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FINAL REPORT

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2024 Load Impact Evaluation for California Non-Residential Critical Peak Pricing Rates (PG&E, SCE, and SDG&E)

Prepared for PG&E, SCE, and SDG&E
By Demand Side Analytics, LLC
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ABSTRACT

This study quantifies the load impacts of the Critical Peak Pricing (CPP) rate plans for PG&E, SCE, and SDG&E for PY2024. CPP rates charge increased prices during peak hours on event days in exchange for lower rates during other summer hours. CPP rates are the default commercial rates for all three utilities.

The study focuses on two primary research questions, separately for each utility: 1) *Ex post*, what were the 2024 demand reductions from 4 to 9 p.m. on event days? 2) *Ex ante*, what is the magnitude of future load reduction by CPP customers under 1-in-2 weather conditions?

Ex post, PG&E's nine events in PY2024 produced an average demand reduction of 7.7 MW from 104,000 customers. SCE's twelve events produced an average demand reduction of 3.8 MW from 220,000 customers. SDG&E's three events produced an average demand reduction in the Large and Medium groups of zero MW from 2,200 customers. Ex ante, CPP customers would be expected to deliver estimated demand reductions of 7.8 (PG&E), 3.8 (SCE), and 1.0 (SDG&E Medium/Large) MW in 2025, with impacts changing over time with changes in forecasted enrollments.

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1 EXECUTIVE SUMMARY

Critical Peak Pricing (CPP) rates are time-of-use (TOU) rates with increased prices during peak hours on event days. Event days are chosen by the utilities based on forecasted demand conditions, and customers can optionally receive notification of events ahead of time. Customers pay lower rates during other summer hours or receive bill credits in exchange for higher pricing on event days.

PG&E called nine event days in 2024, SCE called twelve, and SDG&E called three (all in September). Event day pricing applies to all CPP subgroups, with events covering the TOU peak window from 4 to 9 p.m. All three utilities have high enrollments in CPP rates since they are the default commercial rates for each, with customers able to opt out to another rate at their discretion.

The study focuses on two primary research questions, separately for each utility:

1. *Ex post*, what were the PY2024 demand reductions from 4 to 9 p.m. on event days?
2. *Ex ante*, what is the magnitude of future load reduction by CPP customers under 1-in-2 weather conditions?

Ex post, PG&E's PY2024 event days produced an average hourly demand reduction from 4 to 9 p.m. of 7.7 MW from 104,000 customers. SCE's events produced an average demand reduction of 3.8 MW from 220,000 customers. SDG&E three September events produced an average demand reduction of zero MW from 2,300 Medium and Large customers.[1]

Table 1-1 summarizes the estimated ex post demand reductions for an average weekday event hour by utility. All impacts are incremental to other DR program impacts and statistical significance is noted for each subgroup. Load impacts (demand reductions) are represented as positive numbers in this report.

Table 1-1: Summary of 2024 Average Weekday Event Ex Post Demand Reductions

IOU	Sites	Load without DR (MW)	Load Reduction (MW)	% Load Reduction	Significant (90% CL)	Significant (95% CL)
PG&E (All Groups)	103,577	815.81	7.74	0.9%	Yes	No
SCE (All Groups)	220,658	1147.89	3.79	0.3%	No	No
SDG&E (Med. & Large)	2,286	111.30	-1.21	0.0%	No	No

[1] SDG&E estimated impacts were likely reduced by at least one site with large impacts in previous years that did not receive event notifications by text message in 2024. SDG&E is investigating the cause and extent of this notification issue.

Table 1-2 summarizes forecasted site enrollments by utility. PG&E anticipates declining enrollments due the growth of Community Choice Aggregators (CCAs), which de-enroll sites by default. SCE anticipates a slight growth in enrollments from year to year through 2030. SDG&E anticipates slight growth in enrollment from year to year through 2034.

Table 1-2: Total Ex Ante Site Enrollments by Utility

Year	PG&E	SCE	SDG&E (Med. & Large)
2024	103,622	220,582	2,257
2025	95,750	215,194	2,493
2026	89,497	216,558	2,510
2027	83,680	218,570	2,535
2028	77,424	220,564	2,569
2029	72,426	222,562	2,610
2030	67,810	224,561	2,662
2031	63,518	224,561	2,737
2032	59,528	224,561	2,832
2033	55,849	224,561	2,965
2034	52,363	224,561	3,159

Table 1-3 summarizes the portfolio-adjusted ex ante demand reduction capability for each IOU. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report[2]. Reduction capabilities are for the normal 4 to 9 p.m. CPP event window.

Table 1-3: Total Ex Ante Demand Reductions for August Worst Day, System 1-in-2 Weather (MW, Portfolio-Adjusted and Program-Specific)

Year	PG&E	SCE	SDG&E (Med. & Large)
2024	7.1	4.2	0.8
2025	7.7	3.8	0.8
2026	7.3	3.8	0.9
2027	7.0	3.9	0.9
2028	6.4	3.9	0.9
2029	6.1	4.0	0.9

[2] PG&E's dual-enrolled BIP customers were removed from the analysis per PG&E's DR portfolio rules.

Year	PG&E	SCE	SDG&E (Med. & Large)
2030	5.8	4.0	0.9
2031	5.6	4.0	0.9
2032	5.4	4.0	1.0
2033	5.1	4.0	1.0
2034	4.9	4.0	1.1

Ex ante estimates were calculated using 2024 ex post estimates, 2023 ex post estimates, reference loads for 1-in-2 weather years, and the enrollment forecasts. Based on testing, percentage impacts were applied without any variation by weather or event hour, but they imply larger MW reductions when applied to larger reference loads. Changes over time are a function of changes in the utilities' forecasted enrollment levels.

In PY 2025, CPP customers would ex ante be expected to deliver demand reductions of 7.7 (PG&E), 3.8 (SCE), and 0.8 (SDG&E) MW in 2025, with impacts changing over time with changes in enrollments. Notably, PG&E's impacts are expected to decline significantly in future years with the expansion of CCAs.

2 INTRODUCTION

Critical Peak Pricing (CPP) is a load modifying program delivered as a set of rate plans by each of the California Investor-Owned Utilities (IOUs): PG&E, SCE, and SDG&E. These rates are part of commercial time-of-use (TOU) rates and provide additional costs during the window from 4 to 9 p.m. during event days. Events are called by utilities based on system demand and program goals, and customers can sign up to receive day-ahead or day-of notifications.

CPP rates include price adders when events are called, encouraging load shifting, but not controlling loads directly. CPP customers then pay lower rates during non-CPP hours in the summer. While the Joint Utilities' CPP rates have many common features, their structure and provisions vary by utility.

CPP rates are the default commercial rates at all three IOUs, with customers eligible to opt out by choosing another rate plan at any time. CPP thus has broad participation by defaulting many customers onto the rates, but there is less clarity on customers' awareness of rate features or ability to shift loads.

Overall, CPP is a dynamic rate that incentivizes load shifting by increasing peak prices during events, but the magnitude of impacts in recent years are often zero to 1%. In general, dynamic rates tend to deliver smaller percentage impacts. Commercial electric demand is also relatively inelastic, which may further explain the lack of response to events. General factors that may contribute to lower responses include:

- Lack of interest in load shifting by customers are defaulted onto rates
- Since CPP rates also have TOU components on non-event days, measured impacts must be over-and-above any normal shifting behavior during peak summer hours
- Insurance provided against charges such as first-year bill protection (all IOUs) or reserving loads from CPP event pricing (SDG&E only)
- Lower discretionary loads during 4 to 9 p.m. event window for commercial customers
- Difficulty in responding to varying four-tiered rates (three-tier TOU rates plus CPP adders announced one day ahead)

2.1 CPP RATE FEATURES

2.1.1 Rate Plan & Enrollment Details by IOU

All three utilities offer similar CPP rates, but with some features unique to each. Where relevant, differences will be noted in the ex post results, such as SDG&E customers who protect a portion of their peak loads from CPP pricing via capacity reservations.

A summary of the CPP rates offered by each utility is shown in Table 2-1 below:

Table 2-1: Summary of CPP Rate Details by Utility

Utility/ Program	PG&E	SCE	SDG&E
Marketed as	Peak Day Pricing (PDP)	CPP	CPP
Peak Window	4-9 p.m. year round	4-9 p.m. year round	4-9 p.m. year round
CPP Rate Adder	Generally: ▪ $0.60 per kWh for sites with < 75 kW, ▪ $0.90 per kWh for sites with > 75 kW	$0.80 per kWh	Various, from $0.79 to $3.71 per kWh. Most common are: ▪ $1.17 per kWh for sites with < 20 kW ▪ $2.58 per kWh for sites with > 20kW
Incentive	Lower energy rates (per kWh) during other summer peak hours	Summer bill credits (fixed amount)	Lower energy rates (per kWh) during other summer peak hours (demand charges vary)
Any loads protected from CPP pricing?	No	No	Yes, via monthly Capacity Reservation subscription ($ per kW)
Bill Protection	Yes, for first year	Yes, for first year	Yes, for first year
Program Changes	Changed event hours from 5-8 to 4-9 beginning in 2022	Changed event hours from 2-6 to 4-9 starting 2019	Event hours earlier in previous years (11-6, then 2-6, now 4-9 since 2022)

The IOUs offer various CPP rates for different business sizes and rate classes, but they have generally similar enrollment rules:

Table 2-2: CPP Enrollment Rules by Utility

Utility/ Program	PG&E	SCE	SDG&E
Default rate for C&I customers (bundled)?	Yes	Yes	Yes
CCAs included?	No	No	No
Ag. Included?	Yes	Yes	Yes
Customers eligible for AutoDR programs?	Yes	Yes	Yes

Utility/ Program	PG&E	SCE	SDG&E
Other ineligible categories	Other energy incentives, energy reduction, peak hour or direct bidding programs	Direct Access (DA) customers	Direct Access (DA) customers

2.1.2 Event Dates & Guidelines by IOU

The largest difference in the three IOUs' CPP rates is the number and timing of event days, with each IOU calling its own events based on unique criteria. More details on event guidelines for each IOU are listed in Table 2-3 below:

Table 2-3: CPP Event Day Guidelines by Utility

Utility/ Program	PG&E	SCE	SDG&E
Number of Events - PY2024	9	12 (None in September)	3 (All September)
Min./Max. Possible Events	Min. 9, Max. 15	Min. 12, Max. 12 (up to 15 for grid emergencies)	Max. 18 (no Min.)
Event Triggers	Day ahead with high temps, high demand, or short supply	Forecasted system emergencies or extreme weather conditions, day-ahead prices, or CAISO Energy Emergency Alerts	Day-ahead system load forecast > 4,000 MW (Can also be triggered for high temp.'s, extreme conditions, emergencies)

PG&E called nine event days in 2024, including several during a Northern California heat wave in July. SCE called twelve events, but none after August. SDG&E called three events, all during a Southern California heat wave in September. Event day pricing applies to all CPP subgroups, with events lasting for the TOU peak window from 4 to 9 p.m. Table 2-5 lists the event days in comparison across utilities. Events were generally called on unique dates, aside from three dates that were event days for both PG&E and SCE (7/2, 7/3, and 7/11). The CAISO system peak for 2024 came on Thursday Sept. 5th, with similarly high levels of demand on Sept. 6th and July 23rd – 25th. Individual system demand by event date is shown in the individual IOU sections of this report.

Table 2-4: PY2024 Events by Utility

Date	PG&E	SCE	SDG&E
6/5/2024	✓		
6/20/2024		✓	

Date	PG&E	SCE	SDG&E
7/2/2024	✓	✓	
7/3/2024	✓	✓	
7/5/2024		✓	
7/6/2024	✓		
7/8/2024		✓	
7/9/2024		✓	
7/10/2024	✓		
7/11/2024	✓	✓	
7/23/2024	✓		
8/5/2024		✓	
8/6/2024		✓	
8/7/2024		✓	
8/20/2024		✓	
8/27/2024		✓	
9/4/2024	✓		
9/5/2024	✓		✓
9/6/2024			✓
9/9/2024			✓
Total	**9**	**12**	**3**

2.2 EVALUATION OVERVIEW

The primary goal of the evaluation is to measure CPP event impacts for each IOU by rate class and by size group—Small (under 20kW), Medium (20kW to below 200 kW) and Large (200 kW and above). This consists of estimating hourly ex post load impacts for PY2024 and ex ante load impacts through 2034.

2.2.1 CPP Groups

Table 2-5 summarizes CPP subgroups for the evaluation. These groups do not correspond to specific rate plans, which may have different size cutoffs and vary by IOU. The groups are simply those used for Statewide analyses, following previous evaluations. Note that SDG&E's Small customers (<20 kW demand) are evaluated in a separate study.

SDG&E has previously reported results by rate class (Agricultural vs. Commercial) in separate evaluations of their Small CPP customers – that convention is carried over for Medium and Large customers in this evaluation as well. SCE and SDG&E customer groups combine commercial and agricultural rate classes and are simply distinguished by size.

Table 2-5: CPP Groups for Statewide Evaluation by IOU

Size Group	Max Demand	PG&E Eval. Groups	SCE Eval. Groups	SDG&E Eval. Groups
Large	200 kW and above	Large	Large	Large Commercial
				Large Agricultural
Medium	20 to 199.99 kW	Medium	Medium	Medium Commercial
				Medium Agricultural
Small	Below 20 kW	Small	Small	Small Commercial
				Small Agricultural

2.2.2 Key Research Questions

For clarity, Table 2-6 summarizes the key research questions guiding this evaluation:

Table 2-6: Key Research Questions for PY2024 CPP Evaluation

	Research Question
1	What were the demand reductions due to program operations in 2024 – for each event day and hour?
2	How do load impacts differ for customers in each subgroup (Large, Medium, Small) during PY2024?
3	How do weather and event hour influence the magnitude of demand response?
4	What are the ex ante load reduction capabilities for 1-in-2 weather conditions? And how well do those align with ex post results?
5	What concrete steps or experimental tests can be undertaken to improve program performance?

3 DATA SOURCES AND METHODS

The CPP event day impacts were primarily estimated using differences-in-differences with a matched control group. Site-specific individual regression models were also used in cases where there were too few customers in a segment (customer size and subLAP for PG&E, customer size and climate zone for SCE and SDG&E).

Each IOU supplied data for the evaluation, including hourly meter data, customer characteristics, and weather data. They also supplied program information such as enrollment lists, notification data, and enrollment forecasts for future program years. All CPP customers were included in the analysis except for the Small CPP groups for SCE and PG&E, where samples were drawn due to the large number of customers, and some remaining sites with incomplete data.

The SCE and SDG&E evaluations compare energy use based on customers' net loads, except for several large power generators that were found on CCP rates, in which case delivered loads were employed to improve the modeling. For PG&E, only delivered loads were used for all sites.

Table 3-1 lists further detail on the evaluation data and methods by IOU:

Table 3-1: Evaluation Details by IOU

Utility/ Program	PG&E	SCE	SDG&E
Analysis Method	Differences-in-Differences with matched control group for nearly all sites Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites	Differences-in-Differences with matched control group for nearly all sites Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites	Differences-in-Differences with matched control group Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites
Loads Analyzed	Delivered loads	Net loads (almost all sites) Delivered loads only for power generators	Net loads (almost all sites) Delivered loads only for power generators
Samples drawn?	Yes, for Small group	Yes, for Small group	No
Geographic segmentation	SubLAP, LCA, Climate Zone	SubLAP, LCA, Climate Zone	SubLAP, LCA, Climate Zone
Subgroups	Small, Medium, Large	Small, Medium, Large	Large Ag., Large Comm., Medium Ag., Medium Comm.
Other segmentation	Industry, NEM	Industry, NEM, Power generators	Industry, NEM, Power generators

Utility/ Program	PG&E	SCE	SDG&E
Analyze event notifications?	Yes	No	Yes

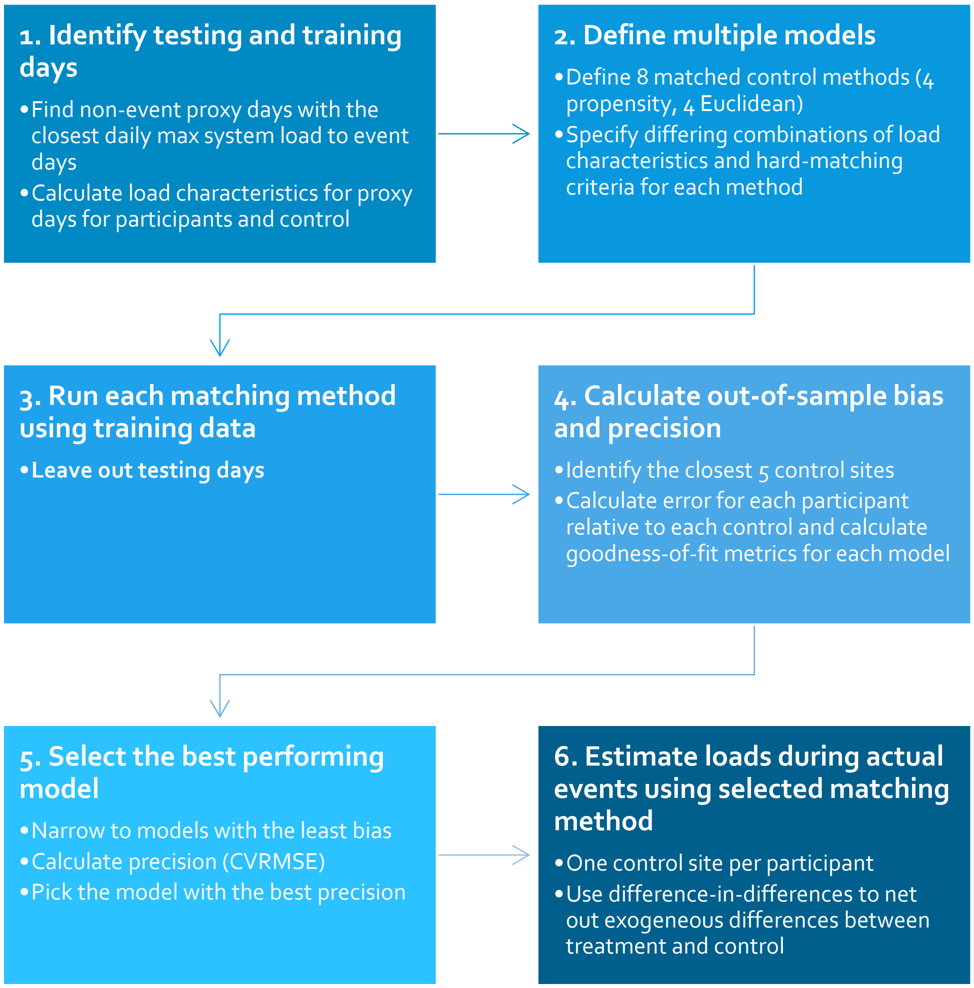
3.1 EX POST METHODOLOGY

3.1.1 Control Group Selection

Figure 3-1 summarizes the process used to select matched controls for the difference-in-difference analyses. First, several event-like, proxy days were chosen, with similar weather and system conditions to event days. Customers were then matched to non-CPP sites with similar energy-use patterns on the proxy days. More detail on proxy day selection can be found in Appendix B.

Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and weather sensitivity. Customers were always matched with control candidates in the same geographic area (subLAP for PG&E, climate zone for SCE and SDG&E), net metering status, and size bin. Size bins were constructed using average usage on event-like, proxy days. For solar customers, size bins were constructed based on system size.

