specific models, we first classify customers according to whether their hourly loads are responsive to changes in weather conditions (weather-sensitive). Individual models for the largest customers are evaluated by utility, industry group, and weather sensitivity classification. We select specifications by customer group (i.e., sixteen groups,

[7] The included event variables depend on the chosen methodology and are therefore either 1) indicators for each event day or 2) a single event variable representing the average over all events (interacted with a weather variable, notification status, and a weekend indicator variable).

with eight industry groups for each of the non-weather-sensitive customers and weather-sensitive customers). This process and its results are explained in Appendix A.

Our models are validated using out-of-sample predictions for event-like non-event days. That is, we withhold one non-event day at a time, re-estimating the regression and evaluating the predicted vs. actual loads for the withheld day. We consider a variety of model specifications that differ by which weather variables and day type variables are included and choose the model that best predicts customer load profiles on non-event days. Model selections are based on statistical parameters such as mean and absolute percentage errors. In addition, we conduct robustness checks of our estimates, comparing them to alternate specifications and models that include a control group.

2.1.4 Regression Model

A typical form for our within-subjects ex-post evaluation model is shown below. The specific form of the model varies across utilities and customer groups, as shown in Appendix A. For customer-specific regressions, we estimate load impacts across all hours of the day by interacting these regression terms with the hour of the day. The model below is written to apply to a single customer; however, it can be modified to represent a panel model by adding customer fixed effects and customer subscripts to the appropriate variables. We estimate the panel models separately for each hour of the day and customer subgroup.[8] The variables used in the regression specifications are explained in Table 2.2.

$$Q_t = a + \sum_{Evt=1}^{E}(b^{Evt} \times CPP_t) + b^{MornLoad} \times MornLoad_t + b^{Wth} \times Wth_t + b^{OthDR} \times OthDR_t + \sum_{j=days\ of\ week} b^j \times DayType_t^j + \sum_{j=months} b^j \times Month_t^j + e_t$$

This specification is referred to as the *event-specific indicator approach*. The first term in the equation containing a summation sign is the component that allows estimation of event-specific load impacts for each hour of the day (the b^{Evt} coefficients). This approach identifies how customers respond differently on event days relative to non-event days while controlling for other factors included in the model (weather, day-type, etc.).

Another specification we incorporate is known as the *functional form approach*. In this approach, the specification models the relationship between the average event day response and factors introduced to explain the variation in load impacts across event days, including weather, notification status, and whether the event occurred on a weekend. The functional form model specification is shown below:

[8] Panel regressions are estimated by size, LCA, and industry group. LCA-level results are aggregated to calculate program-level load impacts. Other subsets of results are estimated by via LCA-level regressions that included an interaction term between the event variables and the specific subgroup of interest (e.g., AutoDR, dually enrolled, customers that receive event notifications).

$$
\begin{aligned}
Q_t = a + b^1 \times CPP_t + b^2 \times (CPP_t \times Wth_t) + b^3 \times (CPP_t \times Notification_t) \\
+ b^4 \times (CPP_t \times Weekend_t) + b^{MornLoad} \times MornLoad_t \\
+ b^{Wth} \times Wth_t + b^{OthDR} \times OthDR_t + \sum_{j=days\,of\,week} b^j \times DayType_t^j \\
+ \sum_{j=months} b^j \times Month_t^j + e_t
\end{aligned}
$$

The event-specific load impacts using the functional form approach are simulated by combining the estimated coefficients that include the event indicator (CPP_t) with the specific weather, notification status, and weekend status of each event, as follows (where b_t^{Evt} is the CPP load impact during event t):

$$b_t^{Evt} = b^1 + b^2 \times Wth_t + b^3 \times Notification_t + b^4 \times Weekend_t$$

The method used to estimate ex-post load impacts differs by utility. The functional form approach is used for PG&E, while the event-specific indicator approach is used for SCE and SDG&E.[9]

[9] The two approaches produce the same answer for the typical event day (when the model is otherwise identical); the methods differ in how they allow load impacts to vary across event days. Both approaches have merit and circumstances may dictate a preference for one over the other. For SDG&E, only one event was called, so both approaches will produce the same result. We chose the functional form approach for PG&E based on the utility's preference.

Table 2.2: Regression Model Variables

Variable Name / Term	Variable / Term Description
Q_t	the customer's usage on day *t*
a and the various *b's*	the estimated parameters
CPP_t	an indicator variable for CPP event days
$Notification_t$	an indicator variable for whether a notification was successfully sent
$Weekend_t$	an indicator variable for whether day t is a weekend
Wth_t	weather conditions on day *t* (e.g., measured by CDD, CDH, THI, or Irradiance)[10]
E	the number of event days that occurred during the program year
$MornLoad_t$	two separate variables equal to the average of the day's load[11]
$DayType^j_t$	an indicator variable for day of week *j* on date *t*[12]
$Month^j_t$	a series of indicator variables for each month[13]
$OthDR_t$	a series of indicator variables representing event days for other DR programs in which the service account is enrolled
e_t	the error term.

The terms in the equation not related to the CPP event day are designed to control for weather and other periodic factors (e.g., days of the week and months of the year) that determine customers' loads. See Appendix A for a summary of the specifications considered for each size group and industry type.

The "morning load" variables are used in the same spirit as the optional day-of adjustment to the 10-in-10 baseline method currently used in some DR programs (e.g., CBP). That is, they are intended to adjust the reference load (the regression-based estimate of the loads that would have occurred in the absence of the event day) for unobserved exogenous factors that may affect customers' loads on a given day. The use of the morning load variable assumes that variations in the morning load are related to variations in reference loads later in the day but that the changes in the morning load are not part of the customer's response to the event itself (e.g., pre-cooling the building in anticipation of an event). Similarly, in some cases, a lagged variable of usage is used to account for changes in customer loads over the analysis period.[14]

[10] We also investigate the inclusion of additional daily weather variables to control for days that have significant buildup of heat, including daily lags of CDD or average temperatures before the event window. These controls were included in addition to the weather variables that were selected during the course of the model validation process and were only added to the panel models and the large customer models for weather sensitive large customers.

[11] For PG&E small and medium customers, in 1) hours-ending 1 through 10 and 2) hours-ending 11 through 15. For PG&E large customers, in 1) hours-ending 1 through 8 and 2) hours-ending 9 through 15. For SCE and SDG&E, in 1) hours-ending 1 through 7 and 2) hours-ending 8 through 14.

[12] In the panel models we only include indicator variables for Mondays and Fridays in the weekday models and Sundays in the weekend/holiday models.

[13] The month fixed effects are omitted from the SDG&E panel models due including only a select number of days that serve as a proxy to the single event day. For SCE, a school indicator variable is used in place of the month fixed effect to account for school begins on August 14th, 2023.

[14] Lagged usage was incorporated for PG&E large customers as well as SDG&E customers.

Estimating distributions of load impacts for different customer segments

The distribution of load impacts across different subgroups of customers is explored by performing load impact analyses at the subgroup level (e.g., load impacts for AutoDR participants, by LCA, or industry group) using interacted models for the panel regressions as previously described.

Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. Thus, in addition to producing point estimates of the ex-post load impacts, we produce *uncertainty-adjusted* program impacts for each event, which show the uncertainty around the estimated impacts, including the 10th, 30th, 50th, 70th, and 90th percentile load changes. These percentiles were generated using the standard errors from the corresponding ex-post regression parameters.

2.2 Developing Ex-Ante Load Impacts

Ex-ante load impacts are created for the following subgroups of customers:

1. Utility program;
2. Size group (under 20 kW, 20 to 200 kW, and over 200 kW); and
3. LCA.

In addition, separate program-specific and portfolio-level forecasts are developed to account for dual enrollment in other DR programs. The program-specific load impacts reflect the full enrollment of the CPP program, while the portfolio-level impacts remove the load impacts from the dual enrolled customers that take priority over CPP (e.g., BIP).

The load impacts are provided for the years 2024 through 2034[15] for several day types and weather scenarios, including the following:

- A typical event day under the four weather scenarios, defined by both utility-specific and CAISO peaking conditions in both 1-in-2 (normal) and 1-in-10 (extreme) scenarios and
- The monthly system peak load day of each month, again under the above four weather scenarios.

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

- A utility-provided *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
- *Reference loads* by customer type;

[15] PG&E and SDG&E requested the inclusion of a "back-cast" of 2023 load impacts, which we also provide.

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

2.2.1 Reference Loads

The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios. The reference load regression models require a full year of load profile data (as opposed to the ex-post regression models, which include only event and event-like days). Reference loads are simulated using the appropriate weather scenario data (i.e., the 1-in-2 and 1-in-10 weather-year conditions to be provided by the utilities) and event-day characteristics (e.g., weekday and weekend).

2.2.2 Per-customer Load Impacts

Per-customer load impacts are derived from an analysis of the current and previous ex-post load impact evaluations, with a particular focus on differences in load impacts across customer types. We use ex-post load impact estimates from the typical event day in 2023 (and 2022 for SCE[16]) to calculate percentage load impacts (the hourly load impact divided by the hourly reference load) for customer groups that are reported in the ex-ante analysis. The resulting per-customer percentage load impacts are then applied to the appropriate simulated reference loads to develop the forecast load impacts. CPP load impacts must be forecast for all months of the year, even though we have historically observed events only during summer months.

We investigate the effect of weather on estimated load impacts to determine whether a statistically significant relationship exists.[17] If so, then the ex-post percentage load impacts that are applied to ex-ante reference loads are adjusted based on the ex-ante weather conditions. For example, if we find that percentage load impacts decrease as temperatures increase, then the ex-ante percentage load impact will also be lower for hotter ex-ante weather scenarios. Likewise, the load impact percentage would increase under cooler ex-ante weather scenarios. Where applicable, the method of weather-adjusted load impact percentages is only applied to ex-ante reference loads during months that have temperatures that were observed in ex-post. For example, percentage load impacts are not adjusted for January because no ex-post events were called in that month.

Uncertainty-adjusted load impacts were generated using the standard errors from the ex-post typical event day load impacts. Scenario-specific percent load impacts were developed from 10th, 30th, 50th, 70th, and 90th percentile load changes estimated for the relevant program year.

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[16] In discussions with SCE, we agreed to use two years of ex-post data for ex-ante forecast.

[17] For SCE, we find a negative relationship between percentage load impacts and temperature. We discuss this analysis further in Section 4.1.8. For PG&E, the relationship between estimated load impacts and temperature is not statistically significant for the majority of LCAs, so for each LCA, the same ex-post percentage load impacts are applied for all ex-ante weather conditions.

3 PG&E

Table 3.1 summarizes the aggregate load impacts in ex-post and ex-ante by size. In ex-post, large customers provide 44% of the aggregate load impacts with only 1% of enrollments. Enrollments are slightly lower in 2024 for three size groups, and aggregate load impacts drop by 0.6 MWh/hour. Enrollments further drop in 2034 for all size groups, and aggregate load impacts are 1.6 MWh/hour lower than in 2024.

Table 3.1: Aggregate Ex-Post and Ex-Ante Load Impacts by Size

Outcome	Size	Ex-Post	Ex-Ante 2024	Ex-Ante 2034
# Enrolled	Small	89,130	86,814	62,819
	Medium	16,807	15,657	11,307
	Large	1,321	1,188	1,087
	All	**107,258**	**103,659**	**75,213**
Load Impact (MW)	Small	2.3	2.1	1.6
	Medium	3.1	3.0	2.1
	Large	4.2	3.9	3.7
	All	**9.6**	**9.0**	**7.4**

3.1 PG&E Ex-Post Load Impacts

This section documents the findings from the ex-post load impact analysis for PG&E. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per customer, for the typical event day as well as for each individual event. Results for all hours for the typical event day are also illustrated in figures and presented in data tables. Detailed results for each hour for each event are available in electronic form in the protocol table generators provided along with this report.

As described in Section 2.1.3, all results presented in this section are derived from either customer-specific or panel fixed-effects regression analyses of hourly data for PDP customers. The estimated model is described in Section 2.1.4 and Appendix A, with the PG&E model including the variables that account for morning load, temperature variations, lagged daily temperature measures, and usage. Furthermore, we control for concurrent BIP events by including indicators for customers who are dually enrolled in PDP and BIP and who are called for any BIP events that occur during any PDP event or non-event day. The evaluation of model specification selection is presented in the appendix.

3.1.1 All Customers

This section summarizes results for all PG&E customers. The average event-hour load impacts for all customers of PG&E are summarized in Figure 3.1. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90% confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

PG&E customers achieve statistically significant load reductions on all nine event days as well as on the typical event day. The load impact is highest on July 15th. The weekend events, July 1st and July 15th, have the highest temperatures. Overall, Figure 3.1 does not show evidence of a strong relationship between load impacts and average event temperatures. For instance, July 1st has the hottest temperature, but the load impact is only the fourth highest. September 26th has the coolest temperature, but the load impact is higher than August 15th and August 16th, which have much higher temperatures.

Figure 3.1: Average Event-Hour Load Impacts by Event, *PG&E All*

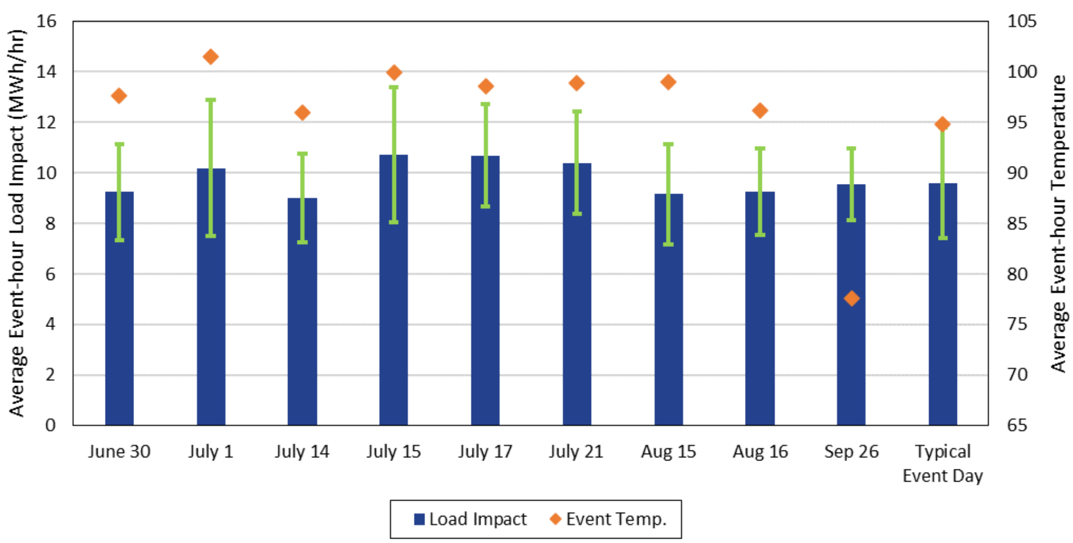


Table 3.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a decrease of more than 1,300 customers over the course of the season. Aggregate load impacts range from 9.0 MWh/hour on July 14th to 10.7 MWh/hour on July 15th and 17th. The estimated load reduction for the typical event day is 9.6 MWh/hour, which is a 1.1% load reduction[18]. Detailed results by hour, industry group, and LCA are presented in subsequent subsections by size group.

[18] The typical event day represents a non-holiday, weekday impact and therefore excludes the weekend events July 1st and July 15th.

Table 3.2: Average Event-Hour Load Impacts by Event, *PG&E All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	107,888	840	9.2	7.8	0.09	1.1%	97.6
7/1/2023	107,832	782	10.2	7.2	0.09	1.3%	101.5
7/14/2023	107,525	837	9.0	7.8	0.08	1.1%	96.0
7/15/2023	107,520	789	10.7	7.3	0.10	1.4%	99.9
7/17/2023	107,495	879	10.7	8.2	0.10	1.2%	98.6
7/21/2023	107,396	878	10.4	8.2	0.10	1.2%	98.9
8/15/2023	106,979	910	9.2	8.5	0.09	1.0%	99.0
8/16/2023	106,968	897	9.3	8.4	0.09	1.0%	96.2
9/26/2023	106,556	693	9.6	6.5	0.09	1.4%	77.6
Typical Event Day	**107,258**	**847**	**9.6**	**7.9**	**0.09**	**1.1%**	**94.8**

3.1.2 Large Customers

This section summarizes results for all large PG&E customers, defined as customers with maximum demand over 200 kW. The presented results include the average event-hour load impact by event day, the hourly load impact for the typical event day, and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for customers dually enrolled in the BIP program, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural, commercial, and government rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's large PDP customers are summarized for all nine events in Figure 3.2. Each element of the figure has the same meaning as Figure 3.1.

Large customers had statistically significant load reductions on all nine event days. Figure 3.2 does not show evidence of a strong relationship between load impacts and event temperatures. The coolest day (September 26th) has the third-highest load impact. July 17th and August 15th have comparable temperatures, but the load impact on August 15th is much lower than July 17th.

Figure 3.2: Average Event-Hour Load Impacts by Event, *PG&E Large*

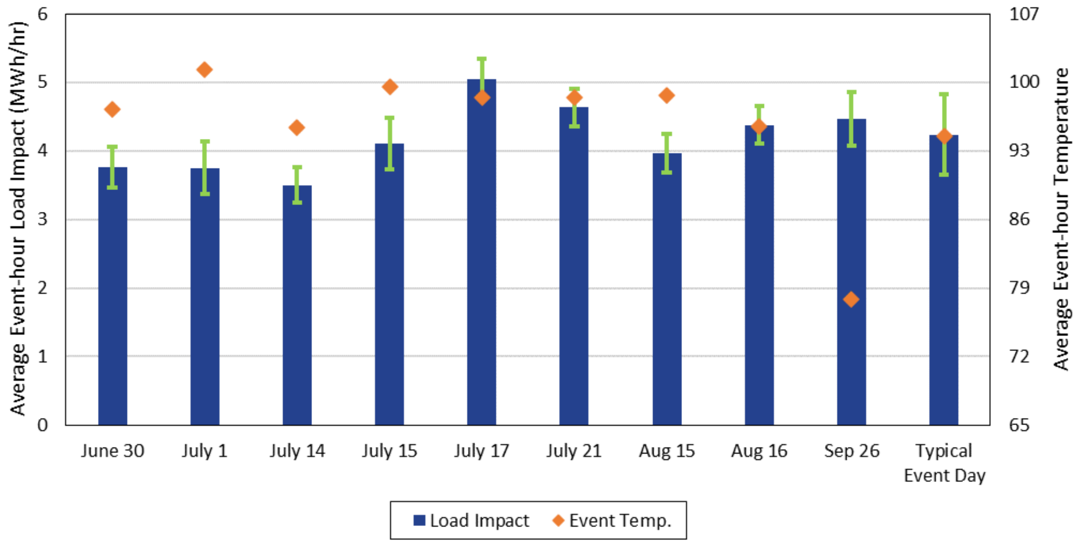


Table 3.3 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a slight decrease in large customer enrollments over the course of the season. Aggregate load impacts range from 3.5 MWh/hour on July 14th to 5.1 MWh/hour on July 17th. The estimated load reduction for the typical event day is 4.2 MWh/hour, which is a 1.5% load reduction.

Table 3.3: Average Event-Hour Load Impacts by Event, *PG&E Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	1,345	268	3.8	199.4	2.80	1.4%	97.2
7/1/2023	1,345	238	3.7	176.8	2.79	1.6%	101.3
7/14/2023	1,327	271	3.5	204.5	2.64	1.3%	95.4
7/15/2023	1,327	244	4.1	183.7	3.09	1.7%	99.6
7/17/2023	1,326	286	5.1	215.6	3.81	1.8%	98.5
7/21/2023	1,324	284	4.6	214.3	3.50	1.6%	98.5
8/15/2023	1,309	294	4.0	224.7	3.03	1.3%	98.7
8/16/2023	1,309	291	4.4	222.6	3.35	1.5%	95.5
9/26/2023	1,307	268	4.5	204.9	3.42	1.7%	77.9
Typical Event Day	**1,321**	**280**	**4.2**	**211.9**	**3.21**	**1.5%**	**94.5**

Figure 3.3 shows the per-customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 3.4 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty-adjusted load impacts. The load impacts for large customers range from 2.5 kWh/customer/hour (1.2%) in the fifth event hour (8 to 9 p.m.) to 3.7 kWh/customer/hour (1.7%) in the second event hour (5 to 6 p.m.). The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are load impacts of approximately 2.1 kWh/customer/hour in the hour immediately preceding (3 to 4 p.m.) and 0.3 kWh/customer/hour in the hour following the event (9 to 10 p.m.). Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

Figure 3.3: Typical Event Day Reference Loads and Load Profile, *PG&E Large*

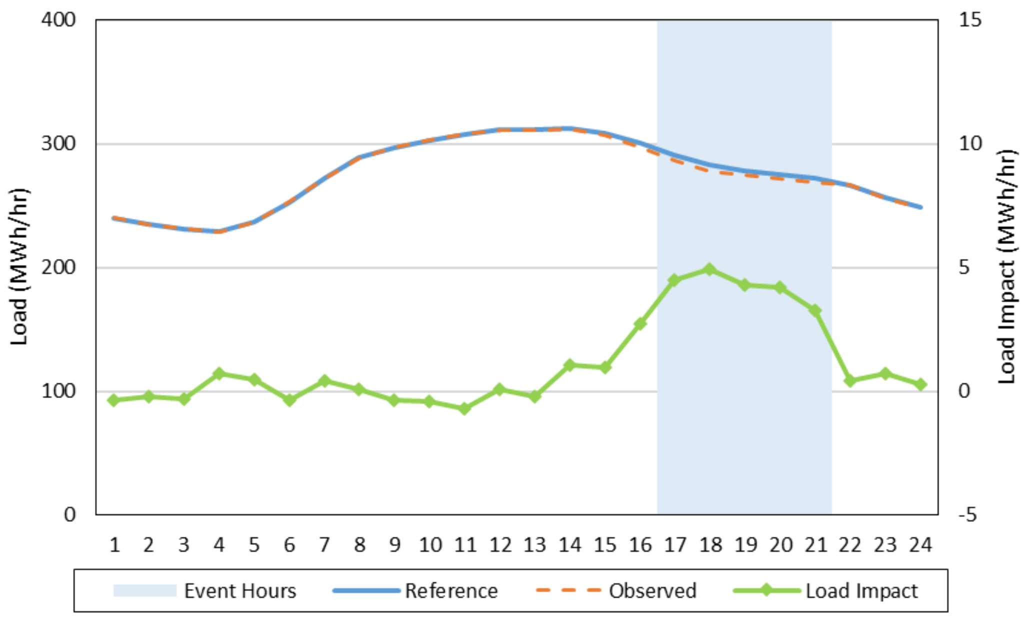


Table 3.4: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by Hour, *PG&E Large*

Hour Ending	Estimated Reference Load (kW)	Observed Event Day Load (kW)	Estimated Load Impact (kW)	Load Impact (%)	Weighted Average Temperature (^oF)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	181.9	182.1	-0.3	-0.1%	78.6	-0.7	-0.4	-0.3	-0.1	0.2
2	177.7	177.8	-0.2	-0.1%	77.3	-0.6	-0.3	-0.2	0.0	0.2
3	174.7	174.9	-0.2	-0.1%	75.8	-0.6	-0.4	-0.2	-0.1	0.2
4	173.6	173.1	0.5	0.3%	74.4	0.2	0.4	0.5	0.7	0.9
5	179.5	179.1	0.4	0.2%	72.9	0.0	0.2	0.4	0.5	0.7
6	191.1	191.4	-0.3	-0.1%	71.9	-0.7	-0.4	-0.3	-0.1	0.1
7	206.1	205.8	0.3	0.2%	71.6	-0.3	0.1	0.3	0.6	0.9
8	218.6	218.5	0.1	0.0%	74.1	-0.6	-0.2	0.1	0.3	0.7
9	224.6	224.8	-0.2	-0.1%	77.7	-0.8	-0.5	-0.2	0.0	0.3
10	228.8	229.1	-0.3	-0.1%	81.5	-0.8	-0.5	-0.3	-0.1	0.2
11	232.9	233.4	-0.5	-0.2%	85.1	-1.0	-0.7	-0.5	-0.4	-0.1
12	235.5	235.4	0.1	0.0%	88.3	-0.4	-0.1	0.1	0.3	0.5
13	235.6	235.7	-0.2	-0.1%	91.0	-0.7	-0.4	-0.2	0.1	0.4
14	236.7	235.9	0.8	0.3%	93.7	0.3	0.6	0.8	1.0	1.3
15	233.4	232.6	0.7	0.3%	95.8	0.2	0.5	0.7	1.0	1.3
16	227.3	225.3	2.1	0.9%	97.1	1.4	1.8	2.1	2.3	2.7
17	220.1	216.7	3.4	1.5%	97.7	2.7	3.1	3.4	3.7	4.1
18	214.1	210.3	3.7	1.7%	97.1	2.9	3.4	3.7	4.1	4.5
19	210.9	207.6	3.2	1.5%	95.3	2.5	2.9	3.2	3.6	4.0
20	208.6	205.4	3.2	1.5%	92.7	2.4	2.9	3.2	3.5	3.9
21	205.9	203.5	2.5	1.2%	89.7	1.7	2.2	2.5	2.8	3.3
22	202.0	201.7	0.3	0.2%	86.7	-0.5	0.0	0.3	0.7	1.1
23	194.6	194.0	0.5	0.3%	84.1	-0.2	0.2	0.5	0.8	1.3
24	188.3	188.1	0.2	0.1%	81.5	-0.5	-0.1	0.2	0.5	1.0
Daily	**5,002.1**	**4,982.3**	**19.9**	**0.4%**	**84.7**	**19.7**	**19.8**	**19.9**	**19.9**	**20.0**

Next, we look at PG&E large customer estimates by industry group. Table 3.5 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments and loads are concentrated in the Agriculture, Mining & Construction; Wholesale, Transportation & Utilities; Manufacturing; and Offices, Hotels, Health & Services industry groups. Wholesale, Transportation & Utilities has the highest aggregate load impact (1.69 MWh/hour) and the highest percentage load impact (3.6%). The only other industry group to achieve more than 1 MWh/hour of load impact is Agriculture, Mining & Construction.

Table 3.5: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Large*

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1.Agriculture, Mining, Construction	553	68	67	1.05	1.5%
2.Manufacturing	179	53	53	0.91	1.7%
3.Wholesale, Transportation, Utilities	199	47	45	1.69	3.6%
4.Retail Stores	41	11	11	0.06	0.5%
5.Offices, Hotels, Health, Services	172	59	59	0.09	0.1%
6.Schools	55	6	6	-0.01	-0.2%
7. Institutional/Government	[redacted]				
8.Other					

To better understand the distribution of results across industries, we look at the shares of estimated load impacts, reference loads, and enrollments by industry group in Figure 3.4. Agriculture, Mining & Construction; Wholesale, Transportation & Utilities; Manufacturing; and Offices, Hotels, Health & Services industry groups represent a combined 84% of large customers and 83% of reference loads. The load impacts for large customers are driven by three industry groups (Wholesale, Transport & Utilities, Agriculture, Mining & Construction, and Manufacturing), which account for 88% of load impacts. Moreover, Wholesale, Transport & Utilities contributes a much higher share of the total load impacts (41%) compared to the share of enrollments (14%) and reference loads (20%).

Figure 3.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Large*

[redacted]

Table 3.6 and Figure 3.5 provide the summaries like those above by LCA. Large customers are concentrated in the Greater Fresno Area and Other LCA, which have reference loads of 79 MWh/hour and 97 MWh/hour, respectively. These two LCAs also account for the majority of the typical event day load impacts with a 0.86 MWh/hour (1.1%) load reduction for Greater Fresno Area and a 2.32 MWh/hour (2.4%) load reduction for Other LCA. Figure 3.5 reflects the prominence of these two LCAs, although Greater Fresno Area has a lower share (20%) of the load impacts compared to the share of customers and reference loads, while Other LCA has a greater share (55%) of the load impacts compared to the share of customers and reference loads.

Table 3.6: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Large*

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	70	22	21	0.48	2.2%
Greater Fresno	474	79	78	0.86	1.1%
Humboldt	[redacted]				
Kern	130	40	40	0.02	0.1%
North Coast/North Bay	[redacted]				
Sierra	91	14	14	0.02	0.1%
Stockton	116	24	23	0.52	2.2%
Other/Unknown	410	97	95	2.32	2.4%

Figure 3.5: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Large*

[redacted]

3.1.3 Medium Customers

This section summarizes results for all medium PG&E customers, defined as customers with maximum demand between 20 and 199.99 kW. The presented results include the average event-hour load impact by event day, the hourly load impact for the typical event day, and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for customers dually enrolled in the BIP program, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural, commercial, and government rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's medium PDP customers are summarized for all nine events in Figure 3.6. Medium customers have statistically significant load reductions on all nine event days and during the typical event day. Figure 3.6 does not show evidence of a strong relationship between load impacts and event temperatures. While load impacts are the highest on the two weekend events with the highest temperatures, the coolest event on September 26th has higher load impacts than August 15th and August 16th, which have much higher temperatures.

Figure 3.6: Average Event-Hour Load Impacts by Event, *PG&E Medium*

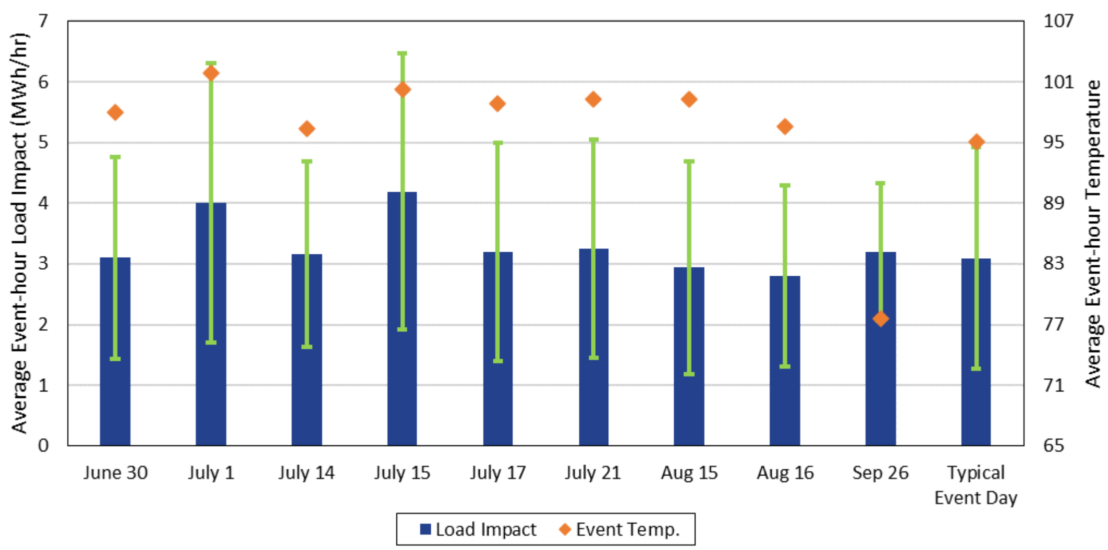


Table 3.7 summarizes enrollments, estimated load impacts, and reference loads for medium customers on each event day as well as for the typical event day. Enrollments decreased slightly over the season for medium customers. Aggregate load impacts range from 2.8 MWh/hour on August 16th to 4.2 MWh/hour on July 15th. The estimated load reduction for the typical event day is 3.1 MWh/hour, which is a 0.8% load reduction.

Table 3.7: Average Event-Hour Load Impacts by Event, *PG&E Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	16,881	383	3.1	22.7	0.18	0.8%	98.0
7/1/2023	16,874	365	4.0	21.7	0.24	1.1%	101.8
7/14/2023	16,835	377	3.2	22.4	0.19	0.8%	96.4
7/15/2023	16,835	366	4.2	21.7	0.25	1.1%	100.3
7/17/2023	16,834	395	3.2	23.4	0.19	0.8%	98.8
7/21/2023	16,820	396	3.3	23.5	0.19	0.8%	99.2
8/15/2023	16,774	410	2.9	24.5	0.18	0.7%	99.3
8/16/2023	16,772	404	2.8	24.1	0.17	0.7%	96.6
9/26/2023	16,736	288	3.2	17.2	0.19	1.1%	77.6
Typical Event Day	**16,807**	**379**	**3.1**	**22.6**	**0.18**	**0.8%**	**95.1**

Figure 3.7 plots per-customer loads for medium customers for the typical event day. Table 3.8 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty-adjusted load impacts for the typical event day for medium customers. The load impacts for medium customers range from 0.12 kWh/customer/hour (0.6%) in the fifth event hour (8 to 9 p.m.) to 0.26 kWh/customer/hour (1.0%) in the first event hour (4 to 5 p.m.). The hourly load impact estimates do not show evidence of a pre-cooling effect. There is some indication of a possible post-event snapback as loads increase in hours following the events.

Figure 3.7: Typical Event Day Reference Loads and Load Profile, *PG&E Medium*

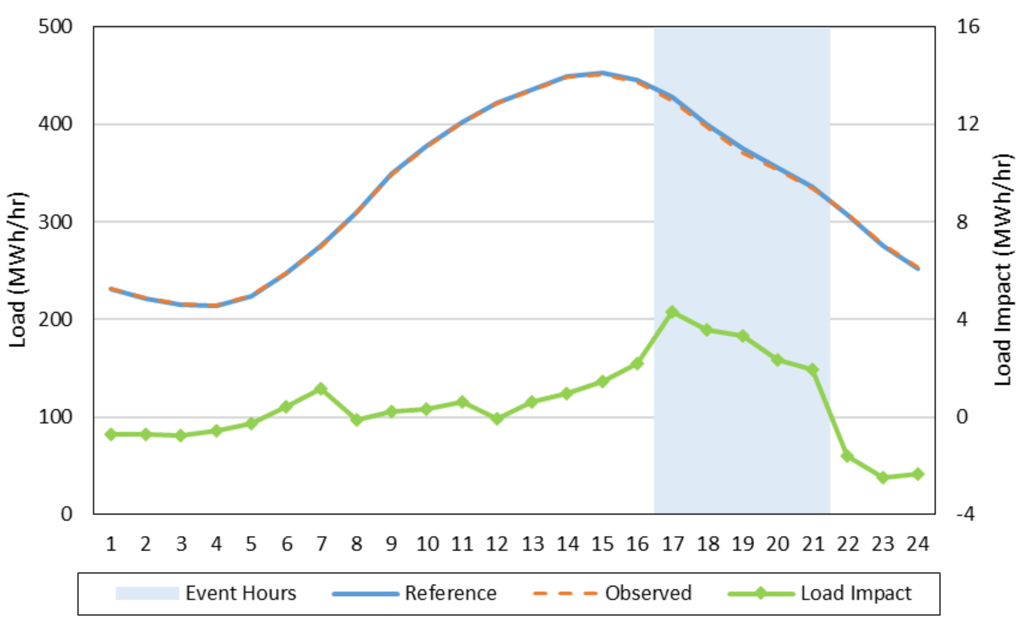


Table 3.8: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Medium*

Hour Ending	Estimated Reference Load (kW)	Observed Event Day Load (kW)	Estimated Load Impact (kW)	Load Impact (%)	Weighted Average Temperature (^{o}F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	13.7	13.8	0.0	-0.3%	78.3	-0.1	-0.1	0.0	0.0	0.0
2	13.2	13.2	0.0	-0.3%	76.9	-0.1	-0.1	0.0	0.0	0.0
3	12.8	12.8	0.0	-0.4%	75.3	-0.1	-0.1	0.0	0.0	0.0
4	12.7	12.8	0.0	-0.3%	73.8	-0.1	0.0	0.0	0.0	0.0
5	13.3	13.3	0.0	-0.1%	72.5	0.0	0.0	0.0	0.0	0.0
6	14.7	14.7	0.0	0.2%	71.5	0.0	0.0	0.0	0.0	0.1
7	16.4	16.4	0.1	0.4%	71.2	0.0	0.1	0.1	0.1	0.1
8	18.4	18.4	0.0	0.0%	73.9	-0.1	0.0	0.0	0.0	0.1
9	20.8	20.8	0.0	0.1%	77.8	-0.1	0.0	0.0	0.0	0.1
10	22.5	22.5	0.0	0.1%	81.9	-0.1	0.0	0.0	0.0	0.1
11	24.0	23.9	0.0	0.2%	85.6	0.0	0.0	0.0	0.1	0.1
12	25.1	25.1	0.0	0.0%	89.0	0.0	0.0	0.0	0.0	0.0
13	25.9	25.9	0.0	0.1%	91.7	0.0	0.0	0.0	0.0	0.1
14	26.7	26.7	0.1	0.2%	94.6	0.0	0.0	0.1	0.1	0.1
15	26.9	26.9	0.1	0.3%	96.8	0.0	0.1	0.1	0.1	0.1
16	26.5	26.4	0.1	0.5%	98.1	0.1	0.1	0.1	0.2	0.2
17	25.5	25.2	0.3	1.0%	98.7	0.2	0.2	0.3	0.3	0.3
18	23.8	23.6	0.2	0.9%	98.0	0.1	0.2	0.2	0.2	0.3
19	22.3	22.1	0.2	0.9%	96.0	0.1	0.2	0.2	0.2	0.3
20	21.2	21.0	0.1	0.7%	93.1	0.0	0.1	0.1	0.2	0.2
21	20.0	19.9	0.1	0.6%	89.7	0.0	0.1	0.1	0.2	0.2
22	18.3	18.4	-0.1	-0.5%	86.6	-0.2	-0.1	-0.1	0.0	0.0
23	16.4	16.5	-0.1	-0.9%	83.9	-0.3	-0.2	-0.1	-0.1	0.0
24	15.0	15.1	-0.1	-0.9%	81.4	-0.2	-0.2	-0.1	-0.1	0.0
Daily	**476.1**	**475.3**	**0.8**	**0.2%**	**84.8**	**-0.2**	**0.4**	**0.8**	**1.2**	**1.8**

Table 3.9 and Figure 3.8 summarize aggregate event-hour results for the typical event day for eight industry groups. Table 3.8 presents the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Figure 3.8 illustrates the share of enrollments, reference loads, and load impacts. Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 36% of enrollments and 165 MWh of reference load. This industry group contributes 1.06 MWh/hour to the total load reduction, which is 33% of the total load reduction. Agriculture, Mining, & Construction contributes 1.03 MWh/hour of load reduction, which is 32% of the total load reduction and 6.6% of their reference load. Figure 3.8 illustrates that the Agriculture, Mining, & Construction industry contributes a much higher share of the total load impacts compared to enrollments and reference loads. In total, these two industry groups contribute 65% of the total load reduction.

