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2022 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates

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EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2022. The evaluation produces estimates of the ex-post load impacts for each hour of each CPP event called for PG&E, SCE, and SDG&E in 2022. The evaluation also develops ex-ante load impact forecasts for the programs through 2033.

ES.1 Resources Covered

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

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2022, by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2022 for each of the utilities' Automated Demand Response (Auto-DR) program for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2023 through 2033;[1]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

Secondary goals include estimating the effect of event notifications on load impacts and comparing the load impacts for other subgroups of interest for PG&E such as net energy metered (NEM) customers, Commercial and Industrial (C&I), agricultural, and government rate classes, customers receiving enhanced in-season support (ESS), and customers assigned Business Energy Support (BES)/CRS.

ES.2 Evaluation Methodologies

In this evaluation, we estimate CPP ex-post load impacts using two primary methodologies: within-subjects panel models and customer-specific regressions. In both

[1] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2022), with the values serving as weather-normalized versions of the ex-post load impacts.

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

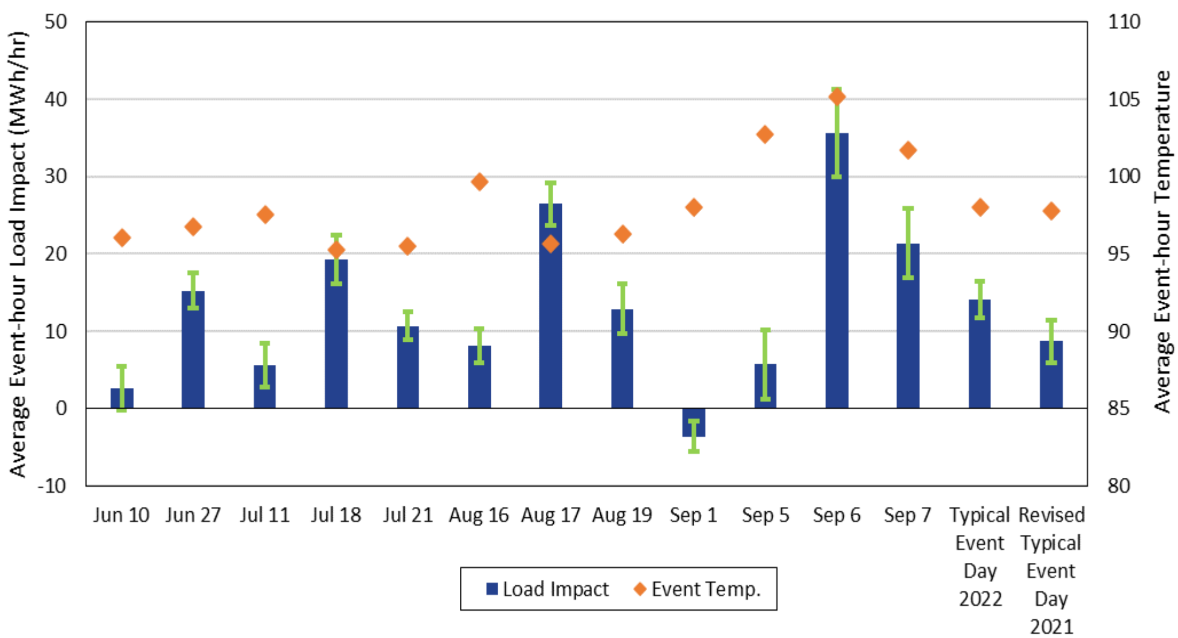
Ex-ante estimates are based on ex-post percentage load impacts, with the reference loads simulated to represent the range of weather and day types required by the Protocols.