Figure 3-1: Out of Sample Process for Control Group Selection



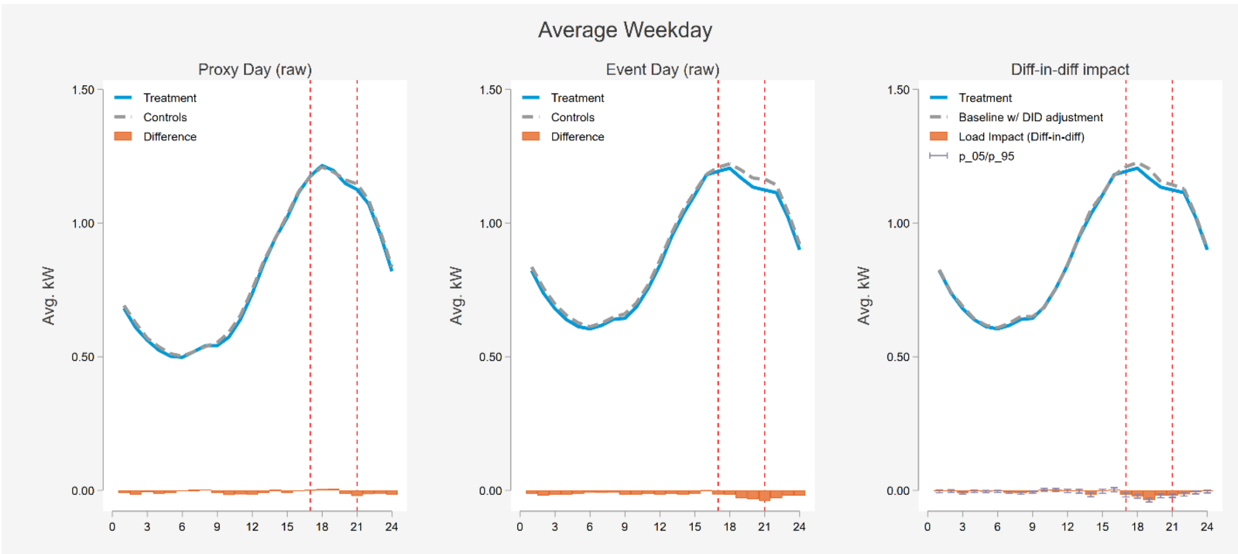
Matches were evaluated and the process was iterated as necessary until strong matches were achieved for each group. Matching was assessed using bias and goodness-of-fit metrics.

The difference-in-differences approach used the matches collectively as a control group to net out changes in energy usage patterns not due to the CPP events. The individual customer regressions also test for the inclusion of matched control sites as explanatory variables, representing the usage patterns on event days from similar sites. As such, regardless of evaluation methodology, each CPP site was matched to one or more non-CPP sites using a matching tournament where match quality was compared across eight different matching models to identify the best performing model.

3.1.2 Differences-in-Differences

Figure 3-2 below demonstrates the mechanics of a difference-in-difference calculation. The data shown is generic and not specific to any group in this evaluation. In the first panel, average observed loads on proxy days are shown for CPP customers and for their matched controls. The difference between these two is the first "difference" and quantifies underlying differences between CPP customers and their controls not attributable to event participation. Note that this first difference is very small, indicative of a high-quality match and sufficient sample size to neutralize the noise inherent in individual customer loads.

Figure 3-2: Difference-in-Differences Calculation Example



The second panel shows the average observed CPP customer and matched control loads on event days. The gap between these two is the second "difference" which includes both the difference due to event participation and the underlying first difference observable on non-event days.

The third panel shows the average event day loads after netting out the proxy day difference from the event day control load. The result is the difference-in-differences impact, or the change in customers' usage on event days vs. proxy days, net of any observed differences in the control group on those same days.

For PY 2024, the evaluation applies simple differences-in-differences calculations (differences in group means) in lieu of more complex regression modelling. Regression models attempt to account for partial impacts of various factors on the reference loads, in addition to the observed control group loads. This evaluation simply uses the aggregated control group loads during event hours as the reference load, net of any pre-existing differences between the groups. This allows for greater flexibility during event hours, allowing the control group's usage to vary in any way necessary, and without extrapolating the reference loads from slope coefficients estimated on non-event days.

The PY 2024 model further omits day-of adjustments for both morning and afternoon loads that were used in PY 2023. These can reduce the noise in estimates, but they may also recalibrate event-day reference loads to include load shifting occurring during earlier hours, biasing the impact estimates. More detail on this modelling decision can be found in Appendix C.

3.1.3 Individual Customer Regressions

In cases where a difference-in-differences approach was not possible due to insufficient sample size in the required matching categories or sites with large, noisy loads, site-specific individual customer regression models were used.

For sites requiring individual customer regressions, an out of sample tournament was used to select site specific regression models among 120 possible specifications across 4 parameters:

- Industry profiles, constructed of loads for other similar commercial and industrial customers[3]
- Local solar irradiance data from nearest weather station
- Number of control sites (up to five matched controls from the matching process above)
- Lags of load data[4]

The industry profiles (based on NAICS codes) and control sites (up to five matches, from the matching process described above) are included as explanatory variables to include the event-day usage patterns of similar sites. A variety of within-subjects lagged loads (1 day, 1 week, 2 weeks) were also included in the model testing.

To implement out of sample testing, the top 50 system load days, excluding event days, were randomly divided into testing and training datasets. Bias and fit metrics were calculated using the testing dataset and the model with the best fit (lowest Root Mean Squared Error) was selected among models with the least bias (Mean Absolute Error[5]). Site-specific load impacts were estimated with using the winning model for each site.

Figure 3-3 shows the different model parameters that were included in the site-specific model tournament and the number of sites for which each parameter was included in the winning model. The wide spread across parameters indicates that it was important to allow for individually-tailored models to be selected for each participating site.

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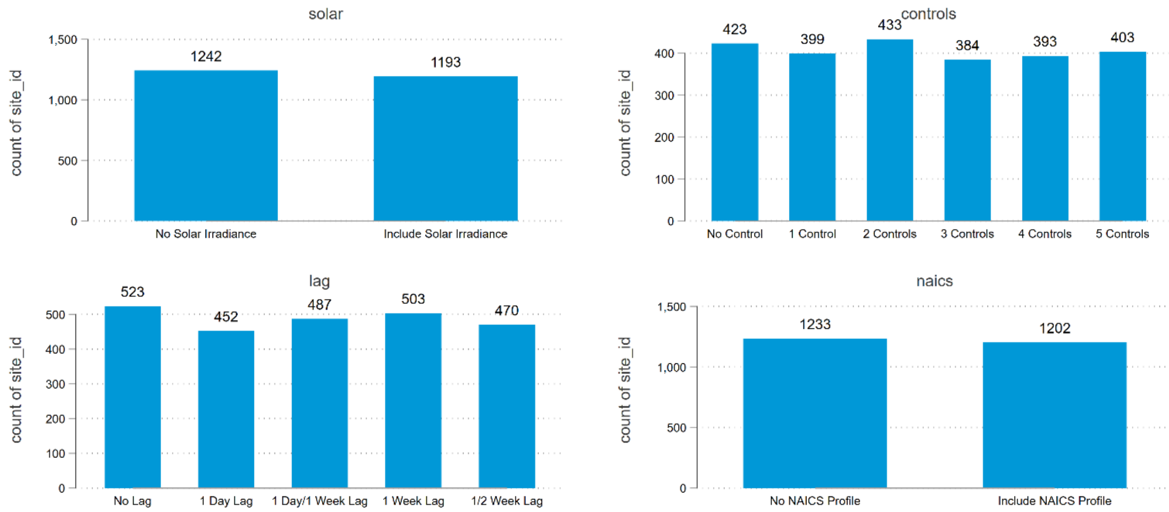
[3] Selected from granular load profiles within climate zone and industry segment constructed and maintained by Demand Side Analytics for PG&E, SCE, and SDG&E for the population NMEC settlement validation purposes for the Summer Reliability Program.

[4] Lags were designed to capture the tendency of large commercial and industrial customers to operate on daily, weekly, or bi-weekly schedules irrespective of weather or time of year.

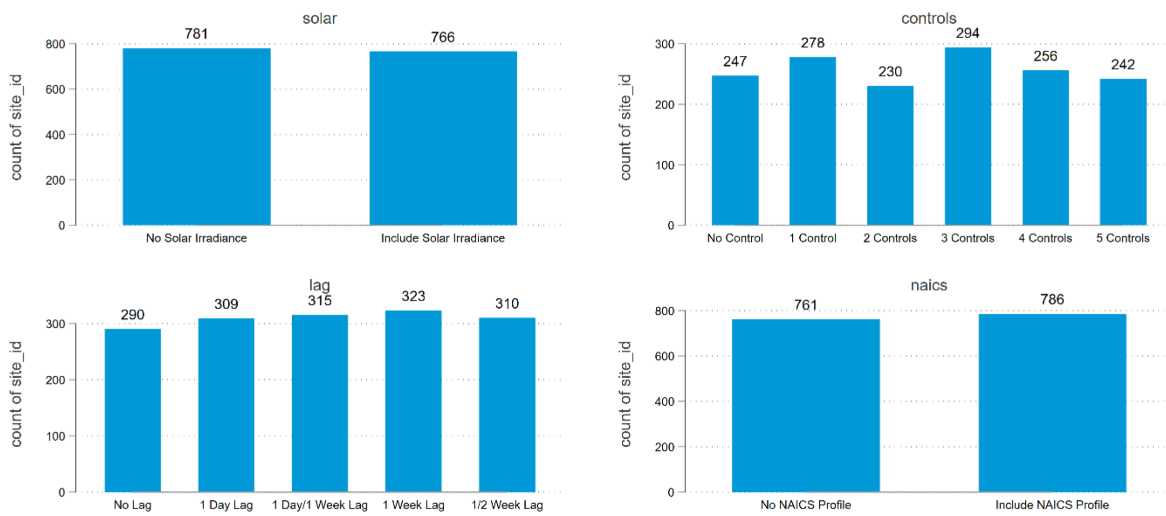
[5] MAE was used rather that Mean Average Percent Error (MAPE) to ensure robustness for sites with loads very close to zero, common for sites with solar or other generation.

Figure 3-3: Modeling Parameters Tested and Inclusion in Best Performing Site Specific Models

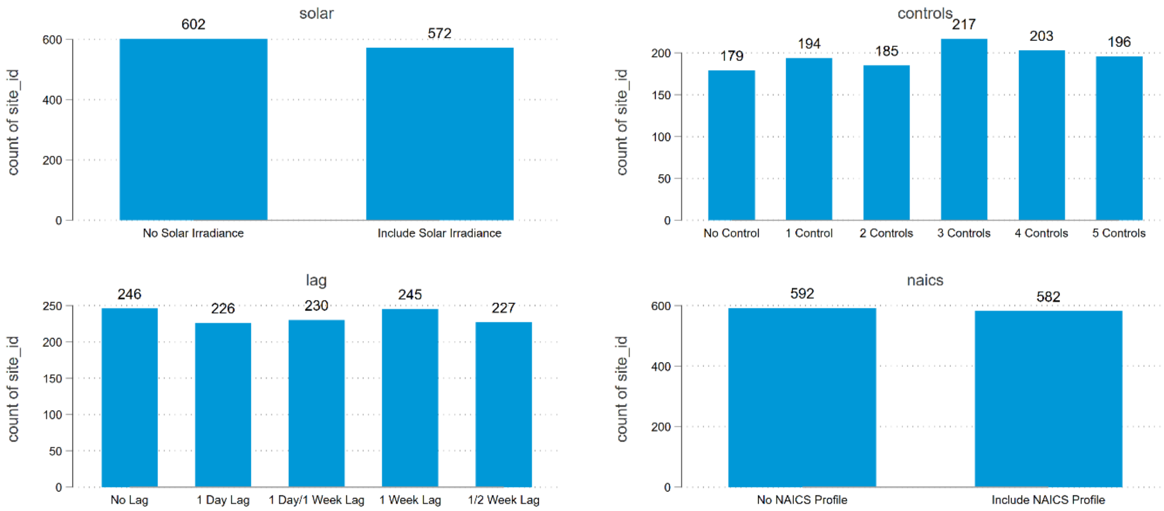
PG&E Models



SCE Models



SDG&E Models



Further detail on the exact regression specification can be found in Appendix A. In general, a small percentage of this evaluation's estimates were generated by the individual customer regressions, however.

3.2 EX ANTE METHODOLOGY

A key objective of the DR evaluations is to quantify the relationship between demand reductions, temperature, and hour of the day. The purpose of doing so is to establish the demand reduction capability under 1-in-2 weather conditions for planning purposes and, increasingly, for operations. When possible, we rely on the historical event performance to forecast ex-ante impacts for future years for different operating conditions.

3.2.1 Ex Ante Model Inputs and Specifications by IOU

For ex ante projections, we use a top-down enrollment model that includes PY2023 – PY2024 percent impact estimates, system loads, and a CPP enrollment forecast from each IOU. Weather and event-hour impacts were also tested for each IOU, but there were no significant trends in either of these measures on the PY2024 impact estimates, so they were not included. More detail on weather and event hour impacts can be found in each individual IOU section of this report.

Table 3-2 lists details on the ex ante methods by IOU. Methods and data included was largely the same across IOUs, though PG&E has a declining enrollment forecast due to anticipated growth in CCAs, which de-enroll CPP customers by default.

Table 3-2: Ex Ante Analysis Details by IOU

Utility/ Program	PG&E	SCE	SDG&E
Reference loads	PG&E, CAISO 1-in-2 weather year loads	SCE, CAISO 1-in-2 weather year loads	SDG&E, CAISO 1-in-2 weather year loads
PY2024 Ex Post impacts included?	Yes, if statistically significant (otherwise set to 0)	Yes, if statistically significant (otherwise set to 0)	Yes, if statistically significant (otherwise set to 0)
Historical impact estimates included?	Yes, PY2023	Yes, PY2023	Yes, PY2023
Weather impacts	No, based on testing	No, based on testing	No, based on testing
Different percent impacts by event hour?	No, based on testing	No, based on testing	No, based on testing
Enrollment forecast	10 years (2025-2034), supplied by IOU	10 years (2025-2034), supplied by IOU	10 years (2025-2034), supplied by IOU
Enrollment forecast trend	Declining	Slight increases via defaults through 2030	Slight increases via defaults through 2034

3.2.2 Portfolio-Adjusted Impacts

For ex ante estimates, program-specific and portfolio-adjusted impacts are developed for each IOU and subgroup.[6] Since customers may be able to participate in more than one energy-saving program, an attribution of savings estimates to separate DR programs is essential. This prevents double-counting savings for planning purposes. Ex post results are properly attributed by calculating the incremental impacts, or the load reduction beyond what was predicted or committed on dually called event hours. Modelling for ex ante is based solely on these incremental impacts.

Across all three IOUs, however, there was little dual-program participation with CPP. The only exception was ELRP – each IOU chose to count CPP impacts before ELRP impacts in their portfolio aggregations, so incremental impacts accounting for dual CPP-ELRP participation are handled in that evaluation. Any impacts for dual CPP-ELRP customers are therefore wholly attributed to CPP in this evaluation.

Among the remaining DR programs with allowable dual participation, only PG&E's and SCE's BIP and SCE's SDP program had dual customers. Of these dual enrollment groups, none produced significant ex post impacts on non-CPP event days necessitating adjustments for the ex ante modeling[7]. As such, in all cases the portfolio-adjusted impacts reported in this evaluation are equal to the program-specific impacts. Ex ante results will generally be presented as "portfolio-adjusted", since these are the impacts used for planning, but they are equivalent to the program-specific values.

Table 3-3 gives more detail on the dual-program considerations by IOU:

Table 3-3: Eligible Dually Enrolled Programs for Ex Ante Considerations by IOU

IOU	BIP	CBP	Thermostat Programs	ELRP
PG&E	Removed from analysis per PG&E	No dual participants	N/A	Adjustments made in ELRP evaluation
SCE	No significant impacts	No dual participants	SDP dual participants evaluated – no significant impacts	Adjustments made in ELRP evaluation
SDG&E	N/A	No dual participants	N/A	Adjustments made in ELRP evaluation

[6] The use of the word "program" in the case of CPP means just the rate load impacts alone, not accounting for any interaction with another demand response program – which is referred to as portfolio-adjusted impacts.
[7] Five PG&E BIP dual enrolled sites were removed from ex post impacts for ex ante portfolio-adjusted modeling but their impacts or effect on reference loads was negligible.

4 PG&E PY2024 IMPACTS

PG&E's CPP rate program, marketed as Peak Day Pricing (PDP) had over 100,000 customers enrolled in PY2024. Most customers were enrolled in CPP rates by default, but they can opt out at any time. CPP rates are offered in both commercial and agricultural rate classes. Most, however, are commercial customers, so they are combined for this evaluation into Small, Medium, and Large size distinctions based on their annual peak kW.

PG&E had nine event days in PY2024, largely coinciding with the hottest summer days in PG&E's territory. Event days extended from June through September and included one weekend event in July. Customers were eligible to receive day ahead or day-of event notifications via email, text, or phone.

4.1 SUMMARY OF RESULTS

Table 4-1 summarizes the estimated ex post demand reductions for the average weekday event for each of PG&E's CPP groups. All impacts are incremental to other DR program impacts, though for PG&E no other programs had significant impacts on the PY2024 estimates. Statistical significance is noted for each subgroup in the last two columns.

PG&E's Large sites had the greatest load reduction for PY2024, both aggregate (3.8 MW) and in percentage terms (1.4%). Medium sites averaged 3.3 MW reductions during event hours (0.9%), in part due to their high enrollment count. The Small group had modest but statistically significant impacts as well (0.4% per site).

Overall the evaluation found a point estimate of roughly 8 MW reduced by PG&E's CPP rate customers during PY2024 event hours. However, this estimate has a broad distribution: Due to high variance in the Large sites' performance, rate impacts were only significant at the 10% level (the 90% confidence interval can be distinguished from zero, but the 95% confidence interval cannot).

Table 4-1: PG&E Ex Post Demand Reductions for an Average Weekday Event

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Large (200 kW and Above)	1,555	268.21	3.79	1.4%	Yes	No
Medium (20 to 199.99 kW)	16,295	373.65	3.31	0.9%	Yes	Yes
Small (Below 20 kW)	85,727	173.95	0.65	0.4%	Yes	Yes
Total	**103,577**	**815.81**	**7.74**	**0.9%**	**Yes**	**No**

Table 4-2 summarizes PG&E's forecasted site enrollments through 2034 by group. Many CPP customers have been automatically de-enrolled in recent years as localities have set up Community Choice Aggregations (CCAs), which do not offer CPP rates. PG&E's team has thus accounted for CPP losses to CCAs in their enrollment forecast, modeled as smooth but decreasing enrollments over time for Medium and Small sites:

Table 4-2: Summary of Ex Ante Site Enrollments

Year	Large	Medium	Small	Total
2024	1,558	16,309	85,755	103,622
2025	1,506	14,448	79,796	95,750
2026	1,531	13,464	74,502	89,497
2027	1,552	12,554	69,574	83,680
2028	1,491	11,418	64,515	77,424
2029	1,510	10,642	60,274	72,426
2030	1,529	9,919	56,362	67,810
2031	1,544	9,250	52,724	63,518
2032	1,566	8,620	49,342	59,528
2033	1,585	8,043	46,221	55,849
2034	1,571	7,499	43,293	52,363

Table 4-3 summarizes the portfolio-adjusted reductions that PG&E CPP rates can be expected to deliver *ex ante* under August peak conditions in an PG&E 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2024. The estimates are instead a function of the percent impacts estimates in this (PY2024) and the previous (Py2023) evaluation. The results reflect reduction capability for a single event across PG&E's CPP event window (4 to 9 p.m.)

Overall, CPP customers can be expected to deliver an aggregate 7.7 MW per five-hour event next year (2025), with ex ante impacts decreasing steadily as enrollments decrease through 2034. Both the Large and Medium groups factor heavily into these projections, accounting for 2.6 and 4.1 MW ex ante for 2025. The Small group, with most of the CPP customers, is only anticipated to deliver about 1 MW per year going forward.