Table 3.9: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Medium*

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1.Agriculture, Mining, Construction	853	16	15	1.03	6.6%
2.Manufacturing	1,071	17	16	0.40	2.4%
3.Wholesale, Transportation, Utilities	2,247	39	39	0.47	1.2%
4.Retail Stores	2,437	69	69	0.00	0.0%
5.Offices, Hotels, Health, Services	6,118	165	164	1.06	0.6%
6.Schools	721	18	18	-0.35	-2.0%
7. Institutional/Government	2,987	49	48	0.24	0.5%
8.Other	376	7	7	0.00	0.0%

Figure 3.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Medium*

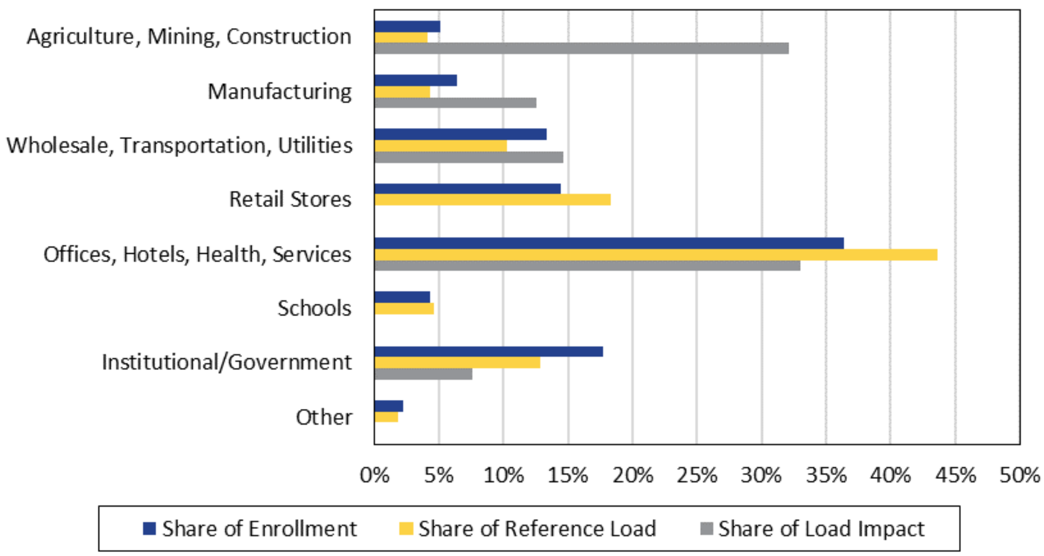
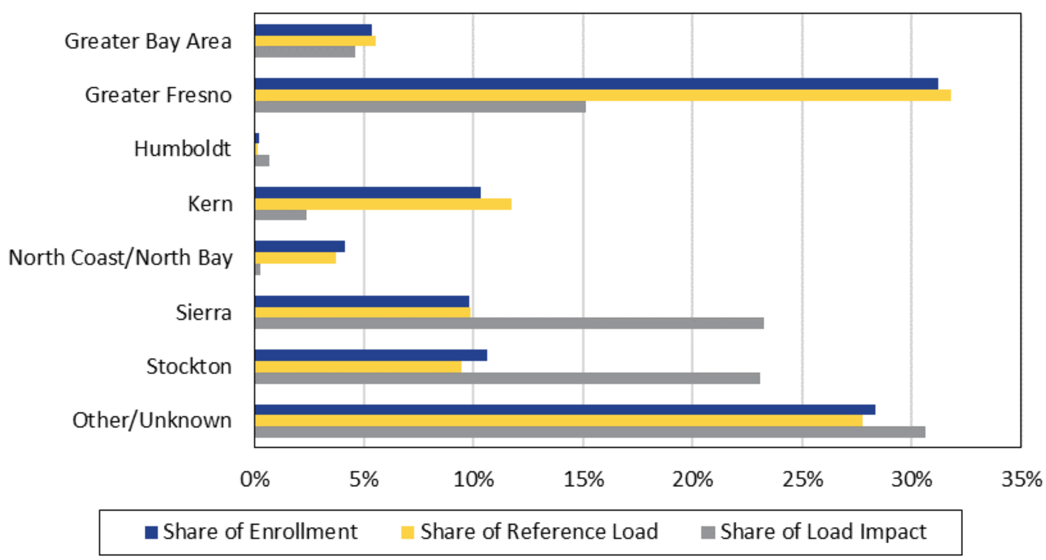


Table 3.10 and Figure 3.9 summarize the results by LCA for medium customers. As with the large customers, enrollments are concentrated in the Greater Fresno Area and Other LCA, which together contain 60% of medium customers and account for 120 MWh/hour and 105 MWh/hour of reference loads, respectively. Estimated load impacts are the greatest for Other, Sierra, and Stockton LCAs, together accounting for 2.38 MWh/hour or 77% of the total estimated load reduction. Figure 3.9 shows that Other LCA, Sierra, and Stockton have larger shares of the total load impacts compared to the share of enrollments or reference loads.

Table 3.10: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Medium*

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	902	21	21	0.14	0.7%
Greater Fresno	5,241	120	120	0.47	0.4%
Humboldt	36	0	0	0.02	4.4%
Kern	1,738	44	44	0.07	0.2%
North Coast/North Bay	692	14	14	0.01	0.1%
Sierra	1,649	37	37	0.72	1.9%
Stockton	1,786	36	35	0.71	2.0%
Other/Unknown	4,763	105	104	0.95	0.9%

Figure 3.9: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Medium*



3.1.4 Small Customers

This section summarizes results for all small PG&E customers, defined as customers with maximum demand below 20 kW. The presented results include the average event-hour load impact by event day, the hourly load impact for the typical event day, and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for customers dually enrolled in the BIP program, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural, commercial, and government rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's small PDP customers are summarized for all nine events in Figure 3.10. The small customers have statistically significant positive load impacts on all nine event days and the typical event day. Figure 3.10 does not show evidence of a strong relationship between load impacts and event temperatures. The highest and second highest load impacts occurred on July 21st and July 17th, with only the fourth and fifth highest temperatures, respectively.

Figure 3.10: Average Event-Hour Load Impacts by Event, *PG&E Small*

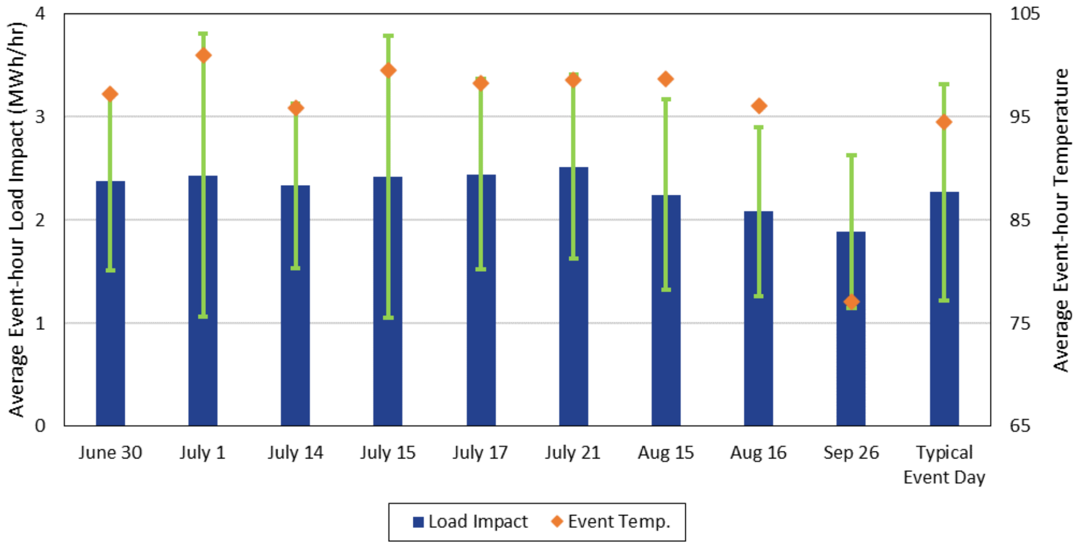


Table 3.11 summarizes enrollments, estimated load impacts, and reference loads for small customers on each event day as well as for the typical event day. Aggregate load impacts range from 1.9 MWh/hour on September 26th to 2.5 MWh/hour on July 21st. The estimated load reduction for the typical event day is 2.3 MWh/hour, which is a 1.2% load reduction.

Table 3.11: Average Event-Hour Load Impacts by Event, *PG&E Small*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	89,662	189	2.4	2.1	0.03	1.3%	97.3
7/1/2023	89,613	178	2.4	2.0	0.03	1.4%	101.0
7/14/2023	89,363	188	2.3	2.1	0.03	1.2%	95.9
7/15/2023	89,358	180	2.4	2.0	0.03	1.3%	99.5
7/17/2023	89,335	199	2.4	2.2	0.03	1.2%	98.3
7/21/2023	89,252	198	2.5	2.2	0.03	1.3%	98.6
8/15/2023	88,896	205	2.2	2.3	0.03	1.1%	98.7
8/16/2023	88,887	201	2.1	2.3	0.02	1.0%	96.1
9/26/2023	88,513	136	1.9	1.5	0.02	1.4%	77.0
Typical Event Day	**89,130**	**188**	**2.3**	**2.1**	**0.03**	**1.2%**	**94.5**

Figure 3.11 plots per-customer loads for small customers for the typical event day. Table 3.12 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty-adjusted load impacts for the typical event day for small customers. The load impacts for small customers range from 0.005 kWh/customer/hour (0.3%) in the fifth event hour (8 to 9 p.m.) to 0.05 kWh/customer/hour (2.0%) in the first event hour (4 to 5 p.m.). The hourly load impact estimates do not show evidence of pre-cooling. There is some indication of a possible post-event snapback as loads increase following the event.

Figure 3.11: Typical Event Day Reference Loads and Load Profile, *PG&E Small*

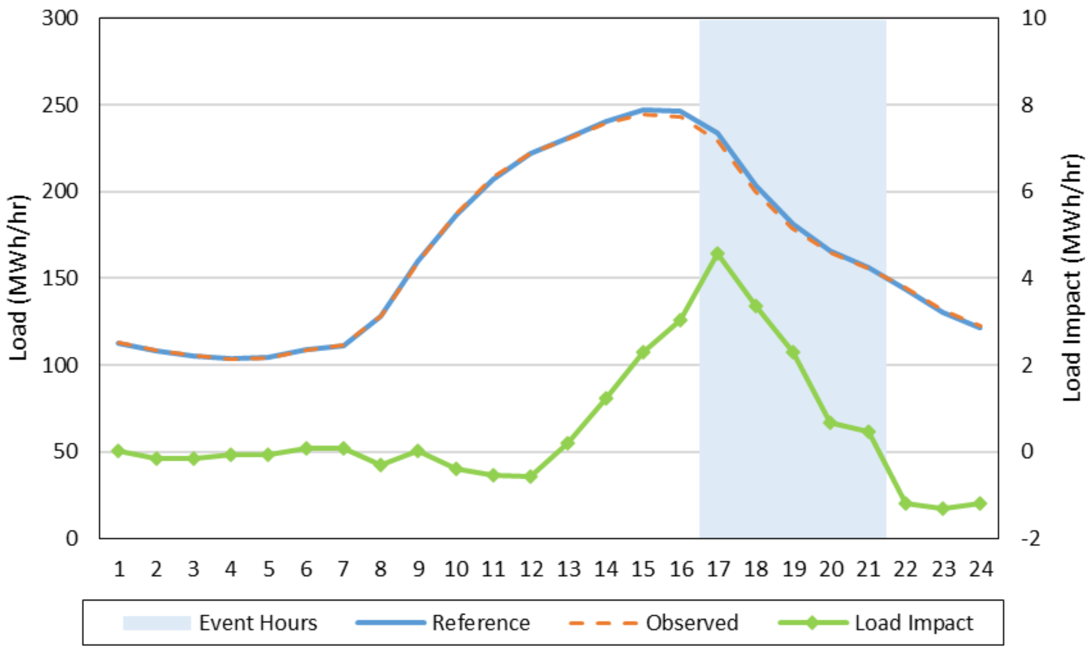


Table 3.12: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, PG&E Small

Hour Ending	Estimated Reference Load (kW)	Observed Event Day Load (kW)	Estimated Load Impact (kW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	1.3	1.3	0.0	0.0%	77.6	0.0	0.0	0.0	0.0	0.0
2	1.2	1.2	0.0	-0.1%	76.2	0.0	0.0	0.0	0.0	0.0
3	1.2	1.2	0.0	-0.1%	74.6	0.0	0.0	0.0	0.0	0.0
4	1.2	1.2	0.0	-0.1%	73.2	0.0	0.0	0.0	0.0	0.0
5	1.2	1.2	0.0	-0.1%	71.9	0.0	0.0	0.0	0.0	0.0
6	1.2	1.2	0.0	0.1%	70.9	0.0	0.0	0.0	0.0	0.0
7	1.2	1.2	0.0	0.1%	70.7	0.0	0.0	0.0	0.0	0.0
8	1.4	1.4	0.0	-0.2%	73.5	0.0	0.0	0.0	0.0	0.0
9	1.8	1.8	0.0	0.0%	77.6	0.0	0.0	0.0	0.0	0.0
10	2.1	2.1	0.0	-0.2%	81.8	0.0	0.0	0.0	0.0	0.0
11	2.3	2.3	0.0	-0.3%	85.6	0.0	0.0	0.0	0.0	0.0
12	2.5	2.5	0.0	-0.3%	88.9	0.0	0.0	0.0	0.0	0.0
13	2.6	2.6	0.0	0.1%	91.6	0.0	0.0	0.0	0.0	0.0
14	2.7	2.7	0.0	0.5%	94.4	0.0	0.0	0.0	0.0	0.0
15	2.8	2.7	0.0	0.9%	96.6	0.0	0.0	0.0	0.0	0.0
16	2.8	2.7	0.0	1.2%	97.9	0.0	0.0	0.0	0.0	0.0
17	2.6	2.6	0.05	2.0%	98.4	0.0	0.0	0.1	0.1	0.1
18	2.3	2.2	0.04	1.6%	97.6	0.0	0.0	0.0	0.0	0.0
19	2.0	2.0	0.03	1.3%	95.5	0.0	0.0	0.0	0.0	0.0
20	1.9	1.9	0.01	0.4%	92.4	0.0	0.0	0.0	0.0	0.0
21	1.8	1.7	0.01	0.3%	88.9	0.0	0.0	0.0	0.0	0.0
22	1.6	1.6	0.0	-0.8%	85.7	0.0	0.0	0.0	0.0	0.0
23	1.5	1.5	0.0	-1.0%	83.1	0.0	0.0	0.0	0.0	0.0
24	1.4	1.4	0.0	-1.0%	80.7	0.0	0.0	0.0	0.0	0.0
Daily	**44.4**	**44.3**	**0.1**	**0.3%**	**84.4**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**

Table 3.13 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 36% of enrollments and 83 MWh/hour of reference loads. While no industry group achieves 1 MWh/hour of load reduction, Offices, Hotel, Health & Services has the highest load impact of 0.59 MWh/hour. Figure 3.12 illustrates the shares of enrollment, reference load, and load impact by industry group. Offices, Hotel, Health & Services and Wholesale, Transportation & Utilities contribute the majority of the total load reduction at 57%, and both Wholesale, Transportation and Utilities and Agriculture, Mining & Construction contribute a higher share of load impacts than their share of enrollments or reference loads.

Table 3.13: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Small*

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1. Agriculture, Mining, Construction	6,520	10	10	0.19	1.8%
2. Manufacturing	2,660	5	5	0.04	0.9%
3. Wholesale, Transportation, Utilities	15,381	19	18	0.38	2.0%
4. Retail Stores	8,328	28	28	0.24	0.9%
5. Offices, Hotels, Health, Services	31,707	83	83	0.59	0.7%
6. Schools	1,257	3	3	-0.03	-1.0%
7. Institutional/Government	17,588	31	30	0.25	0.8%
8. Other	5,689	8	8	0.01	0.2%

Figure 3.12: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Small*

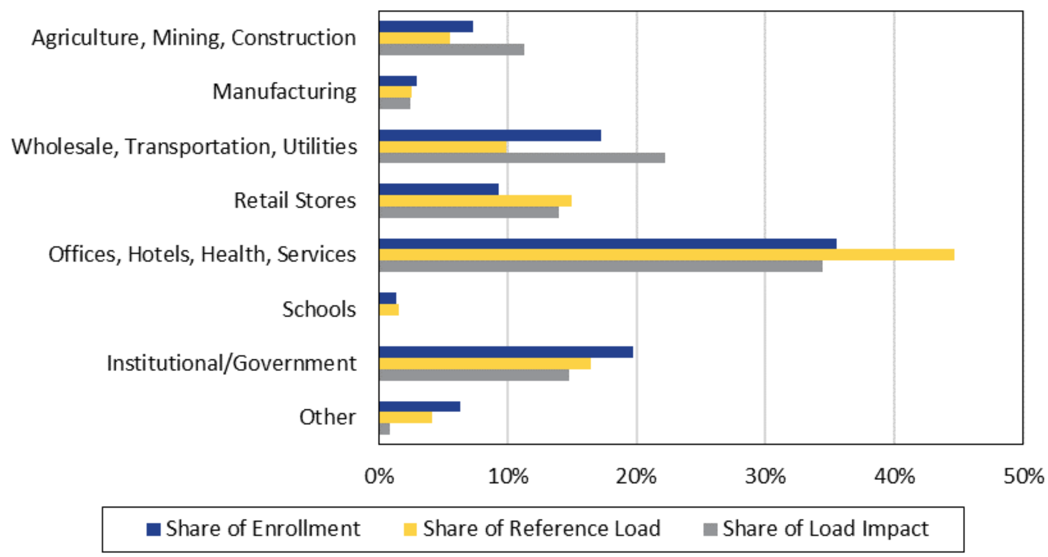
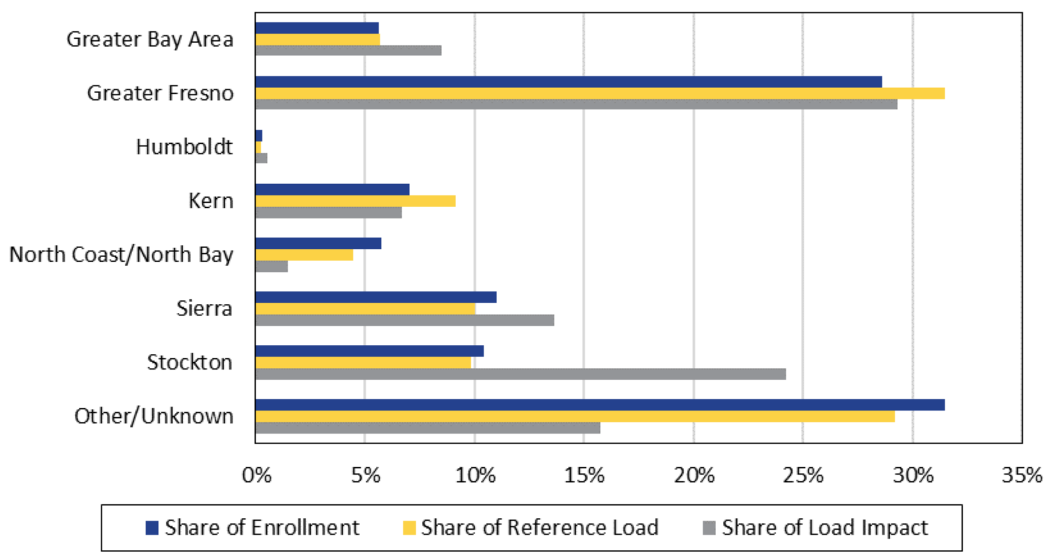


Table 3.14 and Figure 3.13 summarize the results by LCA for small customers. As with the large and medium customers, enrollments are concentrated in the Greater Fresno Area and Other LCA, which together contain 60% of small customers and account for 59 MWh/hour and 55 MWh/hour of reference loads. The majority of the load impact comes from Greater Fresno and Stockton, with a combined 1.21 MWh/hour load impact or 54% of the total load impacts, although no single LCA's load impact exceeds 1 MWh/hour. Figure 3.13 shows that Greater Bay Area, Sierra, and Stockton have a larger share of the total load reduction compared to their share of enrollments and reference loads.

Table 3.14: Typical Event Day Load Event-Hour Load Impacts by LCA, *PG&E Small*

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	4,992	11	10	0.19	1.8%
Greater Fresno	25,466	59	58	0.66	1.1%
Humboldt	248	0	0	0.01	2.5%
Kern	6,248	17	17	0.15	0.9%
North Coast/North Bay	5,086	8	8	0.03	0.4%
Sierra	9,783	19	19	0.31	1.6%
Stockton	9,263	18	18	0.55	3.0%
Other/Unknown	28,044	55	55	0.36	0.6%

Figure 3.13: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Small*



3.1.5 Dually Enrolled Customers

This section summarizes results for customers who are dually enrolled in PDP and BIP. We present results for the average event hour for each event day and the typical event day. Additional results for these customers can be found in electronic form in the protocol table generators provided along with this report.

Table 3.15 summarizes the average event-hour results for each event day as well as the typical event day for customers who are dually enrolled in BIP and PDP, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). [redacted]

Table 3.15: Average Event-Hour Load Impacts for PDP+BIP customers by Event, *PG&E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	[redacted]						
7/1/2023							
7/14/2023							
7/15/2023							
7/17/2023							
7/21/2023							
8/15/2023							
8/16/2023							
9/26/2023							
Typical Event Day							

3.1.6 AutoDR Customers

This section summarizes results for all PDP customers who participated in the Automated Demand Response (AutoDR) program, which provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention.

We present results for the average event hour for each event day as well as for the typical event day. Additional results for these customers can be found in electronic form in the protocol table generators provided along with this report.

Table 3.16 summarizes aggregate event-hour results for each event day as well as the typical event day for PDP customers who participate in AutoDR, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). [redacted]

[redacted]

Table 3.16: Average Event-Hour Load Impacts for AutoDR Customers by Event, *PG&E*[19]

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/30/2023	[redacted]						
7/1/2023							
7/14/2023							
7/15/2023							
7/17/2023							
7/21/2023							
8/15/2023							
8/16/2023							
9/26/2023							
Typical Event Day							

3.1.7 Customer Outreach Programs

This section compares customers who receive notifications or Business Energy Support (BES/CRS) versus customers who do not. We contrast average load impacts for the typical event day for customers that successfully receive notifications or have BES/CRS compared to those who do not by size group. Additional results for these customers can be found in electronic form in the protocol table generators provided along with this report.

Table 3.17 and Table 3.17 summarize aggregate event-hour results for the typical event day, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). Notifications are sent a day ahead of each event, either by email, fax, phone, or SMS. 80% of customers successfully receive notifications on average, and these customers generate 79% of the aggregate load impacts. [redacted]

[19] The load impacts on the following days are not statistically significant at the 10% level: 6/30/2023, 7/14/2023, 7/17/2023, 7/21/2023, 8/15/2023 and the Typical Event Day.

The results for BES/CRS customers show that this customer support program is highly targeted towards large customers: 46% of large customers have BES/CRS compared to 24% of medium customers and 16% of small customers (17% of all customers). Large and small BES/CRS customers generate higher per-customer load impacts, leading to this group representing a larger share of large and small load impacts compared to the share of enrollments. Customers receiving BES/CRS support generate 43% of aggregate load impacts compared to 17% of enrollments.

Table 3.17: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, *PG&E*

Size	Notified	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Large	Yes	1,168	248.7	3.9	213.0	3.34	1.6%	94.6
	[redacted]							
Medium	Yes	13,958	320.7	2.2	23.0	0.16	0.7%	95.1
	[redacted]							
Small	Yes	70,169	154.4	1.4	2.2	0.02	0.9%	94.6
	No	18,961	33.4	0.8	1.8	0.04	2.5%	94.4
All	Yes	85,295	723.9	7.5	8.5	0.09	1.0%	94.8
	No	21,963	122.6	2.0	5.6	0.09	1.7%	94.5

Table 3.18: Average Event-Hour Load Impacts on Typical Event Day by Size and BES/CRS Status, *PG&E*

Size	Have BES/CRS	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Large	Yes	607	182.8	3.1	301.2	5.1	1.7%	94.5
	No	714	95.6	1.1	133.9	1.6	1.2%	94.5
Medium	Yes	4,088	121.8	0.5	29.8	0.1	0.4%	95.2
	No	12,719	257.4	2.6	20.2	0.2	1.0%	95.1
Small	Yes	13,963	29.0	0.6	2.1	0.04	1.9%	94.0
	No	75,166	159.1	1.7	2.1	0.02	1.1%	94.6
All	Yes	18,659	333.7	4.2	17.9	0.2	1.2%	94.7
	No	88,599	512.2	5.4	5.8	0.1	1.1%	94.8

3.1.8 Other Subgroup Results

This section summarizes the average load impacts for customers in the agricultural, commercial, and government rate classes, and NEM customers. We present results for the average event hour for the typical event day by size group. Additional results for these customers can be found in electronic form in the protocol table generators provided along with this report.

Table 3.19 summarizes aggregate event-hour results for the typical event day for PDP customers of different subgroups, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads).

The results for the rate classes show that most customers (97%) are on a commercial/industrial rate class. However, 36% of large customers are on an agricultural rate class. The agricultural rate class has higher load impacts both in per-customer terms (0.82 kWh/customer/hour) and as a percent of reference loads (2.6%) and generates 16% of the load impacts despite having only 2% of customers. The commercial rate class has the highest aggregate load impacts at 8.0 MWh/hour.

The results for NEM customers suggest that only large NEM customers reduce loads during PDP events. Only 2% of PDP customers are NEM customers, but the share of medium and large customers is higher at 4% and 9%, respectively.

Table 3.19: Average Event-Hour Load Impacts on Typical Event Day by Size and Subgroup, *PG&E*

Size	Subgroup	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Large	AGR	476	47.6	0.4	100.02	0.84	0.8%	96.7
	COM/IND	832	215.8	3.8	259.36	4.55	1.8%	94.2
	ST GOV	[redacted]						
	NEM	124	35.1	0.6	283.12	4.61	1.6%	94.6
	All	1,321	279.9	4.2	211.90	3.21	1.5%	94.5
Medium	AGR	270	7.1	1.0	26.27	3.54	13.5%	96.5
	COM/IND	16,335	367.9	2.1	22.52	0.13	0.6%	95.1
	ST GOV	203	4.0	0.1	19.83	0.47	2.4%	94.4
	NEM	726	18.0	-0.4	24.78	-0.53	-2.1%	94.4
	All	16,807	379.0	3.1	22.55	0.18	0.8%	95.1
Small	AGR	1,110	2.6	0.2	2.33	0.15	6.4%	96.3
	COM/IND	87,090	183.7	2.1	2.11	0.02	1.2%	94.5
	ST GOV	926	1.9	0.0	2.00	-0.01	-0.5%	94.8
	NEM	960	2.6	-0.1	2.67	-0.15	-5.5%	94.6
	All	89,130	188.1	2.3	2.11	0.03	1.2%	94.5
All	AGR	1,856	57.3	1.5	30.87	0.82	2.6%	96.6
	COM/IND	104,257	767.3	8.0	7.36	0.08	1.0%	94.7
	ST GOV	[redacted]						
	NEM	1,810	55.5	0.0	30.69	0.03	0.1%	94.6
	All	107,258	847.1	9.6	7.90	0.09	1.1%	94.8

3.2 PG&E Ex-Ante Load Impacts

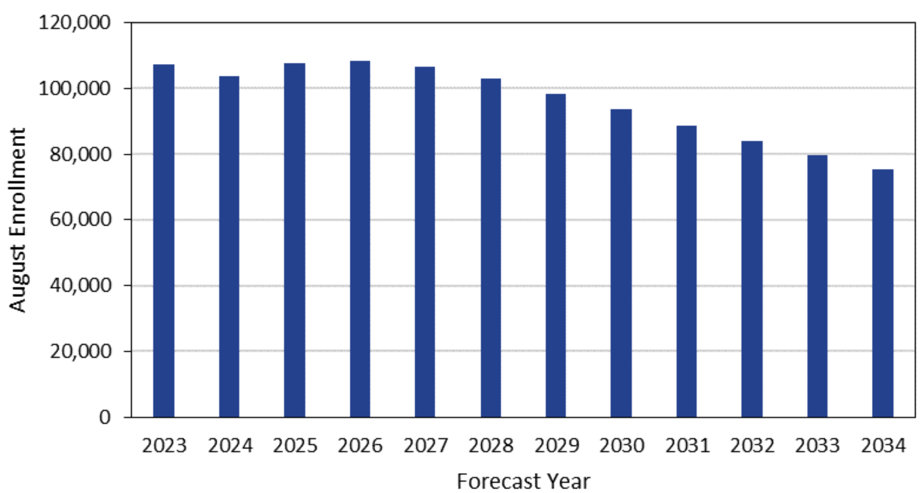
This section provides the ex-ante load impact forecasts for PDP based on an enrollment forecast provided by PG&E. Results are presented by size group. Within each size group, we present the following: a summary of the enrollment forecast provided by PG&E; a figure showing the hourly reference loads and load impacts on a typical event day; a figure showing the share of load impacts by LCA; a table and a figure showing the seasonal pattern of load impacts; and a figure summarizing annual load impacts by weather scenario. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

3.2.1 All Customers

Figure 3.14 summarizes the overall trend of PG&E's enrollment forecast. Table 3.20 provides enrollment counts and aggregate and per-customer load impacts from 2024 to 2034 on Typical Event Day under PG&E 1-in-2 weather conditions. PG&E anticipates an annual attrition of 5.55%.[20] The forecast also considers agriculture and commercial & industrial customers defaulting to PDP in March and November of each year, respectively. From 2024 to 2026, the defaulting rate is higher than overall attrition, so enrollments increase from 103,659 to 108,494. By 2027, the total count of customers leaving the program will surpass the number of new customers joining as eligible pool of customers exponentially decreases. Enrollments diminish to 75,213 in 2034.

The aggregate load impacts increase from 9.0 MWh/hour to 10.0 MWh/hour from 2024 to 2026 and decline to 7.4 MWh/hour in 2034. Per-customer load impacts only vary slightly over the years due to changes in customer composition. The main driver of change in aggregate impacts is the change of aggregate enrollments.

Figure 3.14: PDP Enrollments, *PG&E All*



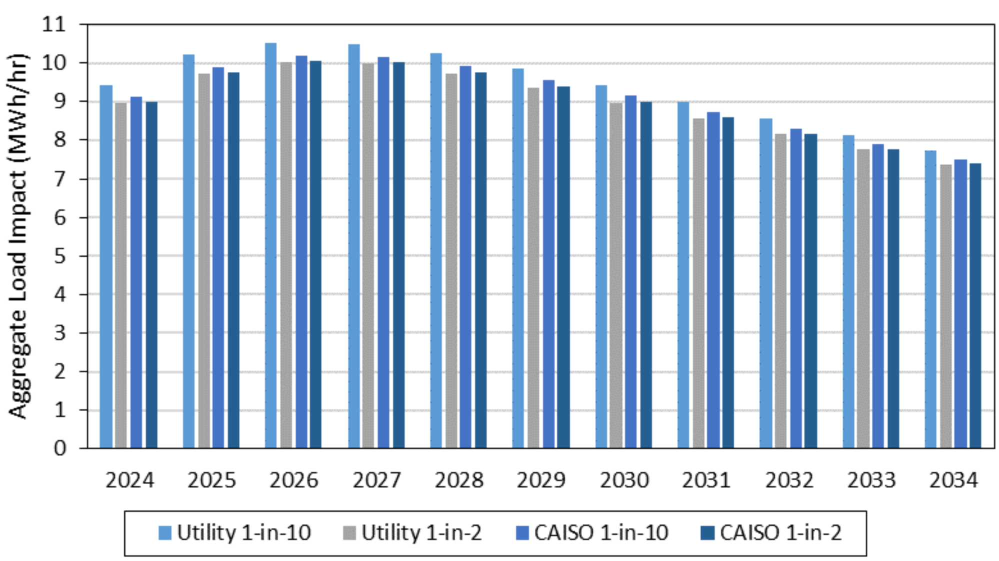
[20] This attrition rate assumes CCA expansion in Sierra will result in customer de-enrollments and there is no marketing-derived backfill.

Table 3.20: Typical Event Day Load Impacts, Utility 1-in-2, *PG&E All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	103,659	779.7	9.0	7.5	0.086
2025	107,798	841.9	9.7	7.8	0.090
2026	108,494	865.7	10.0	8.0	0.092
2027	106,575	859.5	10.0	8.1	0.094
2028	102,975	835.6	9.7	8.1	0.095
2029	98,474	801.2	9.4	8.1	0.095
2030	93,634	763.2	9.0	8.2	0.096
2031	88,763	724.2	8.6	8.2	0.096
2032	84,029	685.6	8.1	8.2	0.097
2033	79,509	649.2	7.8	8.2	0.098
2034	75,213	613.9	7.4	8.2	0.098

Figure 3.15 shows the change in program load impacts for PDP over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average Resource Adequacy (RA) window hour of the typical event day. There are relatively minor differences between load impacts across the weather scenarios. The highest load impacts for all years occur under the PG&E 1-in-10 weather conditions. Additional summaries of the ex-ante forecast are presented by size group.

Figure 3.15: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E All*



3.2.2 Large Customers

Figure 3.16 summarizes PG&E's enrollment forecast for large customers. PG&E anticipates an increase in large customer enrollments from 2023 to 2027 due to customer defaults into the PDP program. After 2027, annual customer attrition of 5.55% per year is expected to exceed the rate of customer defaults into the PDP program, which results in a decrease in total PDP enrollments.

Figure 3.16: PDP Enrollments, *PG&E Large*

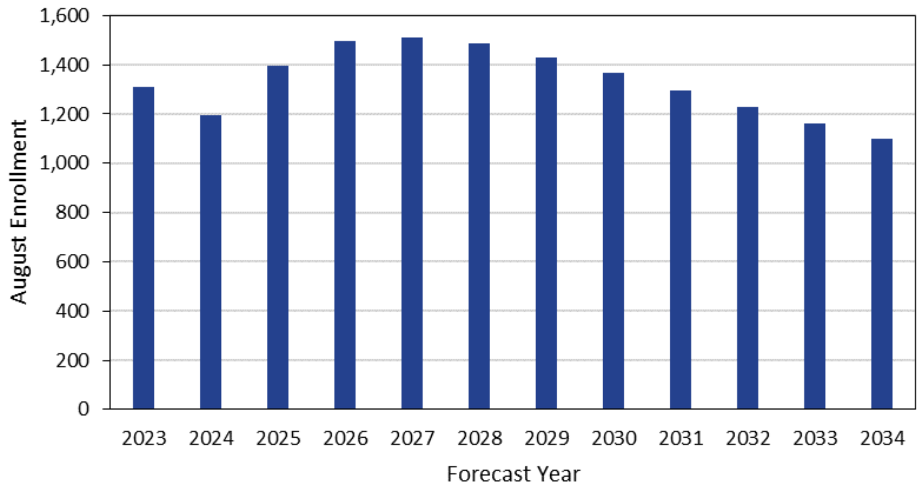


Figure 3.17 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in 2024 for the PG&E 1-in-2 weather scenario. The RA window load impacts have similar shape as the ex-post results in Figure 3.3. The average RA window load impact is 3.9 MWh/hour, or 1.6% of the reference loads. The aggregate load impacts are lower than in ex-post due to lower enrollments. A detailed comparison of ex-post and ex-ante results are shown in Table 3.31.

Figure 3.17: Aggregate Hourly Loads and Load Impacts in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

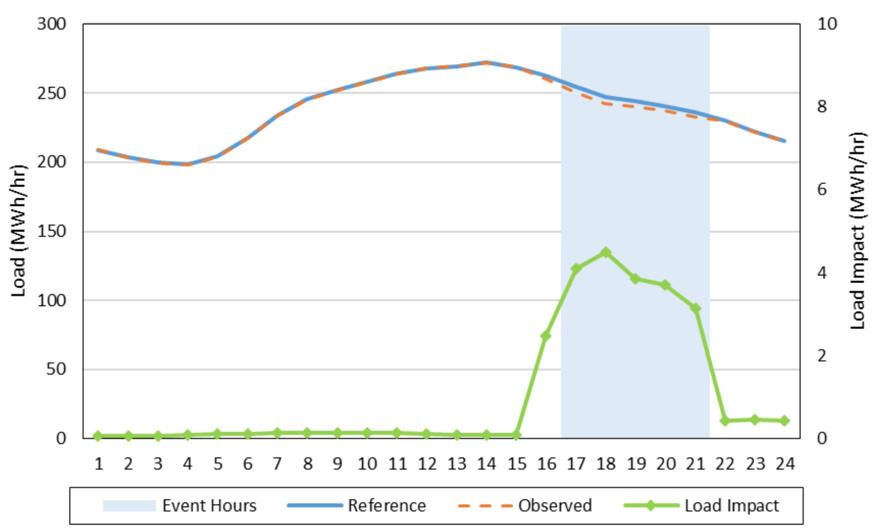


Figure 3.18 shows the forecasted share of load impacts by LCA during the average event hour on the typical event day in 2024 under PG&E's 1-in-2 weather scenario. Other and Greater Fresno Area are the top two LCAs in terms of the share of load impacts, which is consistent with the ex-post results presented in Figure 3.5.

Figure 3.18: Share of Load Impacts by LCA in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

Table 3.21 and Figure 3.19 illustrate the seasonality in the forecasted load impacts for large customers by comparing load impacts for the average hour in the RA window in 2024 across months for PG&E's 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March, April, and May, when it is 5 to 10 p.m. March has the lowest load impacts (2.17 MWh/hour or 1.78 kWh/customer/hour) because the average load impacts over the RA window include one non-event hour. Per-customer and aggregate load impacts are higher in June, August, and September.[21] The highest aggregate load impacts occur in June (3.91 MWh/hour).

[21] September has slightly higher per-customer load impacts than August with a lower average daily temperature because the Other LCA (about 30% of large customers) has higher reference loads in September.

Table 3.21: Aggregate and Per-Customer Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Large*

Month	# Enrolled	Aggregate		Per-Customer		Avg. Daily Temp
		Ref. Load (MWh/hour)	Load Impact (MWh/hour)	Ref. Load (kWh/hour)	Load Impact (kWh/hour)	
January	1,106	162.96	2.27	147.34	2.05	46.3
February	1,101	165.31	2.44	150.15	2.22	46.5
March	1,218	184.46	2.17	151.45	1.78	67.1
April	1,212	193.52	2.36	159.67	1.94	74.7
May	1,207	225.31	3.07	186.67	2.54	80.0
June	1,201	246.36	3.91	205.13	3.26	86.9
July	1,197	245.63	3.82	205.20	3.19	86.4
August	1,188	246.34	3.87	207.35	3.26	86.4
September	1,183	246.84	3.88	208.66	3.28	82.0
October	1,178	246.50	3.77	209.26	3.20	74.0
November	1,359	221.14	3.18	162.72	2.34	59.0
December	1,354	201.61	2.90	148.90	2.14	46.0

Figure 3.19: Aggregate Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Large*

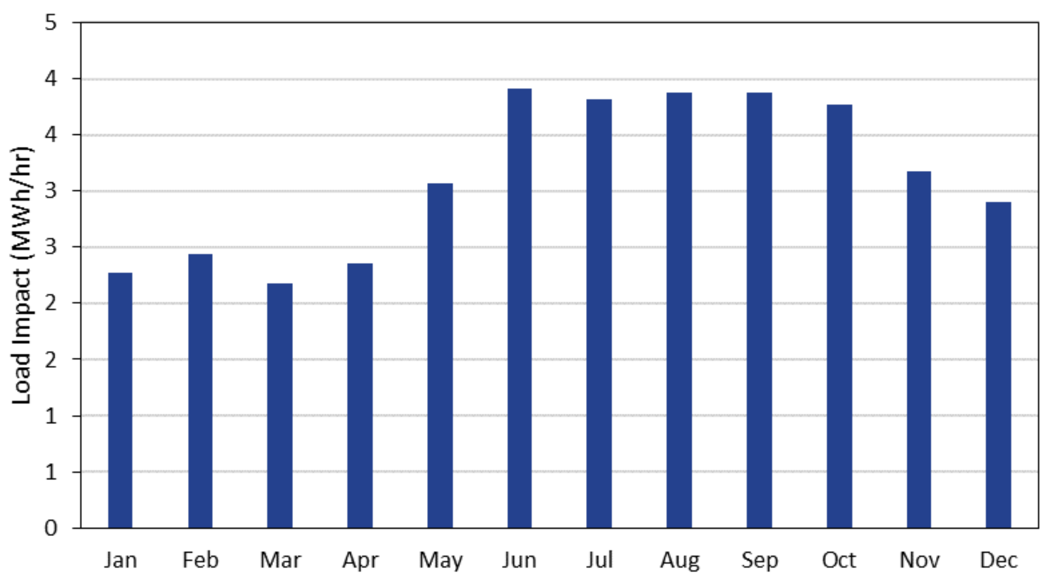
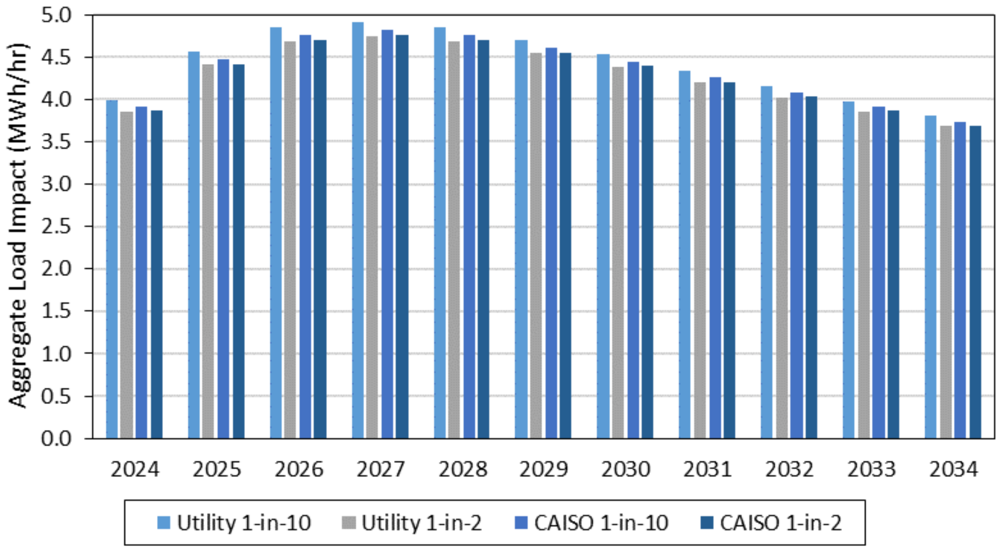


Figure 3.20 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window hour of the typical event day. Changes in aggregate load impacts are driven by enrollment trends. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.20: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Large*



3.2.3 Medium Customers

Figure 3.21 summarizes PG&E's enrollment forecast for medium customers. PG&E anticipates a slight uptick in medium customer enrollments from 2024 to 2026 due to customer defaults in the PDP program. From 2027 onward, medium customer enrollments are expected to decline by an average of 4.5% per year due to an assumed attrition rate of 5.55% for enrolled customers combined with declining ongoing defaults into the PDP program.