Table 4-3: Summary of Ex Ante Demand Reductions for August Worst Day, PG&E 1-in-2 Weather (MW, Portfolio-Adjusted)

Year	Large	Medium	Small	Total
2024	2.9	3.1	1.0	**7.1**
2025	2.6	4.1	1.1	**7.7**
2026	2.5	3.8	1.0	**7.3**
2027	2.4	3.6	1.0	**7.0**
2028	2.2	3.2	0.9	**6.4**
2029	2.2	3.1	0.8	**6.1**
2030	2.2	2.9	0.8	**5.8**
2031	2.1	2.7	0.7	**5.6**
2032	2.1	2.5	0.7	**5.4**
2033	2.1	2.4	0.7	**5.1**
2034	2.0	2.3	0.6	**4.9**

4.2 EVENT CHARACTERISTICS

Table 4-4 shows the nine CPP event days in PY2024 as well as the PG&E system peak load on each day. All nine events ran from 4 to 9 p.m. and covered all sites on CPP rates. PG&E optionally sends day-ahead notifications to customers to help in load shifting during the increased price periods. These are sent via text, email, or phone based on customers' preferences.

Event days covered a range of summer months, but were focused on days with the highest temperatures and system loads in PG&E territory. Eight event days were weekdays and one was a weekend, during the heat wave in early July.

Table 4-4: PG&E CPP Events in 2024

Event date	Day of week	Max PG&E system load (MW)	Event window	All groups
6/5/2024	Wednesday	18,466	4 to 9 p.m.	✓
7/2/2024	Tuesday	20,404	4 to 9 p.m.	✓
7/3/2024	Wednesday	20,566	4 to 9 p.m.	✓
7/6/2024	Saturday	19,664	4 to 9 p.m.	✓
7/10/2024	Wednesday	19,652	4 to 9 p.m.	✓
7/11/2024	Thursday	21,159	4 to 9 p.m.	✓
7/23/2024	Tuesday	20,677	4 to 9 p.m.	✓
9/4/2024	Wednesday	18,291	4 to 9 p.m.	✓
9/5/2024	Thursday	18,349	4 to 9 p.m.	✓

As shown in Figure 4-1, PG&E's events were similar to those called in previous years. PG&E's CPP event days are generally among the hottest days of the summer, but called across a range of dates.

Figure 4-1: PG&E Event Days and Temperature by Year

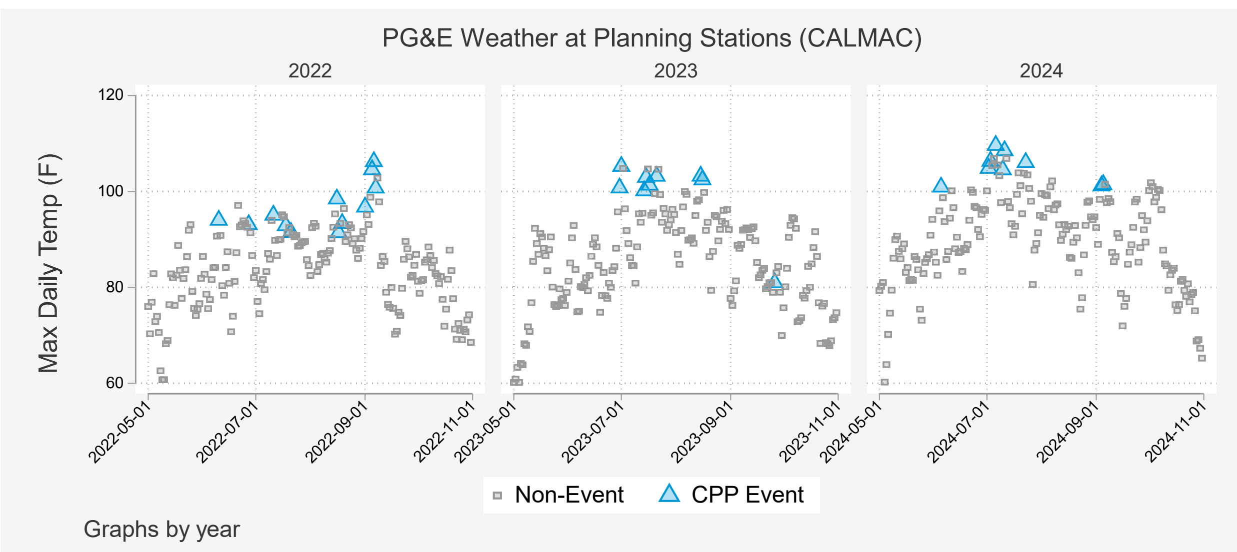


Figure 4-2: PY2024 Impacts by Event Day, All Groups Combined – PG&E

Event date	Total enrolled sites	Avg temp (F, site weighted)	Load reduction (MWh/h)	% Load reduction	Std. error	t-stat	Sig. 90%
6/5/2024	103,484	95.8	0.1	0.0%	5.7	-0.02	No
7/2/2024	103,562	99.6	13.7	1.7%	5.1	-2.67	Yes

Event date	Total enrolled sites	Avg temp (F, site weighted)	Load reduction (MWh/h)	% Load reduction	Std. error	t-stat	Sig. 90%
7/3/2024	103,562	101.6	9.8	1.2%	6.0	-1.64	No
7/6/2024	103,563	104.1	5.5	0.7%	4.4	-1.27	No
7/10/2024	103,573	99.8	0.5	0.1%	3.8	-0.12	No
7/11/2024	103,574	103.3	7.6	0.9%	4.2	-1.79	Yes
7/23/2024	103,593	101.8	13.6	1.6%	4.6	-2.99	Yes
9/4/2024	103,658	96.2	8.8	1.1%	6.6	-1.33	No
9/5/2024	103,658	96.7	6.2	0.8%	8.2	-0.75	No
Avg. Weekday	**103,582**	**99.3**	**7.4**	**0.9%**	**3.5**	**-2.12**	**Yes**
Avg. Weekend	**103,563**	**104.1**	**5.5**	**0.7%**	**4.4**	**-1.27**	**No**

4.3 EX POST LOAD IMPACTS

4.3.1 Sites in Analysis

PG&E had almost 104,000 customers on CPP rates in 2024, including both agricultural and commercial customers. Sites were analyzed in groups based on size, as shown in Table 4-5 below. Most sites (roughly 86,000) were in the Small group, with less than 20 kW peak demand. Due to the large number of sites in this group, a random sample was drawn by industry and climate, with just over 24,000 sites included in the actual analysis. All results were then weighted to reflect the full population of Small CPP customers. For example, PG&E CPP had many small office sites in Climate Zone 3 in the Bay Area – only a subset of these were drawn into the random sample, but each small office in the sample carries large weight in the Small group's impact estimates.

Table 4-5 also shows any other difference between the full CPP enrollment counts and the number of sites used for the ex post analysis. "Total Sites" indicates the total number of sites enrolled for at least one PY2024 event. In additional to the sampling for the Small group, several sites were dropped due to incomplete data, outages, or other data issues.

Table 4-5: PG&E PY2024 Site Enrollments by Size (Avg Weekday Event)

Group	Sector	Total sites	Sites in analysis*
Large (200 kW and above)	Commercial & Agricultural	1,555	1,555
Medium (20 to 199.99 kW)	Commercial & Agricultural	16,295	16,295
Small (below 20 kW)	Commercial & Agricultural	85,727	24,226
Total		**103,577**	**43,523**

*Small group sites in analysis drawn randomly from customer population

4.3.2 Impacts by Event – PG&E Large

For PY2024, PG&E had an average of 1,555 Large customers across its nine summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-6 summarizes Large sites' load reductions and customer-weighted event temperatures during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that listed to the left of each.

Large sites had estimated impacts between 1 and 2% for most events. Events during the early July heat wave in Northern California similarly range from 0.9% to 2.0%. Most individual event days did not have statistically significant impacts, however, indicating a high degree of noise in the estimates. The July 23rd event had a larger impact (2.7%), leading the load reductions for this individual event day to be statistically significant as well. Overall, weekday events had load reductions of 1.4% on average, and this estimate was significant at the 10% level (but not 5% level).

Table 4-6: Ex Post Impact Estimates by Event - PG&E Large

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
6/5/2024	4 to 9 pm	97.0	1,549	5.0	1.9%	3.3	No	No
7/2/2024	4 to 9 pm	100.2	1,555	2.3	0.9%	1.5	No	No
7/3/2024	4 to 9 pm	102.7	1,555	4.0	1.5%	2.6	No	No
7/6/2024	4 to 9 pm	105.2	1,555	4.4	2.0%	2.8	No	No
7/10/2024	4 to 9 pm	101.2	1,555	2.2	0.8%	1.4	No	No
7/11/2024	4 to 9 pm	104.6	1,555	4.4	1.6%	2.8	No	No
7/23/2024	4 to 9 pm	103.4	1,556	7.4	2.7%	4.7	Yes	Yes
9/4/2024	4 to 9 pm	97.6	1,560	9.6	3.5%	6.1	No	No
9/5/2024	4 to 9 pm	98.1	1,560	0.7	0.2%	0.4	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**100.6**	**1,555**	**3.8**	**1.4%**	**2.4**	**Yes**	**No**
Avg Weekend 4-9 pm	**4 to 9 pm**	**105.2**	**1,555**	**4.4**	**2.0%**	**2.8**	**No**	**No**

Large sites had an estimated 2.0% reduction for the single weekend event, but this result is not statistically significant and thus cannot be distinguished from zero impact.

Impacts were also estimated for several subsegments of each group and included in the PG&E Ex Post table generators. As many of these were insignificant or inconsistent (e.g. varying impacts by Industry across the Small, Medium, and Large groups), they should be interpreted with caution.

4.3.3 Impacts by Event – PG&E Medium

For PY2024, PG&E had an average of 16,295 Medium customers (20 to 199.99 kW max demand) across its nine summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-7 summarizes the load reductions and customer-weighted event temperatures for CPP. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

On average, weekday events produced load reductions of 3.3 MW (0.9%) for Medium sites, with the aggregate impact driven in part by the large number of sites in this group. Five event days had statistically significant load reductions (7/2, 7/3, 7/11, 7/23, and 9/5), with impact estimates on these days ranging from 1 to 2%. However, estimated impacts were small and indistinguishable from zero on other event days, leading to the slightly lower estimate for an average weekday.

Table 4-7: Ex Post Impact Estimates by Event - PG&E Medium

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
6/5/2024	4 to 9 pm	96.8	16,263	-1.8	-0.5%	-0.1	No	No
7/2/2024	4 to 9 pm	100.3	16,289	7.3	2.0%	0.4	Yes	Yes
7/3/2024	4 to 9 pm	102.5	16,289	6.0	1.6%	0.4	Yes	Yes
7/6/2024	4 to 9 pm	105.0	16,290	0.6	0.2%	0.0	No	No
7/10/2024	4 to 9 pm	100.9	16,294	-0.6	-0.2%	0.0	No	No
7/11/2024	4 to 9 pm	104.4	16,295	4.6	1.1%	0.3	Yes	Yes
7/23/2024	4 to 9 pm	102.9	16,301	6.7	1.7%	0.4	Yes	Yes
9/4/2024	4 to 9 pm	97.2	16,315	0.9	0.3%	0.1	No	No
9/5/2024	4 to 9 pm	97.6	16,315	3.6	1.0%	0.2	Yes	Yes
Avg Weekday 4-9 pm	**4 to 9 pm**	**100.3**	**16,295**	**3.3**	**0.9%**	**0.2**	**Yes**	**Yes**
Avg Weekend 4-9 pm	**4 to 9 pm**	**105.0**	**16,290**	**0.6**	**0.2%**	**0.0**	**No**	**No**

PG&E's single weekend event on 7/6 did not produce significant load reductions for the Medium group—this estimate can be interpreted as zero.

4.3.4 Impacts by Event – PG&E Small

PG&E had an average of 85,727 Small CPP customers during PY2024 events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-8 summarizes the load reductions and customer-weighted event temperatures for Small sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall, the Small group had modest load reductions in 2024, averaging 0.4% (0.6 MW) lower electric demand during event hours. This impact was, however, statistically significant. Two event days with the largest impact estimates (1.3 % reduction on 7/2, 1.6% reduction on 9/5) were statistically significant at the 5% level, meaning the estimated 95% confidence interval did not include zero. However, several other events had essentially zero reduction, driving down the estimated impacts on an average weekday.

Table 4-8: Ex Post Impact Estimates by Event - PG&E Small

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
6/5/2024	4 to 9 pm	95.6	85,667	-1.1	-0.7%	0.0	Yes	No
7/2/2024	4 to 9 pm	99.5	85,713	2.2	1.3%	0.0	Yes	Yes
7/3/2024	4 to 9 pm	101.4	85,713	1.1	0.6%	0.0	Yes	No
7/6/2024	4 to 9 pm	103.9	85,713	-1.0	-0.6%	0.0	Yes	No
7/10/2024	4 to 9 pm	99.6	85,719	0.5	0.3%	0.0	No	No
7/11/2024	4 to 9 pm	103.0	85,719	0.7	0.4%	0.0	No	No
7/23/2024	4 to 9 pm	101.6	85,731	0.2	0.1%	0.0	No	No
9/4/2024	4 to 9 pm	96.0	85,778	-1.1	-0.7%	0.0	Yes	Yes
9/5/2024	4 to 9 pm	96.5	85,778	2.7	1.6%	0.0	Yes	Yes
Avg Weekday 4-9 pm	**4 to 9 pm**	**99.1**	**85,727**	**0.6**	**0.4%**	**0.0**	**Yes**	**Yes**
Avg Weekend 4-9 pm	**4 to 9 pm**	**103.9**	**85,713**	**-1.0**	**-0.6%**	**0.0**	**Yes**	**No**

The single weekend event (7/6) did not produce any meaningful reduction in event window loads for the Small sites.

4.4 EX ANTE LOAD IMPACTS

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) peak demand weather conditions for both CAISO and the PG&E system.

In general, ex ante forecasts rely on the estimated ex post impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2024, ex ante modeling incorporated both PY2023 and PY2024 ex post impact estimates, but it did not include any differential impacts based on weather or the event hour.

4.4.1 EX ANTE MODEL INPUTS

For PY2024, the key inputs for ex ante impact model are:

- PY2023 ex post impact estimates
- PY2024 ex post impact estimates
- 1-in-2 system weather data for both the CAISO and SCE
- CPP enrollment forecast through 2034

The following factors were also considered, but ultimately were not included in the ex ante model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the ex ante model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

PY 2024 Impact Estimates

Significant ex post impacts estimates by event, hour, and rate class are the primary input. Any individual estimates on these same margins that are statistically insignificant are set to zero in the ex ante analysis to prevent projecting noise forward. Note that even if group-level or program-level ex post estimates are insignificant, there may be underlying events, hours, and rate class combinations where significant impacts were seen, and these are included individually in the model.

Historical Impact Estimates

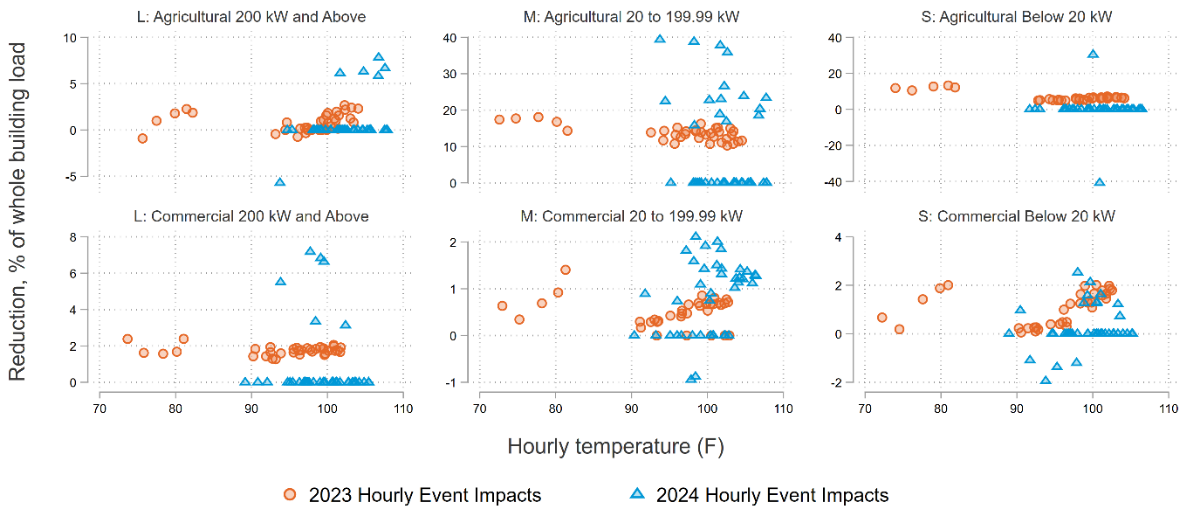
PY2023 ex post impacts were included, along with the current year ex post estimates, in the ex ante model. For PY2024, PG&E's CPP groups had statistically insignificant impacts on many event days. As such, the PY2023 percent impacts were included to add more data to the model. Since the 2023 estimates provided a large number of additional data points, we did not include impact estimates from PY2022 in the ex ante modelling.

Statewide evaluations in previous years have also been performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 impacts can therefore aid in creating greater consistency in the study outputs.

Weather Impacts

Figure 4-3 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2024 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling – significant impacts are shown as-is, while statistically insignificant impacts are set to zero. Note that individual hour or event impacts can be statistically significant in groups that were not significant as a whole. Noise from a small group or single event's estimates should not be projected forward for system planning, so they are assumed to be zero.

Figure 4-3: PG&E Hourly Reductions vs. Average Temperatures

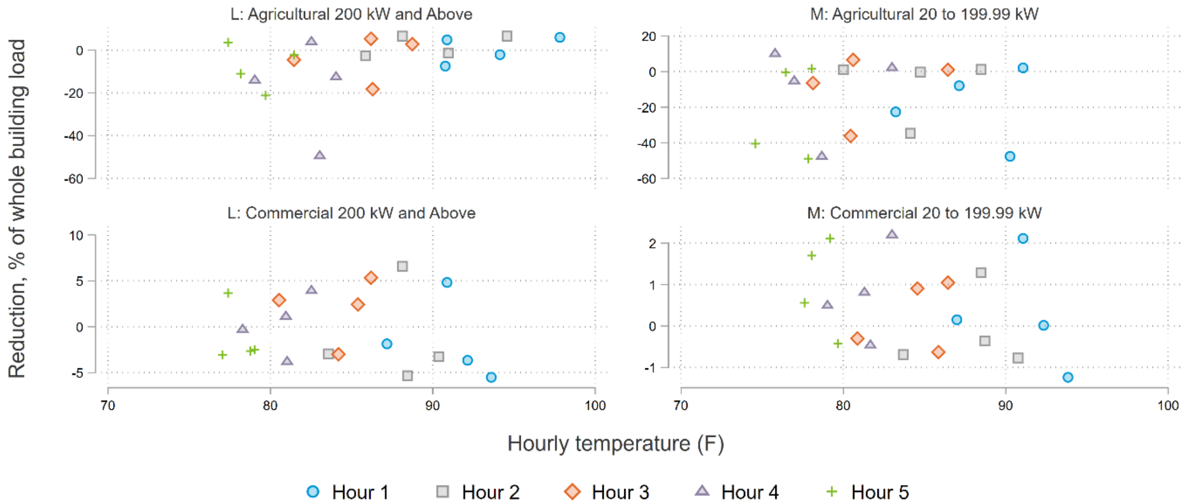


Focusing on the significant impacts (plotted away from zero), there is no clear trend in the percent impacts as temperature increases along the horizontal axes. Some positive trends can be seen between 90 and 100 degrees in the 2023 estimates for Small and Medium commercial sites only, but these do not extend to lower temperature ranges, nor are they evident in the 2024 results to any degree. No weather trends for PG&E were found to be significant in the 2023 evaluation and as such were excluded in that evaluation as well. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

Event Hour Impacts

Figure 4-4 plots the 2024 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 4-4: PG&E Impacts by Event Hour and Temperature



Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 4-9 summarizes the annual enrollment forecast for each subgroup.