Figure 3.21: PDP Enrollments, *PG&E Medium*

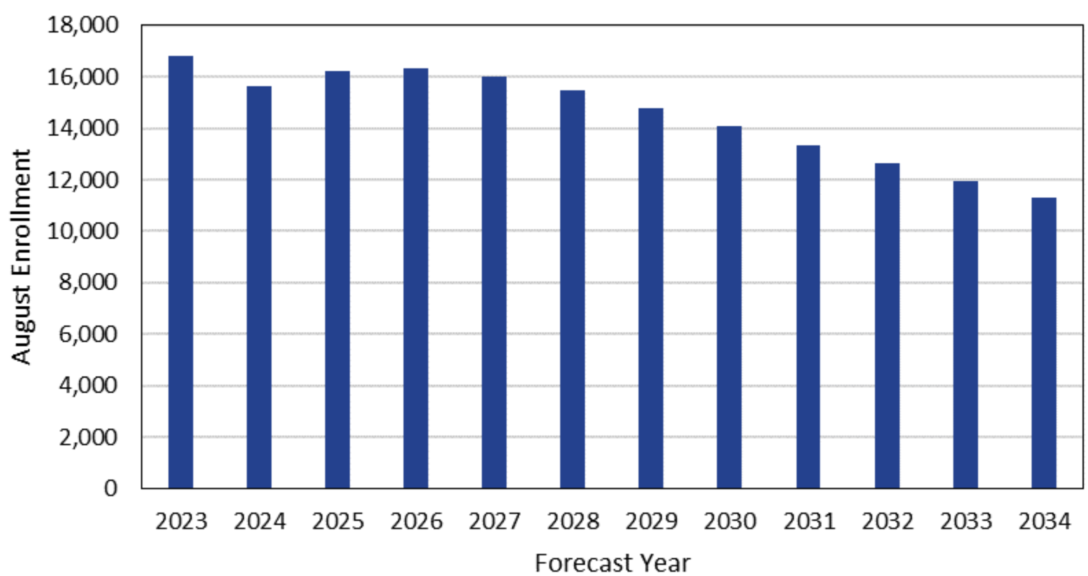


Figure 3.22 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in 2024 for the PG&E 1-in-2 weather scenario. The RA window load impacts have a similar shape as the ex-post results in Figure 3.7. The forecast predicts an average load impact of 3.0 MWh/hour or 0.8% of the reference loads. The aggregate load impacts are lower than in ex-post due to lower enrollments. A detailed comparison of ex-post and ex-ante results is shown in Table 3.36.

Figure 3.22: Aggregate Hourly Loads and Load Impacts in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

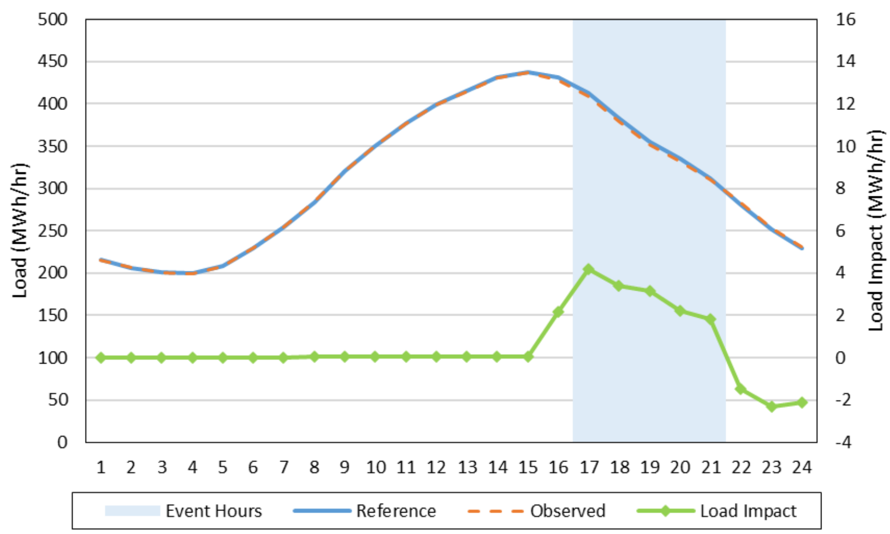


Figure 3.23 shows the forecasted share of load impacts for medium customers by LCA, based on the load impacts during the average RA window on the typical event day in 2024 under PG&E's 1-in-2 weather scenario. Other LCA, Stockton, and Sierra are the top three LCAs contributing to medium customer load reductions, similar to the ex-post results presented in Figure 3.9.

Figure 3.23: Share of Load Impacts by LCA in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

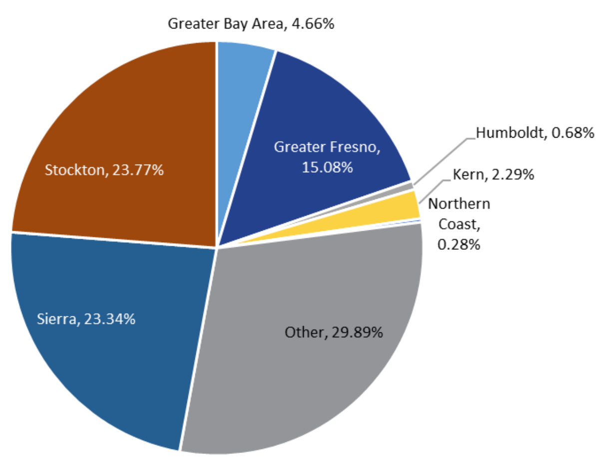


Table 3.22 and Figure 3.24 illustrate the seasonality in the forecasted load impacts for medium customers by comparing load impacts for the average hour in the RA window in 2024 across months for PG&E's 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March, April, and May, when it is 5 to 10 p.m. March has the lowest per-customer and aggregate load impacts because the average load impacts over the RA window include one non-event hour. Per-customer and aggregate load impacts are higher from June to August because of hotter temperatures and higher reference loads. The highest aggregate load impacts occur in August (2.98 MWh/hour).

Table 3.22: Aggregate and Per-Customer Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Medium*

Month	# Enrolled	Aggregate		Per-Customer		Avg. Daily Temp
		Ref. Load (MWh/hour)	Load Impact (MWh/hour)	Ref. Load (kWh/hour)	Load Impact (kWh/hour)	
January	16,154	221.52	1.84	13.71	0.11	45.4
February	16,081	218.48	1.81	13.59	0.11	46.0
March	16,023	228.90	1.22	14.29	0.08	66.8
April	15,952	268.71	1.44	16.85	0.09	74.7
May	15,877	299.61	1.64	18.87	0.10	80.0
June	15,804	357.13	2.93	22.60	0.19	86.9
July	15,730	362.31	2.96	23.03	0.19	86.6
August	15,657	364.03	2.98	23.25	0.19	86.4
September	15,583	331.58	2.74	21.28	0.18	81.8
October	15,513	288.58	2.51	18.60	0.16	73.7
November	16,927	222.21	2.04	13.13	0.12	58.6
December	16,850	229.22	1.95	13.60	0.12	45.5

Figure 3.24: Aggregate Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Medium*

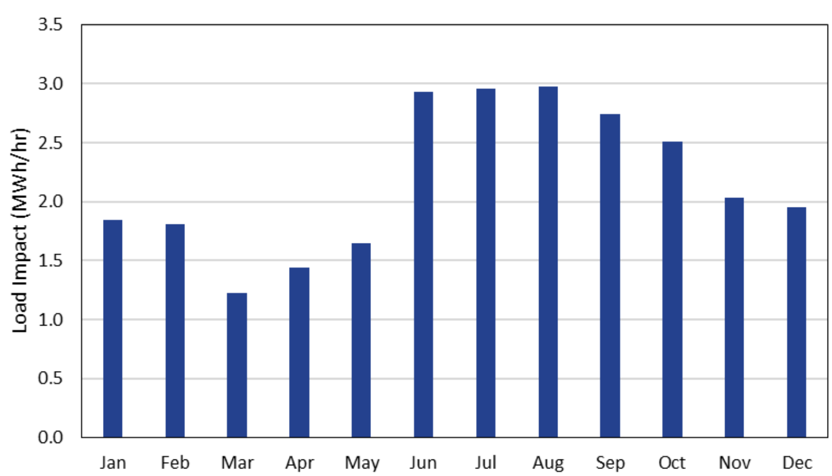
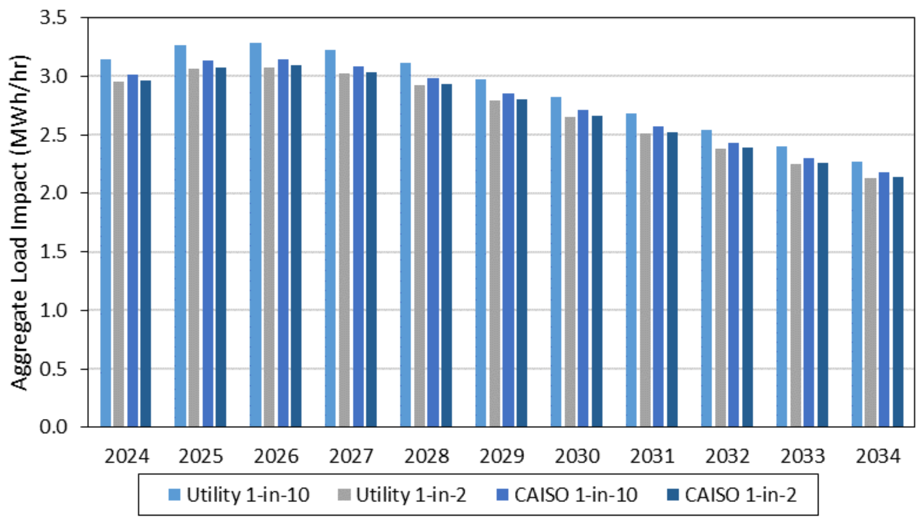


Figure 3.25 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window

hour of the typical event day. Aggregate load impacts vary as enrollments change. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.25: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Medium*



3.2.4 Small Customers

Figure 3.26 summarizes PG&E's enrollment forecast for small customers. Similar to medium customers, PG&E anticipates a slight increase in small customer enrollments until 2026 due to customer defaults into the PDP program. From 2027 onward, small customer enrollments are expected to decline by an average of 4.5% per year due to an assumed attrition rate of 5.55% for enrolled customers combined with declining ongoing defaults into the PDP program.

Figure 3.26: PDP Enrollments, *PG&E Small*

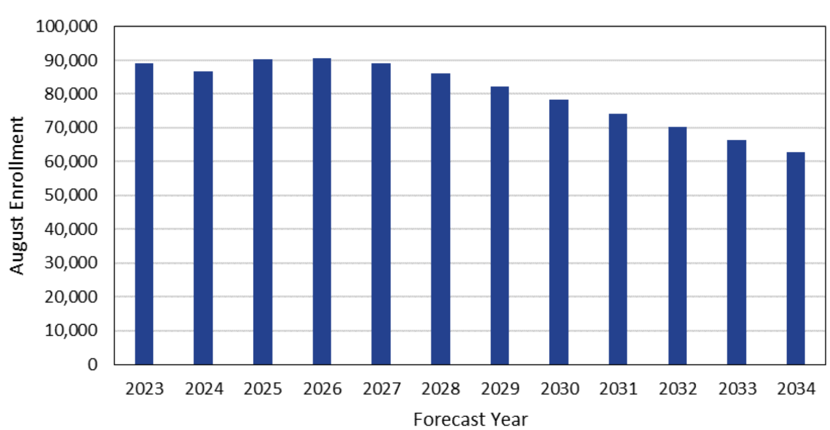


Figure 3.27 illustrates the aggregate reference loads, observed loads, and load impacts for small customers on the typical event day in 2024 for the PG&E 1-in-2 weather scenario. The RA window load impacts have similar shape as the ex-post results as shown in Figure 3.11. The forecast predicts an average load impact of 2.15 MWh/hour, or 1.2% of reference loads. The aggregate load impacts are slightly lower than in ex-post due to lower enrollments. A detailed comparison of ex-post and ex-ante results are shown in Table 3.41.

Figure 3.27: Aggregate Hourly Loads and Load Impacts in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

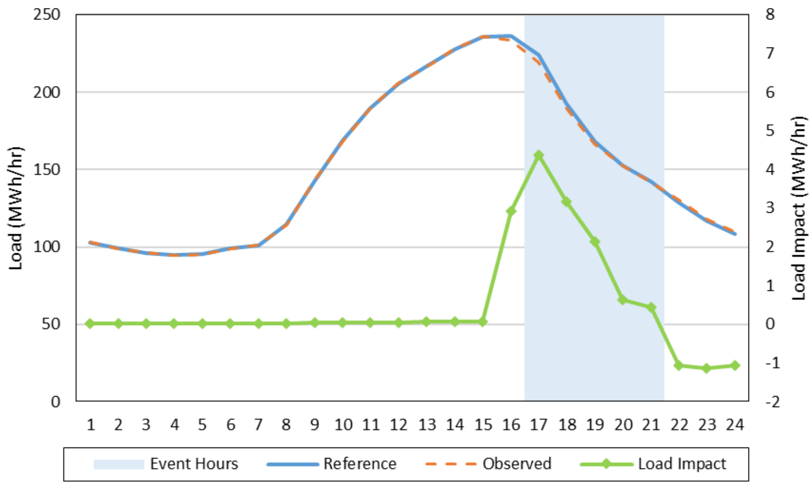


Figure 3.28 shows the forecasted share of load impacts for small customers by LCA, based on the load impacts during the average RA window on the typical event day in 2024 under PG&E's 1-in-2 weather scenario. Greater Fresno Area, Stockton, Other LCA, and Sierra contribute most of the aggregate load reduction. The shares of aggregate load impacts in the forecast are consistent with the ex-post estimates presented in Figure 3.13.

Figure 3.28: Share of Load Impacts by LCA in 2024 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

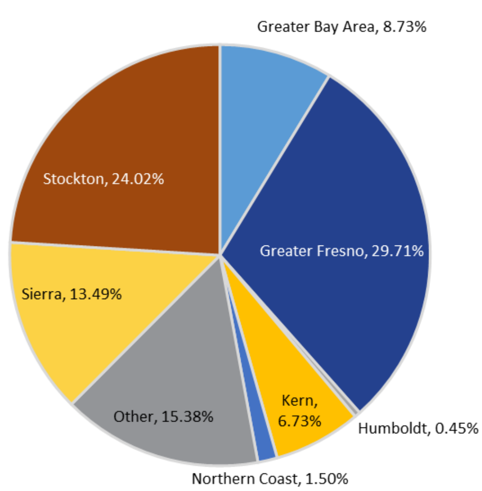


Table 3.23 and Figure 3.29 illustrate the seasonality in the forecasted load impacts for small customers by comparing load impacts for the average hour in the RA window in 2024 across months for PG&E's 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March, April, and May, when it is 5 to 10 p.m. The per-customer and aggregate load impacts are higher from June to August because of hotter temperatures and higher reference loads. The highest aggregate load impacts occur in July (2.20 MWh/hour). The lowest per-customer and aggregate load impacts occur in March because the average load impacts over the RA window include one non-event hour.

Table 3.23: Aggregate and Per-Customer Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Small*

Month	# Enrolled	Aggregate		Per-Customer		Avg. Daily Temp
		Ref. Load (MWh/hour)	Load Impact (MWh/hour)	Ref. Load (kWh/hour)	Load Impact (kWh/hour)	
January	89,571	117.86	1.36	1.32	0.015	45.3
February	89,156	114.61	1.33	1.29	0.015	45.7
March	88,852	110.22	0.68	1.24	0.008	66.4
April	88,438	121.43	0.78	1.37	0.009	74.2
May	88,033	138.35	0.93	1.57	0.011	79.4
June	87,624	172.87	2.13	1.97	0.024	86.3
July	87,219	180.01	2.20	2.06	0.025	86.1
August	86,814	178.36	2.18	2.05	0.025	85.9
September	86,413	159.18	1.94	1.84	0.022	81.4
October	86,016	135.94	1.64	1.58	0.019	73.4
November	93,935	109.17	1.24	1.16	0.013	58.5
December	93,504	122.63	1.42	1.31	0.015	45.5

Figure 3.29: Aggregate Load Impacts by Month over RA Window in 2024 for *PG&E 1-in-2 Peak Day, PG&E Small*

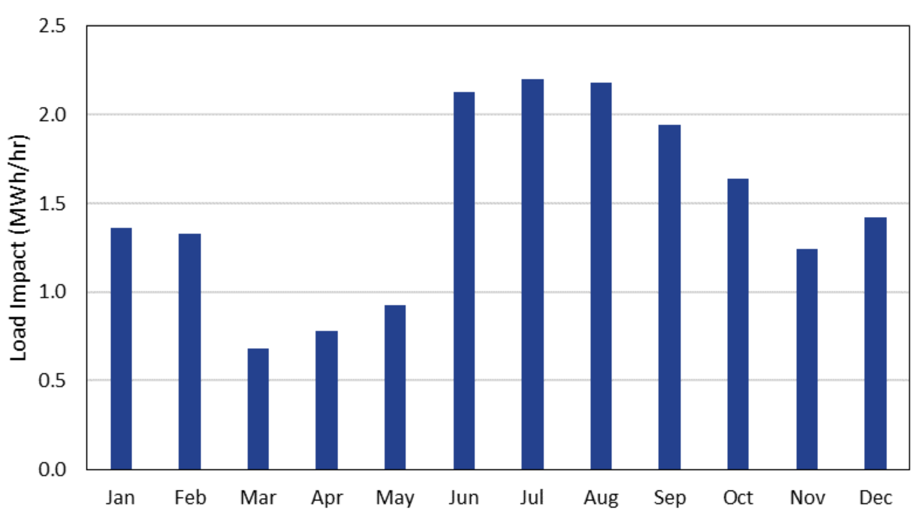
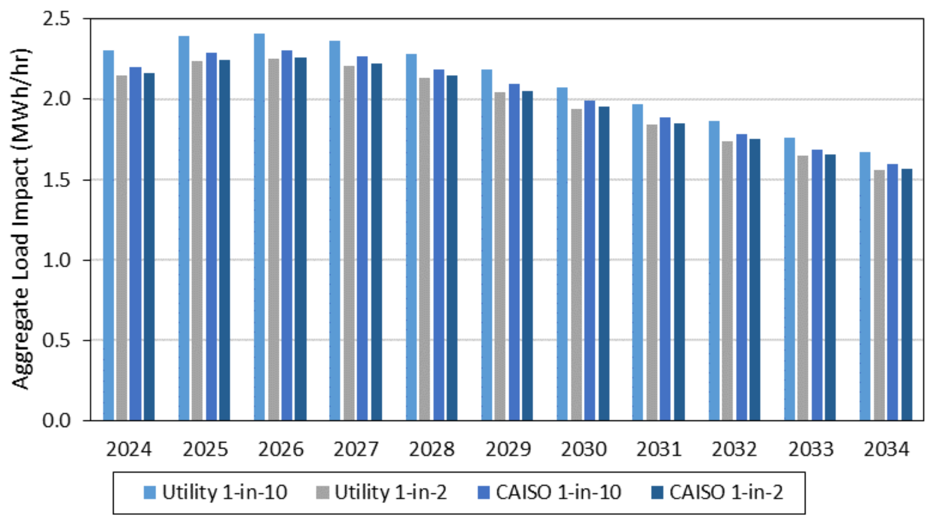


Figure 3.30 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window hour of the typical event day. Aggregate load impacts vary as enrollments change. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.30: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Small*



3.3 PG&E Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts for PDP, including the following:

- Ex-post load impacts from the current and previous studies;
- Ex-ante load impacts from the current and previous studies;
- Current ex-post and previous ex-ante load impacts; and
- Current ex-post and ex-ante load impacts.

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2023. The term "previous" refers to revised findings from the PY2022 evaluation.

3.3.1 All Customers

Previous vs. Current Ex-Post

Table 3.24 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. We perform the comparison over the event hours from 4 to 9 p.m. Enrollments decreased in PY2023 by 4,716 customers, which is a 4% decrease. Per-customer reference loads are 10% lower in

PY2023, which may be related to a decrease in average temperatures and potentially a change in customer composition, especially for large customers. Per-customer load impacts are 0.04 kWh/hour lower in 2023. As a result, percentage load impacts are 0.3 percentage points lower. Aggregate load impacts are 32% lower in PY2023 due to lower per-customer load impacts.

Table 3.24: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E All*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study	Change Level	Change %
Total	# SAIDs	111,974	107,258	-4,716	-4%
	Reference (MW)	980	847	-133	-14%
	Load Impact (MW)	14.1	9.6	-5	-32%
	Avg. Event Temp.	98.0	94.8	-3.2	-3%
	Avg. Daily Temp.	87.3	84.8	-2.5	-3%
Per SAID	Reference (kW)	8.8	7.9	-0.9	-10%
	Load Impact (kW)	0.13	0.09	-0.04	-29%
	% Load Impact	1.4%	1.1%	-0.3%	-21%

Previous Ex-Ante vs. Current Ex-Post

Table 3.25 provides a comparison of the average event-hour load impacts from the PY2022 ex-ante forecast of 2023 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. Both per-customer load impacts and reference loads are lower than forecasted, so percentage load impacts are 0.3 percentage points lower in the current study. The lower reference loads and per-customer load impacts may be related to lower ex-post temperature and a change in customer composition. The aggregate load impacts decrease by 37%.

Table 3.25: Previous Ex-Ante vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E All*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study	Change Level	Change %
Total	# SAIDs	113,501	107,258	-6,243	-6%
	Reference (MW)	1096	847	-249	-23%
	Load Impact (MW)	15.4	9.6	-5.8	-37%
	Avg. Event Temp.	96.9	94.8	-2.1	-2%
	Avg. Daily Temp.	85.4	84.8	-0.6	-1%
Per SAID	Reference (kW)	9.7	7.9	-1.8	-18%
	Load Impact (kW)	0.14	0.09	-0.05	-34%
	% Load Impact	1.4%	1.1%	-0.3%	-19%

Current Ex-Post vs. Current Ex-Ante

Table 3.26 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent a typical event day in 2024 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day.

Table 3.26: Current Ex-Post vs. Current Ex-Ante Load Impacts for the Typical Event Day, *PG&E All*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	107,258	103,659	-3,599	-3%
	Reference (MW)	847	780	-67	-8%
	Load Impact (MW)	9.6	9.0	-0.6	-7%
	Avg. Event Temp.	94.8	96.9	2.1	2%
	Avg. Daily Temp.	84.8	85.3	0.5	1%
Per SAID	Reference (kW)	7.9	7.5	-0.4	-5%
	Load Impact (kW)	0.09	0.09	-0.003	-3%
	% Load Impact	1.1%	1.1%	0.0%	1%

Table 3.27 documents the various potential sources of differences between the ex-post and ex-ante load impacts. Per-customer load impacts and percentage load impacts are similar in 2023 and 2024, with similar average daily temperatures. Enrollments decrease by about 3,600 customers (a 3% decrease), and aggregate load impacts decrease by 0.6 MWh/hour in 2024 (a 7% decrease).

Table 3.27: Comparison of Ex-Post and Ex-Ante Factors, *PG&E All*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average daily temperature of 84.8°F during the typical event day.	Average daily temperature of 85.3°F during the PG&E 1-in-2 Typical Event Day.	Higher ex-ante average daily temperature would increase the per-customer load impacts (ceteris paribus) via higher reference loads.
Event window	HE17-HE21.	RA window (HE17-HE21).	None.
% of resources dispatched	100%	100%	None.
Enrollment	107,258 service accounts.	103,659 service accounts.	Lower ex-ante enrollments lead to lower aggregate load impacts.
Methodology	Large individual customer models.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2022 ex-ante forecast to the ex-ante forecast contained in the current study. Table 3.28 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2024. Per-customer load impacts decreased by 36% between PY2022 and PY2023, consistent with the comparison of ex-post results between the two years. Enrollments decrease by about 1,800 customers between the two forecasts. This 2% decrease in enrollments, in combination with the decreased per-customer load impacts in the PY2023 forecast, leads to aggregate load impacts that are 37% lower.

Table 3.28: Previous vs. Current Ex-Ante Load Impacts, Utility 1-in-2 Typical Event Day, *PG&E All*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	105,461	103,659	-1,802	-2%
	Reference (MW)	1018	780	-238	-23%
	Load Impact (MW)	14.3	9.0	-5.3	-37%
	Avg. Event Temp.	96.9	96.9	0.0	0%
	Avg. Daily Temp.	85.4	85.3	-0.1	0%
Per SAID	Reference (kW)	9.7	7.5	-2.1	-22%
	Load Impact (kW)	0.14	0.09	-0.05	-36%
	% Load Impact	1.4%	1.1%	-0.3%	-18%

3.3.2 Large Customers

Previous vs. Current Ex-Post

Table 3.29 shows the average event-hour reference loads and load impacts for large customers for the typical event day during the current and previous program years. Enrollments decreased in PY2023 by 183 customers, which is a 12% decrease. Per-customer reference loads and per-customer load impacts are lower in PY2023, which may be related to a decrease in event temperatures and a change in customer composition. Aggregate load impacts are 30% lower in PY2023 due to lower per-customer load impacts and enrollment counts.

Table 3.29: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study	Change	
				Level	%
Total	# SAIDs	1,504	1,321	-183	-12%
	Reference (MW)	359	280	-79	-22%
	Load Impact (MW)	6.1	4.2	-1.8	-30%
	Avg. Event Temp.	98.3	94.5	-3.8	-4%
	Avg. Daily Temp.	87.6	84.7	-3.0	-3%
Per SAID	Reference (kW)	238.5	211.9	-26.6	-11%
	Load Impact (kW)	4.0	3.2	-0.84	-21%
	% Load Impact	1.7%	1.5%	-0.2%	-11%

Previous Ex-Ante vs. Current Ex-Post

Table 3.30 provides a comparison of the average event-hour load impacts from the PY2022 ex-ante forecast of 2023 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The PY2022 load impact forecast is slightly higher than the ex-post results in the current study in terms of per-customer load impacts. Reference loads are lower than forecasted, leading to percentage load impacts in 2023 that are in line with the forecasted—1.5% in the current study compared to the forecasted 1.6%. As discussed previously, the lower reference loads and per-customer load impacts may be related to lower ex-post temperature and a change in customer composition. The aggregate load impacts are 42% lower in 2023 because of lower enrollments.

Table 3.30: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Large*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	1,916	1,321	-595	-31%
	Reference (MW)	466	280	-187	-40%
	Load Impact (MW)	7.2	4.2	-3.0	-42%
	Avg. Event Temp.	97.0	94.5	-2.5	-3%
	Avg. Daily Temp.	85.6	84.7	-0.9	-1%
Per SAID	Reference (kW)	243.5	211.9	-31.6	-13%
	Load Impact (kW)	3.8	3.2	-0.57	-15%
	% Load Impact	1.6%	1.5%	0.0%	-3%

Current Ex-Post vs. Current Ex-Ante

Table 3.31 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent a typical event day in 2024 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day.

Table 3.31: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Large*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	1,321	1,188	-133	-10%
	Reference (MW)	280	244	-35	-13%
	Load Impact (MW)	4.2	3.9	-0.4	-9%
	Avg. Event Temp.	94.5	96.8	2.3	2%
	Avg. Daily Temp.	84.7	85.4	0.7	1%
Per SAID	Reference (kW)	211.9	205.8	-6.1	-3%
	Load Impact (kW)	3.21	3.25	0.04	1%
	% Load Impact	1.5%	1.6%	0.1%	4%

Table 3.32 documents the various potential sources of differences between the ex-post and ex-ante load impacts. Per-customer load impacts and percentage load impacts are similar in 2023 and 2024, with similar average daily temperatures. Aggregate load impacts decrease by 0.4 MW (a 9% decrease) in 2024 due to lower enrollments.

Table 3.32: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average daily temperature of 84.7°F during the typical event day.	Average event-hour temperature of 85.4°F during the PG&E 1-in-2 Typical Event Day.	Higher ex-ante average daily temperature would increase the per-customer load impacts (ceteris paribus) via higher reference loads.
Event window	HE17-HE21.	RA window (HE17-HE21).	None.
% of resources dispatched	100%	100%	None.
Enrollment	1,321 service accounts.	1,188 service accounts.	Lower ex-ante enrollments lead to lower aggregate load impacts.
Methodology	Large individual customer models.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2022 ex-ante forecast to the ex-ante forecast contained in the current study. Table 3.33 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2024. The 33% decrease in enrollments and 14% decrease in per-customer load impacts lead to aggregate load impacts that are 43% lower.

Table 3.33: Previous vs. Current Ex-Ante Load Impacts,
Utility 1-in-2 Typical Event Day, PG&E Large

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	1,779	1,188	-591	-33%
	Reference (MW)	433	244	-189	-44%
	Load Impact (MW)	6.8	3.9	-2.9	-43%
	Avg. Event Temp.	97.0	96.8	-0.2	0%
	Avg. Daily Temp.	85.6	85.4	-0.2	0%
Per SAID	Reference (kW)	243.5	205.8	-37.7	-15%
	Load Impact (kW)	3.8	3.2	-0.55	-14%
	% Load Impact	1.6%	1.6%	0.0%	1%

3.3.3 Medium Customers

Previous vs. Current Ex-Post

Table 3.34 shows the average event-hour reference loads and load impacts during 4 to 9 p.m. on the typical event day of the current and previous program years. The number of customers enrolled was lower in 2023 by 916 customers, which is a 5% decrease. There was a decrease in per-customer load impacts from 0.33 to 0.18 kWh/customer/hour. Together with the decrease in enrollments, this leads to a decrease in aggregate load impacts from 5.8 to 3.1 MWh/hour. The percentage load impacts decrease from 1.4% to 0.8%.

Table 3.34: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study	Change	
				Level	%
Total	# SAIDs	17,723	16,807	-916	-5%
	Reference (MW)	418	379	-39	-9%
	Load Impact (MW)	5.8	3.1	-2.7	-47%
	Avg. Event Temp.	98.0	95.1	-2.9	-3%
	Avg. Daily Temp.	87.3	85.0	-2.3	-3%
Per SAID	Reference (kW)	23.6	22.6	-1.0	-4%
	Load Impact (kW)	0.33	0.18	-0.14	-44%
	% Load Impact	1.4%	0.8%	-0.6%	-41%

Previous Ex-Ante vs. Current Ex-Post

Table 3.35 provides a comparison of the average event-hour load impacts from the PY2022 ex-ante forecast of 2023 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day during PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The ex-post load impacts are 0.14 kWh/customer/hour, lower than forecast in PY2022. Part of the difference might be due to lower reference loads in the ex-post results. Ex-post aggregate load impacts decrease by 2.8 MWh/hour (a 47% decrease) compared to the forecast, reflecting a combination of lower per-customer load impacts and medium customer enrollment counts.

Table 3.35: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Medium*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	17,914	16,807	-1,107	-6%
	Reference (MW)	424	379	-45	-11%
	Load Impact (MW)	5.9	3.1	-2.8	-47%
	Avg. Event Temp.	97.0	95.1	-1.9	-2%
	Avg. Daily Temp.	85.3	85.0	-0.3	0%
Per SAID	Reference (kW)	23.7	22.6	-1.1	-5%
	Load Impact (kW)	0.33	0.18	-0.14	-44%
	% Load Impact	1.4%	0.8%	-0.6%	-41%

Current Ex-Post vs. Current Ex-Ante

Table 3.36 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts represent a typical event day in 2024 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day.

Table 3.36: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Medium*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	16,807	15,657	-1,150	-7%
	Reference (MW)	379	359	-20	-5%
	Load Impact (MW)	3.1	3.0	-0.1	-5%
	Avg. Event Temp.	95.1	97.1	2.0	2%
	Avg. Daily Temp.	85.0	85.4	0.4	0%
Per SAID	Reference (kW)	22.6	22.9	0.4	2%
	Load Impact (kW)	0.18	0.19	0.005	3%
	% Load Impact	0.8%	0.8%	0.0%	1%

Table 3.37 documents the various potential sources of differences between the ex-post and ex-ante load impacts. Per-customer load impacts and percentage load impacts are similar in 2023 and 2024, with similar average daily temperatures. The aggregate load impacts are 0.1 MWh/hour lower (a 5% decrease) due to lower enrollments.

Table 3.37: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average daily temperature of 85.0°F during the typical event day.	Average daily temperature of 85.4°F during the PG&E 1-in-2 Typical Event Day.	Higher ex-ante average daily temperature would decrease the per-customer load impacts (ceteris paribus) via lower reference loads.
Event window	HE17-HE 21.	RA window (HE17-HE21).	None.
% of resources dispatched	100%	100%	None.
Enrollment	16,807 service accounts.	15,657 service accounts.	Decreased enrollments should lead to lower aggregate load impacts.
Methodology	Panel models by LCA with customer fixed effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2022 and PY2023 ex-ante forecasts. Table 3.38 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2024. The aggregate load impacts decrease between PY2022 and PY2023 by 46%, driven by a decrease in medium customer performance during PDP events in 2023 as shown in the comparison of the ex-post results in both years, as well as a 6% decrease in medium customer enrollments.

Table 3.38: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, PG&E Medium*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	16,644	15,657	-987	-6%
	Reference (MW)	394	359	-35	-9%
	Load Impact (MW)	5.5	3.0	-2.5	-46%
	Avg. Event Temp.	97.0	97.1	0.1	0%
	Avg. Daily Temp.	85.3	85.4	0.1	0%
Per SAID	Reference (kW)	23.7	22.9	-0.7	-3%
	Load Impact (kW)	0.33	0.19	-0.14	-43%
	% Load Impact	1.4%	0.8%	-0.6%	-41%

3.3.4 Small Customers

Previous vs. Current Ex-Post

Table 3.39 shows the average event-hour reference loads and load impacts for the typical event day during 4 to 9 p.m. of the current and previous program years. Small customer enrollments decreased in PY2023 by 3,617 customers, which is a 4% decrease. Small customers had a slight improvement in customer performance in PY2023. Per-customer load impacts increase by 0.0016 kWh/customer/hour. As a result, aggregate load impacts increase from 2.2 to 2.3 MWh/hour despite the lower enrollment count and temperatures. Percentage load impacts increase from 1.1% to 1.2% of reference loads.

Table 3.39: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study	Change	
				Level	%
Total	# SAIDs	92,747	89,130	-3,617	-4%
	Reference (MW)	203	188	-15	-8%
	Load Impact (MW)	2.2	2.3	0.1	3%
	Avg. Event Temp.	97.1	94.5	-2.6	-3%
	Avg. Daily Temp.	86.6	84.5	-2.1	-2%
Per SAID	Reference (kW)	2.19	2.11	-0.08	-4%
	Load Impact (kW)	0.02	0.03	0.0016	7%
	% Load Impact	1.1%	1.2%	0.1%	11%

Previous Ex-Ante vs. Current Ex-Post

Table 3.40 provides a comparison of the average event-hour load impacts from the PY2022 ex-ante forecast of 2023 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The ex-post per-customer load impacts show a slight increase of 0.0016 kWh/hour over the PY2022 ex-ante forecast of 2023. Percentage load impacts increase from 1.1% to 1.2% of reference loads. Despite the enrollment decrease, the aggregate load impact increased by 0.04 MWh/hour, which is a 2% increase.

Table 3.40: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Small*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	93,671	89,130	-4,541	-5%
	Reference (MW)	205	188	-17	-8%
	Load Impact (MW)	2.2	2.3	0.04	2%
	Avg. Event Temp.	96.6	94.5	-2.0	-2%
	Avg. Daily Temp.	84.9	84.5	-0.4	0%
Per SAID	Reference (kW)	2.19	2.11	-0.1	-4%
	Load Impact (kW)	0.02	0.03	0.0016	7%
	% Load Impact	1.1%	1.2%	0.1%	11%

Current Ex-Post vs. Current Ex-Ante

Table 3.41 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent a typical event day in 2024 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day.

Table 3.41: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Small*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	89,130	86,814	-2,316	-3%
	Reference (MW)	188	176	-12	-6%
	Load Impact (MW)	2.27	2.15	-0.12	-5%
	Avg. Event Temp.	94.5	96.5	2.0	2%
	Avg. Daily Temp.	84.5	84.9	0.4	0%
Per SAID	Reference (kW)	2.11	2.03	-0.1	-4%
	Load Impact (kW)	0.025	0.025	-0.001	-3%
	% Load Impact	1.2%	1.2%	0.0%	1%

Table 3.42 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The per-customer and percentage load impacts are similar in 2023 and 2024, with similar average daily temperatures. The aggregate load impacts decrease by 0.1 MWh/hour (a 5% decrease) in 2024 due to lower enrollments.

Table 3.42: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average daily temperature of 84.5°F during the typical event day.	Average daily temperature of 84.9°F during the PG&E 1-in-2 Typical Event Day.	Higher ex-ante average daily temperature would increase the per-customer load impacts (ceteris paribus) via higher reference loads.
Event window	HE17-HE 21.	RA window (HE17-HE21).	None.
% of resources dispatched	100%	100%	None.
Enrollment	89,130 service accounts.	86,814 service accounts.	Lower ex-ante enrollments should lead to lower aggregate load impacts.
Methodology	Panel models by LCA with customer fixed effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2022 and PY2023 ex-ante forecasts. Table 3.43 reports the RA window average load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2024. Aggregate load impacts increase between PY2022 and PY2023 by 4%, consistent with the improvement in small customer performance presented in the previous sub-section. The per-customer load impacts increase by 4% from PY2022 to PY2023, while the percentage load impacts increase by 0.1 percentage points.

Table 3.43: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, PG&E Small*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study	Change	
				Level	%
Total	# SAIDs	87,038	86,814	-224	0%
	Reference (MW)	190	176	-14	-8%
	Load Impact (MW)	2.07	2.15	0.1	4%
	Avg. Event Temp.	96.6	96.5	0.0	0%
	Avg. Daily Temp.	84.9	84.9	0.0	0%
Per SAID	Reference (kW)	2.19	2.03	-0.2	-7%
	Load Impact (kW)	0.024	0.025	0.00	4%
	% Load Impact	1.1%	1.2%	0.1%	12%

4 SCE

4.1 SCE Ex-Post Load Impacts

This section documents the findings from the ex-post load impact analysis for SCE. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the typical event day as well as for each individual event. Results for all hours for the typical event day are also illustrated in figures and presented in data tables. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.1.3, all results presented in this section are derived from either customer specific or panel fixed-effects regression analyses of hourly data for CPP customers. The estimated model is described in Section 2.1.4, with the SCE model including the variables that account for morning load and temperature variations. Furthermore, we control for concurrent events that are called for other programs (e.g., BIP, SDP, ELRP) by including indicators for customers who are dually enrolled and who are called for a given event that occurs during an event or non-event day. The evaluation of model specification selection is presented in the appendix.

4.1.1 All Customers

This section summarizes results for all SCE customers. The average ex-post load impacts are summarized for all 12 events in Figure 4.1 along with the average weekday event. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90% confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

SCE customers have statistically significant load reductions on nine out of twelve event days. The largest load reduction is 22.8 MWh/hour on August 17th. The load impact averaged 7 MWh/hour across all event days.

Figure 4.1: Average Event-Hour Load Impacts by Event, *SCE All*

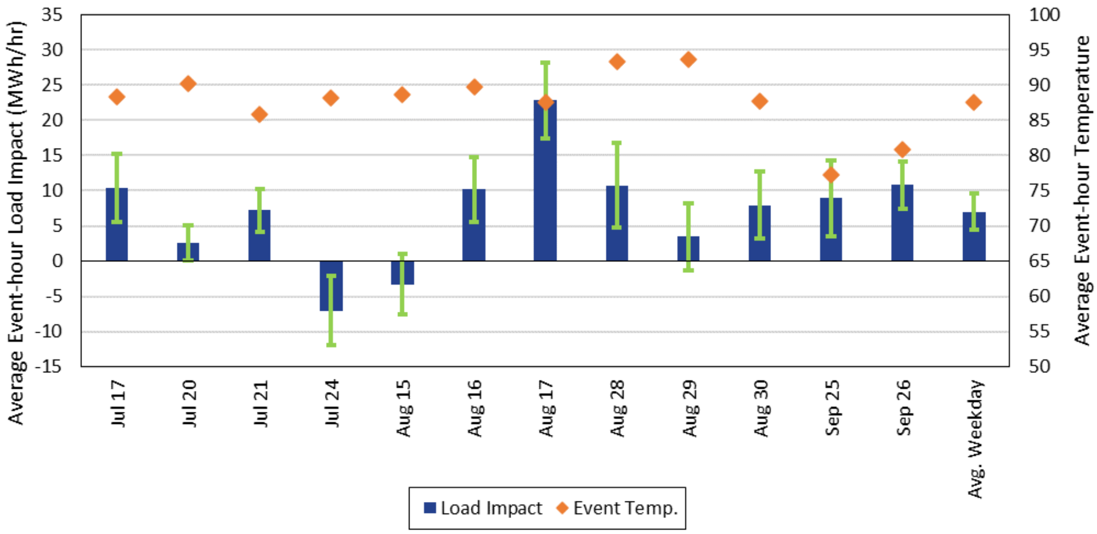


Table 4.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for all SCE customers. Estimated load impacts averaged 0.03 kWh/hour per customer across event days, which amounts to a 0.6% load reduction. Detailed results by hour, industry group and LCA are presented in subsequent subsections by size group.

Table 4.1: Average Event-Hour Load Impacts by Event, *SCE All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	227,581	1,241	10.4	5.5	0.05	0.8%	88.4
7/20/2023	227,405	1,272	2.6	5.6	0.01	0.2%	90.3
7/21/2023	227,422	1,209	7.2	5.3	0.03	0.6%	85.8
7/24/2023	227,379	1,236	-7.1	5.4	-0.03	-0.6%	88.1
8/15/2023	226,261	1,248	-3.3	5.5	-0.01	-0.3%	88.7
8/16/2023	226,175	1,276	10.2	5.6	0.05	0.8%	89.8
8/17/2023	226,133	1,257	22.8	5.6	0.10	1.8%	87.5
8/28/2023	225,758	1,269	10.8	5.6	0.05	0.8%	93.3
8/29/2023	225,724	1,289	3.5	5.7	0.02	0.3%	93.7
8/30/2023	225,655	1,254	7.9	5.6	0.04	0.6%	87.7
9/25/2023	224,393	1,018	8.9	4.5	0.04	0.9%	77.2
9/26/2023	224,411	1,060	10.8	4.7	0.05	1.0%	80.8
Typical Event Day	**226,193**	**1,220**	**7.0**	**5.4**	**0.03**	**0.6%**	**87.6**

4.1.2 Large Customers

This section summarizes results for all large SCE customers, defined as customers with maximum demand over 200 kW.[22] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in subsequent sections.

The ex-post load impacts for SCE's large CPP customers are summarized for all twelve events in Figure 4.2. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90% confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

These results indicate that large customers had statistically significant load reductions on all event days expect July 24th, ranging from 0.2 to 10.3 MWh/hour. The load impact averaged 5 MWh/hour across all event days.

Figure 4.2: Average Event-Hour Load Impacts by Event, *SCE Large*

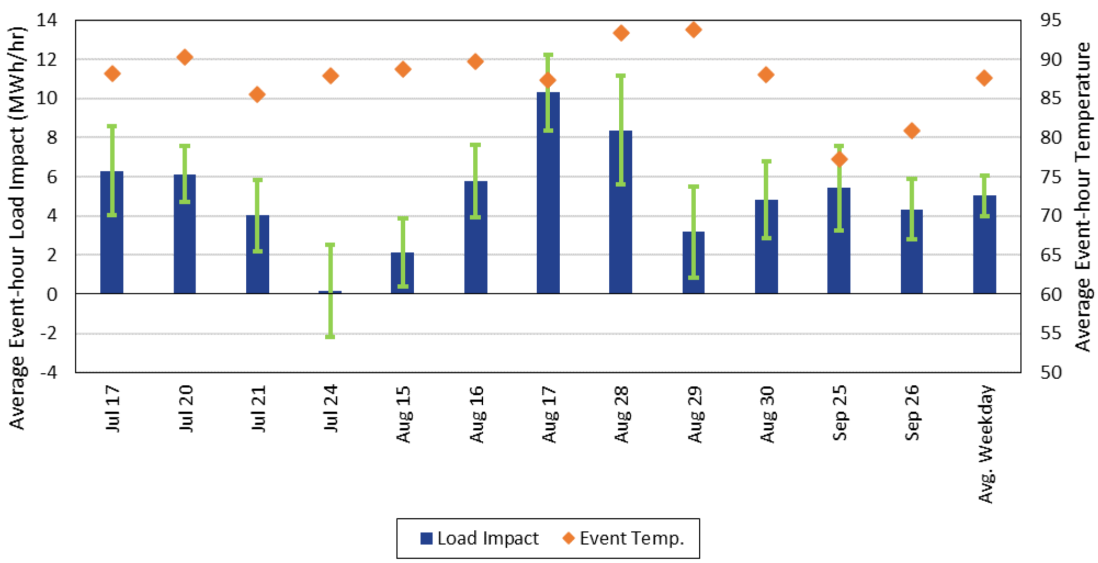


Table 4.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Estimated load reductions averaged 3 kWh/hour per customer across event days, which amounts to a 1.3% load reduction.

[22] Large CPP customers were identified using rate codes provided by SCE. The majority (97%) of Large CPP customers are on rates TOU-8-D, TOU-GS-3D, TOU-PA-3-D.

Table 4.2: Average Event-Hour Load Impacts by Event, *SCE Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	1,715	378	6.3	220.4	3.7	1.7%	88.2
7/20/2023	1,688	385	6.1	227.9	3.6	1.6%	90.2
7/21/2023	1,714	364	4.0	212.5	2.3	1.1%	85.6
7/24/2023	1,714	378	0.2	220.5	0.1	0.0%	88.0
8/15/2023	1,702	388	2.1	228.1	1.2	0.5%	88.7
8/16/2023	1,686	391	5.8	232.1	3.4	1.5%	89.7
8/17/2023	1,702	388	10.3	228.1	6.1	2.7%	87.3
8/28/2023	1,690	386	8.4	228.2	5.0	2.2%	93.4
8/29/2023	1,688	390	3.2	231.1	1.9	0.8%	93.9
8/30/2023	1,686	384	4.8	227.8	2.9	1.3%	88.1
9/25/2023	1,649	328	5.4	198.8	3.3	1.7%	77.3
9/26/2023	1,650	337	4.3	204.4	2.6	1.3%	80.9
Typical Event Day	**1,691**	**376**	**5.0**	**222.3**	**3.0**	**1.3%**	**87.6**

Figure 4.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 4.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are smaller load impacts in the hours immediately preceding (1.8 MWh from 3 to 4 p.m.) and following (2.3 MWh from 9 to 10 p.m.) the event. Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

Figure 4.3: Typical Event Day Reference Loads and Load Profile, *SCE Large*

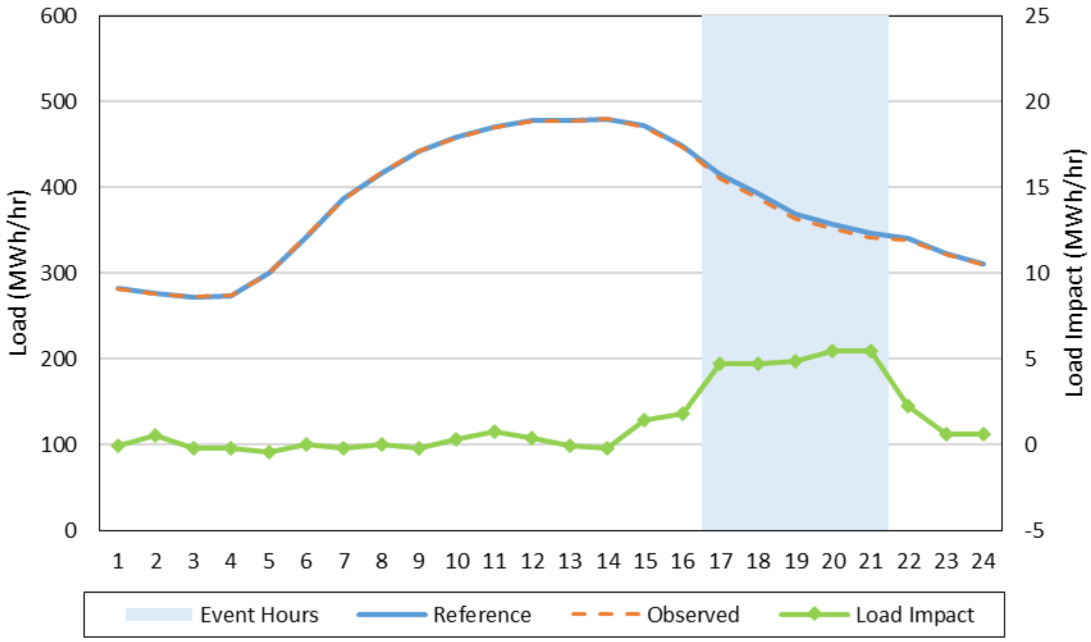


Table 4.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	281.9	282.0	0.0	0.0%	75.5	-1.4	-0.6	0.0	0.5	1.4
2	275.8	275.2	0.6	0.2%	74.2	-0.7	0.0	0.6	1.1	1.9
3	272.1	272.4	-0.2	-0.1%	72.9	-1.2	-0.7	-0.2	0.2	0.8
4	273.6	273.8	-0.2	-0.1%	71.8	-1.1	-0.6	-0.2	0.1	0.6
5	299.9	300.3	-0.4	-0.1%	70.9	-1.3	-0.8	-0.4	0.0	0.5
6	342.6	342.6	0.0	0.0%	70.2	-1.1	-0.4	0.0	0.5	1.2
7	386.5	386.7	-0.2	-0.1%	69.4	-1.6	-0.8	-0.2	0.4	1.2
8	417.6	417.5	0.0	0.0%	68.9	-1.5	-0.6	0.0	0.7	1.6
9	442.3	442.5	-0.2	-0.1%	68.7	-1.6	-0.8	-0.2	0.3	1.1
10	458.7	458.4	0.3	0.1%	70.5	-1.1	-0.2	0.3	0.9	1.7
11	470.4	469.6	0.8	0.2%	73.8	-0.3	0.3	0.8	1.2	1.8
12	478.4	478.1	0.4	0.1%	77.5	-0.7	-0.1	0.4	0.8	1.5
13	477.9	478.0	0.0	0.0%	81.1	-1.6	-0.7	0.0	0.6	1.5
14	480.2	480.5	-0.2	0.0%	84.1	-2.0	-0.9	-0.2	0.5	1.5
15	471.7	470.2	1.4	0.3%	86.4	-0.4	0.7	1.4	2.1	3.2
16	448.7	446.9	1.8	0.4%	87.7	-0.1	1.0	1.8	2.5	3.6
17	415.3	410.6	4.7	1.1%	88.5	2.8	3.9	4.7	5.4	6.5
18	392.7	387.9	4.7	1.2%	88.5	2.9	4.0	4.7	5.5	6.6
19	368.4	363.5	4.9	1.3%	88.4	3.0	4.1	4.9	5.6	6.7
20	357.0	351.6	5.4	1.5%	87.4	3.6	4.7	5.4	6.2	7.2
21	346.2	340.8	5.4	1.6%	85.3	3.7	4.7	5.4	6.1	7.1
22	340.5	338.2	2.3	0.7%	82.1	0.5	1.6	2.3	3.0	4.0
23	322.8	322.2	0.6	0.2%	79.1	-1.4	-0.2	0.6	1.4	2.6
24	311.3	310.7	0.6	0.2%	77.0	-1.6	-0.3	0.6	1.5	2.8
Daily	**9,132**	**9,100**	**32**	**0.4%**	**78.3**	**24.6**	**29.1**	**32.3**	**35.4**	**39.9**

Next, we look at SCE large customer estimate by industry group. Table 4.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments have 65% concentration in three industry groups: Manufacturing; Offices, Hotels, Health, & Services; and Wholesale, Transportation, & Utilities. The estimated reference loads are 90, 77, and 74 MWh/hour for these groups, respectively. The load impact is even more concentrated with 77% (3.51 MWh/hour) of the total load impact coming from two industry groups: Manufacturing and Wholesale, Transportation, & Utilities.

Table 4.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Large*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	125	18	18	0.32	1.8%
2. Manufacturing	403	90	87	3.20	3.6%
3. Wholesale, Transportation, Utilities	327	77	76	0.82	1.1%
4. Retail Stores	92	23	23	0.07	0.3%
5. Offices, Hotels, Health, Services	296	74	74	-0.21	-0.3%
6. Schools	142	23	23	-0.03	-0.1%
7. Institutional/Government	104	27	27	0.56	2.1%
8. Other	204	43	43	0.23	0.5%

To better understand the distribution of results across industries, we illustrate at the shares of estimated positive load impacts, reference loads, and enrollments by industry group in Figure 4.4. Manufacturing represents a large share of the load impact. All other industry groups, except for Institutional/Government, have lower shares of the load impact than the shares of enrolled customers.

Figure 4.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Large*

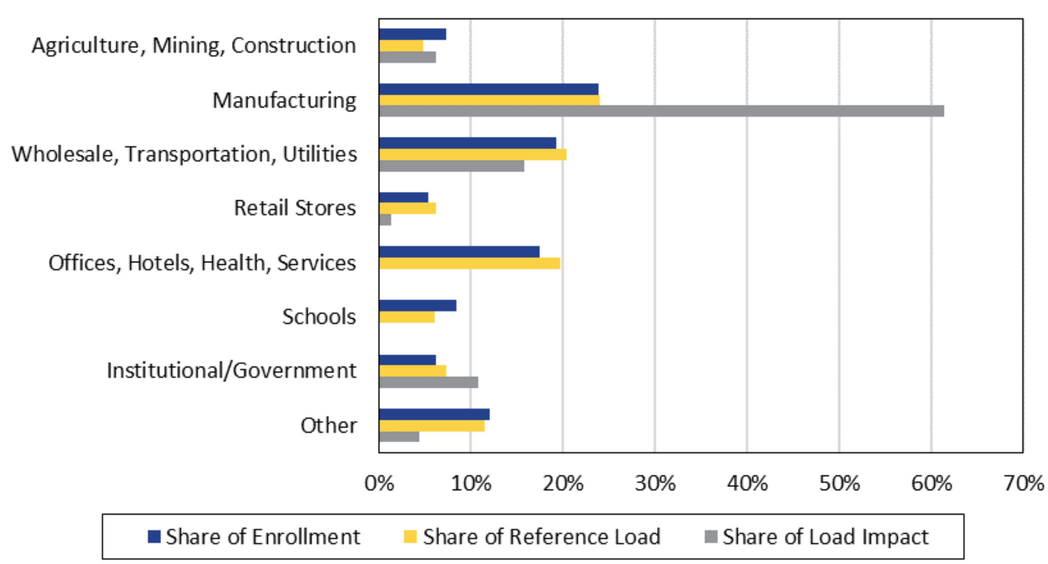
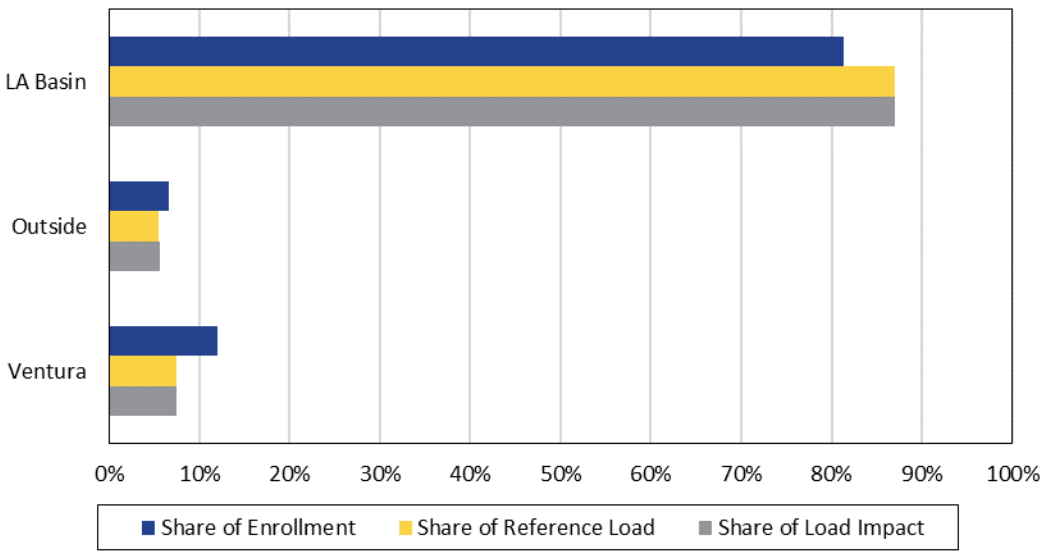


Table 4.5 and Figure 4.5 provide the same summaries as above by LCA. SCE's large CPP customers are concentrated in the LA Basin, which has a combined reference load of 327 MWh/hour. This LCA also accounts for the largest load impact of 4.48 MWh/hour. Figure 4.5 demonstrates that the LA Basin's share of customers, reference loads, and positive load impacts all exceed 80%.

Table 4.5: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Large*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	1,376	327	322	4.48	1.4%
Outside Basin	112	21	21	0.12	0.6%
Ventura	204	28	28	0.42	1.5%

Figure 4.5: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Large*



4.1.3 Medium Customers

This section summarizes results for all medium SCE customers, defined as customers with maximum demand between 20 and 199.99 kW.[23] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in subsequent sections.

The ex-post load impacts for SCE's medium CPP customers are summarized for all twelve events in Figure 4.6. Three of the events days (August 16th, August 17th, and September

[23] Medium CPP customers were identified using rate codes provided by SCE. The majority (99%) of Medium CPP customers are on rate TOU-GS-2-D.

26th) have estimated load reductions that are statistically significant. The average weekday event day load impact of 0.7 MWh/hour is not statistically significant.

Figure 4.6: Average Event-Hour Load Impacts by Event, *SCE Medium*

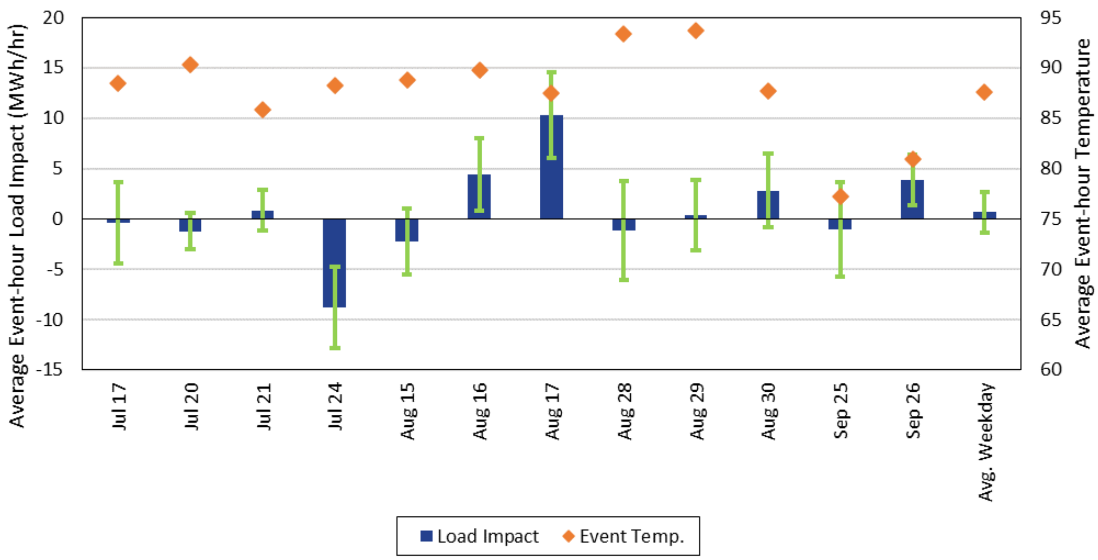


Table 4.6 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Overall, medium customers had an aggregate load impact of 0.7 MWh/hour which is 0.03 kWh/hour per customer and 0.1% of the reference load.

Table 4.6: Average Event-Hour Load Impacts by Event, *SCE Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	21,331	566	-0.4	26.5	0.0	-0.1%	88.4
7/20/2023	21,305	581	-1.2	27.3	-0.1	-0.2%	90.3
7/21/2023	21,323	554	0.8	26.0	0.0	0.2%	85.8
7/24/2023	21,318	563	-8.8	26.4	-0.4	-1.6%	88.2
8/15/2023	21,222	567	-2.3	26.7	-0.1	-0.4%	88.7
8/16/2023	21,201	581	4.4	27.4	0.2	0.8%	89.8
8/17/2023	21,209	571	10.3	26.9	0.5	1.8%	87.5
8/28/2023	21,170	579	-1.1	27.4	-0.1	-0.2%	93.4
8/29/2023	21,163	589	0.4	27.8	0.0	0.1%	93.7
8/30/2023	21,159	571	2.8	27.0	0.1	0.5%	87.7
9/25/2023	21,040	456	-1.0	21.7	0.0	-0.2%	77.3
9/26/2023	21,047	479	3.9	22.7	0.2	0.8%	80.9
Typical Event Day	**21,207**	**555**	**0.7**	**26.2**	**0.03**	**0.1%**	**87.6**

Figure 4.7 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for medium customers. Table 4.7 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The highest event hour load impact, 3.3 MWh/hour, occurs in the last event hour (8 to 9 p.m.). There appears to be is no evidence of pre-cooling or post-event snapback but instead there are positive load impacts in the hours directly following the event.

Figure 4.7: Typical Event Day Reference Loads and Load Profile, *SCE Medium*

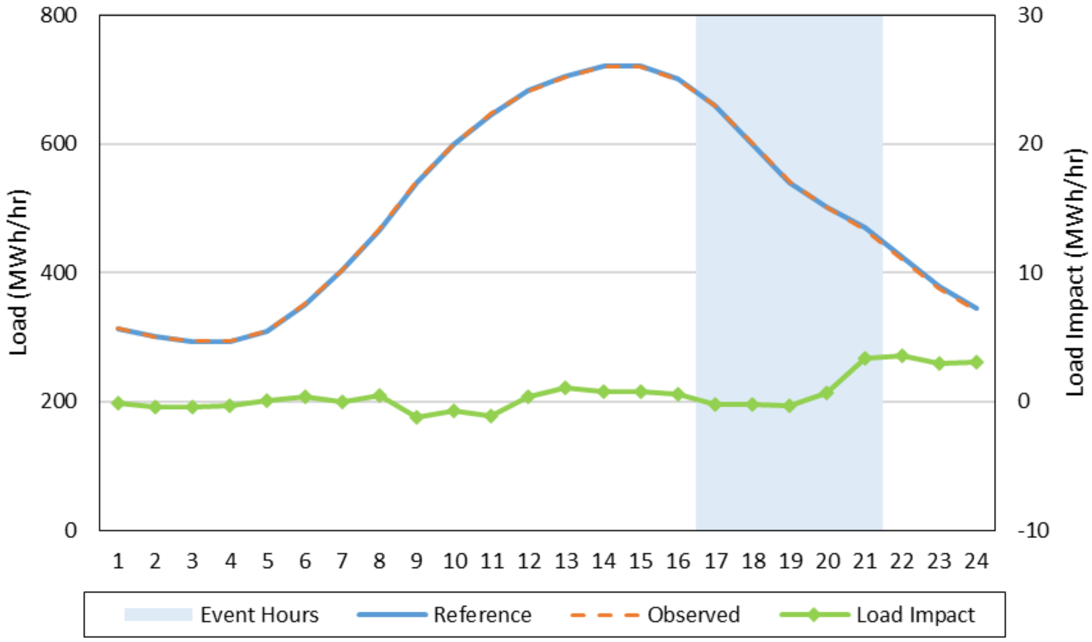


Table 4.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (^{o}F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	312.9	313.0	-0.1	0.0%	75.5	-1.0	-0.4	-0.1	0.2	0.8
2	300.4	300.9	-0.4	-0.1%	74.2	-1.1	-0.7	-0.4	-0.1	0.3
3	293.6	294.0	-0.5	-0.2%	72.9	-0.9	-0.7	-0.5	-0.3	0.0
4	293.6	293.9	-0.3	-0.1%	71.8	-0.6	-0.4	-0.3	-0.2	0.0
5	309.2	309.1	0.1	0.0%	70.9	-0.2	0.0	0.1	0.1	0.3
6	351.3	351.0	0.3	0.1%	70.0	-0.2	0.1	0.3	0.6	0.9
7	403.9	403.9	-0.1	0.0%	69.3	-1.2	-0.6	-0.1	0.4	1.1
8	467.2	466.7	0.5	0.1%	68.8	-0.9	-0.1	0.5	1.0	1.8
9	539.7	540.9	-1.2	-0.2%	68.7	-2.6	-1.8	-1.2	-0.7	0.1
10	599.8	600.5	-0.7	-0.1%	70.5	-1.8	-1.2	-0.7	-0.3	0.3
11	646.4	647.5	-1.1	-0.2%	73.8	-1.9	-1.4	-1.1	-0.8	-0.3
12	683.3	682.9	0.4	0.1%	77.5	-0.6	0.0	0.4	0.7	1.3
13	705.2	704.1	1.1	0.2%	81.1	-0.5	0.4	1.1	1.8	2.7
14	720.6	719.8	0.8	0.1%	84.2	-1.7	-0.2	0.8	1.8	3.3
15	721.0	720.3	0.7	0.1%	86.5	-2.0	-0.4	0.7	1.9	3.5
16	701.3	700.7	0.6	0.1%	87.9	-2.3	-0.6	0.6	1.7	3.4
17	660.4	660.6	-0.2	0.0%	88.6	-2.5	-1.2	-0.2	0.8	2.1
18	600.3	600.6	-0.2	0.0%	88.7	-2.0	-0.9	-0.2	0.5	1.5
19	540.1	540.4	-0.3	-0.1%	88.3	-2.1	-1.0	-0.3	0.5	1.6
20	502.5	501.9	0.7	0.1%	87.3	-1.5	-0.2	0.7	1.5	2.8
21	470.6	467.2	3.3	0.7%	85.2	1.2	2.5	3.3	4.2	5.5
22	424.6	421.1	3.5	0.8%	82.0	1.2	2.6	3.5	4.4	5.8
23	377.8	374.8	3.0	0.8%	78.9	0.9	2.1	3.0	3.8	5.1
24	344.7	341.7	3.0	0.9%	76.9	1.0	2.2	3.0	3.8	5.0
Daily	**11,970**	**11,957**	**13**	**0.1%**	**78.3**	**-1.3**	**7.0**	**12.7**	**18.4**	**26.6**

Next, we look at SCE medium customer estimates by industry group. Table 4.8 summarizes the aggregate average event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services has the largest number of enrollments, reference load (252 MWh/hour), load impact (0.98 MWh/hour), and percentage load impact (0.4%).

Table 4.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1. Agriculture, Mining, Construction	618	11	11	0.03	0.2%
2. Manufacturing	1,988	44	44	-0.25	-0.6%
3. Wholesale, Transportation, Utilities	2,026	46	46	-0.12	-0.3%
4. Retail Stores	2,718	81	81	0.28	0.3%
5. Offices, Hotels, Health, Services	9,177	252	251	0.98	0.4%
6. Schools	562	16	16	-0.07	-0.4%
7. Institutional/Government	2,066	48	48	0.07	0.2%
8. Other	2,052	57	57	-0.04	-0.1%

Figure 4.8 shows the shares of enrollments, reference loads, and load impacts by industry group. The load impacts are concentrated in Offices, Hotels, Health, & Services, which realizes 72% of the total load impact.

Figure 4.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Medium*

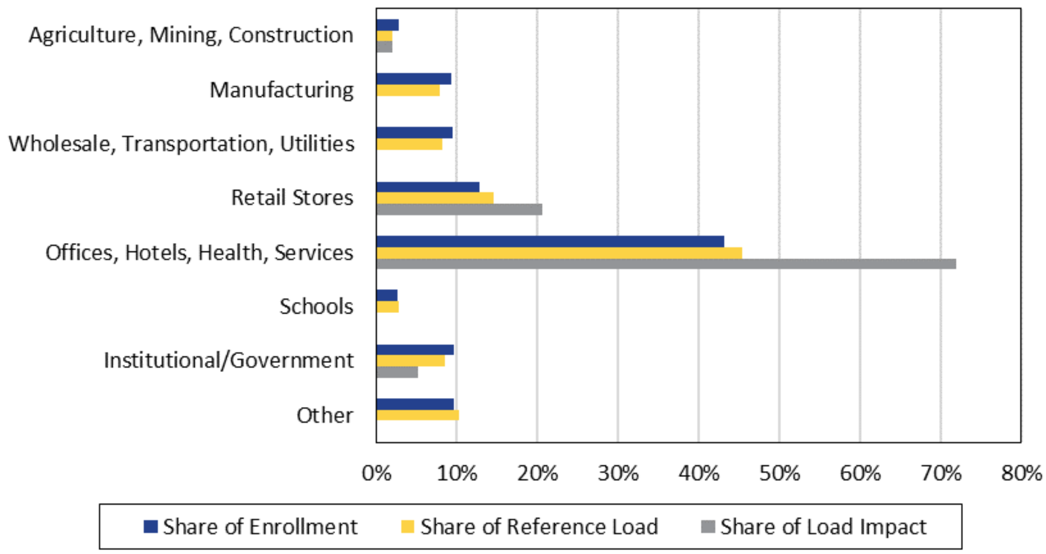
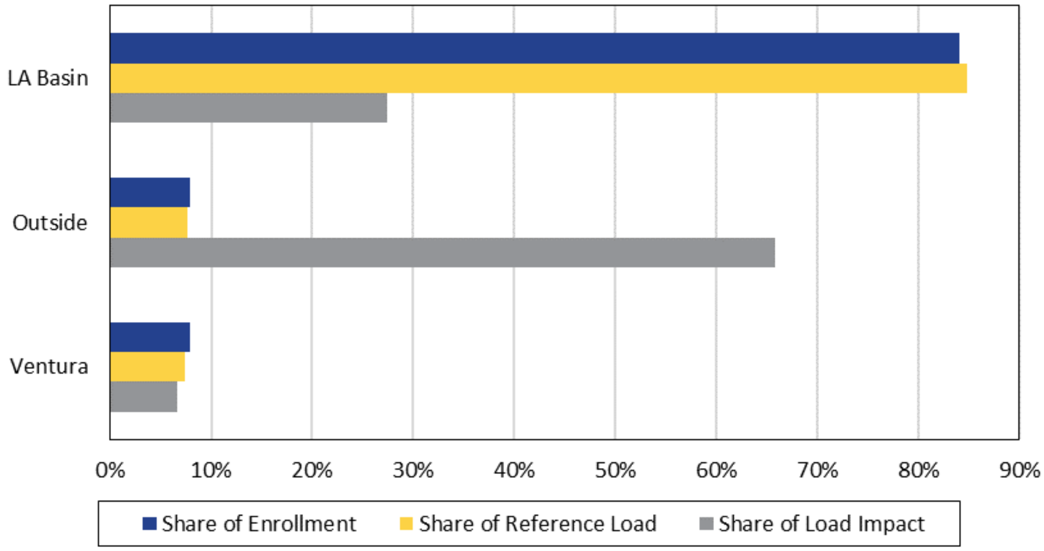


Table 4.9 and Figure 4.9 provide the same summaries as above but by LCA instead of industry group. Enrollments and reference loads are highly concentrated in LA Basin, accounting for over 80%. Nonetheless, the Outside Basin LCA accounts for 66% of the load impacts on the typical event day in 2023.

Table 4.9: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Medium*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	17,845	471	471	0.18	0.0%
Outside Basin	1,676	43	42	0.43	1.0%
Ventura	1,687	41	41	0.04	0.1%

Figure 4.9: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Medium*



4.1.4 Small Customers

This section summarizes results for SCE small CPP customers, defined as customers with maximum demand less than 20 kW.[24] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in subsequent sections.

The ex-post load impacts for SCE's small CPP customers are summarized for all twelve events in Figure 4.10. Six of the twelve events exhibit reductions in usage that are statistically significant (July 17th, July 21st, July 24th, August 28th, September 25th, and September 26th). The average weekday load impact of 1.3 MWh/hour (0.5%) is statistically significant.

[24] Small CPP customers were identified using rate codes provided by SCE. The majority (99%) of Small CPP customers are on rate TOU-GS-1-E.

Figure 4.10: Average Event-Hour Load Impacts by Event, *SCE Small*

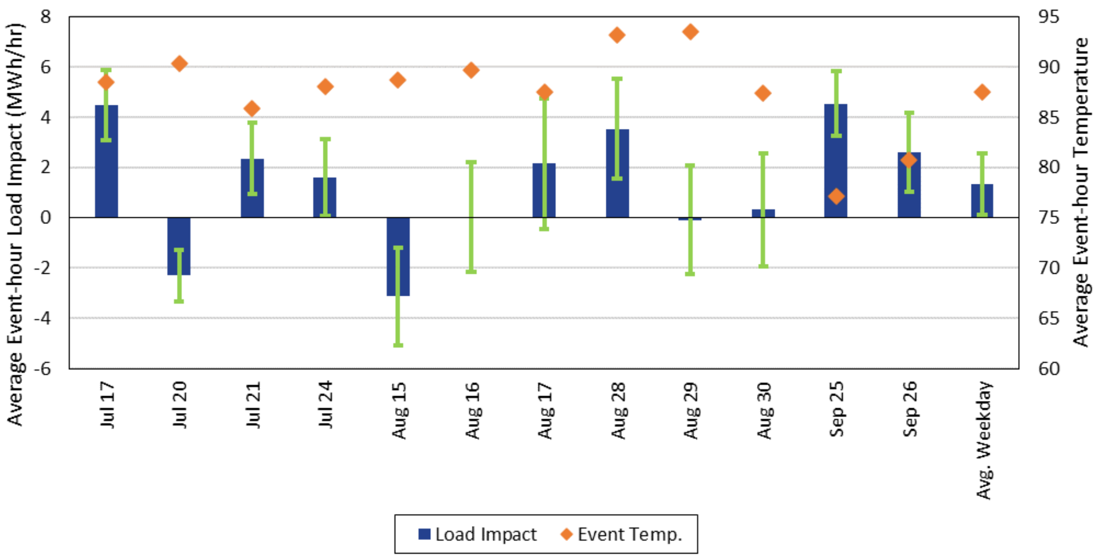


Table 4.10 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Enrollment of small customers in CPP were consistent over the course of the season. Overall, small CPP customers had an aggregate load impact of 1.3 MWh/hour, which is 0.007 kWh/hour per customer on average and 0.5% of the reference load.

Table 4.10: Average Event-Hour Load Impacts by Event, *SCE Small*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	204,535	297	4.5	1.5	0.02	1.5%	88.4
7/20/2023	204,412	306	-2.3	1.5	-0.01	-0.8%	90.3
7/21/2023	204,385	290	2.4	1.4	0.01	0.8%	85.9
7/24/2023	204,347	295	1.6	1.4	0.01	0.5%	88.1
8/15/2023	203,337	293	-3.1	1.4	-0.02	-1.1%	88.7
8/16/2023	203,288	303	0.0	1.5	0.00	0.0%	89.7
8/17/2023	203,222	298	2.1	1.5	0.01	0.7%	87.5
8/28/2023	202,898	304	3.5	1.5	0.02	1.2%	93.2
8/29/2023	202,873	310	-0.1	1.5	0.00	0.0%	93.5
8/30/2023	202,810	299	0.3	1.5	0.00	0.1%	87.4
9/25/2023	201,704	234	4.5	1.2	0.02	1.9%	77.1
9/26/2023	201,714	244	2.6	1.2	0.01	1.1%	80.8
Typical Event Day	**203,294**	**289**	**1.3**	**1.4**	**0.007**	**0.5%**	**87.5**

Figure 4.11 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for small CPP customers. Table 4.11 contains the hourly typical event day results, including hourly temperatures and uncertainty adjusted load impacts. The largest load impact of 2.6 MWh/hour occurred during the last event hour from 8 to 9 p.m.