Table 4-9: PG&E Participant Enrollment Forecast

Year	Large	Medium	Small	Total
2024	1,558	16,309	85,755	103,622
2025	1,506	14,448	79,796	95,750
2026	1,531	13,464	74,502	89,497
2027	1,552	12,554	69,574	83,680
2028	1,491	11,418	64,515	77,424
2029	1,510	10,642	60,274	72,426
2030	1,529	9,919	56,362	67,810
2031	1,544	9,250	52,724	63,518
2032	1,566	8,620	49,342	59,528
2033	1,585	8,043	46,221	55,849
2034	1,571	7,499	43,293	52,363

PG&E developed the CPP enrollment forecast that was used to scale the ex ante impacts. PG&E's forecast is very granular, with estimates for each combination of size, subLAP, and industry group. Some of the underlying subgroups (such as agricultural sites) are forecast to grow in CPP enrollments while others are expected to decline. Overall, PG&E anticipates further expansion of CCAs, which de-enroll CPP customers by default. This drives the large decreases in CPP enrollments through 2034 in the forecast.

4.4.2 Ex Ante Load Impacts – PG&E Large

Table 4-10 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Large CPP customers under different planning conditions. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast includes granular forecasts by industry and subLAP, which accounts for the variance in future enrollments from year to year. In particular, CPP enrollment among agricultural sites, which had smaller ex post impact estimates in this evaluation, is predicted to grow. Enrollment in other industries is generally predicted to decline. Thus the combined ex ante impacts decrease from 2.4-2.6 MW in 2025 from 1.9 to 2.0 MW in 2034.

Table 4-10: PG&E Large Ex-Ante Impacts for 1-in-2 August Worst Day (MW)[8]

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	1,558	2.81	2.81	2.94	2.94
1-in-2	2025	1,506	2.44	2.44	2.55	2.55
1-in-2	2026	1,531	2.38	2.38	2.50	2.50
1-in-2	2027	1,552	2.33	2.33	2.44	2.44
1-in-2	2028	1,491	2.14	2.14	2.25	2.25
1-in-2	2029	1,510	2.09	2.10	2.20	2.20
1-in-2	2030	1,529	2.05	2.05	2.16	2.16
1-in-2	2031	1,544	2.01	2.02	2.12	2.12
1-in-2	2032	1,566	2.00	2.00	2.10	2.11
1-in-2	2033	1,585	1.97	1.97	2.08	2.08
1-in-2	2034	1,571	1.87	1.88	1.98	1.98

[8] Impacts are both portfolio-adjusted and program-specific impacts since no dual-enrollment groups had significant impacts. Any differences are rounding errors in the aggregations.

4.4.3 Ex Ante Load Impacts – PG&E Medium

Table 4-11 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Medium CPP customers under different planning conditions. Since no significant impacts were estimated for any CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Medium customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast anticipates Medium customers falling by half over the next ten years due to the growth of CCAs, which de-enroll sites by default. This accounts for the decline in impacts from 3.8-4.1 MW in 2025 to 2.1 to 2.3 MW in 2034.

Table 4-11: PG&E Medium Ex-Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	16,309	2.87	2.87	3.12	3.12
1-in-2	2025	14,448	3.77	3.76	4.06	4.06
1-in-2	2026	13,464	3.53	3.53	3.81	3.81
1-in-2	2027	12,554	3.32	3.32	3.58	3.58
1-in-2	2028	11,418	3.01	3.01	3.25	3.25
1-in-2	2029	10,642	2.83	2.83	3.06	3.05
1-in-2	2030	9,919	2.66	2.66	2.87	2.87
1-in-2	2031	9,250	2.51	2.51	2.71	2.70
1-in-2	2032	8,620	2.36	2.36	2.55	2.54
1-in-2	2033	8,043	2.23	2.22	2.40	2.40
1-in-2	2034	7,499	2.10	2.10	2.27	2.27

4.4.4 Ex Ante Load Impacts – PG&E Small

Table 4-12 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Small CPP customers under different planning conditions. Since no significant impacts were estimated for any CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Small customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast also predicts that Small customers will decrease by half over the next ten years due CCAs. This accounts for the decline in impacts from 1.0-1.1 MW in 2025 to 0.6 MW by 2034.

Table 4-12: PG&E Large Ex-Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	85,755	0.95	0.95	1.05	1.05
1-in-2	2025	79,796	1.01	1.01	1.11	1.11
1-in-2	2026	74,502	0.94	0.94	1.04	1.04
1-in-2	2027	69,574	0.88	0.88	0.97	0.97
1-in-2	2028	64,515	0.82	0.82	0.90	0.90
1-in-2	2029	60,274	0.77	0.77	0.85	0.85
1-in-2	2030	56,362	0.72	0.72	0.79	0.79
1-in-2	2031	52,724	0.67	0.67	0.75	0.75
1-in-2	2032	49,342	0.63	0.63	0.70	0.70
1-in-2	2033	46,221	0.59	0.59	0.66	0.66
1-in-2	2034	43,293	0.56	0.56	0.62	0.62

4.4.5 COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For PG&E's Large CPP group, Table 4-13 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Large CPP site delivered 1.1% in statistically significant load reductions (3.81 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were 1.1%, similar to ex post inputs. Note that the ex post counterfactual loads ("Load without DR" in the table) include both PY 2023 and PY 2024 loads whereas the ex ante counterfactual loads represent modeled loads for the August worst day only for PY 2024 customers.

Differences between the two are largely explained by the change in the enrollment population from PY 2023 as compared to PY2024 as well as the difference in temperature. Specifically, though there were more customers in PY2024, a few very large PY2023 customers did not participate in PY2024 resulting in lower average customer loads in PY 2024. The PG&E and CAISO weather ex ante predictions are slightly different because ex ante reference increase for hotter temperatures. Percent impacts are equal across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 4-13: PG&E Large Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	343.28	3.81	1.1%	98.7
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	161.29	1.81	1.1%	93.7
Ex Ante (PG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	168.78	1.89	1.1%	97.3

For PG&E's Medium CPP group, Table 4-14 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Medium CPP site delivered 0.9% in statistically significant load reductions (0.2 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were 0.9% as well.

Table 4-14: PG&E Medium Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	22.77	0.20	0.9%	98.0
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	20.63	0.18	0.9%	93.0
Ex Ante (PG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	22.45	0.19	0.9%	97.0

For PG&E's Small CPP group, compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 p.m. to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Small CPP site delivered 0.6% in statistically significant load reductions (0.01 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.6%. compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 p.m. to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Small CPP site delivered 0.6% in statistically significant load reductions (0.01 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.6%.

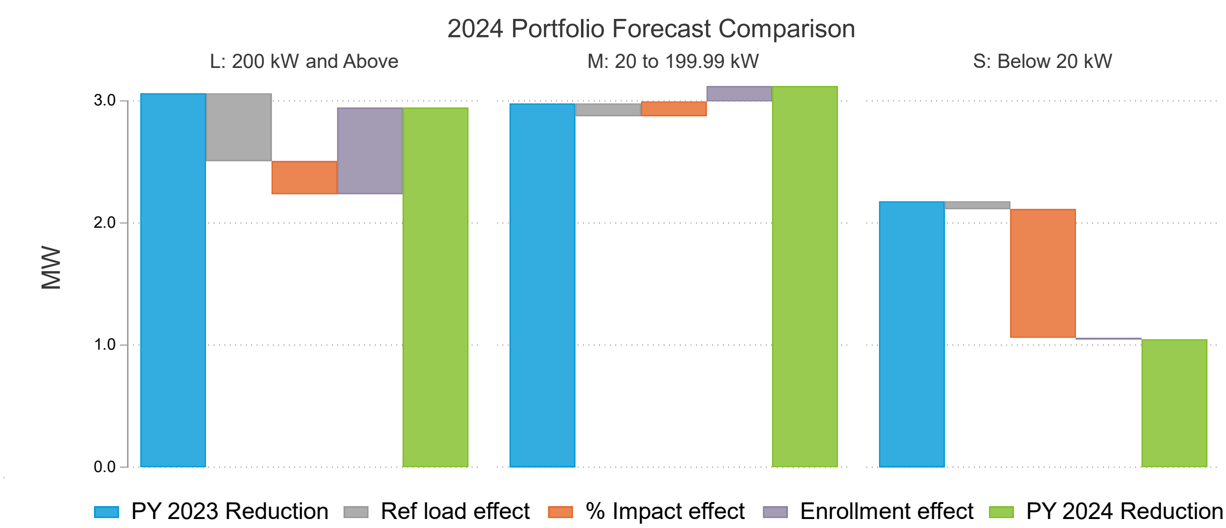
Table 4-15: PG&E Small Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	2.06	0.01	0.6%	97.1
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	1.81	0.01	0.6%	92.0
Ex Ante (PG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	1.99	0.01	0.6%	95.9

4.4.6 Comparison to 2023 Ex Ante Impact Estimates

The ex ante impact estimates in this study are slightly reduced from the previous evaluation, largely due to decreased impacts from the Small sites. The following figure gives a breakdown of the difference in ex ante impact estimates from PY2023 and those generated in in PY2024. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2023 (in blue) and PY2024 (in green).

Figure 4-5: Waterfall Analysis of 2023-2024 PG&E Ex Ante Impacts by Group



The Large group has a lower reference load than in 2023, but slightly higher enrollments. The percent impacts are fairly similar, as are the resulting impact estimates in MW per event hour. The Medium group is fairly similar in term of all three factors. The Small group has not seen significant changes in either the reference load or forecasted enrollments – the reduced projection from roughly 2 MW to 1 MW is the result of lower percent impacts estimated in PY2024.

4.4.7 Ex Ante Load Impact Slice-of-Day Tables

The following tables show the 2024 ex ante aggregate hourly impacts by CPP group for each month under PG&E 1-in-2 monthly worst day conditions. CPP tariffs only allow for dispatch from 4 to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table 4-16: PG&E Large Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2.13	2.13	2.13	2.63	2.86	3.10	3.13	3.10	3.03	2.69	2.26	2.26
18	2.05	2.05	2.05	2.53	2.77	3.00	3.03	3.00	2.94	2.60	2.17	2.17
19	2.01	2.02	2.02	2.48	2.70	2.93	2.96	2.92	2.86	2.54	2.14	2.14
20	2.02	2.02	2.02	2.47	2.68	2.89	2.92	2.89	2.83	2.52	2.14	2.14
21	1.98	1.98	1.98	2.42	2.63	2.84	2.87	2.83	2.77	2.46	2.10	2.10
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 4-17: PG&E Medium Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	1.82	1.82	1.82	2.60	3.06	3.53	3.62	3.54	3.39	2.74	1.90	1.90
18	1.70	1.70	1.70	2.43	2.85	3.29	3.38	3.30	3.16	2.56	1.77	1.77
19	1.62	1.62	1.62	2.30	2.70	3.10	3.19	3.11	2.99	2.42	1.69	1.69
20	1.62	1.62	1.62	2.22	2.57	2.93	3.01	2.95	2.83	2.33	1.68	1.68
21	1.57	1.57	1.57	2.12	2.44	2.77	2.85	2.79	2.69	2.23	1.63	1.63
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 4-18: PG&E Small Slice of Day Table for Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.60	0.60	0.60	0.93	1.14	1.36	1.38	1.33	1.26	0.97	0.60	0.60
18	0.53	0.53	0.53	0.81	0.99	1.17	1.18	1.15	1.09	0.84	0.53	0.53
19	0.49	0.49	0.49	0.73	0.88	1.03	1.04	1.01	0.96	0.75	0.49	0.49
20	0.49	0.49	0.49	0.68	0.80	0.92	0.93	0.90	0.86	0.70	0.50	0.50
21	0.50	0.50	0.50	0.65	0.75	0.85	0.85	0.84	0.80	0.67	0.50	0.50
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

5 SCE PY2024 IMPACTS

SCE's CPP rate program had over 220,000 customers in PY2024, most of them in the Small group (less than 20 kW maximum demand). As with the other IOU's, most of these customers were placed on CPP rates by default, but they can opt out and choose a different rate at any time. SCE offers CPP rates in both commercial and agricultural rate classes. Most, however, are commercial customers, so they are combined for this evaluation into the Small, Medium, and Large size distinctions based on their annual peak kW.

SCE had 12 events in PY2024, each between June and August, with no events in the September heat wave since they had already reached the targeted 60 event hours for the year and emergency conditions were not reached.

5.1 SUMMARY OF RESULTS

Table 5-1 summarizes the estimated ex post demand reductions for the average weekday CPP event for each of SCE's CPP subgroups. All impacts are incremental to other DR program impacts, though for SCE no other programs had significant impacts on the PY2024 estimates. Statistical significance is noted for each subgroup in the last two columns.

The point estimates for each group indicate savings during event hours, but the variance in estimates for the Large and Medium groups was very high. Small Commercial was the only group that produced statistically significant incremental impacts. Overall the evaluation found a point estimate of roughly 4 MW saved by SCE's CPP rate customers during PY2024 event hours, but this result was statistically insignficant (cannot be distinguished from zero).

Table 5-1: SCE Ex Post Demand Reductions for an Average Weekday Event

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Large (200 kW and Above)	1,769	376.42	3.23	0.9%	No	No
Medium (20 to 199.99 kW)	21,412	515.46	0.47	0.1%	No	No
Small (Below 20 kW)	197,477	256.01	0.09	0.0%	No	No
Total	**220,658**	**1147.89**	**3.79**	**0.3%**	**No**	**No**

Table 5-2 summarizes SCE's forecasted site enrollments over the next ten years by group. These are produced internally by SCE and applied to ex ante estimates in the evaluation. In general, site enrollments are anticipated to increase slowly over the next 5 years, and then level off. Note that 2024 enrollments are slightly higher since these were the average number of customers enrolled during PY2024 events, and some de-enrollments have occurred since.

Table 5-2: SCE Summary of Ex ante Site Enrollments

Year	Large	Medium	Small	Total
2024	1,767	21,412	197,476	**220,655**
2025	1,575	19,087	196,001	**216,663**
2026	1,591	19,267	197,810	**218,668**
2027	1,608	19,445	199,618	**220,671**
2028	1,623	19,620	201,422	**222,665**
2029	1,635	19,796	203,236	**224,667**
2030	1,635	19,796	203,236	**224,667**
2031	1,635	19,796	203,236	**224,667**
2032	1,635	19,796	203,236	**224,667**
2033	1,635	19,796	203,236	**224,667**
2034	1,635	19,796	203,236	**224,667**

Table 5-3 summarizes the portfolio-adjusted reductions that SCE CPP rates can be expected to deliver ex ante under August peak conditions in an SCE 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2024. The estimates are instead a function of the percent impacts estimates in this (PY2024) and the previous (Py2023) evaluation. The results reflect reduction capability for a single event across SCE's CPP event window (4 to 9 p.m.).

Overall, Large sites can be expected to deliver an aggregate 2.4 to 2.5 MW per five-hour event in future years. The Medium and Small groups, despite large enrollments, are only expected to deliver 0.7 and 0.8 MW respectively. Combined, SCE's CPP rate customers would be expected to deliver 3.8 to 4.0 MW per event day from 2025-2034.

Table 5-3: Summary of Ex Ante Demand Reductions, August Worst Day, SCE 1-in-2 Weather (MW, Portfolio-Adjusted)

Year	Large	Medium	Small	Total
2024	2.7	0.7	0.8	**4.2**
2025	2.4	0.7	0.8	**3.8**
2026	2.4	0.7	0.8	**3.8**
2027	2.5	0.7	0.8	**3.9**
2028	2.5	0.7	0.8	**3.9**
2029	2.5	0.7	0.8	**4.0**
2030	2.5	0.7	0.8	**4.0**
2031	2.5	0.7	0.8	**4.0**
2032	2.5	0.7	0.8	**4.0**
2033	2.5	0.7	0.8	**4.0**
2034	2.5	0.7	0.8	**4.0**

5.2 EVENT CHARACTERISTICS

Table 5-4 shows the twelve PY2024 CPP event days and the SCE system peak load on each day. All twelve events ran from 4 p.m. to 9 p.m. and covered all sites on CPP rates. SCE optionally sends day-ahead notifications to customers to help in load shifting during the increased price periods. Notification data was not analyzed for differential performance on CPP event days for PY2024.

Event days covered a range of summer months and temperatures. All events were weekdays and none came after August, including no events in the September heat wave as emergency conditions were not reached.

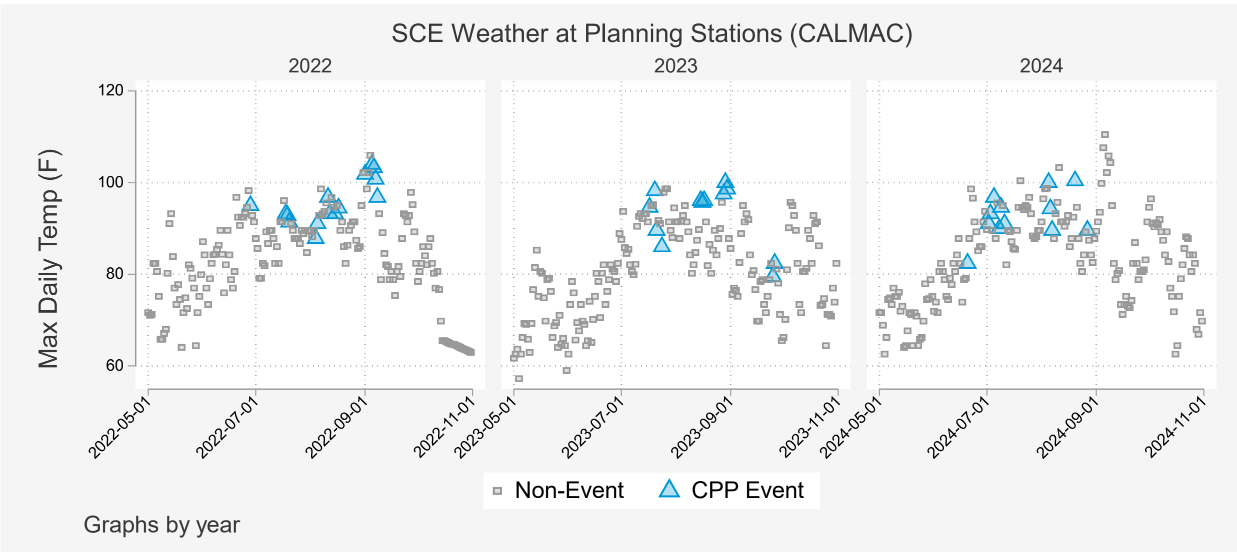
Table 5-4: SCE CPP Event Days for PY2024

Event date	Day of week	Max SCE system load (MW)	Event window	All groups
6/20/2024	Thursday	14,440	4 to 9 p.m.	✓
7/2/2024	Tuesday	18,226	4 to 9 p.m.	✓
7/3/2024	Wednesday	19,239	4 to 9 p.m.	✓
7/5/2024	Friday	19,699	4 to 9 p.m.	✓
7/8/2024	Monday	19,395	4 to 9 p.m.	✓
7/9/2024	Tuesday	20,159	4 to 9 p.m.	✓
7/11/2024	Thursday	19,516	4 to 9 p.m.	✓
8/5/2024	Monday	21,987	4 to 9 p.m.	✓
8/6/2024	Tuesday	21,257	4 to 9 p.m.	✓

8/7/2024	Wednesday	19,562	4 to 9 p.m.	✓
8/20/2024	Tuesday	20,723	4 to 9 p.m.	✓
8/27/2024	Tuesday	18,382	4 to 9 p.m.	✓

As shown in Figure 5-1, SCE's events were generally in line with those called in previous years, with twelve events called across a range of dates. There were several dates in September 2024 that were hotter on average than any in 2022-2023, but those dates were not CPP event days.