Figure 4.11: Typical Event Day Reference Loads and Load Profile, *SCE Small*

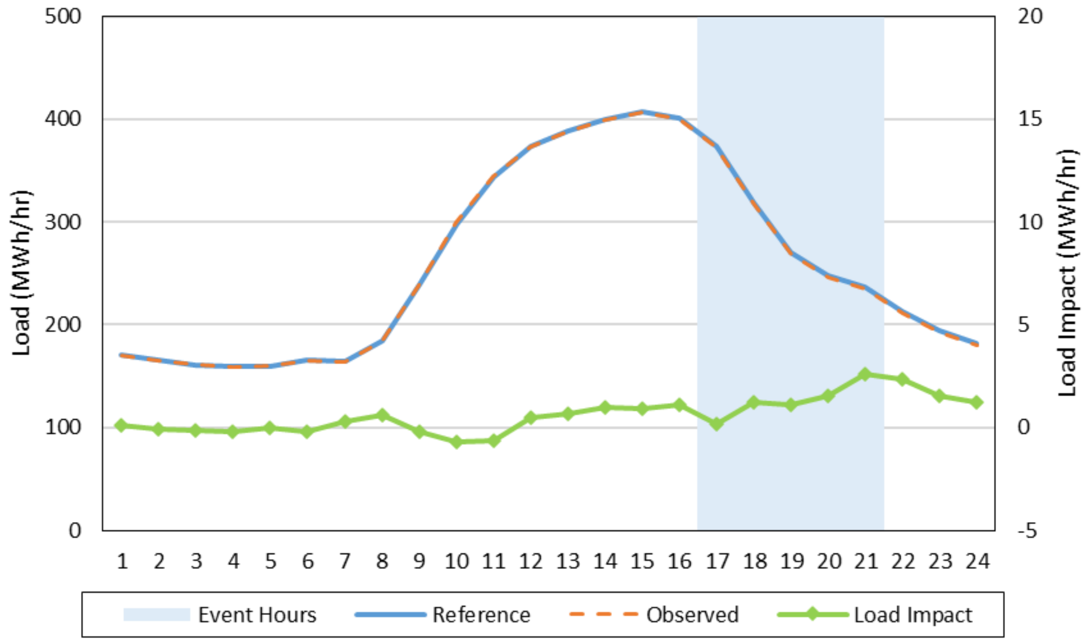


Table 4.11: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Small*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	170.7	170.6	0.1	0.1%	75.5	-0.4	-0.1	0.1	0.3	0.6
2	165.4	165.5	-0.1	-0.1%	74.1	-0.5	-0.3	-0.1	0.1	0.3
3	161.3	161.5	-0.1	-0.1%	72.8	-0.4	-0.3	-0.1	0.0	0.1
4	159.0	159.2	-0.2	-0.1%	71.7	-0.5	-0.3	-0.2	-0.1	0.0
5	160.1	160.1	0.0	0.0%	70.8	-0.2	-0.1	0.0	0.1	0.2
6	165.3	165.5	-0.2	-0.1%	70.1	-0.5	-0.4	-0.2	-0.1	0.1
7	164.1	163.8	0.3	0.2%	69.4	-0.9	-0.2	0.3	0.8	1.5
8	183.8	183.2	0.6	0.3%	68.9	-0.4	0.2	0.6	1.0	1.6
9	238.9	239.1	-0.2	-0.1%	68.8	-1.1	-0.6	-0.2	0.2	0.7
10	298.3	299.0	-0.7	-0.2%	70.6	-1.5	-1.0	-0.7	-0.4	0.0
11	343.8	344.5	-0.7	-0.2%	73.9	-1.2	-0.9	-0.7	-0.4	-0.1
12	373.5	373.1	0.5	0.1%	77.6	0.0	0.3	0.5	0.7	1.0
13	388.7	388.0	0.7	0.2%	81.2	-0.3	0.3	0.7	1.1	1.8
14	400.5	399.5	1.0	0.2%	84.3	-0.4	0.4	1.0	1.6	2.4
15	407.2	406.2	0.9	0.2%	86.5	-0.7	0.3	0.9	1.6	2.6
16	401.0	400.0	1.1	0.3%	87.9	-0.8	0.3	1.1	1.9	3.0
17	373.3	373.1	0.2	0.1%	88.6	-1.6	-0.5	0.2	0.9	2.0
18	318.3	317.1	1.3	0.4%	88.7	0.0	0.7	1.3	1.8	2.5
19	270.2	269.1	1.1	0.4%	88.2	0.0	0.7	1.1	1.6	2.3
20	247.9	246.4	1.5	0.6%	87.1	0.2	1.0	1.5	2.1	2.9
21	236.8	234.3	2.6	1.1%	85.0	1.6	2.2	2.6	3.0	3.5
22	213.7	211.3	2.4	1.1%	81.8	1.4	2.0	2.4	2.8	3.3
23	194.1	192.5	1.6	0.8%	78.9	0.7	1.2	1.6	1.9	2.5
24	181.7	180.5	1.2	0.7%	76.8	0.4	0.9	1.2	1.5	2.0
Daily	6,218	6,203	15	0.2%	78.3	6.8	11.5	14.7	17.9	22.6

Next, we look at SCE small CPP customer estimates by industry group. Table 4.12 summarizes the aggregate event-hour results for the typical event day for each industry group, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services account for the most customers. Five out of eight industry groups exhibited a reduction in loads during event hours on the typical event day.

Table 4.12: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Small*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	8,265	10	10	0.04	0.4%
2.Manufacturing	6,266	8	8	-0.10	-1.3%
3.Wholesale, Transportation, Utilities	10,410	13	13	-0.04	-0.3%
4.Retail Stores	13,470	34	34	0.28	0.8%
5.Offices, Hotels, Health, Services	88,702	124	123	0.49	0.4%
6.Schools	2,227	5	5	-0.27	-5.4%
7. Institutional/Government	26,956	39	38	0.74	1.9%
8.Other	46,997	57	56	0.37	0.7%

Figure 4.12 shows the shares of enrollments, reference loads, and positive load impacts by industry group. About 44% of enrollments and reference loads come from the Offices, Hotels, Health, & Services industry group. The Institutional/Government industry group, however, accounts for 38% of the load impacts.

Figure 4.12 Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Small*

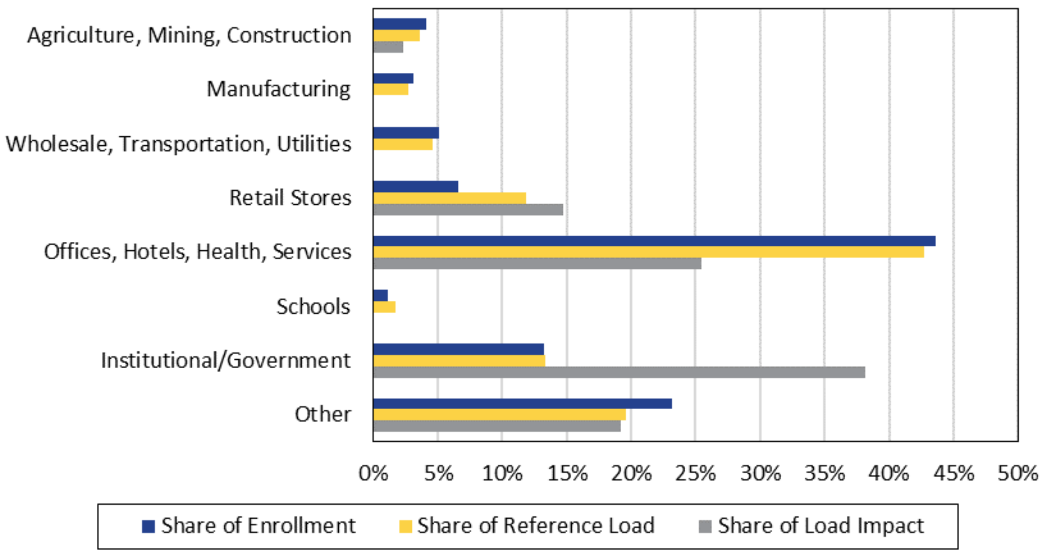
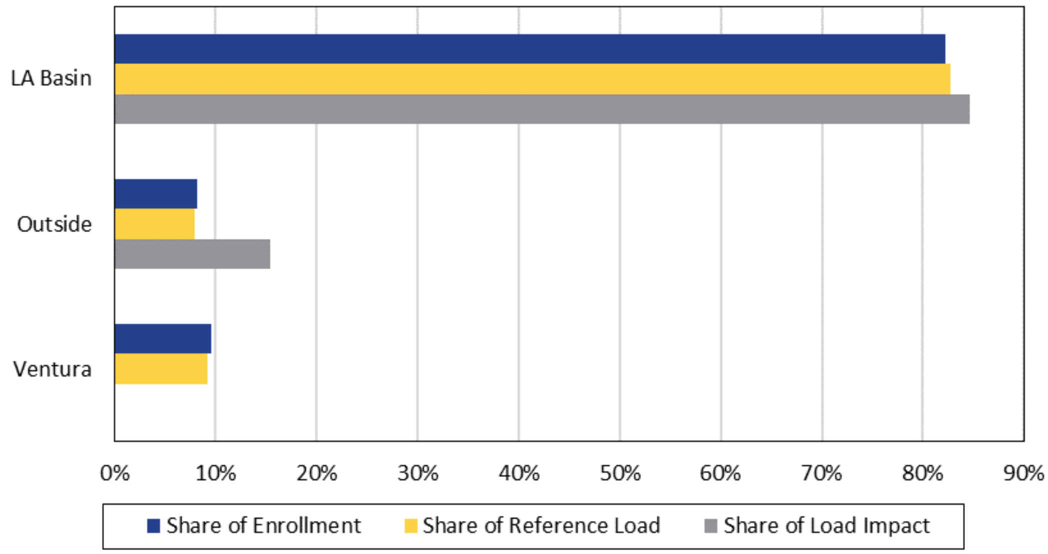


Table 4.13 and Figure 4.13 provide the same summaries as above but by LCA instead of industry group. Enrollments, reference loads, and positive load impacts are highly concentrated in LA Basin, accounting for over 80% of small CPP customers.

Table 4.13: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Small*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	167,063	239	238	1.16	0.5%
Outside	16,789	23	23	0.21	0.9%
Ventura	19,442	27	27	-0.03	-0.1%

Figure 4.13 Typical Event Day Event-Hour Load Impacts by LCA, *SCE Small*



4.1.5 Dually Enrolled Customers

This section summarizes results for customers who are enrolled in CPP as well as another SCE demand response program. Customers that were dually enrolled prior to Decision 18-11-029 could remain grandfathered for dual participation. The other programs in which SCE customers can enroll along with CPP include Base Interruptible Program (BIP), Summer Discount Plan (SDP), and Emergency Load Reduction Program (ELRP). We present results for the average event-hour for each event day and the average event. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 4.14 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who are dually enrolled in CPP. Load impacts are not counted for CPP customers dually enrolled in BIP or SDP when a BIP or SDP event is called on the same day as a CPP event; these customer load impacts are accounted for in the BIP and SDP evaluations. The average dually enrolled customer has a reference load of 32.2 kWh/hour. Dually enrolled customers provided a load impact of 1.5 MWh/hour representing 4.7% of their reference load.

Table 4.14: Average Event-Hour Load Impacts for Dually Enrolled Customers by Event, SCE

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	601	20.3	1.5	33.8	2.4	7.2%	88.1
7/20/2023	558	14.0	-0.1	25.0	-0.2	-0.7%	90.2
7/21/2023	601	18.4	0.2	30.7	0.4	1.2%	86.7
7/24/2023	602	20.2	0.4	33.5	0.62	1.8%	87.9
8/15/2023	600	21.0	1.4	34.9	2.3	6.5%	89.3
8/16/2023	568	18.9	1.6	33.4	2.8	8.3%	89.9
8/17/2023	600	20.9	2.2	34.8	3.6	10.3%	87.4
8/28/2023	605	20.4	0.8	33.7	1.3	3.8%	91.7
8/29/2023	602	21.0	0.3	34.9	0.5	1.4%	92.1
8/30/2023	602	20.6	0.4	34.3	0.7	2.1%	86.8
9/25/2023	601	16.4	0.8	27.3	1.3	4.6%	76.4
9/26/2023	600	16.9	1.2	28.1	2.0	7.1%	79.6
Typical Event Day	**595**	**19.1**	**0.9**	**32.2**	**1.5**	**4.7%**	**87.0**

4.1.6 AutoDR Customers

This section summarizes results for CPP customers who participated in Automated Demand Response (AutoDR) programs. The AutoDR program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention. We present results for the average event-hour for each event day and for the average event. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report. Table 4.15 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who participated in the AutoDR program. There were 42 CPP customers enrolled in AutoDR at SCE. Their combined load impact was 0.4 MWh/hour (6.7%) for the typical event day.

Table 4.15: Average Event-Hour Load Impacts for AutoDR Customers by Event, SC*E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
7/17/2023	42	6.3	0.6	149.1	14.66	9.8%	87.8
7/20/2023	42	6.2	0.6	147.0	14.43	9.8%	89.8
7/21/2023	42	5.9	0.7	140.1	15.82	11.3%	84.9
7/24/2023	42	6.3	0.6	148.9	13.85	9.3%	87.6
8/15/2023	42	6.3	0.3	150.2	6.75	4.5%	88.5
8/16/2023	42	6.3	0.4	149.4	9.50	6.4%	89.8
8/17/2023	42	6.2	0.4	148.8	9.29	6.2%	88.0
8/28/2023	42	6.4	0.1	152.9	2.16	1.4%	92.9
8/29/2023	42	6.3	0.5	150.2	12.92	8.6%	93.1
8/30/2023	42	6.2	0.3	148.8	7.35	4.9%	87.4
9/25/2023	41	5.3	0.3	128.3	6.86	5.4%	76.4
9/26/2023	41	5.5	0.1	134.6	2.47	1.8%	80.8
Typical Event Day	**42**	**6.1**	**0.4**	**144.9**	**9.652**	**6.7%**	**87.3**

4.1.7 Notified vs. Non-Notified Customers

SCE customers can elect to receive day-ahead notification of CPP events by phone, email, or text message. This section summarizes results for CPP customers by notification status. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 4.16 summarizes enrollments, average event-hour load impacts, and reference loads for the average event day by size and notification status. About 67% of all customers were notified during events. Large CPP customers exhibited the largest difference in percentage load impacts between notified and non-notified customers: 2.0 and 0.1%, respectively.

Table 4.16: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, *SCE*

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	541	127	0.1	234.8	0.14	0.1%	88.2
	Medium	5,992	161	0.2	26.9	0.03	0.1%	87.2
	Small	67,997	105	0.4	1.5	0.01	0.4%	87.3
	All	**74,529**	**393**	**0.6**	**5.3**	**0.01**	**0.2%**	**87.4**
Yes	Large	1,150	249	4.9	216.4	4.29	2.0%	87.3
	Medium	15,216	393	0.5	25.9	0.03	0.1%	87.8
	Small	135,297	184	1.0	1.4	0.01	0.5%	87.6
	All	**151,664**	**827**	**6.4**	**5.5**	**0.04**	**0.8%**	**87.6**

4.1.8 Load Impact and Weather Relationship

Figure 4.14 through Figure 4.16 demonstrate the relationship between percentage load impacts and weather for large, medium, and small CPP customers, respectively. Blue and yellow points represent the average event-hour load impact percentages and temperatures for each event in PY22 and PY23, respectively.[25] Each line represents the linear relationship between load impact percentages and weather. The red dashed line indicates the relationship looking at both program years, while the orange and blue dotted lines indicate the linear relationships separately for PY22 and PY23 events, respectively. A decreasing slope of the linear relationship indicates that events with hotter temperatures tend to have lower percentage load impacts. For each size category, the PY23 relationship between weather and temperature is flatter than PY22, indicating less of a relationship. The difference is most prominent for large customers but the relationship between weather and load impact appears to be consistent between years for medium and small customers.[26]

The relationship between temperature and load impacts is not statistically significant for any size group using only the PY23 load impacts. However, there is a statistically significant relationship for large and medium customers when using two years of data, PY22 and PY23. In discussions with SCE, we agreed to use two years of data in determining the relationship that is incorporated in ex-ante. We estimate the magnitude of the effect of temperature on percentage load impacts via a regression for each size and LCA. Statistically significant estimates of the load impact percentage and weather

[25] Holiday events (e.g., Labor Day) are excluded from each figure. However, the load impact percentage and weather relationships are similar if holiday events were included.

[26] It is important to acknowledge that there could be other elements, unobserved by the researcher, which are correlated with higher temperatures and cause a reduction in load impacts. For example, event-day fatigue that results in reduced load impacts for consecutive event days could be misattributed to weather if consecutive events were only called during hot events. However, we do not believe that is the case here since the load impacts and weather relationship remains when consecutive events days are removed. As well, consecutive event days also occurred when temperatures were moderate.

relationship are used in the ex-ante analysis to adjust the percentage load impacts that are applied to ex-ante reference loads that differ by weather scenario.

Figure 4.14: Load Impact Percentage and Weather Relationship, *SCE Large*

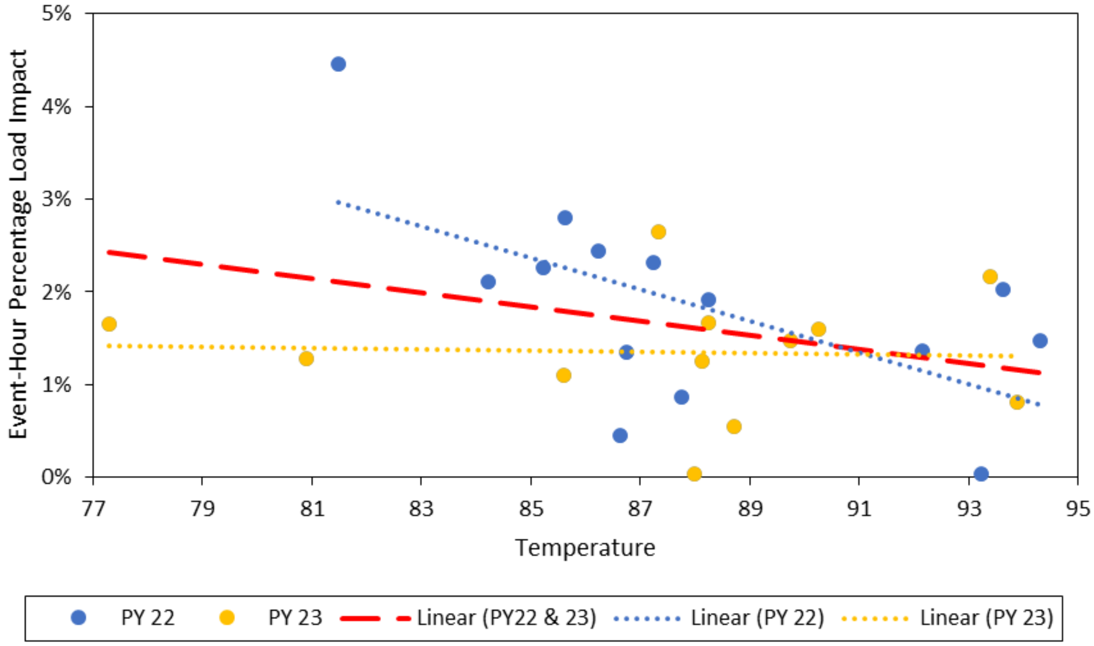


Figure 4.15: Load Impact Percentage and Weather Relationship, *SCE Medium*

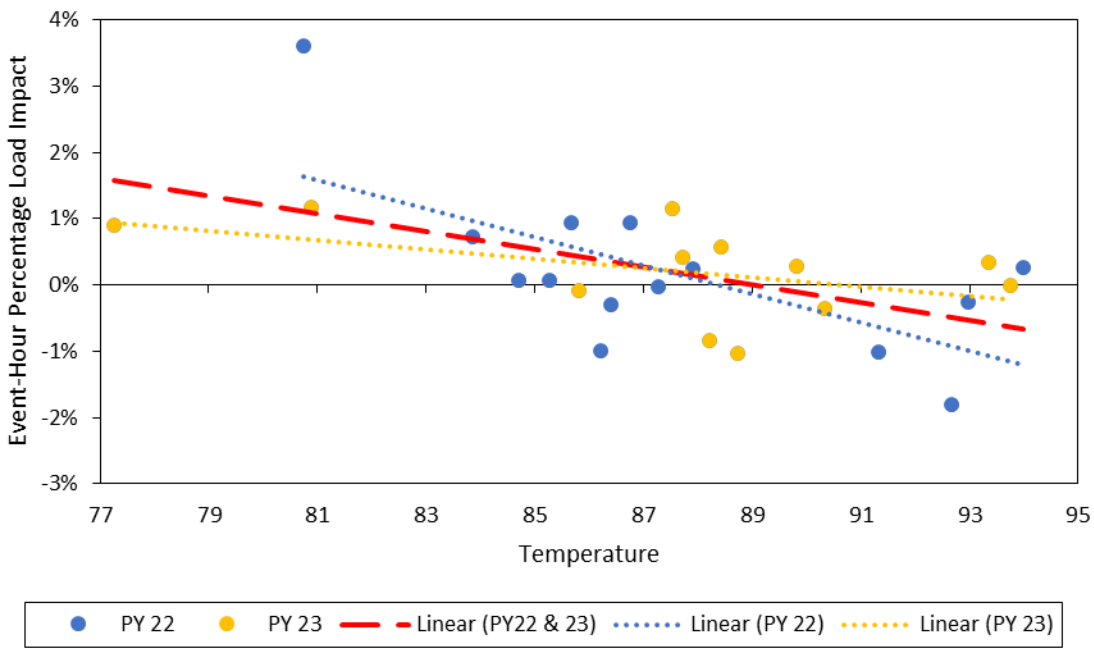
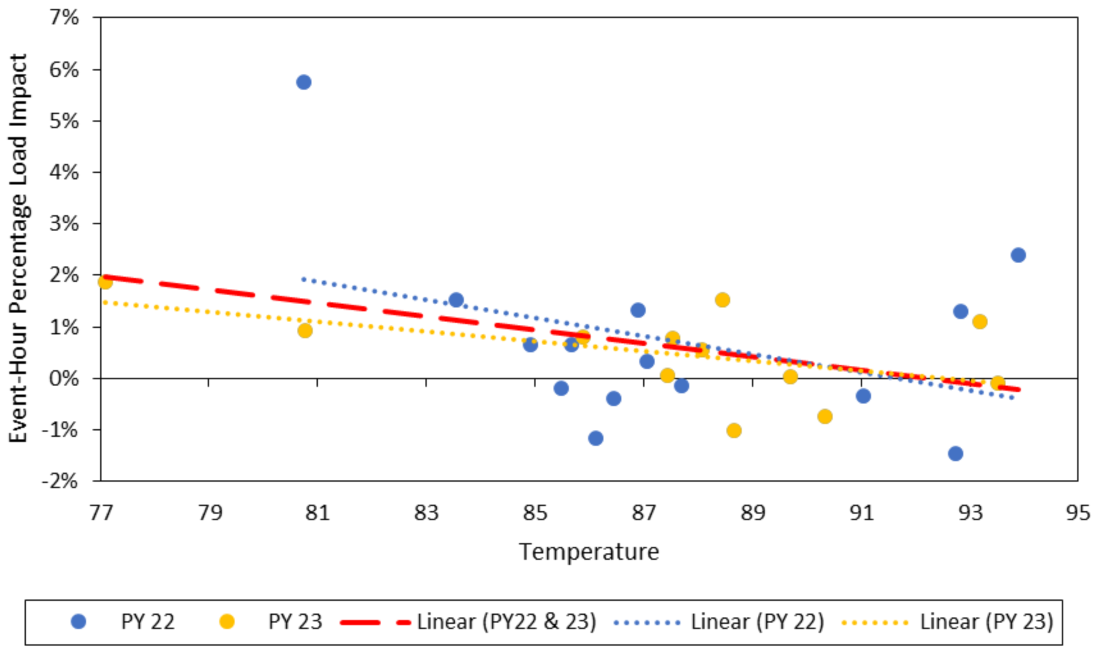


Figure 4.16: Load Impact Percentage and Weather Relationship, *SCE Small*



4.2 SCE Ex-Ante Load Impacts

This section provides the ex-ante CPP load impact forecast based on an enrollment forecast provided by SCE. Results are presented by size group. Within each size group, we present the following: a summary of the enrollment forecast provided by SCE; a figure showing the hourly reference load and load impact on a typical event day; a figure showing the share of load impacts by LCA; a figure showing the seasonal pattern of load impacts; and a figure summarizing annual load impacts by weather scenario. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, per-customer load impacts are derived from analysis of current and previous ex-post load impacts. As demonstrated in Section 4.1.8, we investigated the effect of weather on estimated load impacts and found that there exists a negative relationship for large and medium, but not small customers. The ex-ante load impacts are simulated by multiplying forecast reference loads by the ex-post percentage load impacts (by size, LCA, and hour of the day). The ex-post percentage load impact is adjusted based on ex-ante weather scenarios for large and medium customers.[27]

Another assumption made in these forecasts is that the share of enrollments by LCA within each size group remains constant over time. This was necessary to produce forecasts at the LCA level from SCE's enrollment forecasts, which vary by size group but not by LCA.

[27] As a result, relatively higher ex-ante temperatures have lower percentage load impacts applied to the reference loads.

4.2.1 All Customers

Figure 4.17 summarizes the overall trend of SCE's enrollment forecast. Table 4.17 provides enrollment counts and aggregate and per-customer load impacts from 2024 to 2034 on Typical Event Day under SCE 1-in-2 weather conditions. SCE anticipates that the total number of CPP customers increases by about 2% each year until 2028, whereafter it will remain constant at 244,641 customers. Per-customer load impacts only vary slightly over the years due to changes in customer composition, so the main driver of change in aggregate impacts is the change of aggregate enrollments. The aggregate load impacts increase from 7.8 MWh/hour to 8.4 MWh/hour from 2024 to 2028 and remain constant afterwards until 2034.

Figure 4.17: CPP Enrollments, *SCE All*

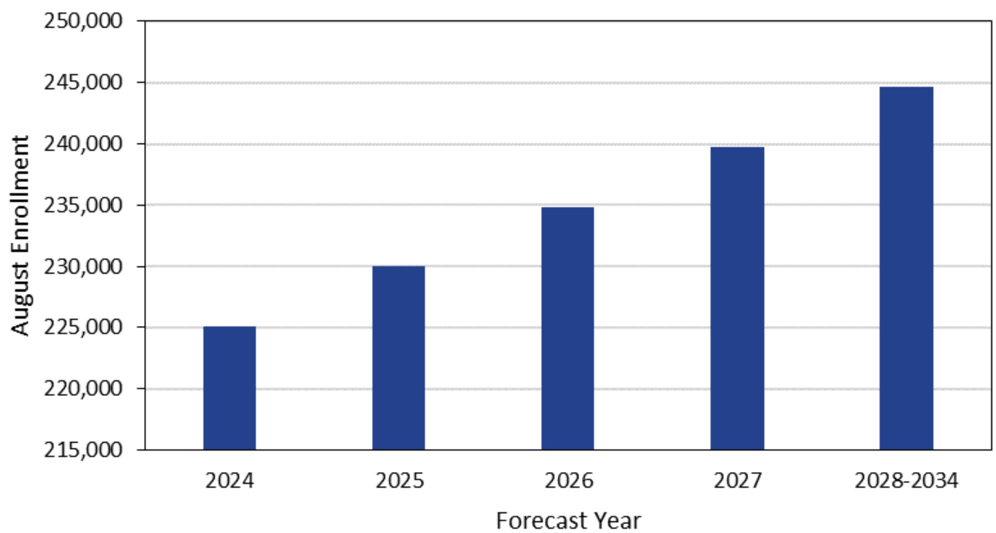
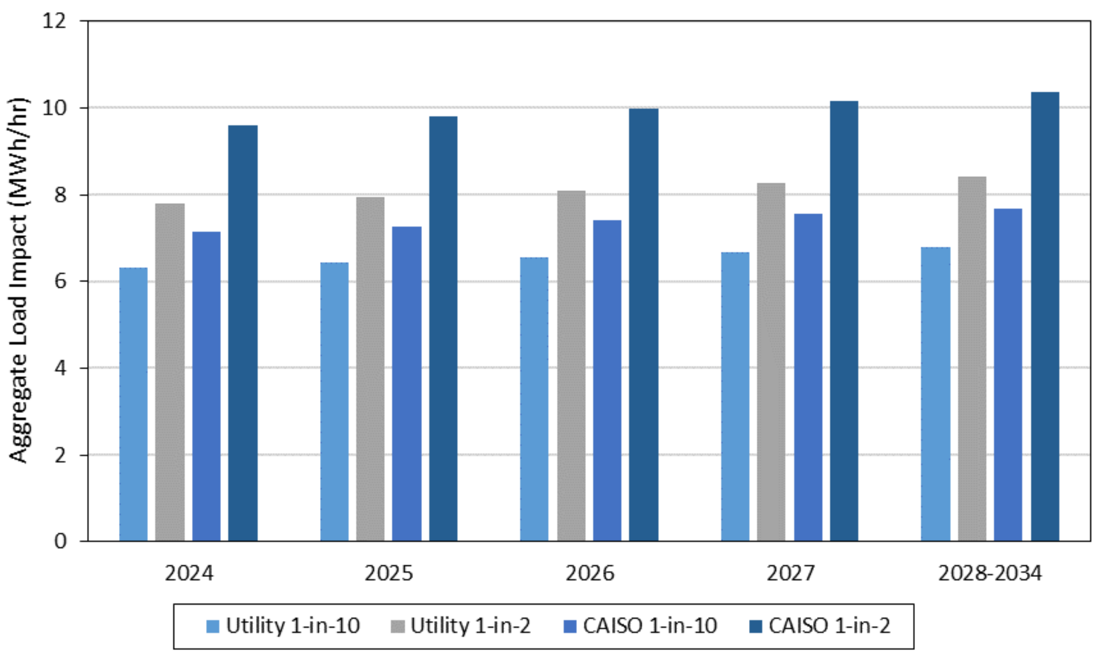


Table 4.17: Typical Event Day Load Impacts, Utility 1-in-2, *SCE All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	225,082	1269.8	7.8	5.6	0.035
2025	229,973	1297.4	8.0	5.6	0.035
2026	234,862	1324.8	8.1	5.6	0.035
2027	239,751	1352.3	8.3	5.6	0.034
2028	244,641	1379.6	8.4	5.6	0.034
2029	244,641	1379.6	8.4	5.6	0.034
2030	244,641	1379.6	8.4	5.6	0.034
2031	244,641	1379.6	8.4	5.6	0.034
2032	244,641	1379.6	8.4	5.6	0.034
2033	244,641	1379.6	8.4	5.6	0.034
2034	244,641	1379.6	8.4	5.6	0.034

Figure 4.18 displays the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. The load impacts increase slightly over time due to the increase in forecasted total enrollment. Aggregate load impacts have a negative relationship with weather; therefore, weather scenarios with hotter temperatures have lower load impacts. For instance, the load impacts for 1-in-2 scenarios are higher than 1-in-10 scenarios, and the largest difference of load impacts between 1-in-2 and 1-in-10 scenarios is about 3.6 MWh/hour. The highest load impacts for each year occur under CAISO-specific 1-in-2 weather conditions. Additional results of ex-ante load impacts are presented in the subsequent sections by size group.

Figure 4.18: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE All*



4.2.2 Large Customers

Figure 4.19 summarizes SCE's enrollment forecast for large CPP customers. SCE anticipates that large CPP customer enrollment will increase by about 2% each year until 2028, whereafter it will remain constant at 1,813 customers.

Figure 4.19: CPP Enrollments, *SCE Large*

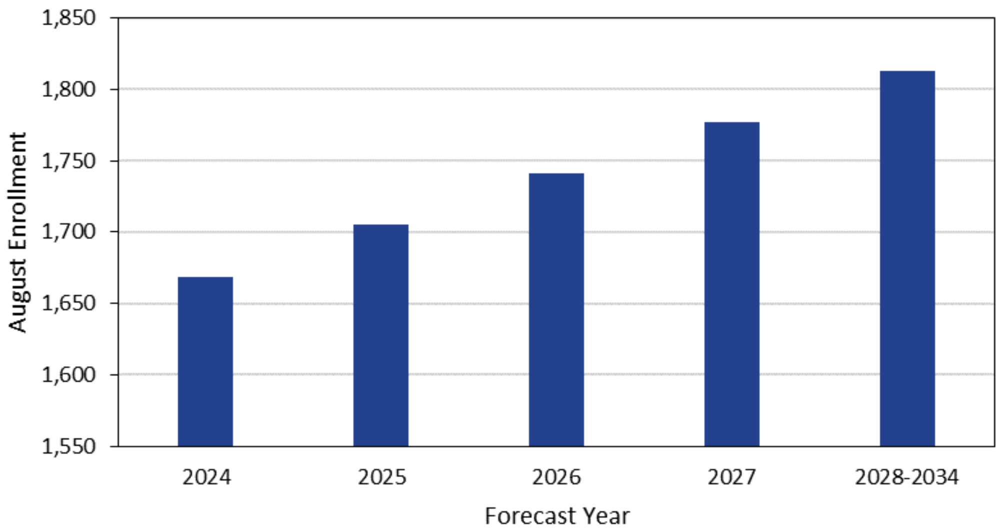


Figure 4.20 illustrates the aggregate reference load, observed load, and load impact for large customers on the typical event day in 2024 for the SCE 1-in-2 weather scenario. The average event-hour load impact is 5.4 MWh/hour, or 1.4% of the reference load. The shape of the ex-ante loads and load impacts is similar to the ex-post results in Figure 4.3.

Figure 4.20: Aggregate Hourly Loads and Load Impacts in 2024 for *SCE 1-in-2 Typical Event Day, SCE Large*

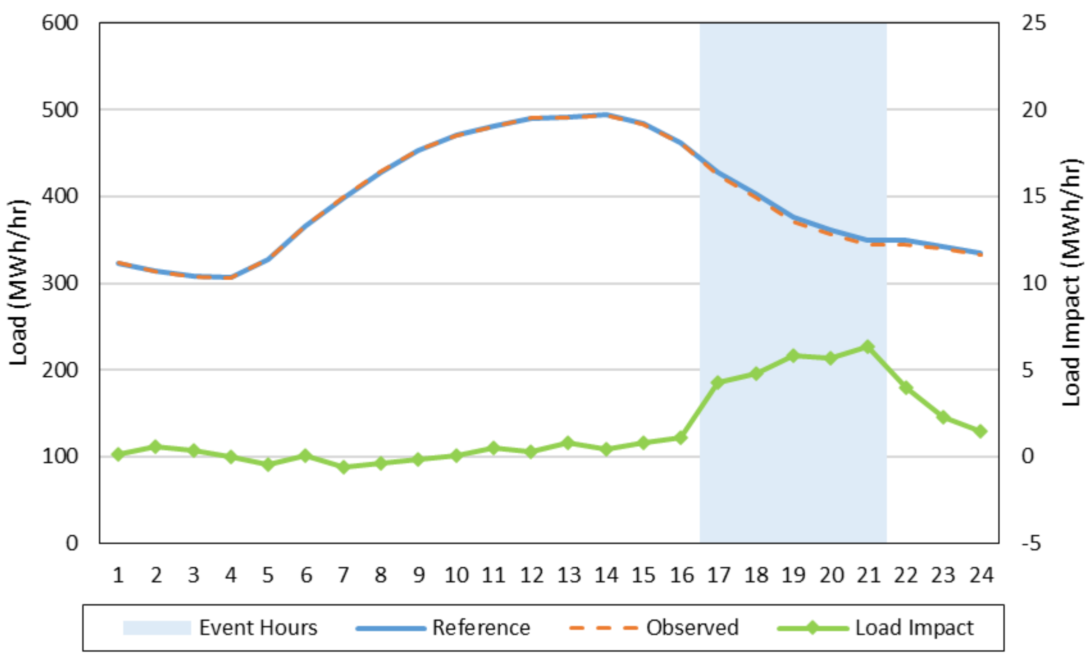


Figure 4.21 shows the forecasted share of large customer load impacts by LCA during the average event hour on the typical event day in 2024 under SCE's 1-in-2 weather scenario. As expected, the LA Basin accounts for 90% of the total load impact.

Figure 4.21: Share of Load Impacts by LCA in 2024 for *SCE 1-in-2 Typical Event Day, SCE Large*

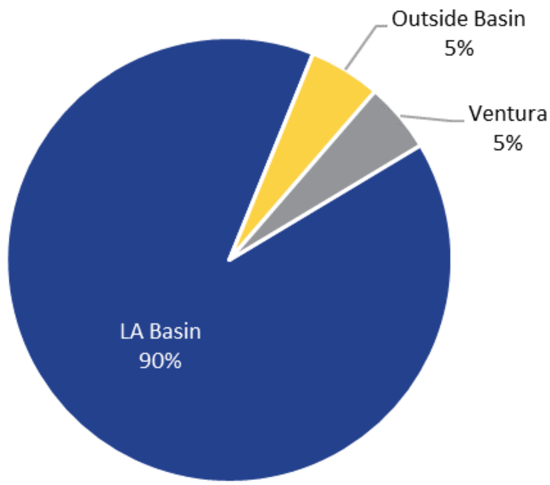


Figure 4.22 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the RA window in 2024 across months for SCE's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. for all months except for March, April, and May, when it is from 5 to 10 p.m. The load impact is highest in June (5.8 MWh/hour) and then decreases over the summer period as temperatures rise. The lowest load impacts occur in September at 4.6 MWh/hour.

Figure 4.22: Aggregate Load Impacts by Month over RA Window in 2024 for *SCE 1-in-2 Peak Day, SCE Large*

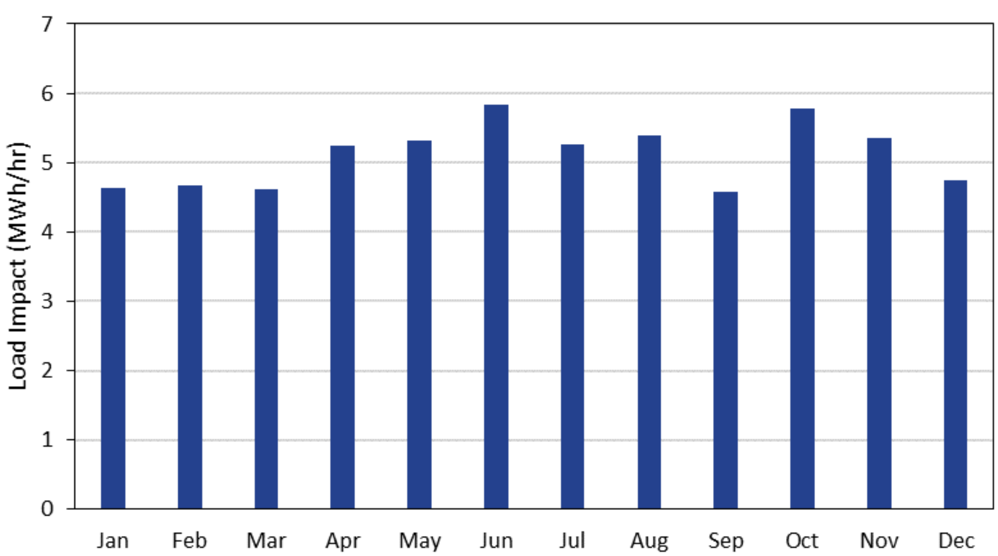
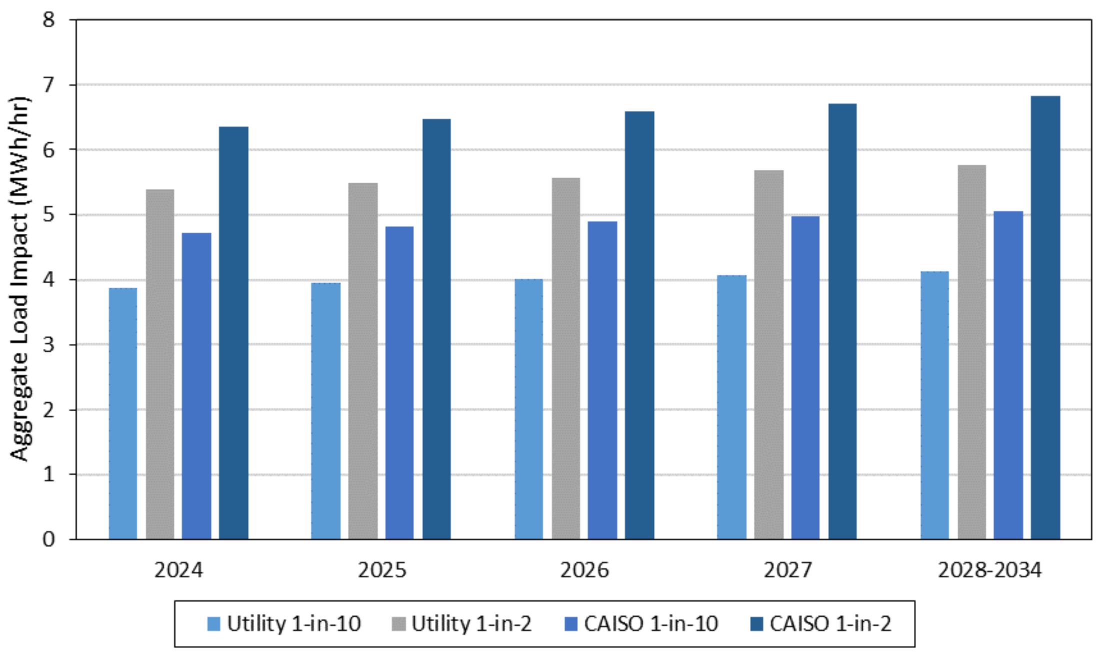


Figure 4.23 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. The load impact decreases over time, within a specific weather scenario, as enrollment numbers decrease. The hottest weather scenarios have relatively lower load impacts. For example, SCE weather scenarios are hotter than CAISO weather scenarios and thus have lower load impacts. Similarly, 1-in-10 weather scenarios are hotter than 1-in-2 weather scenarios and thus have lower load impacts. The largest load impact (6.83 MWh/hour in 2028-2034) occurs under the CAISO 1-in-2 weather condition when temperatures are relatively lower.