Figure 5-1: SCE Event Days and Temperature by Year



5.3 EX POST LOAD IMPACTS

5.3.1 Sites in Analysis

SCE had over 220,000 customers on CPP rates in 2024, including both agricultural and commercial customers. Sites were analyzed in subgroups based on size, as shown in Table 5-5 below. Most sites (roughly 197,000) were in the Small group (less than 20 kW peak demand). Due to the large number of sites in this group, a random sample was drawn by industry and climate, with just under 20,000 sites included in the actual analysis. All results are then weighted to reflect the full population of Small CPP customers. For example, SCE CPP had many small office sites in Climate Zone 8 near Los Angeles – only a subset of these were drawn into the random sample, but each small office in the sample carries large weight in the Small group's impact estimates.

Table 5-5 also shows any other differences between the full CPP enrollment counts and the number of sites used for the ex post analysis. "Total Sites" indicates the total number of sites enrolled for any

PY2024 event. In additional to the sampling for the Small group, several sites were dropped due to incomplete data, outages, or other data issues.

Table 5-5: SCE Participant Populations (Avg Weekday Event)

Group	Sector	Total sites	Sites in analysis*
Large	Commercial & Agricultural	1,769	1,741
Medium	Commercial & Agricultural	21,412	21,211
Small	Commercial & Agricultural	197,477	19,993
Total	**Commercial & Agricultural**	**220,658**	**42,945**

*Small group sites in analysis drawn randomly from customer population

Large electric generators on CPP rates such as solar farms were included in the analysis. However, only the delivered loads were analyzed for these sites. Power generators were determined via NAICS codes as well as other sites with greater than 500 kW daily exports.[9]

SCE's AutoDR customers were evaluated separately, but this group did not have any significant impacts in 2024. Enrollments in this group were also less than half of those shown in the 2023 report. AutoDR customers provided a significant reduction in the 2023 results, so customer turnover may drive the lack of impacts estimated.

5.3.2 Impacts by Event – SCE Large

SCE had almost 1,800 Large CPP customers in PY2024. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 5-6 summarizes the load reductions and customer-weighted event temperatures for Large sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall the Large group had modest load reductions in 2024, averaging 0.9% (3.2 MW) less electric usage during event hours. However, considerable variance in these sites' performance and the small magnitude of performance relative to variation inherent in the loads rendered the point estimates statistically insignificant for both the average 2024 event as well as most individual events.

Only one event with a larger impact estimate (7/5) was statistically significant at the 10% level, meaning the estimated 90% confidence interval did not include zero. However most other events essentially had zero estimated impact, with small, statistically insignificant load reductions.

[9] Power generators defined as sites with five-digit NAICS codes of 22111 – Electric Power Generation.

Table 5-6: Ex Post Impact Estimates by Event – SCE Large

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
6/20/2024	4 to 9 pm	78.4	1,769	4.1	1.1%	2.3	No	No
7/2/2024	4 to 9 pm	84.8	1,769	3.7	1.0%	2.1	No	No
7/3/2024	4 to 9 pm	86.2	1,769	1.6	0.4%	0.9	No	No
7/5/2024	4 to 9 pm	88.8	1,769	14.0	4.2%	7.9	Yes	No
7/8/2024	4 to 9 pm	85.3	1,769	5.1	1.4%	2.9	No	No
7/9/2024	4 to 9 pm	87.1	1,769	8.8	2.3%	5.0	No	No
7/11/2024	4 to 9 pm	87.0	1,769	2.1	0.6%	1.2	No	No
8/5/2024	4 to 9 pm	91.4	1,769	1.4	0.4%	0.8	No	No
8/6/2024	4 to 9 pm	87.5	1,769	1.5	0.4%	0.8	No	No
8/7/2024	4 to 9 pm	82.9	1,769	-1.4	-0.4%	-0.8	No	No
8/20/2024	4 to 9 pm	90.9	1,769	-3.8	-1.0%	-2.1	No	No
8/27/2024	4 to 9 pm	83.3	1,769	2.6	0.7%	1.5	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**86.2**	**1,769**	**3.2**	**0.9%**	**1.8**	**No**	**No**

Impacts were also estimated for several subsegments of each group and included in the SCE Ex Post table generators. As many of these were insignificant or inconsistent (e.g. varying impacts by Industry across the Small, Medium, and Large groups), they should be interpreted with caution.

One group with large impacts in 2024, however, were the power generating sites. These sites often have negative net loads, so only their delivered loads were included in the analysis. While many had no load during event hours, the sites with positive delivered loads significantly reduced their usage.

5.3.3 Impacts by Event – SCE Medium

SCE had over 21,000 Medium CPP customers in PY2024. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. summarizes. Table 5-7 shows the load reductions and customer-weighted event temperatures for Medium sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall the Medium group had very small load reductions during 2024 events, averaging 0.1% (0.5 MW) load reductions. With the small magnitude of performance relative to variation inherent in the loads, these reductions cannot be distinguished from zero. With varying levels of statistical significance, most individual events had impacts close to zero as well.

Table 5-7: Ex Post Impact Estimates by Event – SCE Medium

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
6/20/2024	4 to 9 pm	78.1	21,412	-0.9	-0.2%	0.0	No	No
7/2/2024	4 to 9 pm	84.2	21,412	0.3	0.1%	0.0	No	No
7/3/2024	4 to 9 pm	85.6	21,412	2.5	0.5%	0.1	Yes	Yes
7/5/2024	4 to 9 pm	88.1	21,412	4.4	0.9%	0.2	Yes	Yes
7/8/2024	4 to 9 pm	84.6	21,412	-0.8	-0.1%	0.0	No	No
7/9/2024	4 to 9 pm	86.4	21,412	-0.3	-0.1%	0.0	No	No
7/11/2024	4 to 9 pm	86.3	21,412	0.7	0.1%	0.0	No	No
8/5/2024	4 to 9 pm	90.9	21,412	-4.0	-0.7%	-0.2	Yes	Yes
8/6/2024	4 to 9 pm	86.8	21,412	1.4	0.3%	0.1	Yes	No
8/7/2024	4 to 9 pm	82.2	21,412	4.1	0.8%	0.2	Yes	Yes
8/20/2024	4 to 9 pm	90.6	21,412	-1.1	-0.2%	-0.1	No	No
8/27/2024	4 to 9 pm	82.8	21,412	-0.4	-0.1%	0.0	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**85.6**	**21,412**	**0.5**	**0.1%**	**0.0**	**No**	**No**

5.3.4 Impacts by Event – SCE Small

SCE had over 197,000 Small CPP customers in PY2024. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 5-8 summarizes the load reductions and customer-weighted event temperatures for Small sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall, the Small group had no discernible load reductions in 2024, averaging 0.0% (0.1 MW per hour) less electric usage during event hours. With the very small magnitude of this estimate, it was also statistically insignificant. Point estimates were statistically insignificant for most individual events, however.

Two events with larger impact estimates (7/8 and 7/11) were statistically significant at the 10% level, meaning the estimated 90% confidence interval did not include zero. However most other events essentially had zero estimated impact, with small, statistically insignificant load reductions.

Table 5-8: Ex Post Impact Estimates by Event – SCE Small

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
6/20/2024	4 to 9 pm	77.6	197,477	-0.3	-0.1%	0.0	No	No
7/2/2024	4 to 9 pm	83.6	197,477	-1.7	-0.7%	0.0	No	No
7/3/2024	4 to 9 pm	85.0	197,477	0.6	0.2%	0.0	No	No
7/5/2024	4 to 9 pm	87.3	197,477	-1.1	-0.4%	0.0	No	No
7/8/2024	4 to 9 pm	84.0	197,477	2.3	0.9%	0.0	Yes	No
7/9/2024	4 to 9 pm	85.7	197,477	0.7	0.2%	0.0	No	No
7/11/2024	4 to 9 pm	85.7	197,477	2.4	0.9%	0.0	Yes	No
8/5/2024	4 to 9 pm	90.2	197,477	1.9	0.7%	0.0	No	No
8/6/2024	4 to 9 pm	86.0	197,477	-2.0	-0.7%	0.0	No	No
8/7/2024	4 to 9 pm	81.6	197,477	-0.8	-0.3%	0.0	No	No
8/20/2024	4 to 9 pm	90.1	197,477	-1.1	-0.4%	0.0	No	No
8/27/2024	4 to 9 pm	82.2	197,477	0.1	0.1%	0.0	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**84.9**	**197,477**	**0.1**	**0.0%**	**0.0**	**No**	**No**

5.4 EX ANTE LOAD IMPACTS

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) peak demand weather conditions for both CAISO and the SCE system.

In general, ex ante forecasts rely on the estimated ex post impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2024, ex ante modeling incorporated both PY2023 and PY2024 ex post impact estimates, but it did not include any differential impacts based on weather or the event hour.

5.4.1 EX ANTE MODEL INPUTS

For PY2024, the key inputs for ex ante impact model are:

- PY2023 ex post impact estimates
- PY2024 ex post impact estimates
- 1-in-2 system weather data for both the CAISO and SCE
- CPP enrollment forecast through 2034

The following factors were also considered, but ultimately were not included in the ex ante model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the ex ante model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

PY 2024 Impact Estimates

Significant ex post impacts estimates by event, hour, and rate class are the primary input. Any individual estimates on these same margins that are statistically insignificant are set to zero in the ex ante analysis to prevent projecting noise forward. Note that even if group-level or program-level ex post estimates are insignificant, there may be underlying events, hours, and rate class combinations where significant impacts were seen, and these are included individually in the model.

Historical Impact Estimates

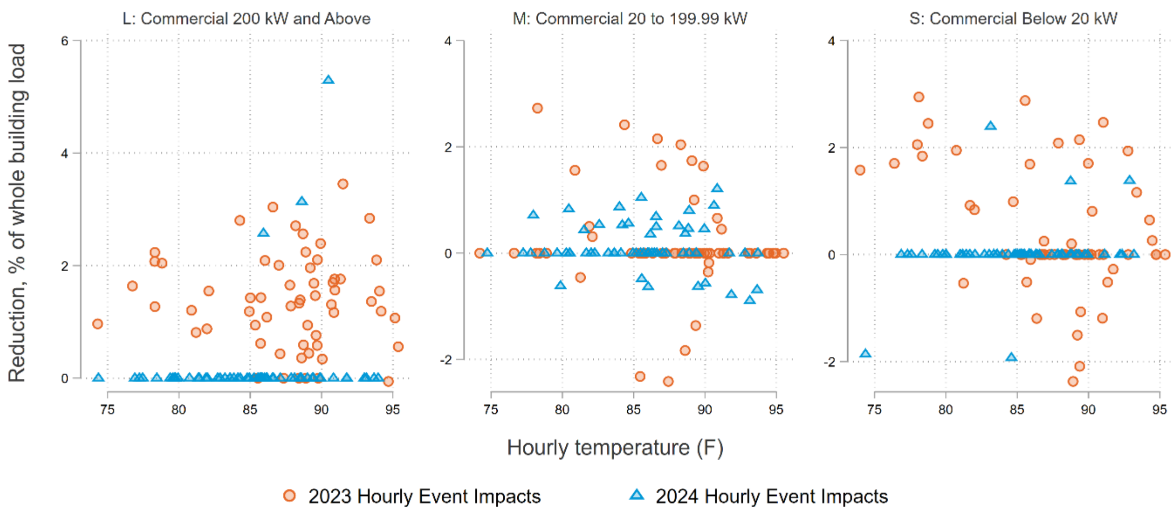
PY2023 ex post impacts were included, along with the current year ex post estimates, in the ex ante model. For PY2024, SCE's CPP groups had statistically insignificant impacts on most event days. This could imply that CPP truly has little impact on these sites, or that there is a great deal of noise in the 2024 outcomes as various businesses chose their loads for reasons besides CPP pricing. As such, the PY2023 percent impacts were included to add more data points to the model. Since the 2023 estimates provided a large number of additional data points, we did not include impact estimates from PY2022 in the ex ante modelling.

Statewide evaluations in previous years have also been performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 impacts can therefore aid in creating greater consistency in the study outputs.

Weather Impacts

Figure 5-2 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2024 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling – significant impacts are shown as-is, while statistically insignificant impacts are set to zero. Note that individual hour or event impacts can be statistically significant in groups that were not significant as a whole. Noise from a small group or single event's estimates should not be projected forward for system planning, so they are assumed to be zero.

Figure 5-2: SCE Hourly Reductions vs. Average Temperatures

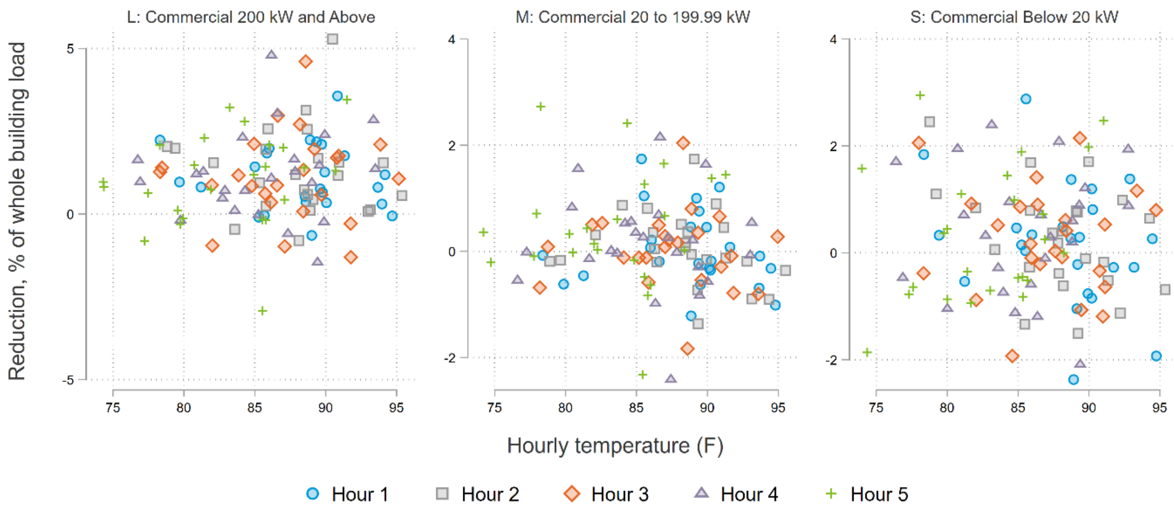


Focusing on the significant impacts (plotted away from zero), there is no clear trend in the percent impacts as temperature increases along the horizontal axes. In some previous years, a negative temperature gradient (higher impacts for event days with lower temperatures) has been applied to SCE's Small group, but this trend is not evident in the 2024 results, nor was it observed in the other two groups or in the other two IOUs more generally. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

Event Hour Impacts

Figure 5-3 plots the 2024 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 5-3: SCE Impacts by Event Hour and Temperature



Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 5-9 summarizes the annual enrollment forecast for each subgroup through 2034.

Table 5-9: SCE Participant Enrollment Forecast

Year	Large	Medium	Small	Total
2024	1,767	21,412	197,476	**220,655**
2025	1,575	19,087	196,001	**216,663**
2026	1,591	19,267	197,810	**218,668**
2027	1,608	19,445	199,618	**220,671**
2028	1,623	19,620	201,422	**222,665**
2029	1,635	19,796	203,236	**224,667**
2030	1,635	19,796	203,236	**224,667**
2031	1,635	19,796	203,236	**224,667**
2032	1,635	19,796	203,236	**224,667**
2033	1,635	19,796	203,236	**224,667**
2034	1,635	19,796	203,236	**224,667**

SCE developed the CPP enrollment forecast that was used to scale the ex ante impacts. After accounting for some de-enrollments in late 2024, the forecasts anticipate moderate growth in CPP participation through 2030, with no growth beyond that point. This is based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

5.4.2 Ex Ante Load Impacts – SCE Large

Table 5-10 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE's Large CPP customers under different planning conditions. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Large customers' estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE's enrollment forecast anticipate slight growth in Large CPP customers year-over-year through 2030, at which point enrollments level off through 2034. Aggregate ex ante impacts for the Large group thus follow a similar trend, increasing slightly through 2030, then remaining constant through 2034. Thus the combined ex ante impacts increase slightly from roughly 2.4 MW in 2025 to 2.5 MW by 2030.

Table 5-10: SCE Large Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio-Adj.	Program	Portfolio-Adj.
1-in-2	2024	1,767	2.65	2.65	2.70	2.70
1-in-2	2025	1,575	2.36	2.36	2.40	2.40
1-in-2	2026	1,591	2.38	2.38	2.42	2.42
1-in-2	2027	1,608	2.41	2.41	2.45	2.45
1-in-2	2028	1,623	2.43	2.43	2.47	2.47
1-in-2	2029	1,635	2.45	2.45	2.49	2.49
1-in-2	2030	1,635	2.45	2.45	2.49	2.49
1-in-2	2031	1,635	2.45	2.45	2.49	2.49
1-in-2	2032	1,635	2.45	2.45	2.49	2.49
1-in-2	2033	1,635	2.45	2.45	2.49	2.49
1-in-2	2034	1,635	2.45	2.45	2.49	2.49

5.4.3 Ex Ante Load Impacts – SCE Medium

Table 5-11 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE's Medium CPP customers under different planning conditions. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Medium customers' estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE's enrollment forecast anticipates slight growth in Medium CPP customers year-over-year through 2030, at which point enrollments level off through 2034. Aggregate ex ante impacts for the Medium group thus follow a similar trend, increasing slightly through 2030, then remaining constant through 2034. This accounts for the slight increase in impacts from 0.64 to 0.66 MW in 2025 to 0.66 to 0.68 MW in 2030.

Table 5-11: SCE Medium Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	21,412	0.71	0.71	0.74	0.74
1-in-2	2025	19,087	0.64	0.64	0.66	0.66
1-in-2	2026	19,267	0.64	0.64	0.66	0.66
1-in-2	2027	19,445	0.65	0.65	0.67	0.67
1-in-2	2028	19,620	0.65	0.65	0.67	0.67
1-in-2	2029	19,796	0.66	0.66	0.68	0.68
1-in-2	2030	19,796	0.66	0.66	0.68	0.68
1-in-2	2031	19,796	0.66	0.66	0.68	0.68
1-in-2	2032	19,796	0.66	0.66	0.68	0.68
1-in-2	2033	19,796	0.66	0.66	0.68	0.68
1-in-2	2034	19,796	0.66	0.66	0.68	0.68

5.4.4 Ex Ante Load Impacts – SCE Small

Table 5-12 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE's Small CPP customers under different planning conditions. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Small customers' estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE's enrollment forecast anticipate slight growth in Small CPP customers year-over-year through 2030, at which point enrollments level off through 2034. Aggregate ex ante impacts for the Small group thus follow a similar trend, increasing slightly through 2030, then remaining constant through 2034. The increased enrollments lead to slight increase in impacts from 0.74 to 0.75 MW per event hour in 2025 to 0.76 to 0.78 MW by 2030.

Table 5-12: SCE Small Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	197,476	0.75	0.75	0.77	0.77
1-in-2	2025	196,001	0.74	0.74	0.75	0.75
1-in-2	2026	197,810	0.74	0.74	0.76	0.76
1-in-2	2027	199,618	0.75	0.75	0.77	0.77
1-in-2	2028	201,422	0.76	0.76	0.77	0.77
1-in-2	2029	203,236	0.76	0.76	0.78	0.78
1-in-2	2030	203,236	0.76	0.76	0.78	0.78
1-in-2	2031	203,236	0.76	0.76	0.78	0.78
1-in-2	2032	203,236	0.76	0.76	0.78	0.78
1-in-2	2033	203,236	0.76	0.76	0.78	0.78
1-in-2	2034	203,236	0.76	0.76	0.78	0.78

5.4.5 COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For SCE's Large CPP group, Table 5-13 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Large CPP site delivered 0.7% in statistically significant load reductions (2.62 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.7%. Differences in ex ante and ex post counterfactual loads ("Load without DR" in the table) are largely explained by the change in the enrollment population from PY2024 ex post enrollment as compared to PY2024 ex ante. Specifically, though there were more customers in PY2024, a few very large PY2023 customers did not participate in PY2024. The SCE and CAISO weather ex ante predictions are slightly different because ex ante reference increase for hotter temperatures. Percent impacts are equal across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 5-13: SCE Large Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	396.04	2.62	0.7%	86.9
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	226.52	1.50	0.7%	87.7
Ex Ante (SCE)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	230.27	1.53	0.7%	90.0

For SCE's Medium CPP group, Table 5-14 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Medium CPP site delivered 0.1% in statistically significant load reductions (0.03 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were 0.1% as well.

Table 5-14: SCE Medium Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	25.05	0.03	0.1%	86.6
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	25.78	0.03	0.1%	87.3
Ex Ante (SCE)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	26.55	0.03	0.1%	89.6

For SCE's Small CPP group, Table 5-15 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 p.m. to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Small CPP site delivered 0.3% in statistically significant load reductions (0.004 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were a similar 0.3%.

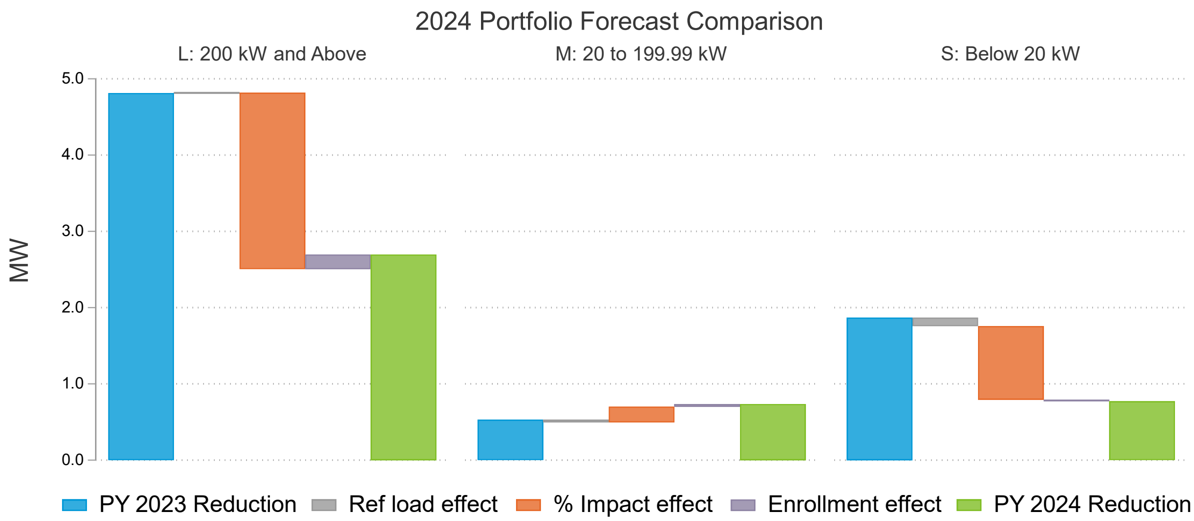
Table 5-15: SCE Small Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	1.36	0.004	0.3%	86.2
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	1.42	0.004	0.3%	86.7
Ex Ante (SCE)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	1.46	0.004	0.3%	89.1

5.4.6 COMPARISON TO 2023 EX ANTE IMPACT ESTIMATES

The ex ante impact estimates in this study are significantly reduced from the previous evaluation, largely due to decreased impacts from the Large sites. The following figure gives a breakdown of the difference in ex ante impact estimates from PY2023 and those generated in in PY2024. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2023 (in blue) and PY2024 (in green).

Figure 5-4: Waterfall Analysis of 2023-2024 SCE Ex Ante Impacts by Group



The Large group's reference load during event hours is similar to 2023, with enrollments increased slightly. The reduced projection results instead from the lower percent impacts estimated in PY2024. The Medium group is fairly similar in term of all three factors, with slightly higher impact estimates leading to slightly larger ex ante impacts. The Small group did not see significant changes in either the reference load or forecasted enrollments, with the reduced estimate again resulting from the lower percent impacts estimated in PY2024.

5.4.7 Ex Ante Load Impact Slice-of-Day Tables

The following tables show the 2024 ex ante aggregate hourly impacts by CPP group for each month under SCE 1-in-2 monthly peaking conditions. CPP tariffs only allow for dispatch from 4 p.m. to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table 5-16: SCE Large Slice of Day Table for Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2.29	2.28	2.29	2.65	2.64	2.89	2.94	2.98	3.04	2.85	2.62	2.29
18	2.20	2.20	2.20	2.53	2.52	2.75	2.80	2.83	2.89	2.72	2.51	2.20
19	2.12	2.11	2.11	2.40	2.39	2.58	2.63	2.65	2.69	2.54	2.37	2.11
20	2.09	2.08	2.09	2.33	2.33	2.50	2.53	2.56	2.59	2.45	2.30	2.08
21	2.04	2.04	2.04	2.27	2.27	2.42	2.46	2.48	2.50	2.38	2.24	2.04
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 5-17: SCE Medium Slice of Day Table for Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.55	0.54	0.54	0.72	0.72	0.84	0.86	0.88	0.91	0.82	0.71	0.54
18	0.50	0.50	0.50	0.66	0.66	0.76	0.79	0.80	0.83	0.75	0.65	0.50
19	0.46	0.46	0.46	0.60	0.60	0.69	0.71	0.72	0.74	0.67	0.58	0.46
20	0.44	0.44	0.44	0.56	0.56	0.63	0.65	0.66	0.68	0.62	0.54	0.44
21	0.42	0.42	0.42	0.52	0.52	0.59	0.60	0.61	0.62	0.57	0.51	0.42
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 5-18: SCE Small Slice of Day Table for Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.53	0.52	0.52	0.78	0.78	0.94	0.98	1.00	1.04	0.90	0.75	0.52
18	0.47	0.46	0.46	0.67	0.67	0.80	0.83	0.85	0.87	0.77	0.64	0.46
19	0.42	0.42	0.42	0.58	0.58	0.69	0.71	0.73	0.74	0.66	0.56	0.42
20	0.42	0.42	0.42	0.55	0.55	0.63	0.65	0.66	0.67	0.61	0.53	0.42
21	0.43	0.43	0.43	0.53	0.53	0.59	0.61	0.62	0.62	0.57	0.51	0.43
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

6 SDG&E PY2024 IMPACTS

SDG&E's Large and Medium CPP customers were evaluated for this study, while the Small CPP customers' analysis is reported separately. The Large and Medium groups are further broken down by rate class (Agricultural and Commercial). In total these groups make up over 2,220 CPP customers, with most customers falling in the Medium Commercial (2,027) and Large Commercial (228) groups.

SDG&E had three events in PY2024. All were called under extreme conditions during a September heat wave in Southern California, with customers drawing their largest loads of the summer.

6.1 SUMMARY OF RESULTS

Table 6-1 summarizes the estimated ex post demand reductions for the average weekday event for SDG&E's Large and Medium groups. All impacts are incremental to other DR program impacts and statistical significance is noted for each subgroup. These groups showed no load reductions during the three PY2024 events, all of which came under extreme conditions.[10]

Many of SDG&E's CPP customers also pay a monthly subscription for capacity reservations, which shield all or part of their loads from CPP event pricing. This evaluation found that customers in the Large Commercial, Medium Commercial, and Medium Agriculture groups reserved large shares of their loads and thus had some insurance against price increases on event days.[11]

[10] Estimated impacts were likely reduced by at least one site with large impacts in previous years that did not receive event notifications by text message in 2024. SDG&E is investigating the cause and extent of this notification issue.

[11] Customers have the option to select a capacity level (in kW) that is reserved from the CPPD Event Day Adder applicable during a CPP Event. Usage during a CPP Event that is protected under the customer's capacity reservation is billed the corresponding energy charges for the time period but not the CPP Event Day Adder. All usage during a CPP Event that is not protected under the customer's capacity reservation is billed at the CPP Event Day Adder and the corresponding energy charges for the time period.

Table 6-1: SDG&E Ex Post Demand Reductions for an Average Weekday Event

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Agricultural - Large (200 kW and Above)	[redacted]					
Agricultural - Medium (20 to 199.99 kW)	[redacted]					
Commercial - Large (200 kW and Above)	236	54.61	-1.15	-2.1%	No	No
Commercial - Medium (20 to 199.99 kW)	2,032	56.31	-0.02	0.0%	No	No

Table 1-2 summarizes forecasted site enrollments by subgroup. Enrollments are anticipated to grow slowly year to year through 2034 for each group.

Table 6-2: SDG&E Summary of Ex ante Site Enrollments

Year	Large Agriculture	Medium Agriculture	Large Commercial	Medium Commercial
2024	[redacted]		234	2,005
2025	[redacted]		256	2,218
2026	[redacted]		258	2,233
2027	[redacted]		260	2,256
2028	[redacted]		263	2,287
2029	[redacted]		268	2,323
2030	[redacted]		273	2,370
2031	[redacted]		279	2,435
2032	[redacted]		289	2,520
2033	[redacted]		303	2,639
2034	[redacted]	16	324	2,808

Table 6-3 summarizes the portfolio-adjusted, reductions that SDG&E's Medium and Large customers can be expected to deliver *ex ante* under August worst day conditions in an SDG&E 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2024. The estimates are instead a function of the percent impacts estimates in this (PY2024) and the previous (Py2023) evaluation. The results reflect reduction capability for a single event across SDG&E's CPP event window (4 to 9 p.m.).

Overall, Large Commercial sites can be expected to deliver an aggregate 0.6 to 0.8 MW per event hour in future years. Medium Commercial sites are expected to provide an additional 0.2 to 0.3 MW, while the agricultural groups are not expected to add any meaningful reductions. Combined, SDG&E's

Medium and Large CPP customers are expected to deliver 0.8 to 1.1 MW per event hour from 2025-2034.

Table 6-3: SDG&E Summary of Ex Ante Demand Reductions, August 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Year	Large Agriculture	Medium Agriculture	Large Commercial	Medium Commercial	Total
2024	[redacted]	[redacted]	0.6	0.2	**0.8**
2025	[redacted]	[redacted]	0.6	0.2	**0.8**
2026	[redacted]	[redacted]	0.6	0.2	**0.9**
2027	[redacted]	[redacted]	0.7	0.2	**0.9**
2028	[redacted]	[redacted]	0.7	0.2	**0.9**
2029	[redacted]	[redacted]	0.7	0.2	**0.9**
2030	[redacted]	[redacted]	0.7	0.2	**0.9**
2031	[redacted]	[redacted]	0.7	0.2	**0.9**
2032	[redacted]	[redacted]	0.7	0.3	**1.0**
2033	[redacted]	[redacted]	0.8	0.3	**1.0**
2034	[redacted]	0.0	0.8	0.3	**1.1**

6.2 EVENT CHARACTERISTICS

Table 6-4 lists the three PY2024 CPP event days and the SDG&E system peak load on each day. All three events ran from 4 to 9 p.m. and covered all sites on CPP rates.[12] SDG&E optionally sends day-ahead notifications to customers to help in load shifting during the increased price periods. Notification data was analyzed for differential performance on CPP event days for PY2024.

SDG&E's events came on three consecutive weekdays (with a weekend in between) during a September heat wave. These event days all came under extreme conditions – these were the hottest weekdays by temperature and had the largest system loads of summer 2024. SDG&E's system peak demand came on Sunday Sept. 8th.

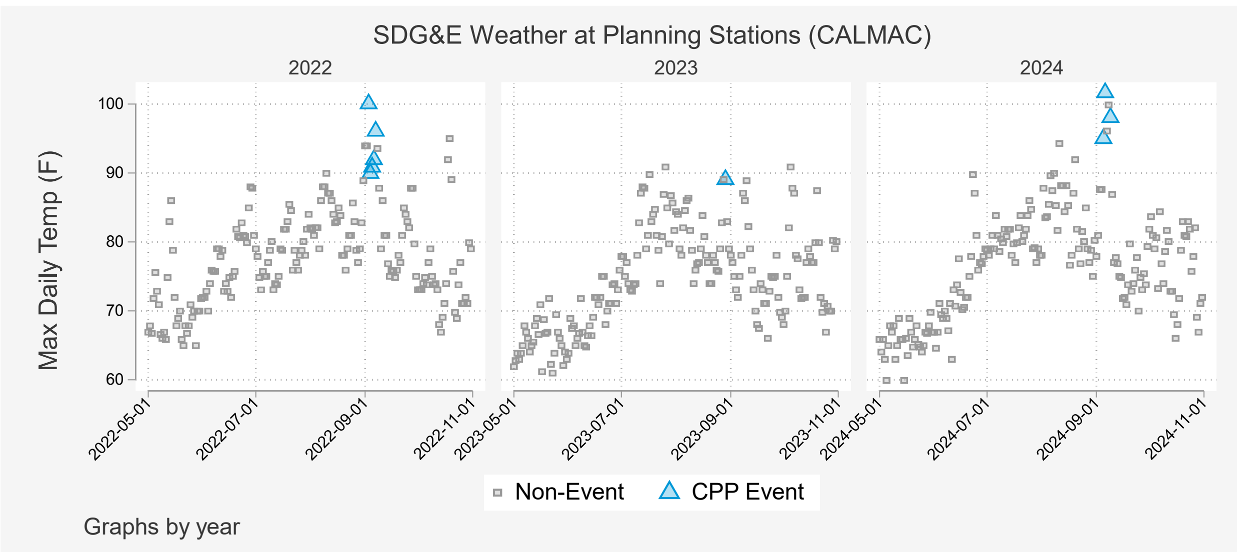
[12] A CPP Event may be triggered if the day-ahead system load forecast for the potential event day is greater than 4,000 MW. Events may also be triggered in response to high forecasted temperatures, extreme conditions, and emergencies. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule

Table 6-4: SDG&E CPP Events in 2024

Event date	Day of week	Max SDG&E system load (MW)	Event window	All groups
9/5/2024	Thursday	4,633	4 to 9 p.m.	✓
9/6/2024	Friday	4,381	4 to 9 p.m.	✓
9/9/2024	Monday	4,698	4 to 9 p.m.	✓

As shown in Figure 6-1, SDG&E's events were in line with those called in previous years, when fewer events on extreme load days were also called.

Figure 6-1: SDG&E Event Days and Temperature by Year



6.3 EX POST LOAD IMPACTS

6.3.1 SITES IN ANALYSIS

SDG&E had over 2,200 Large and Medium customers on CPP rates in 2024, including both agricultural and commercial customers. Sites were analyzed in subgroups based on size, as shown in Table 6-5 below. No samples were drawn for these groups, so nearly all sites were included in the analysis. Only a handful of sites in the Medium Commercial group were dropped from the analysis due to incomplete data.

Table 6-5: SDG&E Site Enrollments by Size

Group	Sector	Total sites	Sites in analysis*
Large Ag.	Agricultural	[redacted]	[redacted]
Medium Comm.	Agricultural	[redacted]	[redacted]
Large Ag.	Commercial	236	236
Medium Comm.	Commercial	2,032	2,025

Large electric generators on CPP rates such as solar farms were included in the analysis. However, only the delivered loads were analyzed for these sites. Power generators were determined either via NAICS codes for electric generation or load data that showed greater than 500 kW exports during daytime hours.[13]

6.3.2 Impacts by Event - SDG&E Large

For PY2024, SDG&E had an average of 236 Large Commercial customers (200 kW max demand and above) across its three summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 6-6 summarizes Large Commercial sites' load reductions and customer-weighted event temperatures during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that listed to the left of each.

Large Commercial sites had essentially zero estimated impact for the three PY2024 event days, as none of the impacts were statistically significant. Estimated impacts were likely reduced by at least one site with large impacts in previous years that did not receive event notifications by text message in 2024. SDG&E is investigating the cause and extent of this notification issue. These impacts also reflect only the performance of these sites during a single week (Thursday, Friday, and Monday) in September during a heat wave, so it may not indicate these sites' ability to perform in future events. Note also that part of these sites' loads were withheld from CPP event pricing via capacity reservations.

Table 6-6: Ex Post Impact Estimates by Event - SDG&E Large Commercial

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
9/5/2024	4 to 9 pm	85.9	236	-0.9	-1.7%	-3.9	No	No
9/6/2024	4 to 9 pm	81.3	236	-0.6	-1.1%	-2.5	No	No
9/9/2024	4 to 9 pm	84.9	237	-2.0	-3.7%	-8.5	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**84.0**	**236**	**-1.2**	**-2.1%**	**-4.9**	**No**	**No**

[13] Power generators defined as sites with five-digit NAICS codes of 22111 – Electric Power Generation

For PY2024, SDG&E had [redacted] Large Agricultural customers, with load reductions summarized in Table 6-7. This group had loads that were already optimized for TOU rates, with very little load during peak hours. As a result, there was little load left to curtail on CPP event days, hence the zero impacts shown in the table (statistically insignificant).

Table 6-7: Ex Post Impact Estimate by Event – SDG&E Large Agriculture

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
9/5/2024	4 to 9 pm	[redacted]						
9/6/2024	4 to 9 pm	[redacted]						
9/9/2024	4 to 9 pm	[redacted]						
Avg Weekday 4-9 pm	**4 to 9 pm**	[redacted]						

Impacts were also estimated for several subsegments of each group and included in the SDG&E Ex Post table generators. As many of these were insignificant or inconsistent (e.g. varying impacts by Industry across the Small, Medium, and Large groups), they should be interpreted with caution.

6.3.3 Impacts by Event – SDG&E Medium

For PY2024, SDG&E had an average of 2,032 Medium Commercial customers (20 to 199.99 kW max demand) across its nine summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 6-8 summarizes the load reductions and customer-weighted event temperatures for CPP In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 6-8: Ex Post Impact Estimates by Event – SDG&E Medium Commercial

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
9/5/2024	4 to 9 pm	86.4	2,031	-0.4	-0.7%	-0.2	No	No
9/6/2024	4 to 9 pm	81.6	2,032	0.0	0.0%	0.0	No	No
9/9/2024	4 to 9 pm	85.2	2,033	0.4	0.6%	0.2	No	No
Avg Weekday 4-9 pm	**4 to 9 pm**	**84.4**	**2,032**	**0.0**	**0.0%**	**0.0**	**No**	**No**

These sites had zero load reduction for the three PY2024 events. However, as detailed in Section 6.3.4, a majority of the Medium Commercial sites' loads were withheld from CPP event pricing via capacity reservations.

For PY2024, SDG&E had [redacted] Medium Agricultural customers, with load reductions summarized in Table 6-9. These sites had zero load reduction for PY2024.

Table 6-9: Ex Post Impact Estimates by Event – SDG&E Medium Agriculture

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)				
				Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
9/5/2024	4 to 9 pm	[redacted]						
9/6/2024	4 to 9 pm	[redacted]						
9/9/2024	4 to 9 pm	[redacted]						
Avg Weekday 4-9 pm	**4 to 9 pm**	[redacted]						

6.3.4 Capacity Reservations and Event Loads

SDG&E allows CPP customers to designate loads that are protected from CPP pricing by subscription, with varying monthly subscription prices per kW by rate plan. This provides customers with insurance against event-day price adders for the part of their loads that is inflexible.