Figure 4.23: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Large*



4.2.3 Medium Customers

Figure 4.24 summarizes SCE's enrollment forecast for medium CPP customers. SCE anticipates that Medium CPP customer enrollment increases by about 2% each year until 2028, whereafter it will remain constant at 22,210 customers.

Figure 4.24: CPP Enrollments, *SCE Medium*

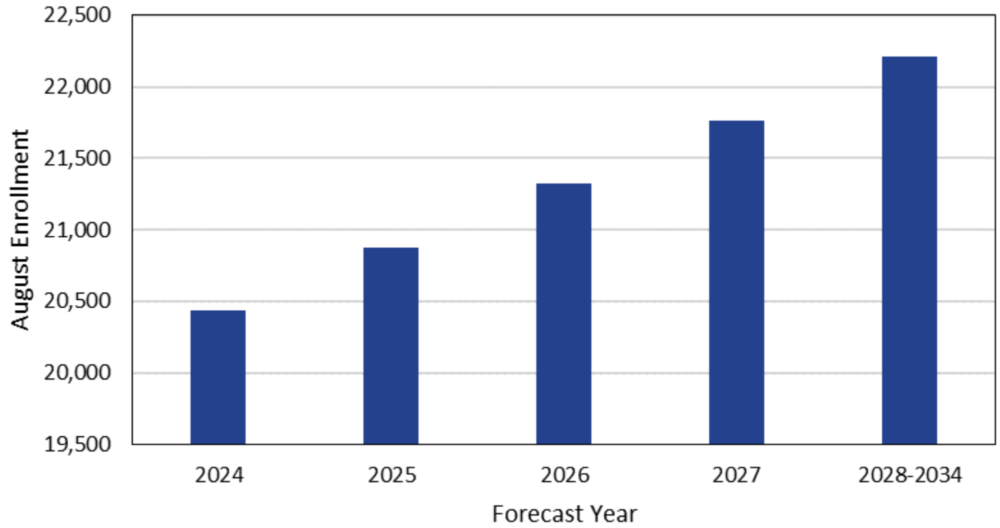


Figure 4.25 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August in 2024 for the SCE 1-in-2 weather scenario. The forecast predicts an average load impact of 0.58 MWh/hour for medium CPP customers on the typical event day in 2024, which is a 0.1% reduction in reference loads.

Figure 4.25: Aggregate Hourly Loads and Load Impacts in 2024 for *SCE 1-in-2 Typical Event Day, SCE Medium*

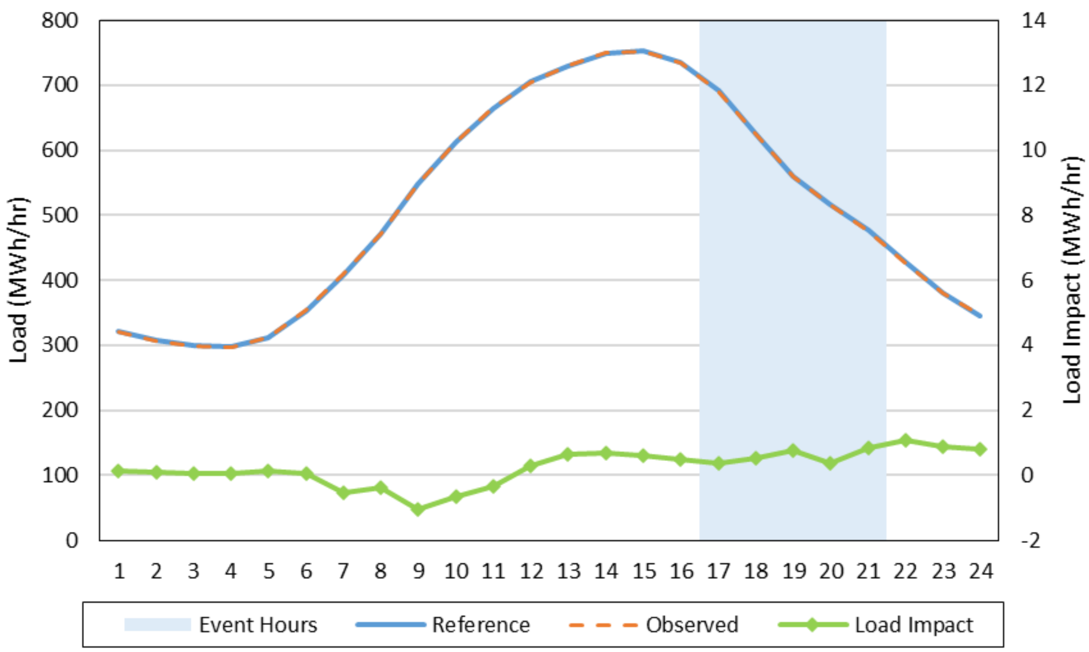


Figure 4.26 shows the forecasted share of load impacts for medium CPP customers by LCA, based on the average event-hour load impact on the typical event day in 2024 under SCE's 1-in-2 weather scenario. Outside Basin is expected to have the largest share of load impacts at 46%, followed by Ventura at 42%, then LA Basin at 12%.

Figure 4.26: Share of Load Impacts by LCA in 2024 for *SCE 1-in-2 Typical Event Day, SCE Medium*

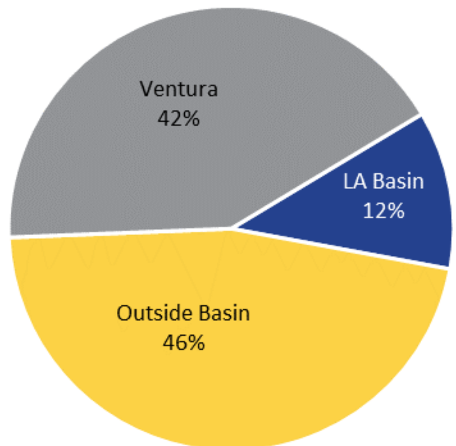


Figure 4.27 shows the seasonality of the forecasted load impacts for medium CPP customers based on the 2024 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The RA window is 4 to 9 p.m. in all months except for March, April, and May when it is 5 to 10 p.m. The load impact is highest in May (0.7 MWh/hour) and lowest in August (0.5 MWh/hour). Over the summer period, load impact percentages decrease as weather temperatures rise because of the observed negative relationship between temperatures and load impacts in the ex-post analysis for medium customers.

Figure 4.27: Aggregate Load Impacts by Month over RA Window in 2024 for *SCE 1-in-2 Peak Day, SCE Medium*

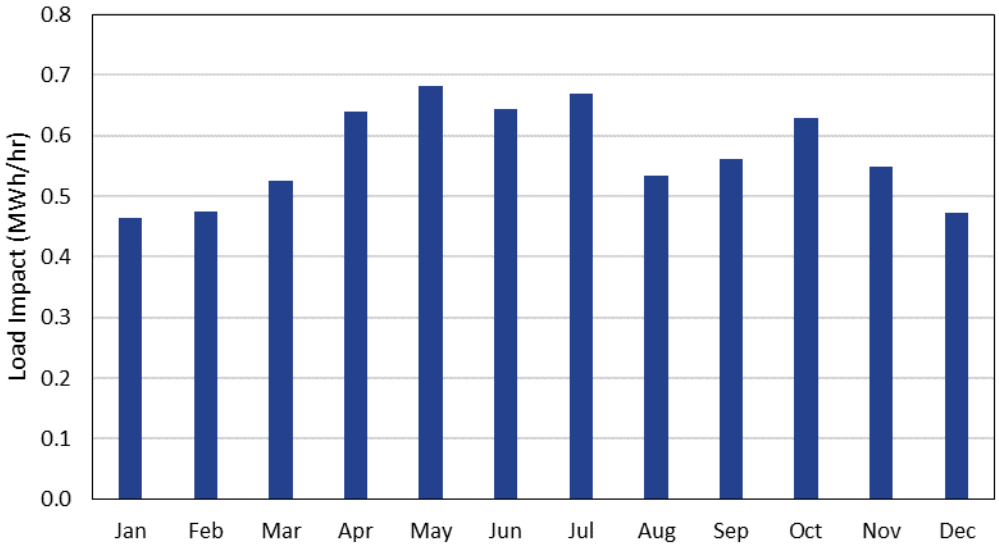
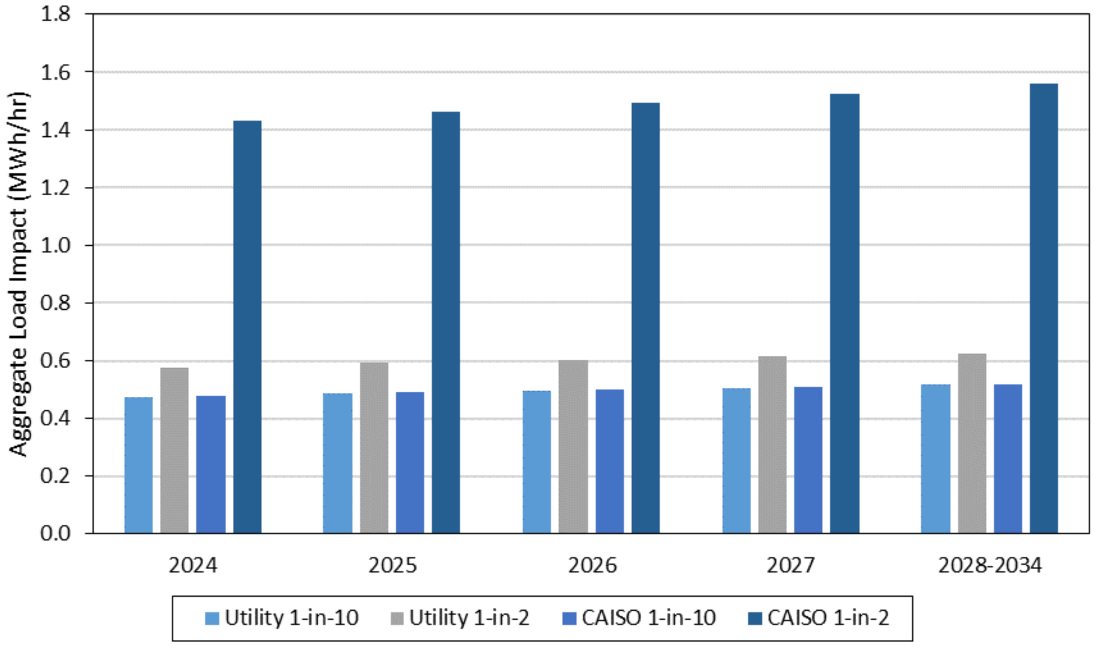


Figure 4.28 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. The CAISO 1-in-2 weather scenario, when temperatures are relatively cooler, has the largest load impact of 1.6 MWh/hour during the years 2028-2034. The other weather scenarios in have load impacts that range from 0.47 to 0.63 MWh/hour. These scenarios have hotter temperatures than the CAISO 1-in-2 scenario which result in lower load impacts. There is less variation for these scenarios because weather adjusted load impacts are capped at a lower bound.[28]

[28] The weather adjusted percentage load impacts are capped at a lower bound of 0.01% to prevent estimates that indicate an increase in usage during CPP events.

Figure 4.28: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Medium*



4.2.4 Small Customers

Figure 4.29 summarizes SCE's enrollment forecast for small CPP customers. SCE anticipates that small CPP customer enrollment to increase by about 2% each year until 2028, whereafter it will remain constant at 220,618 customers.

Figure 4.29: CPP Enrollments, *SCE Small*

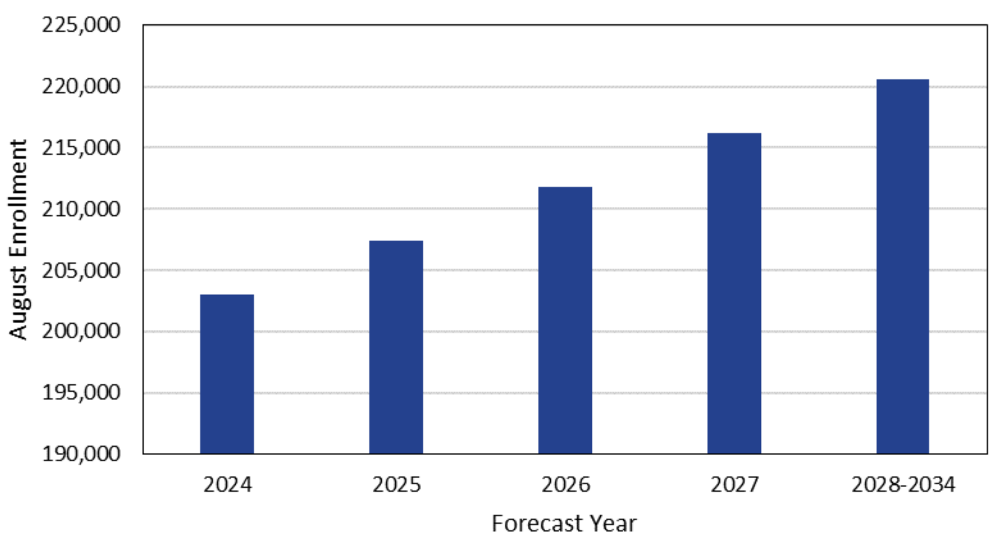


Figure 4.30 illustrates the aggregate reference loads, observed loads, and load impacts for small CPP customers on the typical event day in August in 2024 for the SCE 1-in-2

weather scenario. The forecast predicts an average load impact of 1.8 MWh/hour for small CPP customers on the typical event day in 2024 for the SCE 1-in-2 weather scenario, which represents a 0.6% reduction in reference loads.

Figure 4.30: Aggregate Hourly Loads and Load Impacts in 2024 for *SCE 1-in-2 Typical Event Day, SCE Small*

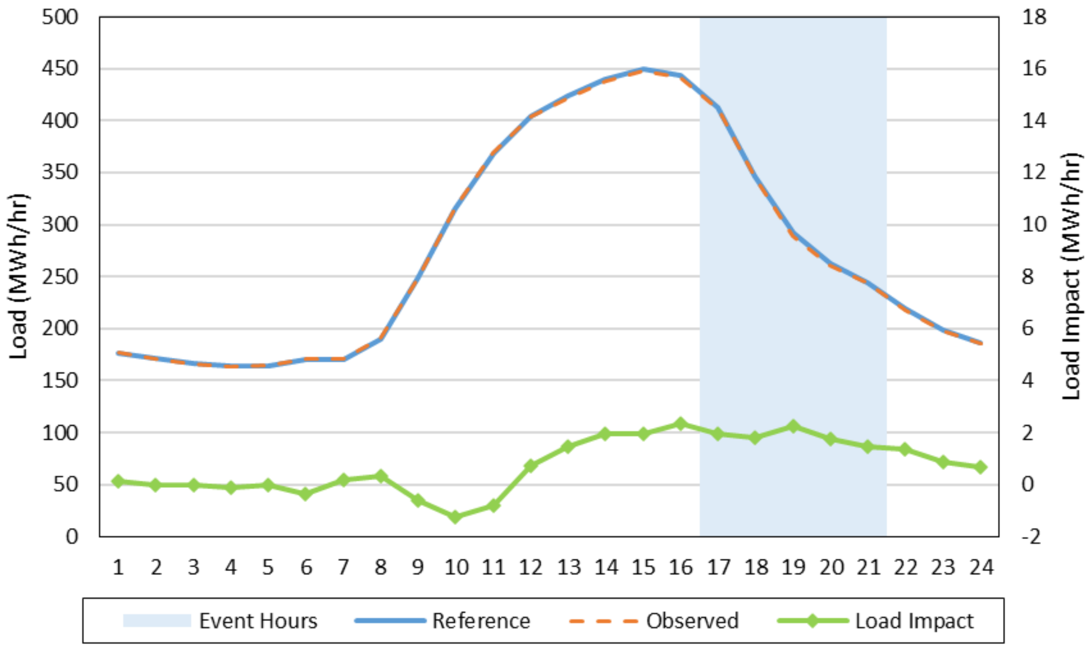


Figure 4.31 shows the forecasted share of load impacts for small customers by LCA, based on the average event-hour load impact on the typical event day in 2024 under SCE's 1-in-2 weather scenario. LA Basin has the largest share of load impacts at 84%, followed by Ventura at 10%, then Outside Basin at 6%.

Figure 4.31: Share of Load Impacts by LCA in 2024 for *SCE 1-in-2 Typical Event Day, SCE Small*

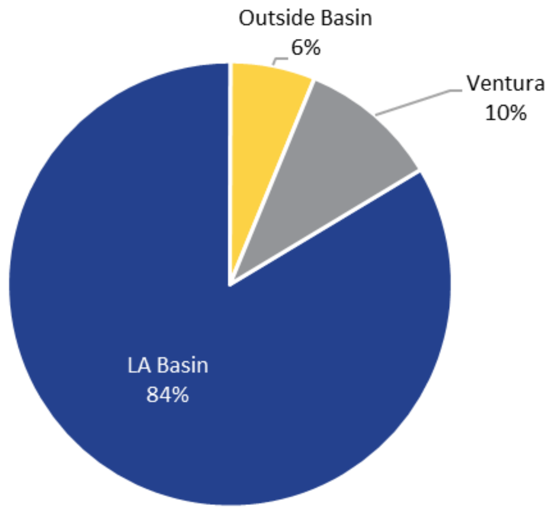


Figure 4.32 shows the seasonality of the forecasted load impacts for small CPP customers based on the 2024 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The load impact is highest in August at 1.9 MWh/hour. The load impact is lowest in March at 1.22 MWh/hour, driven by differences in the March through May RA window (i.e., RA window is 5 to 10 p.m. in March, April, and May and 4 to 9 p.m. in all other months). The peak load impact in August is driven by higher references loads.[29]

[29] Ex-post percentage load impacts were applied to ex-ante reference loads. No weather adjustment is applied to ex-ante load impacts for small CPP customers since there was little to no relationship between load impacts and weather in the ex-post analysis.

Figure 4.32: Aggregate Load Impacts by Month over RA Window in 2024 for *SCE 1-in-2 Peak Day, SCE Small*

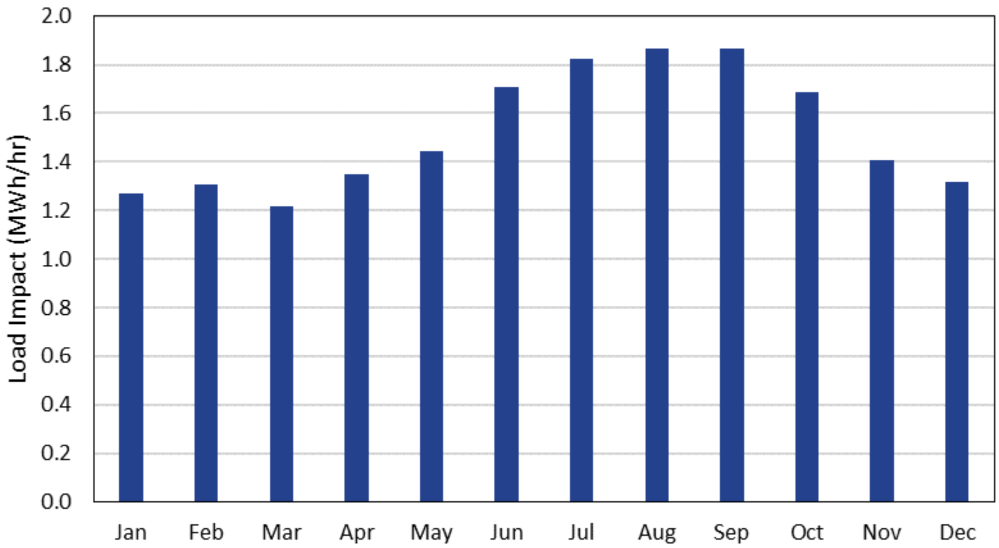
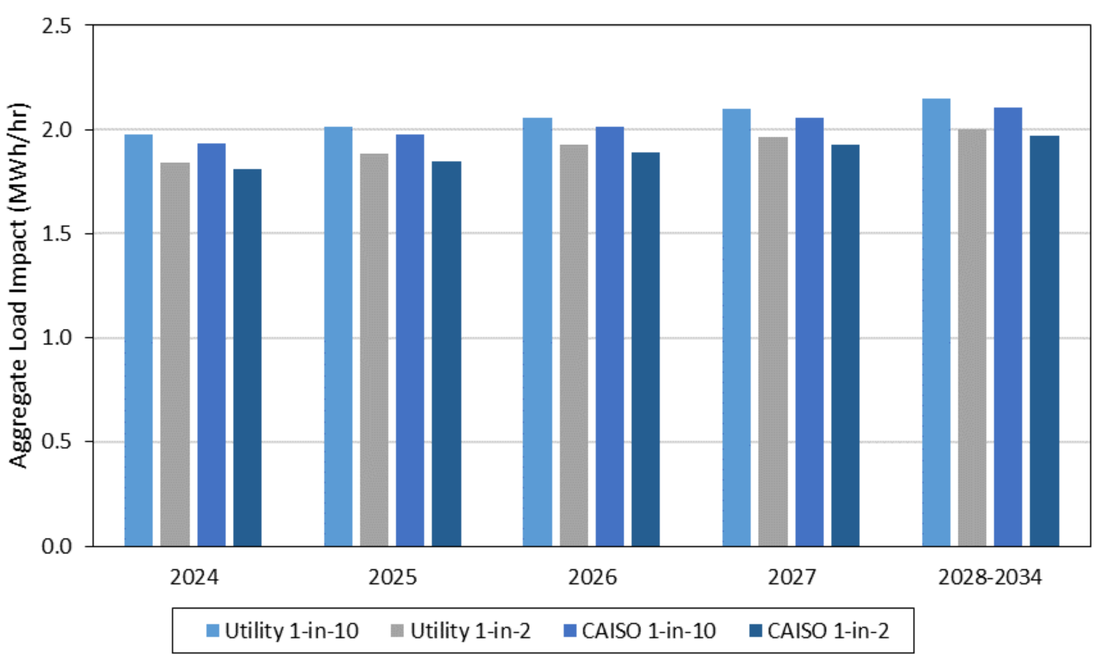


Figure 4.33 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The largest load impact occurs during the SCE 1-in-10 weather scenario at 2.2 MWh/hour during the 2028-2034 forecast period.

Figure 4.33: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Small*



4.3 SCE Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts for CPP, including the following:

- Ex-post load impacts from the current and previous studies;
- Ex-ante load impacts from the current and previous studies;
- Current ex-post and previous ex-ante load impacts; and
- Current ex-post and ex-ante load impacts.

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2023. The term "previous" refers to findings in reports for PY2022.

4.3.1 Large Customers

Previous vs. Current Ex-Post

Table 4.18 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The total load impact is lower in the current study (5.0 MWh/hour vs. 6.7 MWh/hour in the previous study). The reference loads, aggregate and per-customer, are larger in the current study. The average event temperature and percentage load impact, on the other hand, are smaller in the current study.

Table 4.18: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	1,687	1,691
	Reference (MW)	369	376
	Load Impact (MW)	6.7	5.0
	Avg. Temp.	88.0	87.6
Per SAID	Reference (kW)	218.9	222.3
	Load Impact (kW)	4.0	3.0
	% Load Impact	1.8%	1.3%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.19 reports the average event-hour load impacts for a typical event day in 2024 under SCE 1-in-2 weather conditions. The forecast load impact is slightly higher in the current study (5.4 MWh/hour vs. 5.3 MWh/hour in the previous study). Increased enrollments only partially cause the higher load impacts. The per-customer load impact and percentage load impact are slightly smaller in the current study because of lower ex-post load impacts in PY23.

Table 4.19: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, SCE Large*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study
Total	# SAIDs	1,615	1,668
	Reference (MW)	363	384
	Load Impact (MW)	5.3	5.4
	Avg. Temp.	89.7	89.4
Per SAID	Reference (kW)	225	230
	Load Impact (kW)	3.3	3.2
	% Load Impact	1.5%	1.4%

Previous Ex-Ante vs. Current Ex-Post

Table 4.20 provides a comparison of the ex-ante forecast of 2023 load impacts prepared following PY2022 and the PY2023 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post typical event day load impacts are based on the average non-holiday weekday event. The ex-ante enrollments are higher in the current ex-post study. Per-customer reference loads are smaller in the current ex-post study along with lower event temperatures. The percentage load impact is also smaller in the current ex-post study.

Table 4.20: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Large*

Level	Outcome	Ex-Ante for 2023 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	1,660	1,691
	Reference (MW)	373	376
	Load Impact (MW)	5.4	5.0
	Avg. Temp.	89.7	87.6
Per SAID	Reference (kW)	225	222
	Load Impact (kW)	3.2	3.0
	% Load Impact	1.4%	1.3%

Current Ex-Post vs. Current Ex-Ante

Table 4.21 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2024 under SCE 1-in-2 weather conditions. Reference loads are slightly larger in ex-ante due to hotter temperatures, even with a decreased enrollment forecast. The load impact and percentage load impact are larger in ex-ante due to the hotter temperatures and because the ex-ante results are based on the PY22 and PY23 ex-post load impacts.

Table 4.21: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Large*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2024 Typical Event Day Current Study
Total	# SAIDs	1,691	1,668
	Reference (MW)	376	384
	Load Impact (MW)	5.0	5.4
	Avg. Temp.	87.6	89.4
Per SAID	Reference (kW)	222	230
	Load Impact (kW)	3.0	3.2
	% Load Impact	1.3%	1.4%

Table 4.22 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 4.22: Comparison of Ex-Post and Ex-Ante Factors, *SCE Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 87.6 °F during the average event day.	Average event-hour temperature of 89.4 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load but decrease the load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100%	100%	None.
Enrollment	1,691 service accounts.	1,668 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.2 Medium Customers

Previous vs. Current Ex-Post

Table 4.23 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load impact is smaller in the current study (0.7 MWh/hour vs. 0.9 MWh/hour in the previous study).

Enrollments are lower in the current study resulting in lower aggregate reference loads. The per-customer reference loads are also lower in the current study. The percentage load impact is similar between the previous and current ex-post study.

Table 4.23: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	22,119	21,207
	Reference (MW)	599	555
	Load Impact (MW)	0.9	0.7
	Avg. Temp.	87.5	87.6
Per SAID	Reference (kW)	27.1	26.2
	Load Impact (kW)	0.04	0.03
	% Load Impact	0.1%	0.1%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.24 reports the average event-hour load impacts for a typical event day in 2024 under SCE 1-in-2 weather conditions. Enrollments and reference loads, aggregate and per-customer, are larger in the current study. The aggregate, per-customers, and percentage load impacts are similar between each study.

Table 4.24: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 August Typical Event Day, SCE Medium*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study
Total	# SAIDs	19,634	20,435
	Reference (MW)	540	574
	Load Impact (MW)	0.6	0.6
	Avg. Temp.	89.2	89.3
Per SAID	Reference (kW)	27.5	28.1
	Load Impact (kW)	0.03	0.03
	% Load Impact	0.1%	0.1%

Previous Ex-Ante vs. Current Ex-Post

Table 4.25 provides a comparison of the ex-ante forecast of 2023 load impacts prepared following PY2022 and the PY2023 ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post load impacts are based on the average non-holiday weekday event. The ex-post enrollments in the current study are higher than what was forecast resulting in larger load impacts. The per-customer load impact and percentage load impact are similar between the previous ex-ante forecast and the current ex-post results.

Table 4.25: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Medium*

Level	Outcome	Ex-Ante for 2023 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	20,185	21,207
	Reference (MW)	555	555
	Load Impact (MW)	0.6	0.7
	Avg. Temp.	89.2	87.6
Per SAID	Reference (kW)	27.5	26.2
	Load Impact (kW)	0.03	0.03
	% Load Impact	0.1%	0.1%

Current Ex-Post vs. Current Ex-Ante

Table 4.26 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2024 under SCE 1-in-2 weather conditions. Enrollments decrease in ex-ante which result in lower aggregate reference loads and load impacts. Aggregate reference loads, however, are higher in ex-ante because of the hotter temperatures relative to ex-post. The per-customer load impact and percentage load impacts are similar between the current ex-post and ex-ante study.

Table 4.26: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Medium*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2024 Typical Event Day Current Study
Total	# SAIDs	21,207	20,435
	Reference (MW)	555	574
	Load Impact (MW)	0.7	0.6
	Avg. Temp.	87.6	89.3
Per SAID	Reference (kW)	26.2	28.1
	Load Impact (kW)	0.03	0.03
	% Load Impact	0.1%	0.1%

Table 4.27 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.27: Comparison of Ex-Post and Ex-Ante Factors, *SCE Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 87.6 °F during the average event day.	Average event-hour temperature of 89.3 °F during the SCE 1-in-2 August peak day.	Higher temperatures result in larger reference loads but lower load impacts.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100%	100%	None.
Enrollment	21,207 service accounts.	20,435 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.3 Small Customers

Previous vs. Current Ex-Post

Table 4.28 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load impact is 2.2 MWh/hour in the previous study and 1.3 MWh/hour in the current study. Enrollment numbers increased in the current study, but the average per-customer reference loads were lower despite similar event temperatures for these customers. The per-customer load impact and percentage load impact are smaller in the current ex-post study.

Table 4.28: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	201,453	203,294
	Reference (MW)	306	289
	Load Impact (MW)	2.2	1.3
	Avg. Temp.	87.5	87.5
Per SAID	Reference (kW)	1.52	1.42
	Load Impact (kW)	0.011	0.007
	% Load Impact	0.7%	0.5%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.29 reports the average event-hour load impacts for a typical event day in 2024 under SCE 1-in-2 weather conditions. Enrollments increase in the current study forecast, resulting in larger aggregate reference loads. The aggregate load impact in the current study, however, is lower because of the smaller per-customer load impact and percentage load impacts. The per-customer reference load is similar between each study.

Table 4.29: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, SCE Small*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study
Total	# SAIDs	181,775	202,979
	Reference (MW)	281	312
	Load Impact (MW)	2.1	1.8
	Avg. Temp.	89.2	89.2
Per SAID	Reference (kW)	1.55	1.54
	Load Impact (kW)	0.011	0.009
	% Load Impact	0.7%	0.6%

Previous Ex-Ante vs. Current Ex-Post

Table 4.30 provides a comparison of the ex-ante forecast of 2023 load impacts prepared following PY2022 and the PY2023 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post load impacts are based on the average non-holiday weekday event. Enrollments increased in the current ex-post study; however, the aggregate reference load is similar between the previous ex-ante and the current ex-post because of the lower PY23 event temperatures. Per-customer reference loads are smaller in the current study because of the lower temperatures. The percentage load impact is smaller in the current study.

Table 4.30: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Small*

Level	Outcome	Ex-Ante for 2023 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	186,878	203,294
	Reference (MW)	289	289
	Load Impact (MW)	2.1	1.3
	Avg. Temp.	89.2	87.5
Per SAID	Reference (kW)	1.55	1.42
	Load Impact (kW)	0.011	0.007
	% Load Impact	0.7%	0.5%

Current Ex-Post vs. Current Ex-Ante

Table 4.31 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2024 under SCE 1-in-2 weather conditions. The enrollment forecast reduces; however, the aggregate and per-customer reference load are larger in ex-ante because of the hotter forecasted temperatures relative to ex-post. The ex-ante percentage load impact is slightly larger than the PY23 ex-post percentage load impact because the average percentage load impacts from PY22 and PY23 events is used to inform the ex-ante. The higher per-customer reference loads in ex-ante also result in larger load impacts.

Table 4.31: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Small*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2024 Typical Event Day Current Study
Total	# SAIDs	203,294	202,979
	Reference (MW)	289	312
	Load Impact (MW)	1.3	1.8
	Avg. Temp.	87.5	89.2
Per SAID	Reference (kW)	1.42	1.54
	Load Impact (kW)	0.007	0.009
	% Load Impact	0.5%	0.6%

Table 4.32 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.32: Comparison of Ex-Post and Ex-Ante Factors, *SCE Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 87.5 °F during the average event day.	Average event-hour temperature of 89.2 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100%	100%	None.
Enrollment	203,294 service accounts.	202,979 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

5 SDG&E

5.1 SDG&E Ex-Post Load Impacts

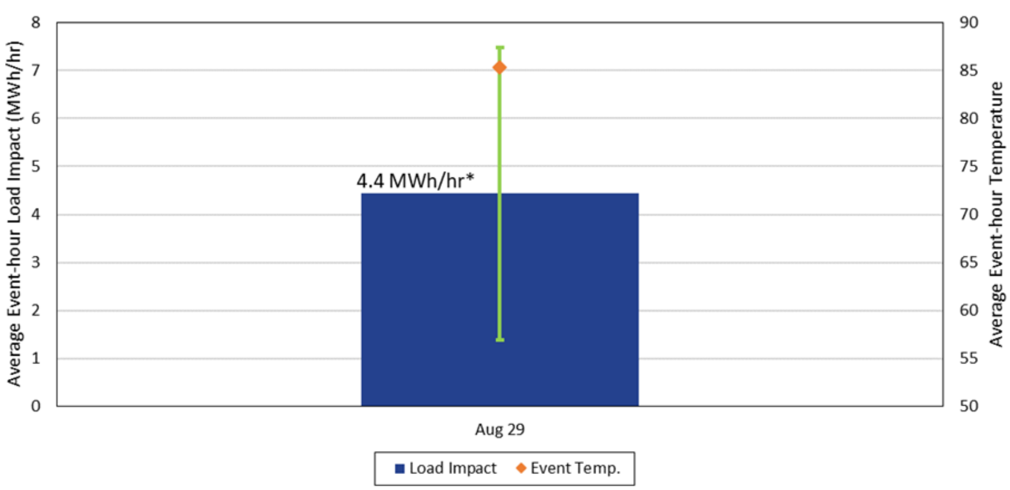
This section documents the findings from the ex-post load impact analysis for SDG&E. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer units, for the CPP event on August 29th. Results for all hours for the event day are also illustrated in figures and presented in data tables. Detailed results for each hour for the event are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.1.3, all results presented in this section are derived from either customer specific or panel fixed-effects regression analyses of hourly data for CPP customers. The estimated model is described in Section 2.1.4, with the SDG&E model including the variables that account for morning load and temperature variations. Furthermore, we control for concurrent events that are called for other programs (e.g., AC Saver Day-of, ELRP, CBP) by including indicators for customers who are dually enrolled and who are called for a given event that occurs during an event or non-event day. The evaluation of model specification selection is presented in the appendix.

5.1.1 All Customers

This section summarizes results for all SDG&E customers. The ex-post load impact is summarized in Figure 5.1. The blue bar indicates the magnitude of the aggregate load impact (in MWh/hour). The green band corresponds to a 90% confidence interval around this estimate (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icon represents the average temperatures experienced by the customers during the event hours. SDG&E customers have statistically significant load reductions on the event day, with a load reduction of 4.4 MWh/hour.

Figure 5.1: Average Event-Hour Load Impacts, *SDG&E All*



Note: A statistically significant result is denoted with *

Table 5.1 summarizes enrollments, average event-hour load impacts, and reference loads for all SDG&E customers. The estimated load impact was 1.6 kWh/hour per customer, which amounts to a 3.2% load reduction. Detailed results by hour and industry group are presented in subsequent subsections by size group.

Table 5.1: Average Event-Hour Load Impacts, *SDG&E All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
8/29/2023	2,861	139	4.4	48.6	1.6	3.2%	85.4

5.1.2 Large Customers

This section summarizes results for all large SDG&E customers, defined as customers with maximum demand over 200 kW. The presented results include: the average event-hour load impact; the hourly load impact; and load impacts by industry group for the average event hour. Summaries of load impacts for dually enrolled and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impact for SDG&E's large CPP customers is summarized in Figure 5.2. The blue bar indicates the magnitude of the aggregate load impact (in MWh/hour). The green band corresponds to a 90% confidence interval around this estimate (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icon represents the average temperature experienced by customers during the event hours. These results indicate that large customers had a statistically significant load reduction of 3.2 MWh/hour on the August 29th event day.

Figure 5.2: Average Event-Hour Load Impacts, *SDG&E Large*

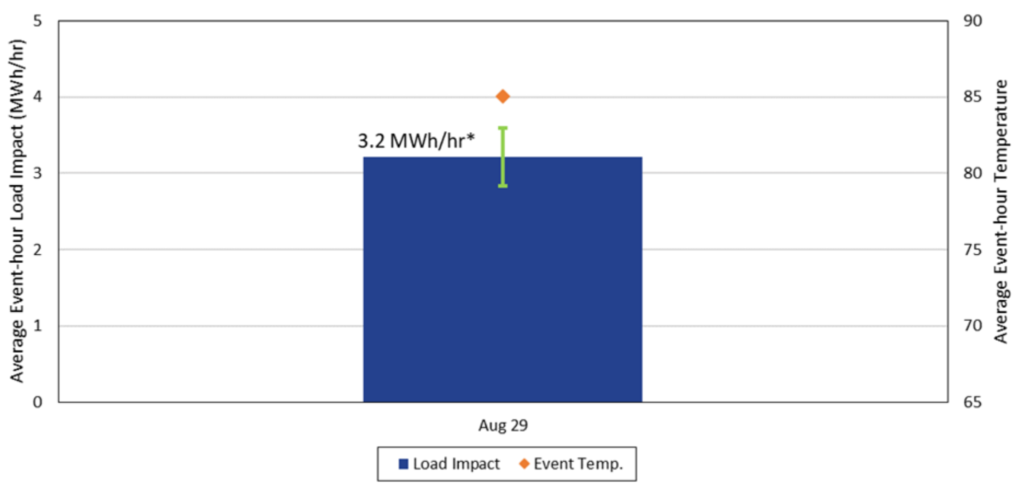


Table 5.2 summarizes enrollments, the average event-hour load impact, and the reference load on the event day. The per-customer estimated load reduction was 10.2 kWh/hour, which amounts to a 4.9% load reduction.

Table 5.2: Average Event-Hour Load Impacts, *SDG&E Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
8/29/2023	316	66	3.2	207.4	10.2	4.9%	85.0

Figure 5.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the event day. Table 5.3 contains the hourly event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The hourly load impact estimates do not show evidence of significant pre-cooling but there does appear to be some snapback, as evidenced by a load increase in the hours following the event.