Table 6-10 shows sites' average reference loads during PY2024 event hours compared with the average capacity reservations (in kW). The net loads that faced CPP adders are then shown in the final column, with values greatly reduced from the reference loads reported here and used elsewhere in this report. Note that some sites reserved an even greater capacity that they reached on event days, so the final column is not a simple difference between columns two and three.

Table 6-10: SDG&E Capacity Reservations and CPP Event Loads by Group

Group	Avg. Reference Load during Event Hours (kW)	Avg. Capacity Reservation (kW)	Net Load Facing CPP Event-Day Adder
Large Agricultural	[redacted]		
Medium Agricultural	[redacted]		
Large Commercial	236.3	124.9	**141.8**
Medium Commercial	27.7	19.2	**11.4**

These results imply that both the Large Commercial and Medium Commercial groups have substantial loads that are reserved from CPP event-day adders, which may attenuate the results in this study. Reserved loads could substantially explain the lack of estimated impacts for these groups in 2024, especially for the Large and Medium Commercial groups that had the largest loads to potentially reduce. SDG&E customers have reserved capacities in previous years, however, so this may not explain year-to-year variations in impact estimates.

6.4 EX ANTE LOAD IMPACTS

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) worst day demand weather conditions for both CAISO and the SDG&E system.

In general, ex ante forecasts rely on the estimated ex post impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2024, ex ante modeling incorporated both PY2023 and PY2024 ex post impact estimates, but it did not include any differential impacts based on weather or the event hour. The included ex post impact estimates for both PY2023 and PY2024 are significant impacts (in percentage terms) by group and event day. Insignificant ex post estimates are also included but set to zero to prevent projecting noise into future years' estimates.

6.4.1 Ex Ante Model Inputs

For PY2024, the key inputs for ex ante impact model are:

- PY2023 ex post impact estimates (percent impacts)
- PY2024 ex post impact estimates (percent impacts)
- 1-in-2 system weather data for both CAISO and SDG&E
- CPP enrollment forecast through 2034

The following factors were also considered, but ultimately were not included in the ex ante model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the ex ante model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

PY 2024 Impact Estimates

Significant ex post impacts estimates by event, hour, and rate class are the primary input. Any individual estimates on these same margins that are statistically insignificant are set to zero in the ex ante analysis to prevent projecting noise forward. Note that even if group-level or program-level ex post estimates are insignificant, there may be underlying events, hours, and rate class combinations where significant impacts were seen, and these are included individually in the model.

Historical Impact Estimates

PY2023 ex post impacts were included, along with the current year ex post estimates, in the ex ante model. PY2024 impacts were not statistically significant for any of SDG&E's Large or Medium CPP groups. This outcome does not require the inclusion of historical impact estimates, but the low number of event days (three) likely impacted the variance in the overall estimates. As such, the PY2023 percent impacts were included to add more data to the model.

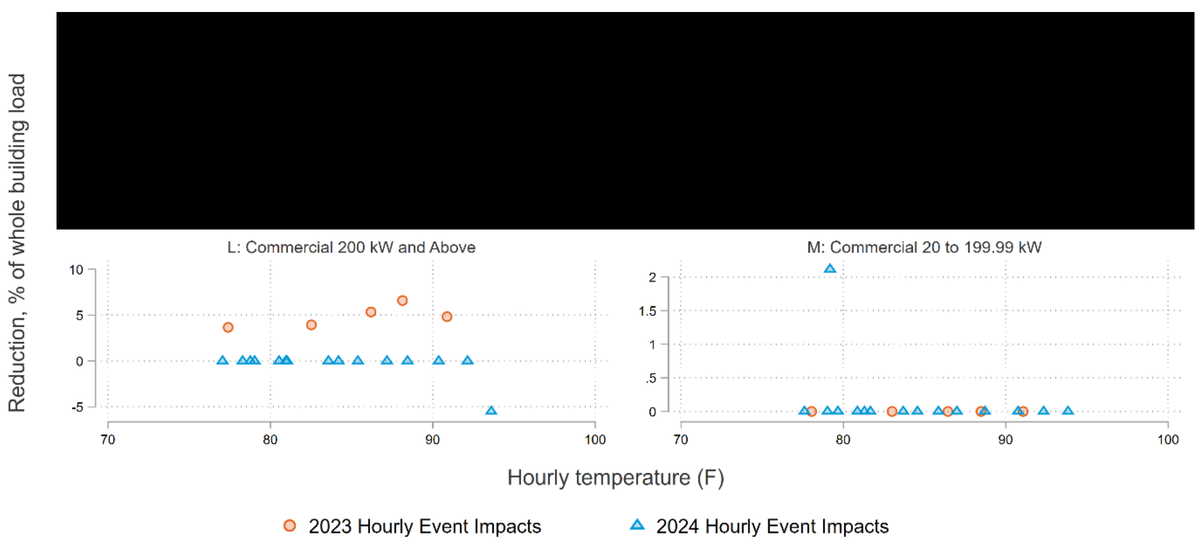
Impact estimates from PY2022 were not included since the number of customers has changed dramatically since that year: current CPP enrollments are less than 50% of what they were in the summer of 2022. These large decreases (due to the CCA expansion) likely affected not only the number of customers but also the composition of the customer pool. As such, the 2022 results would be less applicable to the customer populations that SDG&E can expect going forward.

Statewide evaluations in previous years have also been performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 impacts can therefore aid in creating greater consistency in the study outputs.

Weather Impacts

Figure 6-2 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2024 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling – significant impacts are shown as-is, while statistically insignificant impacts are set to zero. Note that individual hour or event impacts can be statistically significant in groups that were not significant as a whole. Noise from a small group or single event's estimates should not be projected forward for system planning, so they are assumed to be zero.

Figure 6-2: SDG&E Medium & Large Hourly Reductions vs. Average Temperatures

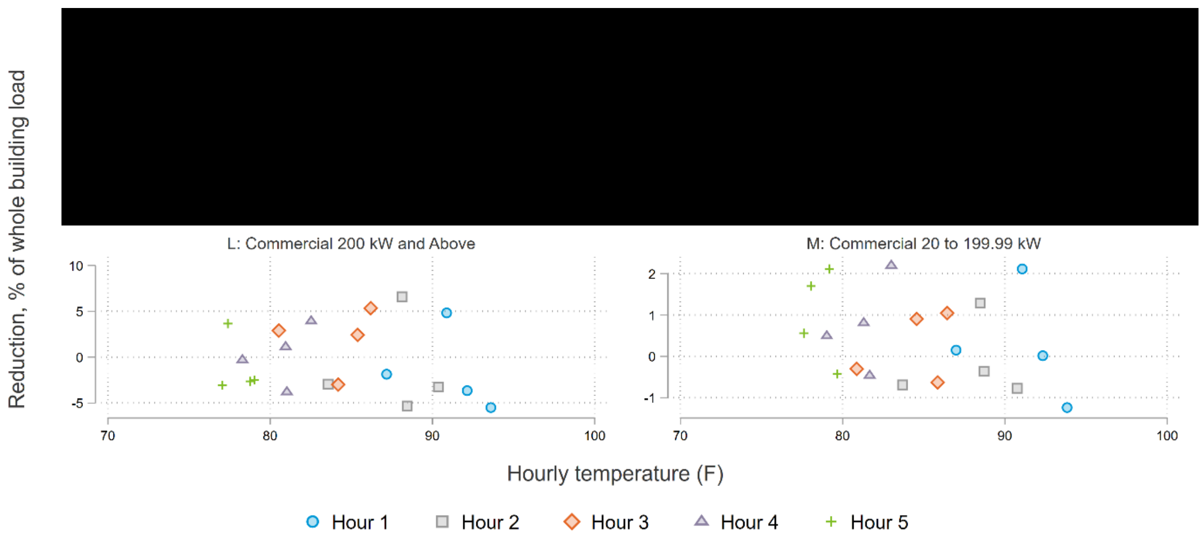


Focusing on the significant impacts (plotted away from zero), there is no clear trend in the percent impacts as temperature increases along the horizontal axes. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

Event Hour Impacts

Figure 6-3 plots the 2024 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 6-3: SDG&E Medium & Large Impacts by Event Hour and Temperature



Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 6-11 summarizes the annual enrollments forecast for each subgroup through 2034.

Table 6-11: Participant Enrollment Forecast

Year	Ag: Large	Ag: Medium	Comm: Large	Comm: Medium
2024	[redacted]	[redacted]	234	2,005
2025	[redacted]	[redacted]	256	2,218
2026	[redacted]	[redacted]	258	2,233
2027	[redacted]	[redacted]	260	2,256
2028	[redacted]	[redacted]	263	2,287
2029	[redacted]	[redacted]	268	2,323
2030	[redacted]	[redacted]	273	2,370
2031	[redacted]	[redacted]	279	2,435

2032	[redacted]		289	2,520
2033	[redacted]		303	2,639
2034	[redacted]	16	324	2,808

SDG&E developed the CPP enrollment forecast that was used to scale the ex ante impacts. After accounting for some de-enrollments in late 2024, the forecasts anticipate moderate growth in CPP participation through 2034. This is based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

6.4.2 Ex Ante Load Impacts – SDG&E Large

Table 6-12 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Large Commercial CPP customers under different planning conditions. Since no significant impacts were estimated for any Large Commercial CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Large Commercial customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SDG&E's enrollment forecast anticipates slight growth in Large Commercial CPP customers year-over-year through 2034. Aggregate ex ante impacts for the Large Commercial group thus follow a similar trend, increasing slightly through 2034.

The Large Commercial CPP group is expected to deliver about 0.6 MW peak savings during a 1-in-2 event day in 2025, with this figure increasing to 0.8 MW over time due to increases in enrollments.

Table 6-12: SDG&E Large Commercial Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	234	0.58	0.58	0.59	0.59
1-in-2	2025	256	0.63	0.63	0.64	0.64
1-in-2	2026	258	0.63	0.63	0.65	0.65
1-in-2	2027	260	0.64	0.64	0.65	0.65
1-in-2	2028	263	0.65	0.65	0.66	0.66
1-in-2	2029	268	0.66	0.66	0.68	0.68
1-in-2	2030	273	0.67	0.67	0.69	0.69
1-in-2	2031	279	0.69	0.69	0.70	0.70
1-in-2	2032	289	0.71	0.71	0.73	0.73
1-in-2	2033	303	0.74	0.74	0.76	0.76
1-in-2	2034	324	0.80	0.80	0.81	0.81

Table 6-13 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Large Agricultural CPP customers. These estimates also represent the program-specific demand reductions. Impact estimates represent Large Agricultural customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year.

SDG&E's enrollment forecast anticipates [redacted] in Large Agricultural CPP customers year-over-year through 2034. There are [redacted] from this group in the ex ante forecast.

Table 6-13: SDG&E Large Agriculture Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	[redacted]				
1-in-2	2025	[redacted]				
1-in-2	2026	[redacted]				
1-in-2	2027	[redacted]				
1-in-2	2028	[redacted]				
1-in-2	2029	[redacted]				
1-in-2	2030	[redacted]				
1-in-2	2031	[redacted]				
1-in-2	2032	[redacted]				
1-in-2	2033	[redacted]				
1-in-2	2034	[redacted]				

6.4.3 Ex Ante Load Impacts – SDG&E Medium

Table 6-14 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Medium Commercial CPP customers under different planning conditions. Since no significant impacts were estimated for any Medium Commercial CPP dual-enrollment groups in PY2024, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Medium Commercial customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SDG&E's enrollment forecast anticipates slight growth in Medium Commercial CPP customers year-over-year through 2034. This is based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

The Medium Commercial CPP group is expected to deliver about 0.2 MW peak savings during a 1-in-2 event day in 2025, with this figure increasing to 0.3 MW over time due to increases in enrollments.

Table 6-14: SDG&E Medium Commercial Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	2,005	0.20	0.20	0.20	0.20
1-in-2	2025	2,218	0.22	0.22	0.22	0.22
1-in-2	2026	2,233	0.22	0.22	0.22	0.22
1-in-2	2027	2,256	0.22	0.22	0.23	0.23
1-in-2	2028	2,287	0.22	0.22	0.23	0.23
1-in-2	2029	2,323	0.23	0.23	0.23	0.23
1-in-2	2030	2,370	0.23	0.23	0.24	0.24
1-in-2	2031	2,435	0.24	0.24	0.24	0.24
1-in-2	2032	2,520	0.25	0.25	0.25	0.25
1-in-2	2033	2,639	0.26	0.26	0.26	0.26
1-in-2	2034	2,808	0.28	0.28	0.28	0.28

Table 6-15 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Medium Agricultural CPP customers. These estimates also represent the program-specific demand reductions. Impact estimates represent Medium Agricultural customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year.

SDG&E's enrollment forecast [redacted] in Medium Agricultural CPP customers year-over-year through 2034. There are [redacted] from this group in the ex ante forecast.

Table 6-15: SDG&E Medium Agriculture Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2024	[redacted]				
1-in-2	2025					
1-in-2	2026					
1-in-2	2027					
1-in-2	2028					
1-in-2	2029					
1-in-2	2030					
1-in-2	2031					
1-in-2	2032					
1-in-2	2033					
1-in-2	2034	16	-0.03	-0.03	-0.03	-0.03

6.4.4 COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For SDG&E's Large CPP group, Table 6-16 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Large CPP site delivered 1.2% in statistically significant load reductions (3.54 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 1.2%. Differences in ex ante and ex post counterfactual loads ("Load without DR" in the table) are largely explained by the change in the enrollment population from PY2024 ex post enrollment as compared to PY2024 ex ante. Specifically, though there were more customers in PY2024, a few very large PY2023 customers did not participate in PY2024. The SDG&E and CAISO weather ex ante predictions are slightly different because ex ante reference loads increase for hotter temperatures. Percent impacts are equal across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 6-16: SDG&E Large Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	302.12	3.54	1.2%	84.3
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	204.30	2.37	1.2%	82.5
Ex Ante (SDG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	208.81	2.42	1.2%	84.8

For SDG&E's Medium CPP group, Table 6-17 compares the PY2024 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Medium CPP site delivered 0.4% in statistically significant load reductions (0.1 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were 0.4% as well.

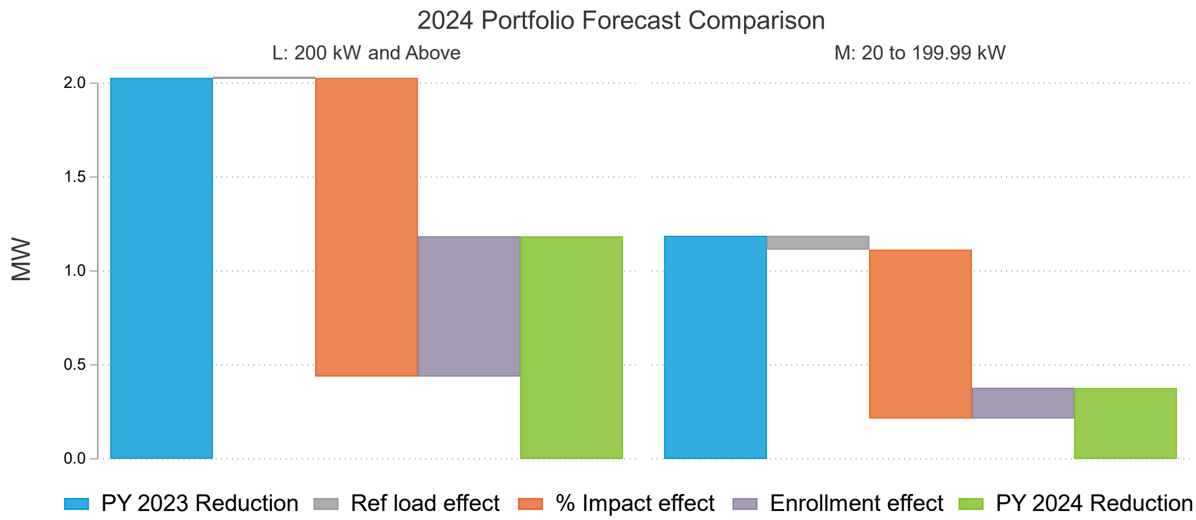
Table 6-17: SDG&E Medium Comparison of Ex Post and Ex Ante Load Impacts for 2024

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	27.85	0.10	0.4%	84.6
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	25.82	0.09	0.4%	82.1
Ex Ante (SDG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	26.34	0.09	0.4%	84.0

6.4.5 COMPARISON TO 2023 EX ANTE IMPACT ESTIMATES

The ex ante impact estimates in this study are lower than in the previous evaluation, largely due to decreased impacts from the Small sites. The following figure gives a breakdown of the difference in ex ante impact estimates from PY2023 and those generated in in PY2024. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2023 (in blue) and PY2024 (in green).

Figure 6-4: Waterfall Analysis of 2023-2024 SDG&E Ex Ante Impacts by Group



The Large group has a much lower percent impact estimate than in 2023. This is the driver of the reduced MW projection for that group, even with an increase in enrollments. The Medium group follows a similar pattern, with the decrease in ex ante MW impacts driven by lower estimated percent impacts, with enrollments and reference loads largely unchanged from 2023.

6.4.6 EX ANTE LOAD IMPACT SLICE-OF-DAY TABLES

The following tables show the 2024 ex ante aggregate hourly impacts by CPP group for each month under SDG&E 1-in-2 monthly worst day conditions. CPP tariffs only allow for dispatch from 4 to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table 6-18: SDG&E Large Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.44	0.45	0.46	0.57	0.56	0.59	0.66	0.69	0.72	0.64	0.57	0.46
18	0.42	0.43	0.45	0.55	0.54	0.57	0.63	0.65	0.68	0.61	0.55	0.45
19	0.42	0.43	0.45	0.53	0.52	0.54	0.59	0.61	0.63	0.58	0.53	0.45
20	0.41	0.42	0.43	0.50	0.50	0.51	0.55	0.57	0.59	0.54	0.50	0.43
21	0.39	0.40	0.41	0.47	0.47	0.49	0.53	0.54	0.56	0.51	0.48	0.42
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 6-19: SDG&E Medium Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.12	0.12	0.06	0.09	0.08	0.18	0.21	0.22	0.24	0.21	0.18	0.14
18	0.11	0.11	0.12	0.16	0.16	0.17	0.19	0.20	0.22	0.19	0.17	0.13
19	0.11	0.11	0.11	0.15	0.15	0.15	0.18	0.19	0.20	0.18	0.16	0.12
20	0.10	0.11	0.11	0.14	0.14	0.15	0.16	0.17	0.18	0.16	0.15	0.12
21	0.10	0.10	0.11	0.13	0.13	0.13	0.15	0.16	0.17	0.15	0.14	0.11
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

7 RECOMMENDATIONS

Overall, in PY 2024 CPP rates delivered small demand reductions, generally in the range of 0 to 1% across IOUs and groups. Reasons for the general lack of response are not directly tested in this evaluation. However, some factors that may contribute to lower responses, independent of any IOU programming, include:

- Customers that are defaulted onto rates may have a lack of interest in load shifting/reduction
- Since CPP rates also have TOU components on non-event days, measured impacts must be over-and-above any normal shifting behavior during peak summer hours
- Many customers have insurance provided against charges such as first-year bill protection (all IOUs) or reserving loads from CPP event pricing (SDG&E only)
- Lower discretionary loads during 4 to 9 p.m. event window for commercial customers
- Customers may have difficulty in responding to varying four-tiered rates (three-tier TOU rates plus CPP adders announced one day ahead)

The recommendations below present options to possibly improve reductions or at least to understand customer barriers to producing greater demand reductions. The recommendations below may not be currently funded and may not be within each IOU's control, and costs and feasibility need to be considered alongside other research and rate design priorities.