Figure 5.3: Event Day Reference Loads and Load Profile, *SDG&E Large*

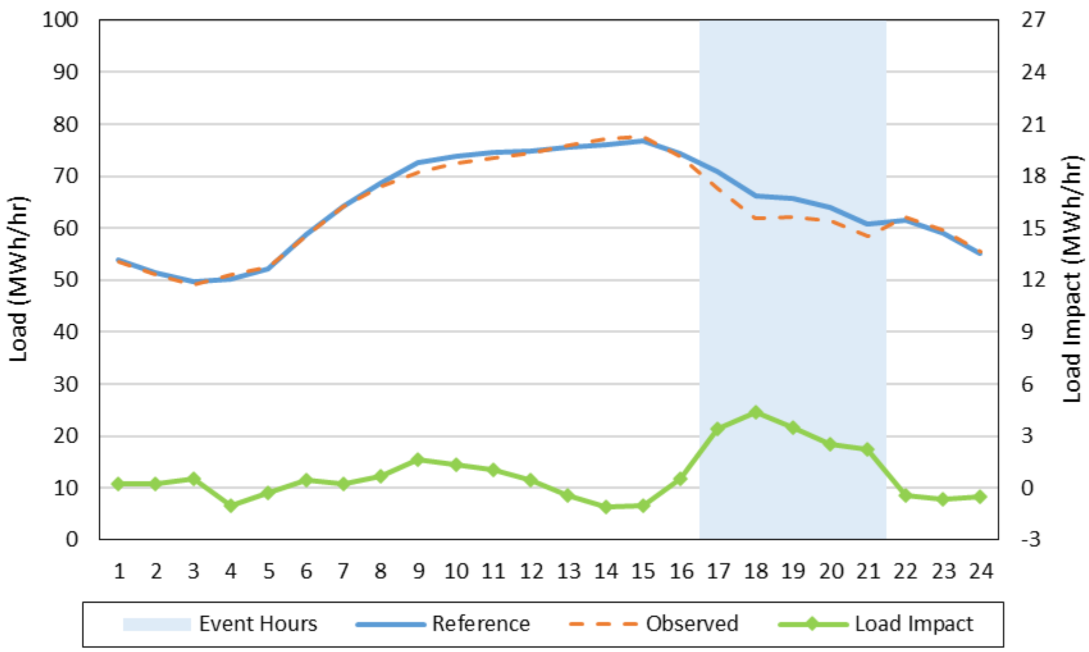


Table 5.3: Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	53.8	53.5	0.3	0.5%	69.4	0.1	0.2	0.3	0.3	0.4
2	51.3	51.1	0.2	0.4%	69.1	0.0	0.1	0.2	0.3	0.4
3	49.7	49.1	0.6	1.1%	67.1	0.4	0.5	0.6	0.6	0.7
4	50.1	51.1	-1.0	-2.0%	66.9	-1.2	-1.1	-1.0	-0.9	-0.9
5	52.2	52.5	-0.3	-0.5%	66.3	-0.4	-0.3	-0.3	-0.2	-0.1
6	58.8	58.4	0.4	0.8%	65.1	0.3	0.4	0.4	0.5	0.6
7	64.3	64.1	0.2	0.3%	64.5	0.0	0.1	0.2	0.3	0.5
8	68.7	68.1	0.7	1.0%	65.4	0.4	0.6	0.7	0.8	0.9
9	72.5	70.8	1.7	2.3%	72.5	1.4	1.6	1.7	1.8	1.9
10	73.9	72.6	1.3	1.8%	80.1	1.1	1.2	1.3	1.4	1.6
11	74.5	73.5	1.0	1.4%	83.8	0.8	0.9	1.0	1.1	1.3
12	74.9	74.5	0.5	0.6%	86.8	0.2	0.4	0.5	0.6	0.7
13	75.6	76.0	-0.4	-0.5%	89.8	-0.7	-0.5	-0.4	-0.3	-0.1
14	76.1	77.2	-1.1	-1.4%	91.7	-1.4	-1.2	-1.1	-0.9	-0.7
15	76.7	77.7	-1.0	-1.3%	92.6	-1.4	-1.2	-1.0	-0.8	-0.6
16	74.4	73.8	0.6	0.8%	91.3	0.2	0.4	0.6	0.7	1.0
17	70.9	67.5	3.4	4.8%	90.9	3.0	3.3	3.4	3.6	3.8
18	66.3	61.9	4.4	6.6%	88.1	4.0	4.2	4.4	4.5	4.7
19	65.7	62.2	3.5	5.3%	86.2	3.2	3.4	3.5	3.6	3.8
20	64.0	61.5	2.5	3.9%	82.5	2.1	2.4	2.5	2.7	2.9
21	60.7	58.5	2.2	3.7%	77.4	1.9	2.1	2.2	2.4	2.6
22	61.6	62.1	-0.5	-0.7%	75.6	-0.7	-0.6	-0.5	-0.3	-0.2
23	59.1	59.7	-0.6	-1.1%	73.4	-0.9	-0.8	-0.6	-0.5	-0.4
24	55.0	55.5	-0.5	-0.9%	71.5	-0.8	-0.6	-0.5	-0.4	-0.2
Daily	**1,551**	**1,533**	**18**	**1.2%**	**77.8**	**10.4**	**15.0**	**18.1**	**21.2**	**25.8**

Next, we look at SDG&E large customer estimates by industry group. Table 5.4 summarizes aggregate event-hour results for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). The Offices, Hotels, Health, Services industry group has the largest number of enrolled customers (77 service accounts) and reference load (19 MWh/hour). The load impact is also highest for this industry group (2.34 MWh/hour).

Table 5.4: Event-Hour Load Impacts by Industry Group, *SDG&E Large*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	[redacted]				
2. Manufacturing	72	18	18	0.00	0.0%
3. Wholesale, Transportation, Utilities	53	7	6	0.75	11.0%
4. Retail Stores	15	3	3	-0.02	-0.5%
5. Offices, Hotels, Health, Services	77	19	17	2.34	12.2%
6. Schools	56	6	6	-0.34	-6.0%
7. Institutional/Government	36	11	10	0.47	4.3%
8. Other	[redacted]				

To better understand the distribution of results across industries, we look at the shares of estimated positive load impacts, reference loads, and enrollments by industry group in

Figure 5.4. [redacted]

Figure 5.4: Event-Hour Load Impacts by Industry Group, *SDG&E Large*

[redacted]

5.1.3 Medium Customers

This section summarizes results for all medium SDG&E customers, defined as customers with maximum demand between 20 and 199.99 kW. The presented results include: the average event-hour load impact on the event day; the hourly load impact on the event day; and load impacts by industry group for the average event hour. Summaries of load impacts for dually enrolled and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impact for SDG&E's medium CPP customers is summarized in Figure 5.5. There is an estimated load reduction on the August 29th event day; however, this result is not statistically significant.

Figure 5.5: Average Event-Hour Load Impact, *SDG&E Medium*

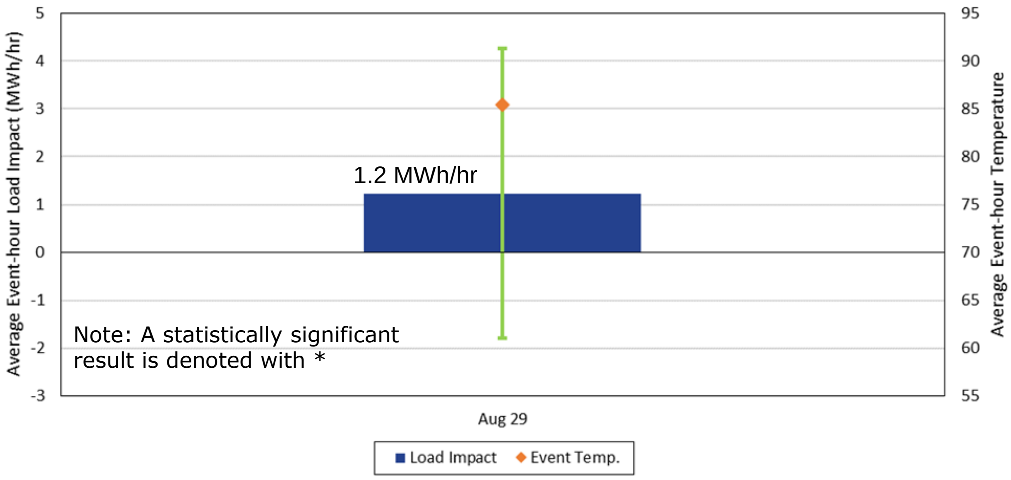


Table 5.5 summarizes enrollments, the average event-hour load impact, and the reference load on the event day. Overall, medium customers had an aggregate load impact of 1.2 MWh/hour.

Table 5.5: Average Event-Hour Load Impact, *SDG&E Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
8/29/2023	2,545	73	1.2	28.9	0.5	1.7%	85.4

Figure 5.6 illustrates the aggregate hourly reference loads, observed loads, and estimated load impacts on the event day for medium customers. Table 5.6 contains the hourly event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. While there was an estimated reduction in usage for medium customers on the event day, the estimate was not statistically significant.

Figure 5.6: Event Day Reference Loads and Load Profile, *SDG&E Medium*

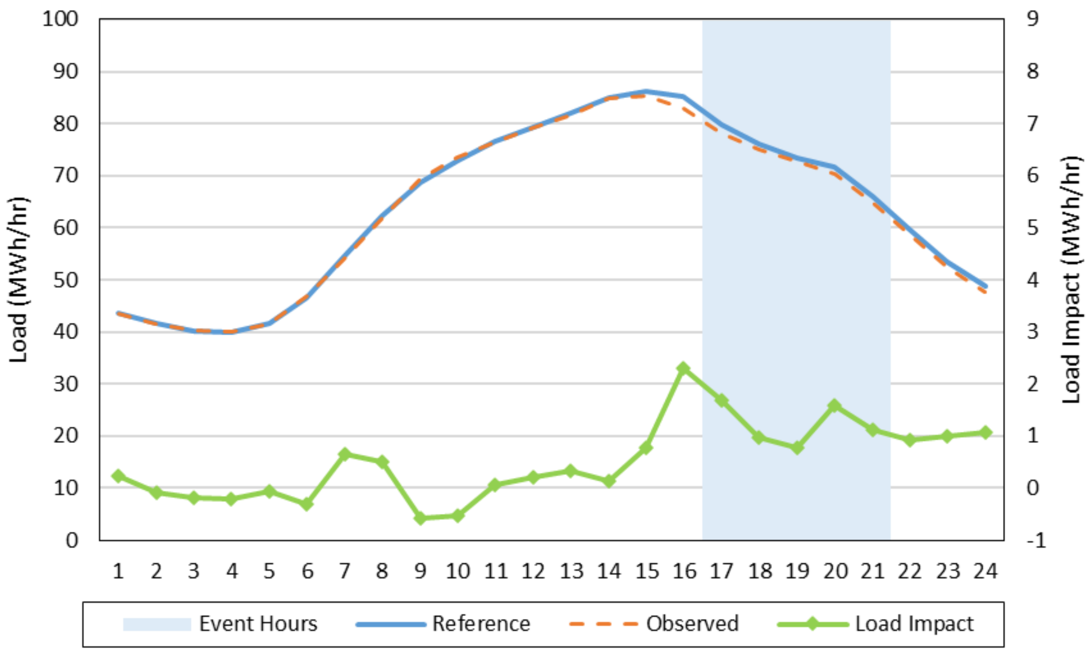


Table 5.6: Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	43.6	43.4	0.2	0.5%	70.0	-0.4	0.0	0.2	0.5	0.9
2	41.5	41.6	-0.1	-0.2%	69.7	-0.5	-0.2	-0.1	0.1	0.3
3	40.2	40.4	-0.2	-0.5%	67.8	-0.5	-0.3	-0.2	-0.1	0.1
4	39.9	40.1	-0.2	-0.5%	67.7	-0.4	-0.3	-0.2	-0.1	-0.1
5	41.5	41.6	-0.1	-0.2%	66.9	-0.4	-0.2	-0.1	0.1	0.3
6	46.6	47.0	-0.3	-0.7%	65.8	-1.0	-0.6	-0.3	-0.1	0.3
7	54.8	54.1	0.7	1.2%	65.2	0.0	0.4	0.7	0.9	1.4
8	62.4	61.9	0.5	0.8%	66.0	-0.2	0.2	0.5	0.8	1.2
9	68.6	69.2	-0.6	-0.8%	72.5	-1.1	-0.8	-0.6	-0.4	0.0
10	72.9	73.4	-0.5	-0.7%	79.6	-1.2	-0.8	-0.5	-0.3	0.1
11	76.5	76.5	0.1	0.1%	83.1	-0.4	-0.1	0.1	0.3	0.5
12	79.4	79.2	0.2	0.2%	86.4	-0.3	0.0	0.2	0.4	0.7
13	82.0	81.7	0.3	0.4%	89.6	-0.5	0.0	0.3	0.7	1.1
14	84.9	84.8	0.1	0.2%	92.0	-0.7	-0.2	0.1	0.5	1.0
15	86.2	85.4	0.8	0.9%	92.4	-1.0	0.1	0.8	1.5	2.5
16	85.2	82.9	2.3	2.7%	91.2	-0.4	1.2	2.3	3.4	5.0
17	79.9	78.2	1.7	2.1%	91.1	-0.7	0.7	1.7	2.7	4.0
18	76.1	75.1	1.0	1.3%	88.5	-1.8	-0.2	1.0	2.1	3.8
19	73.5	72.7	0.8	1.0%	86.4	-1.0	0.0	0.8	1.5	2.5
20	71.8	70.2	1.6	2.2%	83.0	-0.1	0.9	1.6	2.3	3.3
21	66.1	65.0	1.1	1.7%	78.0	-0.8	0.3	1.1	1.9	3.1
22	59.7	58.7	0.9	1.6%	76.2	-1.3	0.0	0.9	1.8	3.1
23	53.4	52.4	1.0	1.9%	74.0	-0.9	0.2	1.0	1.8	2.9
24	48.7	47.7	1.1	2.2%	72.5	-0.5	0.4	1.1	1.7	2.6
Daily	1,535	1,523	12	0.8%	78.1	-3.9	5.7	12.3	19.0	28.5

Next, we look at SDG&E medium customer estimates by industry group. Table 5.7 summarizes the aggregate average event-hour results for the event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services has the largest number of enrollments (1,001 service accounts) and reference load (33 MWh/hour) and exhibited a load reduction of 0.28 MWh/hour. However, the largest load impact was measured in the Wholesale, Transportation, Utilities group, which comprised a large share of the load impact for large customers as well, with an estimated load reduction of 0.54 MWh/hour. The Retail Stores group was the only industry group with a statistically significant load impact.

Table 5.7: Event-Hour Load Impacts by Industry Group, *SDG&E Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	[redacted]				
2. Manufacturing	301	7	6	0.17	2.6%
3. Wholesale, Transportation, Utilities	157	5	4	0.54	10.8%
4. Retail Stores	315	11	11	0.35	3.2%
5. Offices, Hotels, Health, Services	1,001	33	32	0.28	0.9%
6. Schools	187	4	4	-0.06	-1.4%
7. Institutional/Government	453	11	11	-0.49	-4.6%
8. Other	[redacted]				

Figure 5.7 shows the shares of enrollments, reference loads, and load impacts by industry group. [redacted]

Figure 5.7: Event-Hour Load Impacts by Industry Group, *SDG&E Medium*

[redacted]

5.1.4 Dually Enrolled Customers

This section summarizes results for customers who are enrolled in CPP as well as another SDG&E demand response program. The other programs in which SDG&E customers enrolled in along with CPP included AC Saver Day-of (ACSDO), Emergency Load Reduction Program (ELRP), and Capacity Bidding Program (CBP). We present results by size category for the average event-hour on the event day. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 5.8 summarizes enrollments, average event-hour load impacts, and reference loads for customers who are dually enrolled in CPP. The average dually enrolled customer had a reference load of 110.3 kWh/hour. Dually enrolled customers provided a load impact of 3.4 MWh/hour, or 16.6% of their reference load. Note that all of this reduction in load came from large customers. While the load impact is negative for medium customers, this result is not statistically significant.

Table 5.8: Average Event-Hour Load Impacts for Dually Enrolled Customers, *SDG&E*

Size	Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
All	8/29/2023	180	19.8	3.3	110.3	18.29	16.6%	85.7
200 kW and above	8/29/2023	47	16.1	3.4	342.0	73.18	21.4%	84.0
20 to 199.99 kW	8/29/2023	133	3.8	-0.1	28.4	-1.11	-3.9%	86.1

5.1.5 Notified vs. Non-Notified Customers

SDG&E customers can elect to receive day-ahead notification of CPP events by phone, email, or text message. This section summarizes results for CPP customers by notification status. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 5.9 summarizes enrollments, average event-hour load impacts, and reference loads by size and notification status. About 64% of all customers were notified before the event day. Medium CPP customers have the greatest proportion of notified customers (66%) compared to large CPP customers with a proportion of 47%.

For both the large and medium customers, the notified customers, on average, had larger reference loads and a significantly larger load reduction on the event day. The reference load for notified customers was 86 MWh/hour compared to 53 MWh/hour for non-notified customers, and the load impact was significantly larger at 5 MWh/hour for notified customers compared to -0.6 MWh/hour for non-notified customers.

Table 5.9: Average Event-Hour Load Impacts on Event Day by Size and Notification Status, *SDG&E*

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	166	28	-0.7	168.0	-4.18	-2.5%	84.5
	Medium	854	26	0.1	29.9	0.09	0.3%	85.6
	All	**1,020**	**53**	**-0.6**	**52.4**	**-0.61**	**-1.2%**	**85.4**
Yes	Large	150	38	3.9	251.0	26.02	10.4%	85.5
	Medium	1,691	48	1.1	28.3	0.66	2.3%	85.3
	All	**1,841**	**86**	**5.0**	**46.4**	**2.72**	**5.9%**	**85.3**

5.2 SDG&E Ex-Ante Load Impacts

This section provides the ex-ante CPP load impact forecasts based on an enrollment forecast provided by SDG&E. Results are presented by size group. First, the enrollment forecast provided by SDG&E is summarized in figures on an annual basis. Second, results for all hours for the average weekday event in 2024 are illustrated in figures to convey the shape of ex-ante reference loads. Finally, forecasted ex-ante load impacts are summarized in figures by month and forecast year. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, per-customer load impacts are derived from analysis of current ex-post load impacts. Because we observe only one event day, we cannot investigate the effect of weather on estimated load impacts (and percentage load impacts), though in the previous report we found that there was not enough evidence of a strong relationship between load impacts and weather conditions. Therefore, we simulate ex-ante load impacts by multiplying forecasted reference loads by ex-post percentage load impacts (by size and hour of the day). For both medium and large customer groups, the load reduction is set at 0.01% during event hours that had an increase in usage during ex-post. Additionally, load impacts before 3 p.m. are set to zero to reduce the effect of statistical noise on the forecasts.

5.2.1 All Customers

Figure 5.8 summarizes the trend of SDG&E's enrollment forecast for medium and large customers combined. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[30] Table 5.10 provides enrollment counts and aggregate and per-customer load impacts from 2024 to 2034 on Typical Event Day under SDG&E 1-in-2 weather conditions. SDG&E anticipates the total number of customers to decrease from 2,570 to 2,365 customers from 2024 to 2025, and thereafter to increase at a pace of about 0.5%

[30] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

each year, reaching 2,470 in 2034. Per-customer load impacts vary across years due to changes in customer composition. Aggregate load impacts decrease from 3.2 MWh/hour to 2.3 MWh/hour from 2024 to 2025 due to both the decrease of enrollments and lower per-customer load impacts. Aggregate load impacts increase slightly after 2025 because of forecasted enrollments.

Figure 5.8: CPP Enrollments, *SDG&E All*

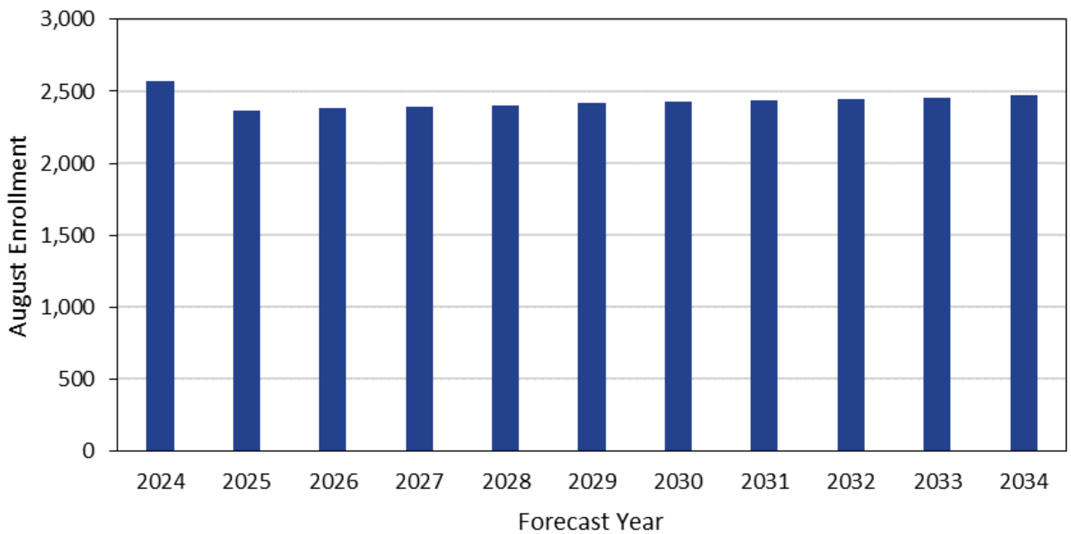


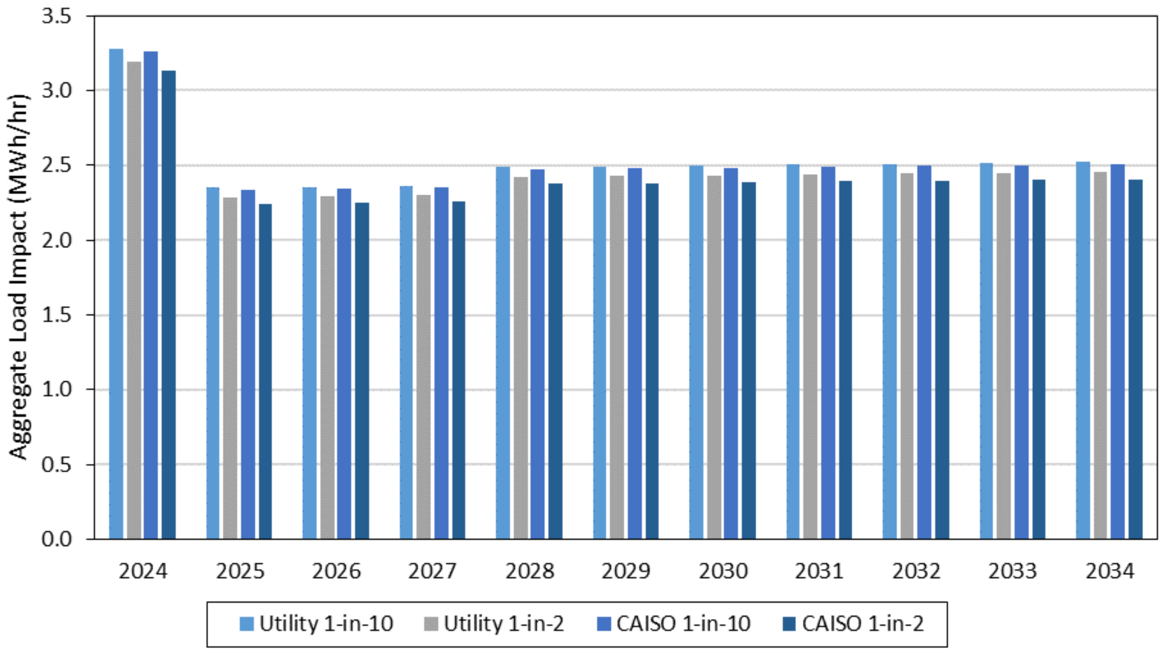
Table 5.10: Typical Event Day Load Impacts, Utility 1-in-2, *SDG&E All*

Year	# Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hour)	Event Load Impact (MWh/hour)	Event Ref. Load (kWh/hour)	Event Load Impact (kWh/hour)
2024	2,570	102.6	3.2	39.9	1.243
2025	2,365	87.0	2.3	36.8	0.967
2026	2,380	87.5	2.3	36.8	0.964
2027	2,393	87.8	2.3	36.7	0.961
2028	2,405	88.7	2.4	36.9	1.007
2029	2,417	89.1	2.4	36.9	1.004
2030	2,427	89.3	2.4	36.8	1.002
2031	2,438	89.9	2.4	36.9	1.000
2032	2,449	90.3	2.4	36.9	0.998
2033	2,460	90.6	2.4	36.8	0.996
2034	2,470	91.0	2.5	36.8	0.994

Figure 5.9 shows the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease in 2025 primarily due to the sharp drop in forecasted enrollments from CCA migration, then increase slightly each year. The load impacts of the 1-in-10 scenarios are higher than 1-in-2 scenarios by about

0.11 MWh/hour. Additional results of ex-ante load impacts are presented in the subsequent sections by size group.

Figure 5.9: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E All*



5.2.2 Large Customers

Figure 5.10 summarizes SDG&E's enrollment forecast for large customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[31] SDG&E anticipates a decrease in large customers of 29% from 2024 to 2025 due to CCA migration and then an increase of about 0.5%% each year thereafter.

[31] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

Figure 5.10: CPP Enrollments, *SDG&E Large*

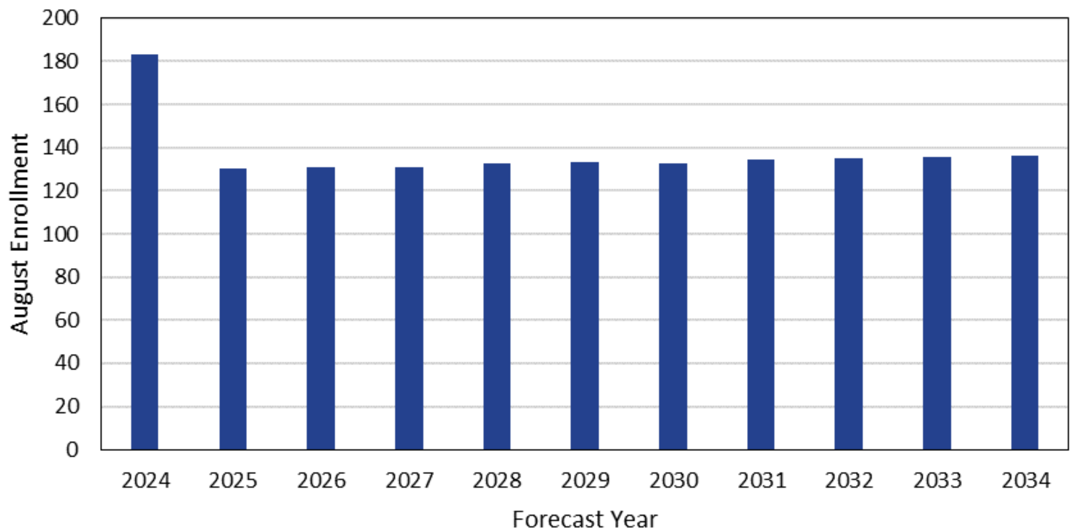


Figure 5.11 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in August of 2024 for the SDG&E 1-in-2 weather scenario. The shape follows that of the ex-post load impact, exhibiting reduction in usage during event hours and a slight snapback following the event hours. The forecast predicts an average load impact of 2.04 MWh/hour for large customers on the average weekday event in 2024 for the SDG&E 1-in-2 weather scenario, which is a 5.5% reduction in reference loads.

Figure 5.11: Aggregate Hourly Loads and Load Impacts in 2024 for *SDG&E 1-in-2 Typical Event Day, SDG&E Large*

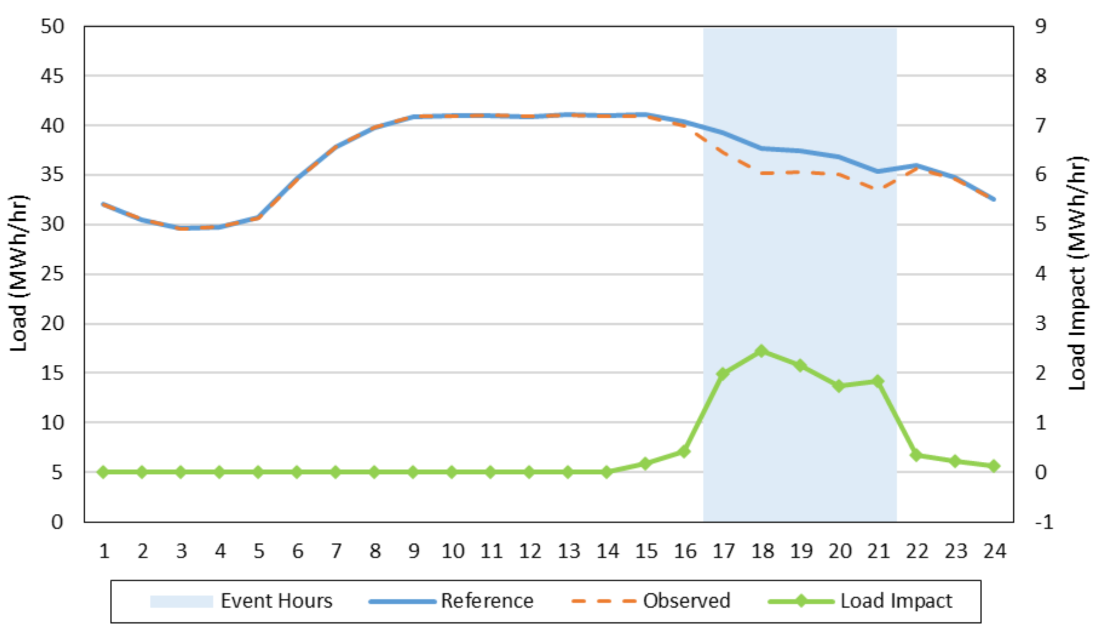


Figure 5.12 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the RA window in 2025 across months for SDG&E's 1-in-2 peak day weather scenario. In order to isolate the effect of seasonality in this figure, we chose 2025 instead of 2024 due to the reduction in enrollments throughout 2024. The RA window is 4 to 9 p.m. for all months except March, April, and May, when it is 5 to 10 p.m. The load impact is highest in September (1.24 MWh/hour) and lowest in March (0.83 MWh/hour).

Figure 5.12: Aggregate Load Impacts by Month over RA Window in 2025 for *SDG&E 1-in-2 Peak Day, SDG&E Large*

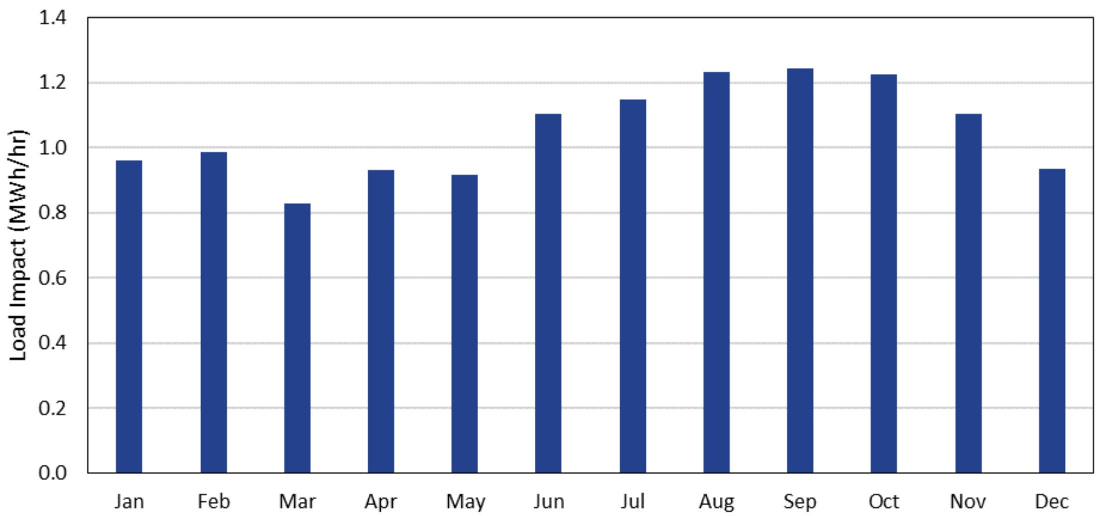
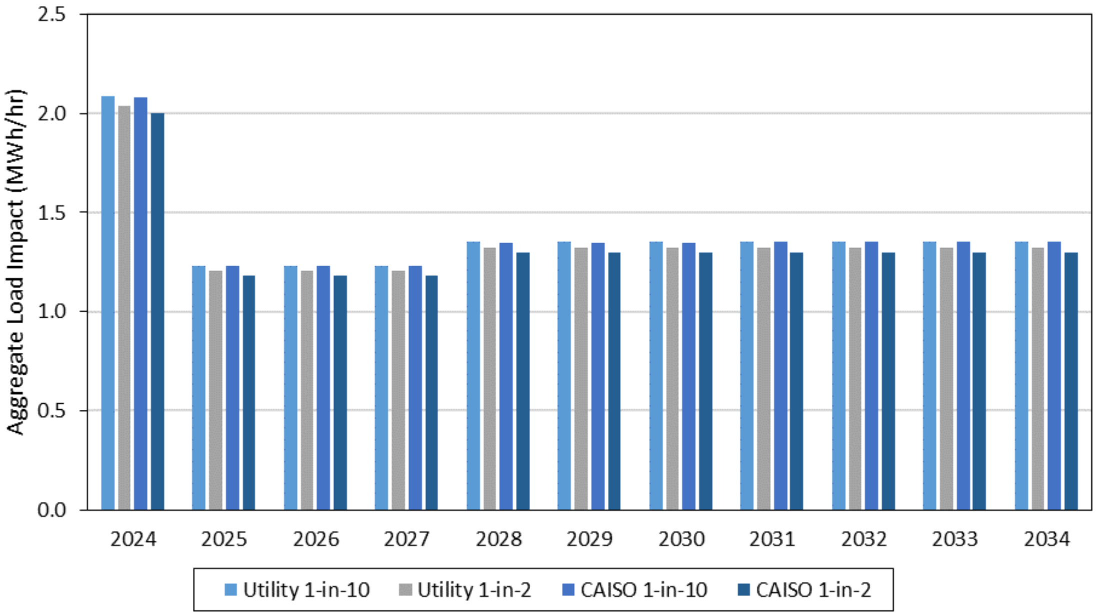


Figure 5.13 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease in 2025, then increase slightly over time following the trend in enrollments. As expected, the largest load impacts occur for the SDG&E 1-in-10 weather year while the lowest load impacts occur during the CAISO 1-in-2 weather year because of reference loads being increases/decreasing with hotter/cooler temperatures. The range of difference in load impacts between weather scenarios is about 0.05 MWh/hour.

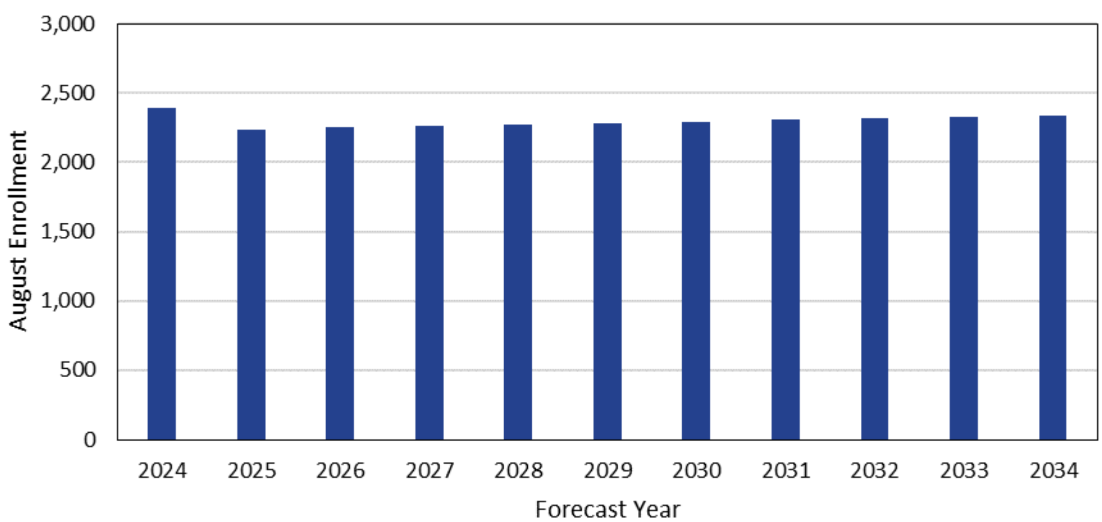
Figure 5.13: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Large*



5.2.3 Medium Customers

Figure 5.14 summarizes SDG&E's enrollment forecast for medium customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead. [32] SDG&E anticipates a reduction in customers until 2025 due to CCA migration, then a slight increase each year of about 0.6%.

Figure 5.14: CPP Enrollments, *SDG&E Medium*



[32] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

Figure 5.15 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August of 2024 for the SDG&E 1-in-2 weather scenario. The forecast predicts an average load impact of 1.2 MWh/hour, or 1.8%% of the reference load.

Figure 5.15: Aggregate Hourly Loads and Load Impacts in 2024 for *SDG&E 1-in-2 Typical Event Day, SDG&E Medium*

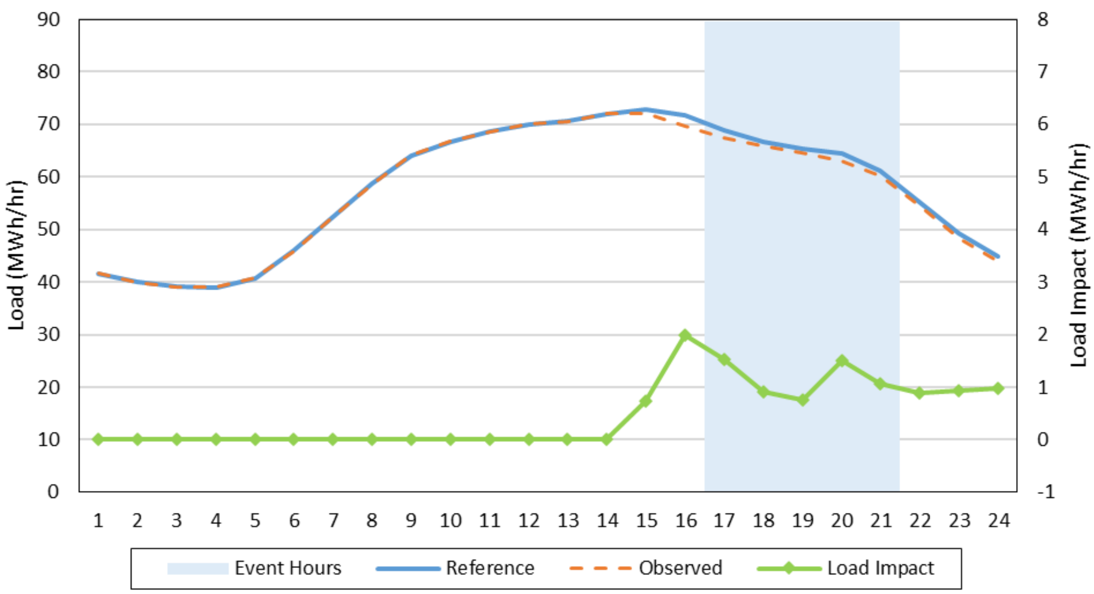


Figure 5.16 shows the seasonality of the forecasted load impacts for medium customers based on the 2025 aggregate load impacts for the average hour in the RA window for SDG&E's 1-in-2 weather scenario. As with the large customers, the load impacts follow the seasonal pattern of reference loads over the RA window (4 to 9 p.m. for all months except March, April, and May, when it is 5 to 10 p.m.). The load impact is highest in September (1.12 MWh/hour) and lowest in March (0.68 MWh/hour).

Figure 5.16: Aggregate Load Impacts by Month over RA Window in 2025 for *SDG&E 1-in-2 Peak Day, SDG&E Medium*

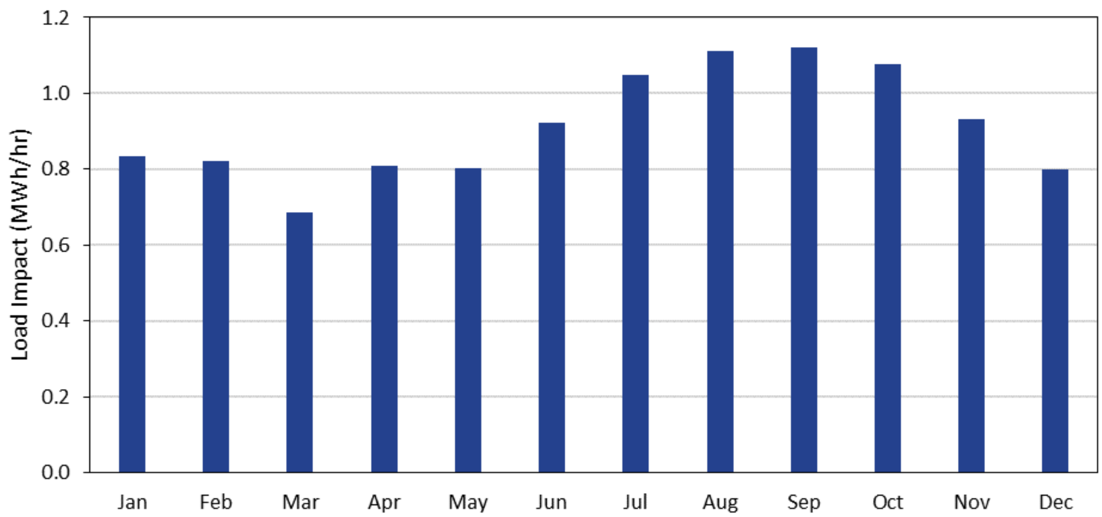
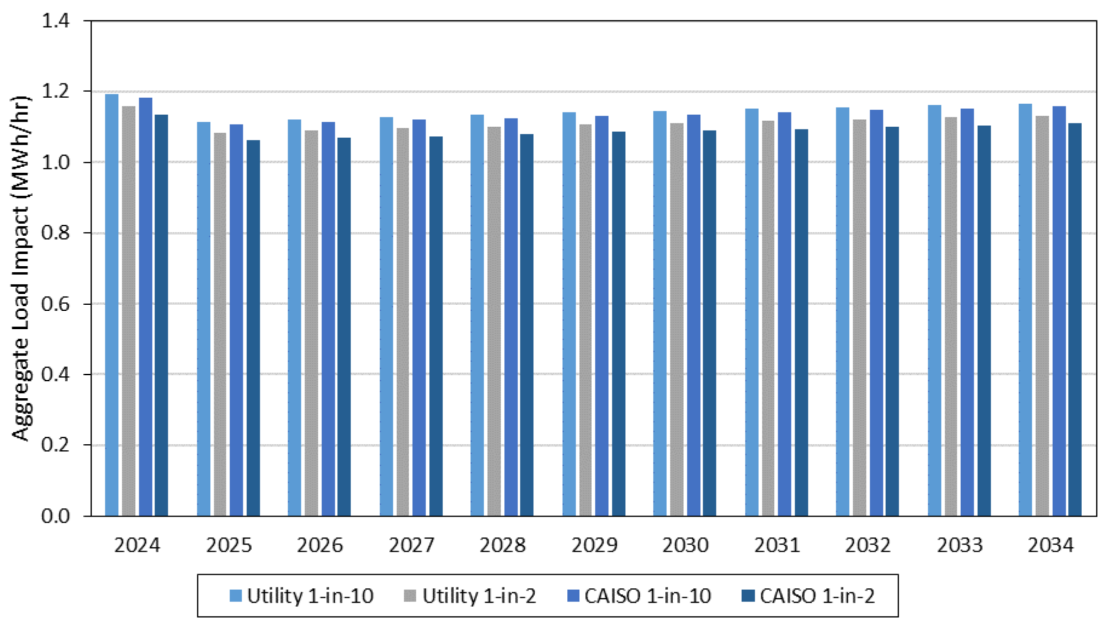


Figure 5.17 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts follow the general trend of forecasted enrollments. Reference loads are largest for the SDG&E and CAISO 1-in-10 weather scenarios, resulting in higher load impacts for the 1-in-10 scenarios relative to 1-in-2 scenarios.

Figure 5.17: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Medium*



5.3 SDG&E Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares findings from this study to those of the previous study. In the text below, the term "current" refers to the present study while the term "previous" refers to findings from PY2022.

5.3.1 Large Customers

Previous vs. Current Ex-Post

In this sub-section, we compare the ex-post results for an average weekday event prepared in the previous study to the ex-post results contained in this study for large customers. Table 5.11 shows that despite a drop in enrollments, the load impact was estimated to be larger in this study, with a load impact per customer in this study that is roughly twice the size as it was in the previous study. As more customers switch to CCA programs, the rise in the per-customer load impact may be due to selection, as customers who are most likely to benefit from critical peak pricing remain enrolled.

Table 5.11: Previous vs. Current Ex-Post Load Impacts*, SDG&E Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	533	316
	Reference (MW)	111	66
	Load Impact (MW)	2.5	3.2
	Avg. Temp.	86.3	85.0
Per SAID	Reference (kW)	208.5	207.4
	Load Impact (kW)	4.7	10.2
	% Load Impact	2.2%	4.9%

Previous vs. Current Ex-Ante

Table 5.12 compares the ex-ante forecast prepared in the previous study with the ex-ante forecast contained in this study. The average event-hour load impacts are shown for a typical event day in 2024 under SDG&E 1-in-2 weather conditions. The current study forecasts fewer customers than the previous study, resulting in smaller aggregate reference loads and load impacts. At a per-customer level, however, the current study load impacts (11.1 kW) are roughly twice as high relative to the previous study (5.8 kW), due to compositional changes in the set of large customers that are remaining on the program.

Table 5.12: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 2024 Typical Event Day, SDG&E Large*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study
Total	# SAIDs	424	183
	Reference (MW)	89	37
	Load Impact (MW)	2.5	2.0
	Avg. Temp.	82.5	83.1
Per SAID	Reference (kW)	210	203.6
	Load Impact (kW)	5.8	11.1
	% Load Impact	2.8%	5.5%

Previous Ex-Ante vs. Current Ex-Post

Table 5.13 provides a comparison of the ex-ante forecast of 2023 load impacts prepared following PY2022 and the PY2023 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SDG&E 1-in-2 weather conditions.

The ex-ante forecast in the previous study had predicted a decrease in enrollments to 475, but enrollments decreased more significantly than expected to 316. Because of the drop in enrollments, the aggregate reference load is smaller in the current study. As above, the per-customer load impacts and percentage load impacts are roughly twice the size in the current study though, perhaps because large customers that remained are more likely to benefit from the CPP program.

Table 5.13: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SDG&E Large*

Level	Outcome	Ex-Ante for 2023 Typical Event Day Previous Study	Ex-Post Event Day Current Study
Total	# SAIDs	475	316
	Reference (MW)	100	66
	Load Impact (MW)	2.8	3.2
	Avg. Temp.	82.5	85.0
Per SAID	Reference (kW)	210	207
	Load Impact (kW)	5.8	10.2
	% Load Impact	2.8%	4.9%

Current Ex-Post vs. Current Ex-Ante

Table 5.14 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2024 under SDG&E 1-in-2 weather conditions. The ex-ante enrollment forecasts a decrease in enrollments resulting in lower aggregate reference loads. Lower temperatures result in lower per-customer reference loads. The ex-ante percentage load impact is based on the percentage load impact from ex-post. The percentage load impacts are slightly higher in ex-ante because of the composition changes of customers between ex-post and ex-ante.[33]

[33] Ex-post percentage load impacts are applied separately for dually enrolled and non-dually enrolled customers since dually enrolled customers have larger ex-post load impacts. The increased

Table 5.14: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SDG&E Large*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2024 Typical Event Day Current Study
Total	# SAIDs	316	183
	Reference (MW)	66	37
	Load Impact (MW)	3.2	2.0
	Avg. Temp.	85.0	83.1
Per SAID	Reference (kW)	207	204
	Load Impact (kW)	10.2	11.1
	% Load Impact	4.9%	5.5%

Table 5.15 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 5.15: Comparison of Ex-Post and Ex-Ante Factors, *SDG&E Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 85.0 °F on the event day.	Average event-hour temperature of 83.1 °F during the SDG&E 1-in-2 August peak day.	Lower ex-ante temperatures reduce the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
Day of Week	August 29th	Average Weekday	None.
% of resource dispatched	100%	100%	None.
Enrollment	316 service accounts.	183 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

5.3.2 Medium Customers

Previous vs. Current Ex-Post

In this sub-section, we compare the ex-post results for an average weekday event prepared in PY2022 (the "previous study") to the ex-post results contained in this study

percentage load impact in ex-ante is driven by a slightly higher proportion of dually enrolled customers in ex-ante as non-dually enrolled customer counts decrease in the enrollment forecast.

(the "current study") for medium customers. Table 5.16 shows that the most significant difference is the sign of the estimated load impact. The load impact in the previous study was -3.2 MW compared to 1.2 MW in this study. However, while the estimated load impact is positive in this study, the statistical uncertainty of the result is such that we cannot reject the hypothesis that the true impact was zero.

Table 5.16: Previous vs. Current Ex-Post Load Impacts*, SDG&E Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	4,324	2,545
	Reference (MW)	129	73
	Load Impact (MW)	-3.2	1.2
	Avg. Temp.	86.5	85.4
Per SAID	Reference (kW)	29.9	28.9
	Load Impact (kW)	-0.74	0.48
	% Load Impact	-2.5%	1.7%

Previous vs. Current Ex-Ante

Table 5.17 compares the ex-ante forecast prepared in the previous study with the ex-ante forecast contained in this study. The average event-hour load impacts are shown for a typical event day in 2024 under SDG&E 1-in-2 weather conditions. The enrollment forecast is higher in the current study resulting in higher aggregate reference loads. The load impacts and percentage load impacts are more significant in this study at 1.2 MW compared to 0 MW, which is percentage effect of 1.8%.

Table 5.17: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 2024 Typical Event Day, SDG&E Medium*

Level	Outcome	Ex-ante for 2024 Typical Event Day, Previous Study	Ex-ante for 2024 Typical Event Day, Current Study
Total	# SAIDs	1,817	2,387
	Reference (MW)	51	65
	Load Impact (MW)	0.0	1.2
	Avg. Temp.	82.5	82.5
Per SAID	Reference (kW)	28.1	27.4
	Load Impact (kW)	0.01	0.48
	% Load Impact	0.0%	1.8%

Previous Ex-Ante vs. Current Ex-Post

Table 5.18 provides a comparison of the ex-ante forecast of 2023 load impacts prepared following PY2022 and the PY2023 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SDG&E 1-in-2 weather conditions. The ex-ante forecast in the previous study had predicted a decrease in enrollments, but enrollments did not reduce as much as expected. The per-customer reference load in the current study is slightly higher due to hotter temperatures. Medium customers in the current study exhibited a load reduction of 1.7%, while the previous study forecast a reduction of 0%.

Table 5.18: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SDG&E Medium*

Level	Outcome	Ex-Ante for 2023 Typical Event Day Previous Study	Ex-Post Current Study
Total	# SAIDs	2,381	2,545
	Reference (MW)	67	73
	Load Impact (MW)	0.0	1.2
	Avg. Temp.	82.5	85.4
Per SAID	Reference (kW)	28.1	28.9
	Load Impact (kW)	0.01	0.48
	% Load Impact	0.0%	1.7%

Current Ex-Post vs. Current Ex-Ante

Table 5.19 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2024 under SDG&E 1-in-2 weather conditions. The medium customer enrollment is forecasted to decrease from 2,545 customers in 2023 to 2,387 customers in 2024. The reduction in enrollments reduces the aggregate reference load of the program. The per-customer reference load is lower in ex-ante due to lower temperatures. The ex-ante load impact forecast for 2024 is approximately equal to the measured ex-post impact in 2023.

Table 5.19: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SDG&E Medium*

Level	Outcome	Ex-Post Current Study	Ex-Ante for 2024 Typical Event Day Current Study
Total	# SAIDs	2,545	2,387
	Reference (MW)	73	65
	Load Impact (MW)	1.2	1.16
	Avg. Temp.	85.4	82.5
Per SAID	Reference (kW)	28.9	27.4
	Load Impact (kW)	0.48	0.48
	% Load Impact	1.7%	1.8%

Table 5.20 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 5.20: Comparison of Ex-Post and Ex-Ante Factors, *SDG&E Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 85.4 °F on the event day.	Average event-hour temperature of 82.5 °F during the SDG&E 1-in-2 August peak day.	Lower ex-ante temperatures reduce the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100%	100%	None.
Enrollment	2,545 service accounts.	2,387 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

6 RECOMMENDATIONS

For PG&E, we recommend retaining larger BIP customers because they outperform other PDP only customers. We also recommend continue to call events under different weather conditions to help understand the relationship between weather and load impacts.

For SCE, we found a negative relationship between ex-post load impacts and weather based on two years of data. In other words, hotter temperature events were associated with lower load impacts. The relationship, however, did not exist with using only PY23 events. We suggest continuing to call events under different weather conditions to provide more evidence of this relationship.

For SDG&E, one events was called during the hottest day of the year. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures and months.

APPENDICES

The following Appendices accompany this report. Appendix A presents the model validity assessment associated with our ex-post load impact evaluation.

Appendix B	7a. PGE_2023_CPP_Ex_Post
Appendix C	7b. PGE_2023_CPP_Ex_Ante
Appendix D	PY2023_SCE_NRCPP_Ex_Post_Load_Impacts
Appendix E	PY2023_SCE_NRCPP_Ex_Ante_Load_Impacts
Appendix F	SDG&E PY23 NonResCPP Ex-Post Load Impact Tables
Appendix G	SDG&E PY23 NonResCPP Ex-Ante Load Impact Tables

Appendix A. Model Validity Assessment

This appendix presents additional details regarding our model validation process to determine which regression specifications are used in our ex-post analysis.

A.1 Selection of Event-Like Non-Event Days

To select event-like non-event days, we create an average weather profile using the load-weighted average temperature across customers, each of which is associated with a weather station. For each event day, we select non-event days that are closest to the average weather profile of the event day. The comparison between average weather profiles is based on the Euclidean distance of hourly temperatures.

We select days according to the average event-hours, omitting holidays, event days for programs in which customers are dually enrolled (e.g., BIP), Flex Alert days, and Public Safety Power Shutoff days. The selection process resulted in selecting the hottest qualifying days. Table A.1 lists the event-like non-event days selected, separated by weekday and weekend.

Table A.1: List of Event-Like Non-Event Days by IOU

PG&E		SCE	SDG&E
Weekday	**Weekend**	**Weekday**	**Weekday**
6/8/2023	7/2/2023	7/12/2023	7/12/2023
6/9/2023	7/16/2023	7/13/2023	7/26/2023
6/12/2023	7/22/2023	7/14/2023	8/28/2023
7/3/2023	7/23/2023	7/18/2023	9/8/2023
7/12/2023	7/29/2023	7/19/2023	
7/13/2023	7/30/2023	7/25/2023	
7/24/2023	8/5/2023	7/26/2023	
7/27/2023	8/6/2023	7/27/2023	
7/28/2023	8/12/2023	7/28/2023	
7/31/2023	8/13/2023	8/1/2023	
8/7/2023		8/2/2023	
8/14/2023		8/7/2023	
8/17/2023		8/14/2023	
8/23/2023		8/18/2023	
8/24/2023		8/25/2023	
8/30/2023		8/31/2023	
9/18/2023		9/7/2023	
9/22/2023		9/8/2023	
9/25/2023		9/19/2023	
9/27/2023		9/27/2023	
10/16/2023		9/28/2023	
10/17/2023			

A.2 Model Specification Tests

Customer-Specific Models

We test a range of model specifications before arriving at the model used in the ex-post load impact analysis of customer specific models. The tests are conducted using average-customer data by industry group and weather-sensitivity classification. Model variations include 17 combinations of weather-related variables for weather-sensitive customers and 5 different specifications of non-weather-related variables for non-weather sensitive customers.

The basic structure of the model for weather-sensitive customers is shown in Section 2.1.4. The weather variables include: temperature-humidity index (THI)[34]; heat index

[34] THI = T – 0.55 x (1 – HUM) x (T – 58) if T>=58 or THI = T if T<58, where T = ambient dry-bulb temperature in degrees Fahrenheit and HUM = relative humidity (where 10% is expressed as "0.10").

(HI)[35]; cooling degree hours (CDH)[36], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[37], including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we test for weather-sensitive customers is provided in Table A.2, including 17 specifications for the individual customer ex-post analysis.[38]

Table A.2: Weather Variables Included in the Tested Specifications for Weather Sensitive Customers, *Customer-Specific Models*

Model Number	Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDD60
6	CDD65
7	Mean 17
8	CDH60_MA3
9	CDH65_MA3
10	THI Lag_CDD60
11	HI, Lag_CDD60
12	CDH60, Lag_CDD60
13	CDH65, Lag_CDD60
14	CDH60_MA3, Lag_CDD60
15	CDH65_MA3, Lag_CDD60
16	CDH60, Mean17
17	CDH65, Mean17

The model specifications for non-weather sensitive customers do not include any weather variables but have different combinations of non-weather-related variables. The variables include combinations of indicator variables with interactions between month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is shown in Table A.3, where an "X" between two variables represents the interaction of these two variables. Each specification includes the following variables in common: hour

[35] HI = $c_1 + c_2T + c_3R + c_4TR + c_5T^2 + c_6R^2 + c_7T^2R + c_8TR^2 + c_9T^2R^2 + c_{10}T^3 + c_{11}R^3 + c_{12}T^3R + c_{13}TR^3 + c_{14}T^3R^2 + c_{15}T^2R^3 + c_{16}T^3R^3$, where T = ambient dry-bulb temperature in degrees Fahrenheit and R = relative humidity (where 10% is expressed as "10"). The values for the various c's may be found here: http://en.wikipedia.org/wiki/Heat_index.
[36] Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.
[37] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.
[38] Humidity data for PG&E was not available in PY2022. Therefore, the set of specifications we test for PG&E excludes the entries that require humidity.

indicators, day type indicators, and events interacted with hour indicators. For the ex-ante analysis, we exclude the specifications with the morning load variable.

Table A.3: Variables Included in the Tested Specifications for Non-Weather Sensitive Customers, *Customer-Specific Models*

Model Number	Included Non-Weather-Related Variables
1	Month X Hour
2	Month X Hour, Monday X Hour, Friday X Hour
3	Month, Monday X Hour, Friday X Hour, Morningload X Hour
4	Month X Hour, Morningload X Hour
5	Month X Hour, Monday X Hour, Friday X Hour, Morningload X Hour

Panel Models

Similar to the customer-specific model specification search described above, a range of models are tested before determining which variables are included in the ex-post panel regression models. For each size category, model validation tests are conducted using average per-customer event-hour usage (hours ending 17-21) over days including events and selected event-like non-event days (see Table A.1). Panel models follow the basic structure provided in Section 2.1.4, including day type and weather variables. The day type variable includes controls for events (both CPP and other demand response programs), day of week (e.g., Monday, Friday), month, and morning load patterns. Table A.4 provides the 11 weather specifications that were tested. Variables that include lags or moving averages are excluded from the model search because the panel days only include event-days and event-like non-event days, unlike the customer-specific models.

Table A.4: Weather Variables Included in Tested Specifications, *Panel Models*

Model Number	Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDD60
6	CDD65
7	Mean 17
8	CDH60, Mean17
9	CDH65, Mean17
10	CDD60, Mean17
11	CDD65, Mean17

Validation Test

For both the customer-specific and panel models, the model variations are evaluated according to the ability to predict usage on event-like *non-event days*. Specifically, we identify a set of days that are similar to event days, but were not called as event days (i.e., "test days"). The use of non-event test days allows us to test model performance against known "reference loads," or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for each test day. The model fit (i.e., the difference between the actual and predicted loads on the test days, during afternoon hours in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.

A.3 Results from Tests of Alternative Weather Specifications

For customer-specific models, we test 17 different sets of weather variables for weather sensitive customers and 5 different specifications for non-weather sensitive customers. For panel models, we test 11 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each industry group and weather sensitivity categorization in the customer-specific models. In contrast, the aggregate load profiles were constructed separately by size group for the panel models. Only customers who were called on at least one event day are included.

The tests are conducted by estimating one model for every group (i.e., industry and weather sensitivity for customer specific models; and size for panel models), specification (17 for weather sensitive customers, 5 for non-weather sensitive customers, 11 for panel model customers), and event-like day. Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days. The MPE and MAPE values are also calculated across the entire day for the panel model results.

Tables A.5 through A.10 summarize for the Joint Utilities the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for both customer the customer-specific and panel models. The results are bifurcated by weekday and weekend for PG&E because of the weekend events called in PY2023.

Table A.5: Specification Test Results for Customer-Specific Models, *PG&E*

Group	Industry Type	Selected Specification	Event-Hour MPE	Event-Hour MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	16	1.8%	7.3%	4
	2. Manufacturing	16	1.2%	3.0%	6
	3. Wholesale, Transportation, Utilities	16	0.6%	2.1%	7
	4. Retail	16	0.9%	2.4%	4
	5. Offices, Hotels, Health, Services	16	1.4%	6.8%	16
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	17	0.1%	2.8%	3
	8. Other or unknown	N/A	N/A	N/A	N/A
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	0.3%	6.2%	13
	2. Manufacturing	5	1.6%	7.1%	16
	3. Wholesale, Transportation, Utilities	5	0.1%	6.8%	4
	4. Retail	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	5	2.1%	5.3%	4
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	5	0.3%	6.4%	3
	8. Other or unknown	5	71.2%	114.1%	1

Table A.6: Specification Test Results for Panel Models, *PG&E*

Size	Selected Specification	Event-Hour MPE	Event-Hour MAPE	Number of Customers
Medium	3	0.0%	1.3%	16,801
Small	3	0.1%	2.0%	84,316

Table A.7: Specification Test Results for Customer-Specific Models, SCE

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	4.0%	11.5%	2
	2. Manufacturing	7	-0.2%	2.6%	19
	3. Wholesale, Transportation, Utilities	17	-0.1%	3.9%	12
	4. Retail	16	0.3%	4.2%	4
	5. Offices, Hotels, Health, Services	1	0.0%	2.4%	17
	6. Schools	17	-1.4%	4.8%	4
	7. Entertainment, Other Services, Government	4	-0.1%	2.6%	9
	8. Other or unknown	7	0.1%	2.6%	7
Non-Weather Sensitive	1. Agriculture, Mining, Construction	4	21.1%	37.3%	3
	2. Manufacturing	3	4.1%	6.3%	17
	3. Wholesale, Transportation, Utilities	5	0.2%	5.8%	9
	4. Retail	5	0.2%	11.4%	1
	5. Offices, Hotels, Health, Services	5	-2.0%	6.4%	4
	6. Schools	N/A	N/A	N/A	0
	7. Entertainment, Other Services, Government	3	33.1%	55.9%	1
	8. Other or unknown	4	-0.8%	5.0%	3

Table A.8: Specification Test Results for Panel Models, SCE

Day Type	Size	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weekday	Large	8	-0.02%	0.96%	0.10%	2.55%	1,606
	Medium	8	0.03%	1.01%	0.02%	0.87%	21,374
	Small	8	-0.03%	2.04%	-0.01%	1.24%	204,704

Table A.9: Specification Test Results for Customer-Specific Models, SDG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	2. Manufacturing	12	0.5%	2.8%	5
	5. Offices, Hotels, Health, Services	4	0.2%	3.0%	2
	7. Entertainment, Other Services, Government	7	-0.2%	2.3%	2
	99. Generation	12	3.8%	9.3%	14
Non-Weather Sensitive	2. Manufacturing	5	-0.6%	3.3%	2
	3. Wholesale, Transportation, Utilities	5	7.0%	23.4%	1
	5. Offices, Hotels, Health, Services	3	0.1%	3.8%	1
	7. Entertainment, Other Services, Government	1	1.5%	4.8%	2
	99. Generation	0	7.2%	14.4%	12

Table A.10: Specification Test Results for Panel Models, SDG&E

Size	Selected Specification	Event-Hour		All-Day		Number of Customers
		MPE	MAPE	MPE	MAPE	
Large	11	-3.55%	10.22%	-1.37%	11.17%	289
Medium	8	-4.92%	16.73%	0.21%	11.74%	2,532

A.4 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.1 through A.8 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen for each customer or group. In each figure, the solid line represents the observed load, and the dashed line represents the load predicted by the statistical model. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

Figures A.1 and A.2 provide weekday load profiles for PG&E. Figure A.1 compares predicted and observed loads for large customers, and Figure A.2 compares predicted and observed loads for small and medium customers.

Figure A.1: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *PG&E*

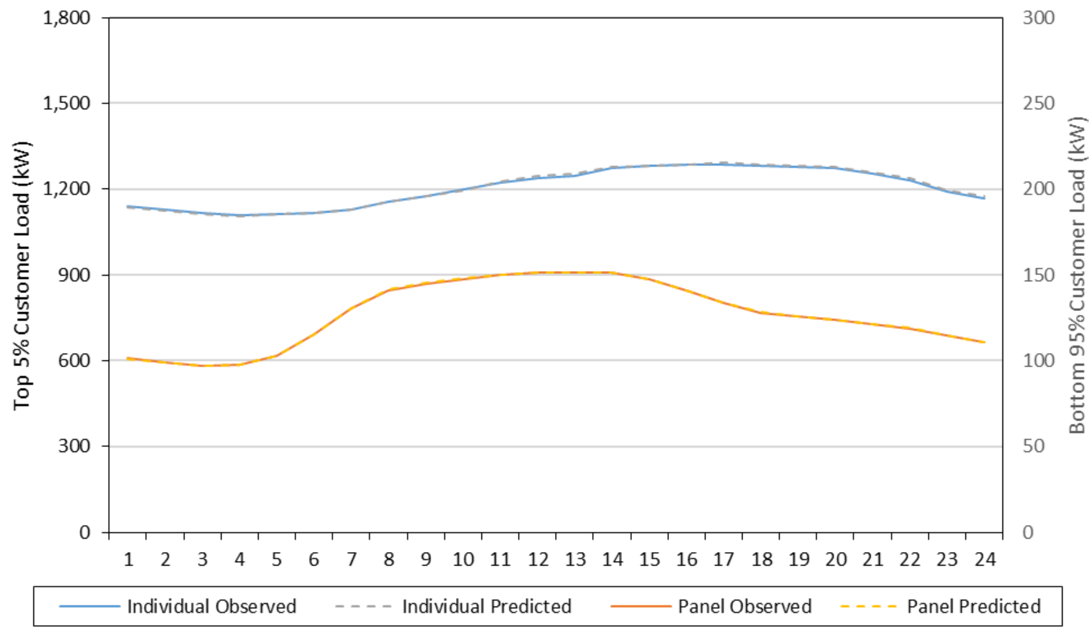
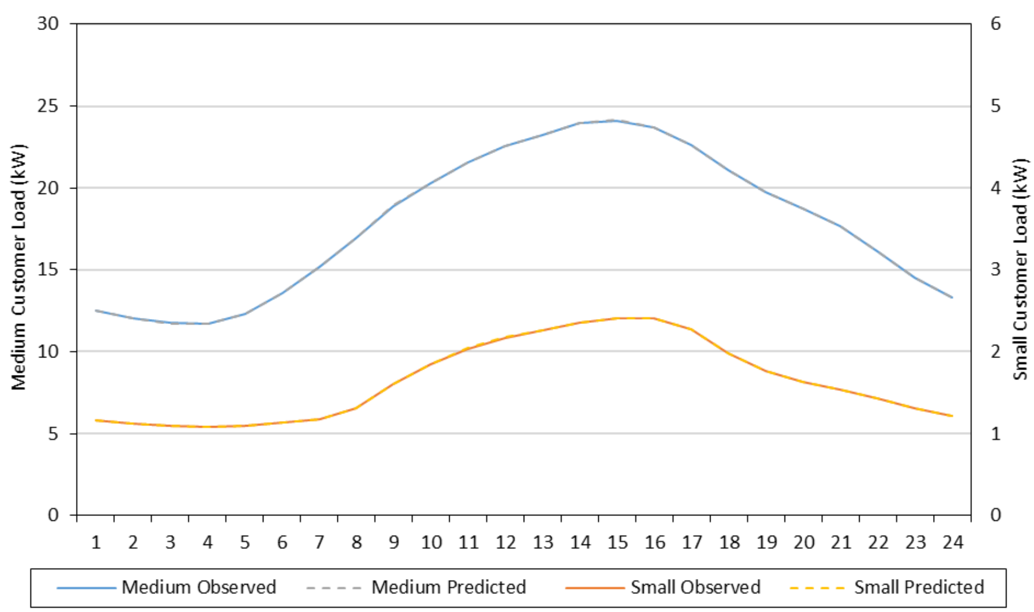


Figure A.2: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers, *PG&E*



Figures A.3 and A.4 provide weekend load profiles for PG&E. Figure A.3 compares predicted and observed loads for large customers, and Figure A.4 compares predicted and observed loads for small and medium customers.

Figure A.3: Average Observed & Predicted Loads on Weekend Event-Like Days, Large Customers, *PG&E*

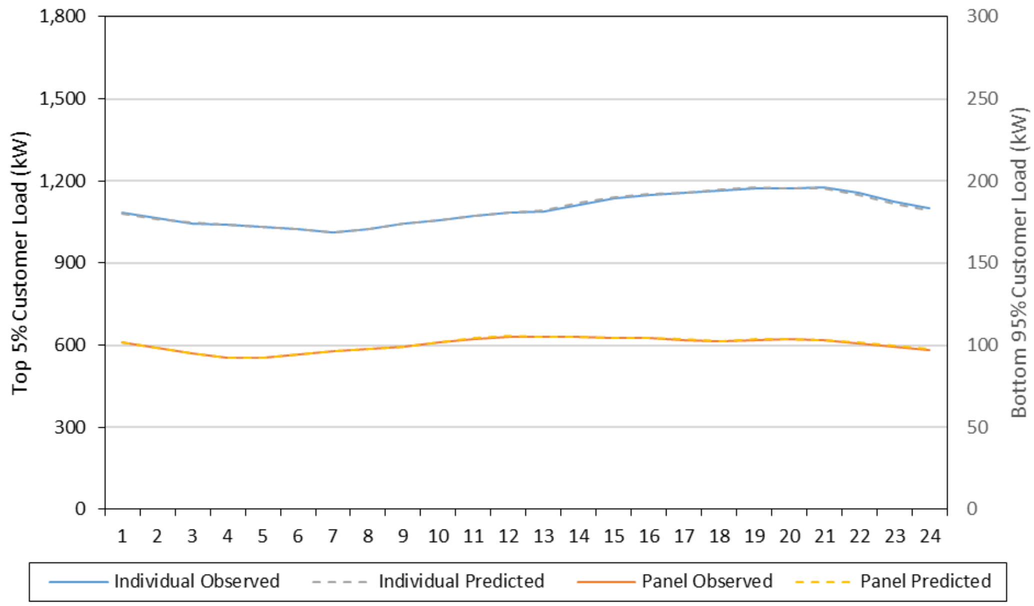
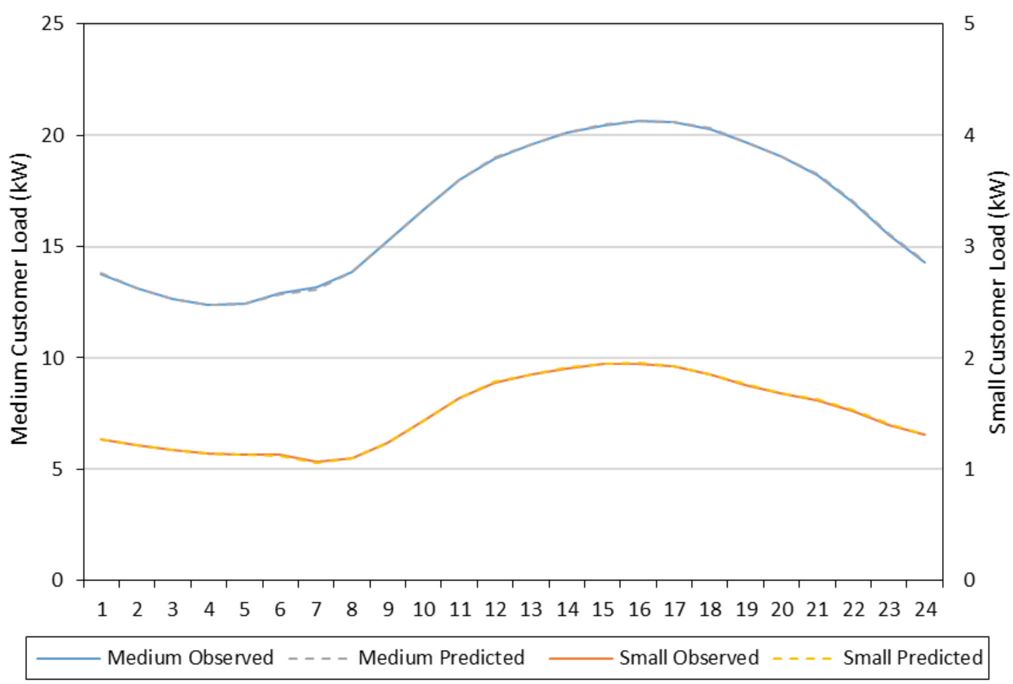


Figure A.4: Average Observed & Predicted Loads on Weekend Event-Like Days, Small and Medium Customers*, PG&E*



Figures A.5 and A.6 provide weekday load profiles for SCE. Figure A.5 compares predicted and observed loads for large customers, and Figure A.6 compares predicted and observed loads for small and medium customers.

Figure A.5: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *SCE*

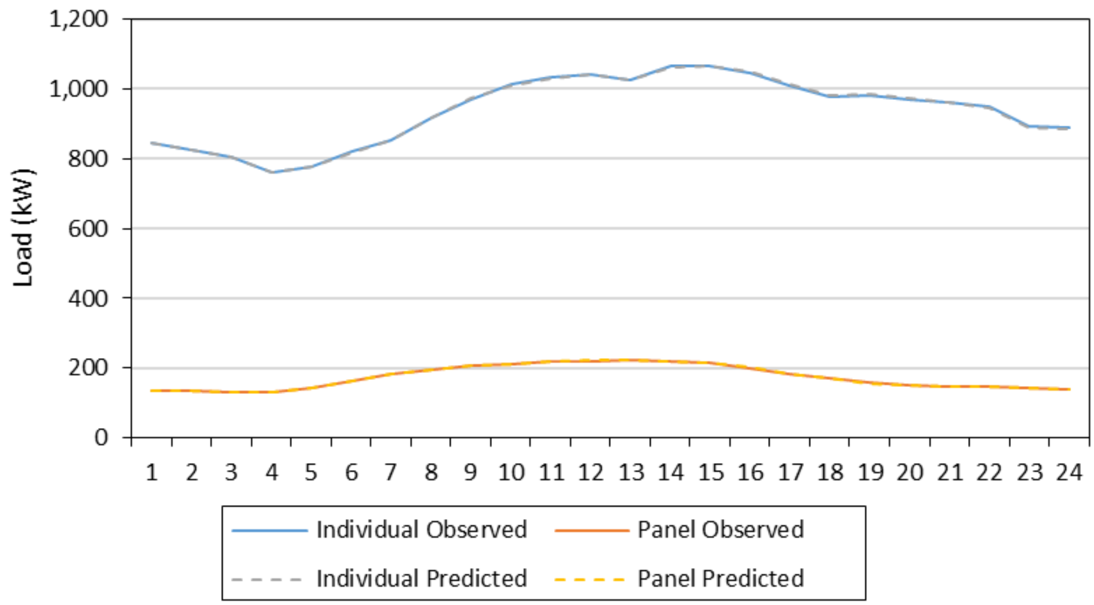
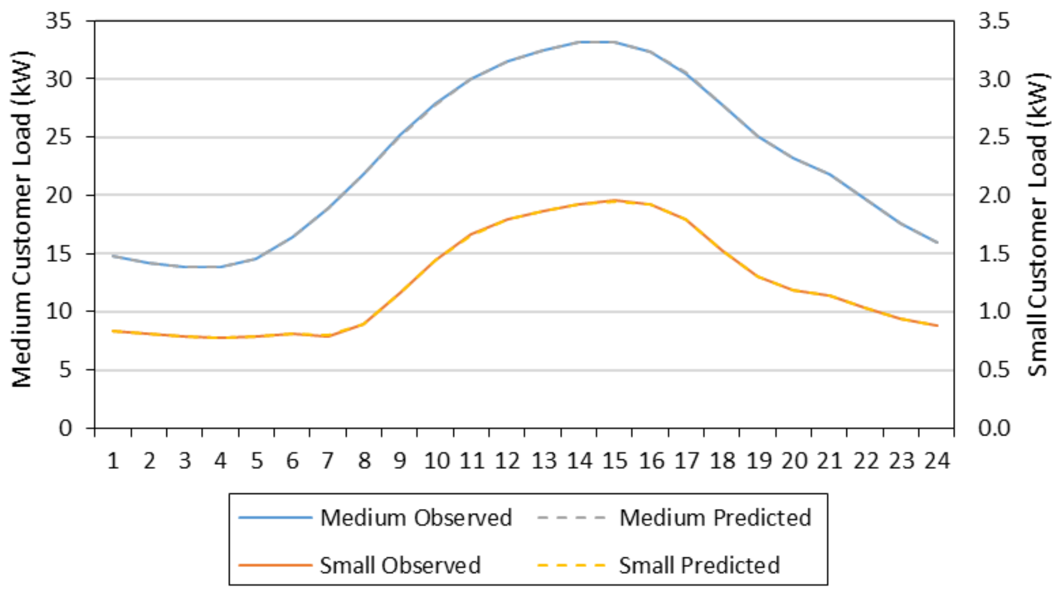


Figure A.6: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers*, SCE*



Figures A.7 and A.8 provide weekday load profiles for SDG&E. Figure A.7 compares predicted and observed loads for large customers, and Figure A.8 compares predicted and observed loads for medium customers.

Figure A.7: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *SDG&E*

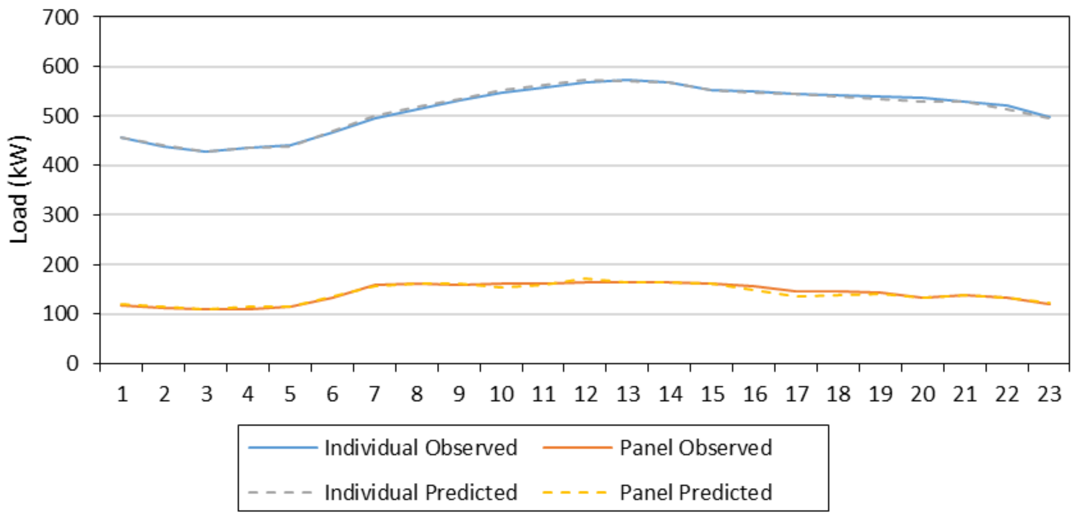


Figure A.8: Average Observed & Predicted Loads on Weekday Event-Like Days, Medium Customers*, SDG&E*