7.1 PDP RECOMMENDATIONS – PG&E

- Survey customers to identify or understand barriers to shifting on event days. Topics to consider may include awareness, flexibility of loads business conditions, cost of shifting loads, etc.
- Analyze the types of customers remaining on CPP rates vs. average commercial customers or customers in other DR programs.
- Analyze customer turnover in light of changing impacts by year.

7.2 CPP RECOMMENDATIONS – SCE

- Remove some large, non-performing sites from CPP rates
- Evaluate the delivery and impact of notifications
- Survey customers to identify or understand barriers to shifting on event days. Topics to consider may include awareness, flexibility of loads business conditions, cost of shifting loads, etc.

- Analyze the types of customers remaining on CPP rates vs. average commercial customers or customers in other DR programs.
- Analyze customer turnover in light of changing impacts by year, especially in the Large group that produced larger impacts in PY 2023.

7.3 CPP RECOMMENDATIONS – SDG&E

- Remove large exporters from rate or evaluate delivered loads.
- Evaluate delivery success for notifications (current analysis just segments customers as enrolled in notifications or not).
- Investigate the various CPP rate options, including differential pricing for non-event peak hours, event-day adders, and per-kW subscriptions for capacity reservations.
- Consider evaluating loads that are truly exposed to CPP pricing, i.e. loads net of capacity reservations.
- More events could help evaluation precision, though these may not be intention of SDG&E's CPP rate, where CPP events are used more for emergency purposes relative to other IOUs.

APPENDIX

A. INDIVIDUAL SITE REGRESSIONS WITH SYNTHETIC CONTROLS

Individual site regressions were used as a supplementary method for estimating load impacts for PY 2024 impacts for CPP customers. The approach is implemented on hourly site loads. It relies on control sites that did not experience the intervention (up to five matched to each CPP site), lagged customer site usage, an industry usage profile, solar irradiance, plus weather and time characteristics, to estimate the counterfactual. The model estimates a counterfactual load using weather and these various synthetic controls and predictors. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed CPP site and predicted counterfactual loads. With a regression model with synthetic controls, one should observe:

- Very similar energy use patterns for CPP site and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of individually specified site specific regression models allows for incorporation of a subset of possible parameters that best predict out of sample loads for each site and does not rely on finding a single ideal match. The model equation including the full set up possible parameters is presented below in Equation A-1 and Table A-1. In practice the model used for each site and included a varying subset of these parameters. A separate model was estimated for each hour of the day.

Equation A-1: Ex Post Regression Model for Non-Residential ELRP

$$kW_t = \mathrm{a} + \sum_{n=1}^{max} \mathrm{b} \cdot kW\_0_{n,t} + \sum_{n=1}^{max} \mathrm{c}_n \cdot kW\_1_{t-n} + \sum_{n=1}^{max} \mathrm{d}_n \cdot month_n + \sum_{n=1}^{max} \mathrm{e}_n \cdot dow_n + \mathrm{f} \cdot solar_t + \mathrm{g} \cdot industry_t + \sum_{n=1}^{max} \mathrm{h}_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

Where:

Table A-1: Ex Post Regression Elements for Non-Residential ELRP

$\mathrm{kW_t}$	Is the site usage for each time period.
$\mathrm{kW\_0_t}$	Is the synthetic control usage for up to 5 matched controls for each time period. The specific number of controls used varied by site. These synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
$\mathrm{kW\_1_{t-n}}$	Is the lagged customer site usage and could by one of: no lags, 1 day, 1 week, 2 weeks, 1 day and 1 week, and 1 and 2 weeks. The specific lags used varied by site.
a	Is the model intercept.

b	Coefficients for the synthetic control loads. The specific number of controls used varied by site and ranged from 0 to 5.
c	Coefficients for the customer site usage lags. The specific lags used varied by site.
d	Coefficients for each month.
e	Coefficients for each day of week.
f	Coefficient for solar irradiance across for each time period. Inclusion of this parameter varied by site.
g	Coefficient for industry load profile: normalized hourly loads (scaled from 0 to 1) for control sites in the same industry as the customer site. Industry grouping developed using NAICS code and customer names indicative of industry activity. Inclusion of this parameter varied by site.
h	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 24 hour moving average of temperature, averaged across CPP sites for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

Most sites did not require individual site regressions, as a comparable control group was available to estimate event-day counterfactuals. Among sites that did require the individual regressions, loads were often variable or the sites were located in areas with few similar businesses. The tables below report the bias and fit metrics for the models used by utility and group. Mean absolute percent error (MAPE) indicates the percent difference between predicted values and actual kWh on non-event days in summer 2024. The average percent bias is the mean of the percent errors – without taking an absolute value, this becomes the mean of both positive and negative values, with strong models calibrated to achieve a bias close to zero.

Table A-2: Bias and Fit Measures for Individual Customer Regressions – PG&E

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Large Commercial	850	2	593.3	0.012	-0.002
Medium Commercial	16,034	1037	39.2	0.002	0.003
Small Commercial	23,859	98	3.4	0.021	0.012
Large Agricultural	553	527	238.7	0.008	-0.022
Medium Agricultural	196	65	69.8	0.024	-0.004
Small Agricultural	174	73	5.7	0.074	-0.068

Table A-3: Bias and Fit Measures for Individual Customer Regressions – SCE

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Large Commercial	1,536	58	431.9	0.009	-0.008
Medium Commercial	21,133	84	-167.3	0.016	0.005
Small Commercial	19,984	69	-203.1	0.004	0.001
Large Agricultural	205	193	338.3	0.004	-0.003

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Medium Agricultural	78	65	61.4	0.007	-0.015

Table A-4: Bias and Fit Measures for Individual Customer Regressions – SDG&E

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Large Commercial	233	5	960.4	0.131	-0.125
Medium Commercial	2,012	6	51.8	0.006	0.001
Large Agricultural	[redacted]				
Medium Agricultural					

B. PROXY DAY SELECTION

For the differences-in-differences estimates, customers are compared both over time (event days vs. non-event days) and with a pool of similar, non-CPP customers (the matched control group). Proxy days, the non-event days used for comparison, are selected to be as similar as possible to actual event days. In general, these are often the hottest non-holiday weekdays of the summer (e.g. for SDG&E and PG&E, which call CPP events on days with extreme weather).

Proxy days are selecting by matching customers pre-event loads on event days (through 2 p.m.) to loads for the same hours on non-event days. Matches are tested and selected as the group that minimizes bias between the event day and non-event day loads.

A t-test can show the likelihood that two data series in fact different from each other. For proxy day selection, better matches should produce results with a higher probability that the two series are not different from each other.

The following tables report the p-values from t-tests of the hypothesis that pre-event hour loads on event days and proxy days are the same. Values are generally greater than 0.05, corresponding to the 95% confidence level, and frequently very close to one, meaning the hypothesis of similar loads cannot be rejected at the 95% confidence level and the series are in fact very similar.

Table A-5: PG&E Proxy and Event Day Matching: p-Values from t-Tests

Event Date	Medium Ag.	Small Ag.	Large Comm.	Medium Comm.	Small Comm.
06-05	0.789	0.155	0.942	0.964	0.909
07-02	0.815	0.002	0.894	0.938	0.916
07-03	0.583	0.703	0.887	0.949	0.775
07-06	0.360	0.025	0.750	0.466	0.286
07-10	0.590	0.149	0.720	0.995	0.958
07-11	0.636	0.007	0.315	0.564	0.560
07-23	0.012	0.001	0.351	0.565	0.595
09-04	0.663	0.038	0.830	0.989	0.923
09-05	0.109	0.002	0.820	0.953	0.998

Table A-6: SCE Proxy and Event Day Matching: p-Values from t-Tests

Event Date	Large Comm.	Medium Comm.	Small Comm.
06-20	0.944	0.964	0.955
07-02	0.884	0.947	0.979
07-03	0.854	0.960	0.997

Event Date	Large Comm.	Medium Comm.	Small Comm.
07-05	0.062	0.809	0.865
07-08	0.708	0.929	0.999
07-09	0.796	0.944	0.939
07-11	0.922	0.873	0.934
08-05	0.914	0.939	0.955
08-06	0.844	0.898	1.000
08-07	0.724	0.986	0.963
08-20	0.725	0.932	0.924
08-27	0.879	0.938	0.949

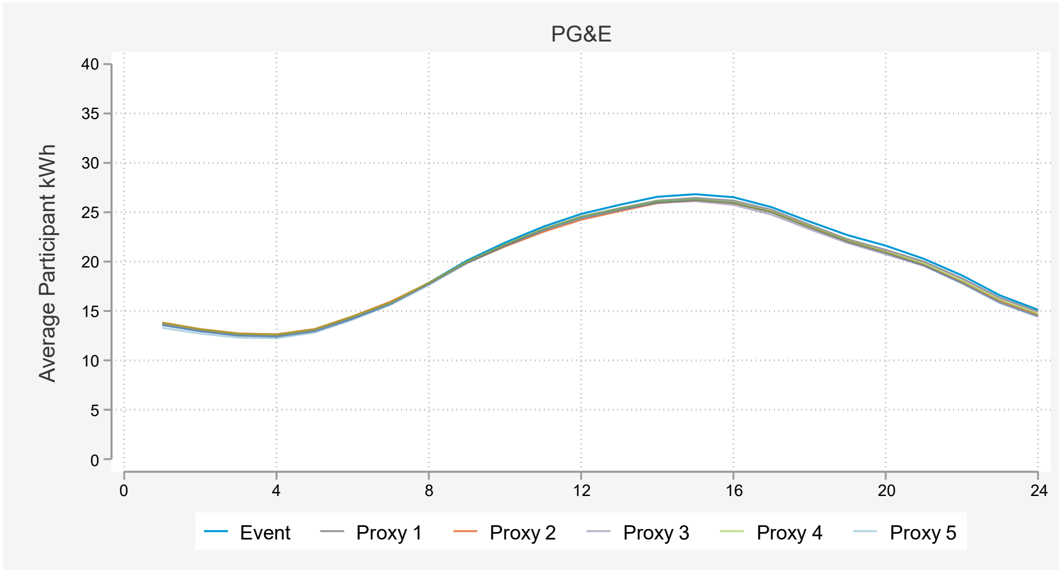
Table A-7: SDG&E Proxy and Event Day Matching: p-Values from t-Tests

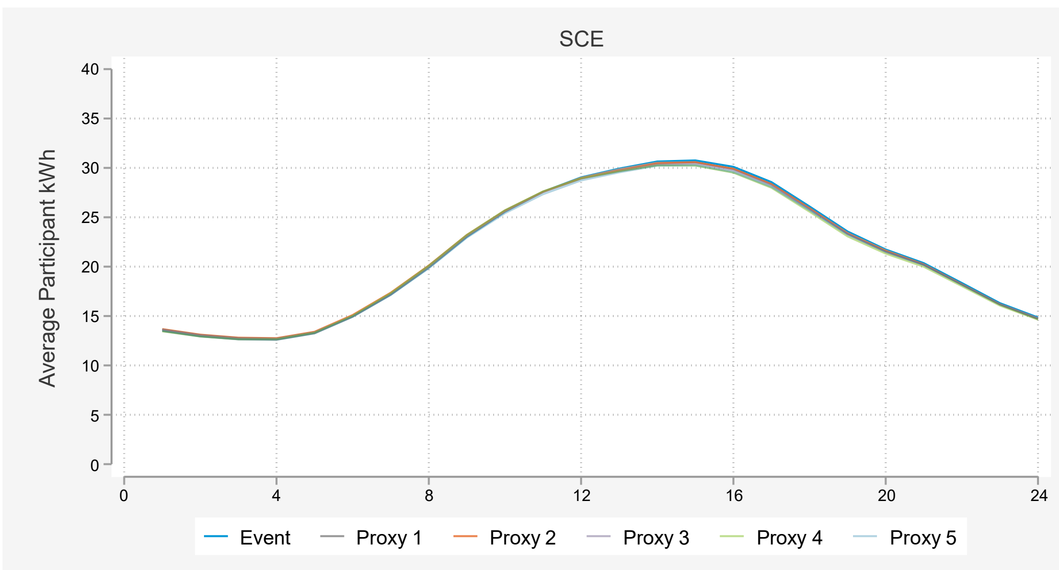
Event Date	Large Comm.	Medium Comm.
09-05	0.152	0.320
09-06	0.060	0.174
09-09	0.013	0.050

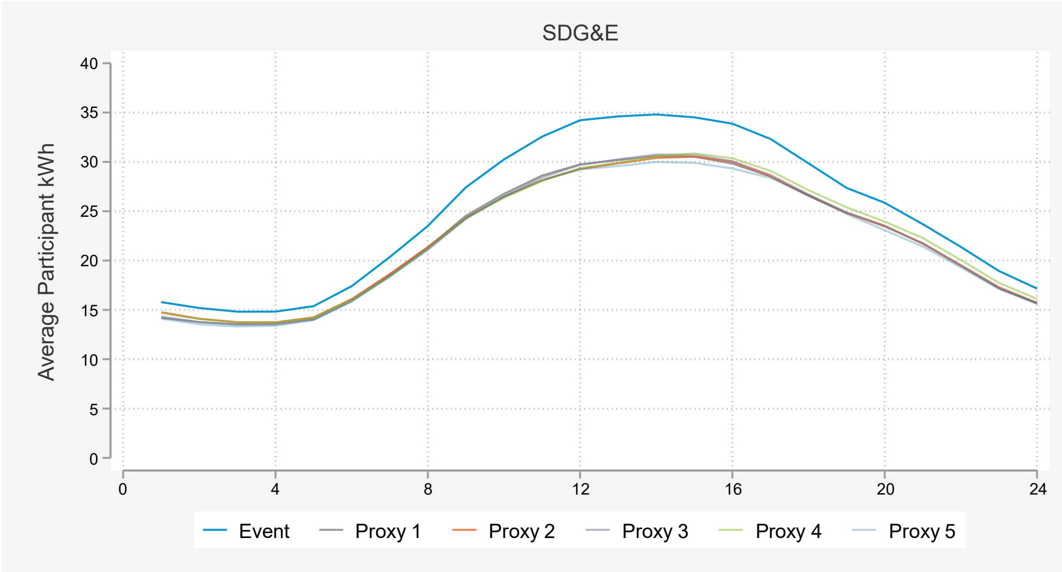
Some smaller values are found in PG&E's agricultural groups, which had fewer customers, and for SDG&E's commercial groups, which were also relatively small. SDG&E's event days were also very extreme, so some difference with the best proxy days can be expected. At certain levels, the SDG&E t-tests in fact imply the hypothesis of similar loads can be rejected (e.g. September 9th has significant differences at the 5% level).

Figure A-0-1 shows proxy day and event day loads for CPP customers by IOU, focusing on the Medium Commercial group (which has a large number of customers at each IOU).

Figure A-0-1: Event Day and Proxy Day Loads for CPP Customers







Even if very closely matching proxy days cannot be found, differences-in-differences can still be the best estimation method for a DR evaluation. In such cases, dissimilarities between event days and proxy days may simply mean that the event days are very different from other summer days. Differences-in-differences then would still allow for comparison to a control group on these very hot days, with the control group serving as a proxy for the types of loads seen on those extreme days.

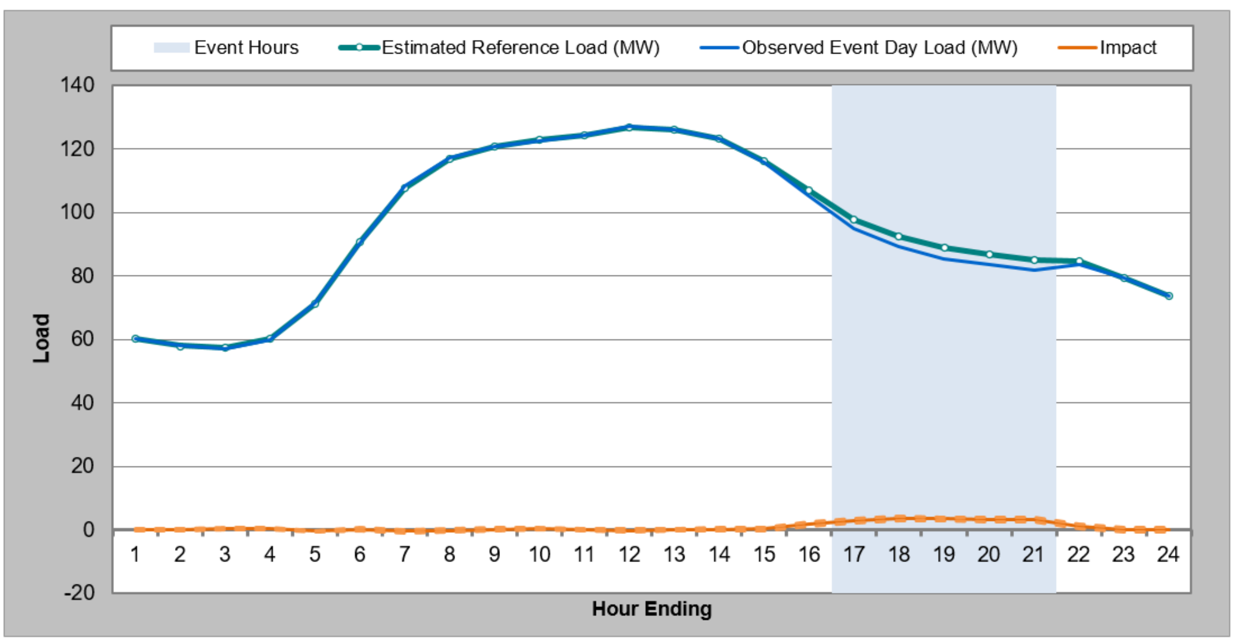
Regression modeling would instead require a very precise model to extrapolate each site's usage on an extremely hot day, based only on their behavior on other, milder days. The small impacts observed for CPP groups (0-1%) make this type of prediction with regression modeling even more difficult. For this reason, differences-in-differences were still used wherever possible for SDG&E's event day impacts.

C. DIFFERENCES-IN-DIFFERENCES MODEL FOR PY 2024

A methodological change from the 2023 evaluations included simpler modeling for greater flexibility. Specifically, to tightly predict event-day loads, previous evaluations employed regression models that included same-day loads in the morning and afternoon leading up to the event start. This type of modelling tends to reduce noise in the estimates, since the event-day loads are able to describe a great deal of the variation in loads observed in the data.

However, including same-day loads, especially in the afternoon leading up to the events, makes the assumption that CPP impacts can occur only during the event window itself. This is a strong assumption for a behavioral program in which customers can receive day-ahead notice of events. If day-of adjustments are included in the model, then reference loads (estimated loads without any DR intervention) may instead contain a part of the event impacts.

As an example, the following graph shows the publicly reported ex post event day and reference loads for manufacturing sites in SCE's Large CPP group. Calibrating the reference load to event-day loads leads to nearly identical loads in the hours leading up to an event. However, if some load had been shifted into earlier hours, then the reported reference loads would be too high, since they were calibrated to match the now-higher loads in the earlier hours. In this case, the impacts shown would double-count the CPP impacts, since event-hour loads would now drop even further from the now-higher reference load.



For all PY 2024 estimates, day-of adjustments were not made to the loads. The drawback to this approach, however, is that it is more difficult to generate the precise reference loads needed to detect impacts of 0-1%. Including day-of adjustments leads to much greater precision (smaller standard errors), but it is unclear if this is false precision.

Since both approaches may have value in projecting future impacts, the PY 2024 ex ante models include a blend of the PY 2023 and PY 2024 ex post impact estimates.