ES.3 Ex-Post Load Impacts

ES.3.1 PG&E

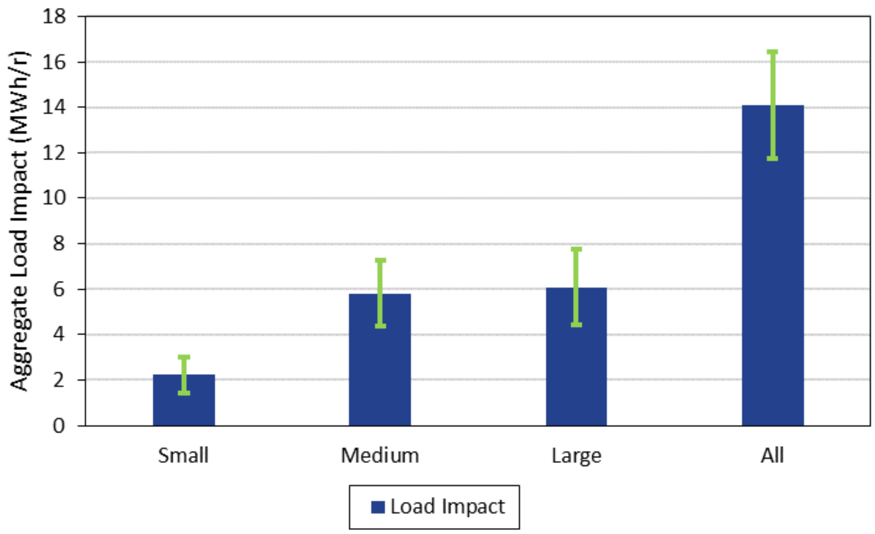
Figure ES.1 shows the estimates of the average event-hour load impacts by event day, along with a 90 percent confidence interval for all PG&E's PDP customers. These customers achieve statistically significant load reductions on ten out of twelve event days as well as on the typical event day. The estimated load reduction for the typical event day is 14.1 MWh/hour, which is a 1.4 percent load reduction. Figure ES.1 does not provide evidence of a strong relationship between load impacts and average temperatures. Typical event day load impacts increased between PY2021 and PY2022 due to increased enrollments from customer defaults and improvement of per-customer load impacts for small and medium customers.

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



Small and large customers had statistically significant load reductions on eight out of twelve event days, while medium customers had statistically significant load reductions on ten out of twelve event days. Figure ES.2 shows the estimates of the average event-hour load impacts on the typical event day by customer size with 90 percent confidence intervals. The estimated load reduction for the typical event day is 6.1 MWh/hour for large customers, 5.8 MWh/hour for medium customers, and 2.2 MWh/hour for small customers.

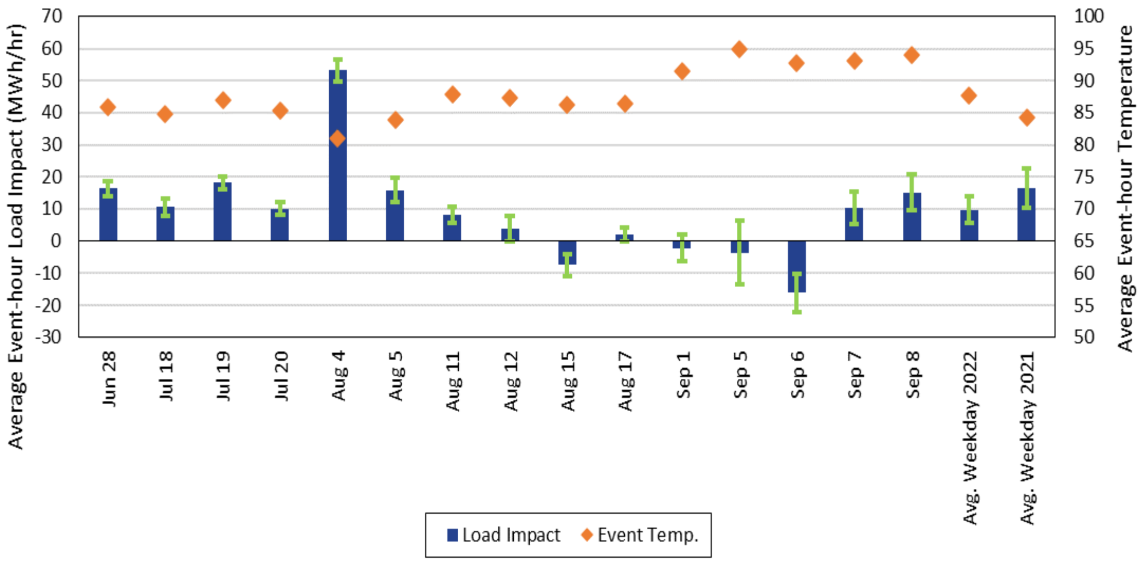
Figure ES.2 Average Event-Hour Load Impacts on Typical Event Day by Size, PG&E



ES.3.2 SCE

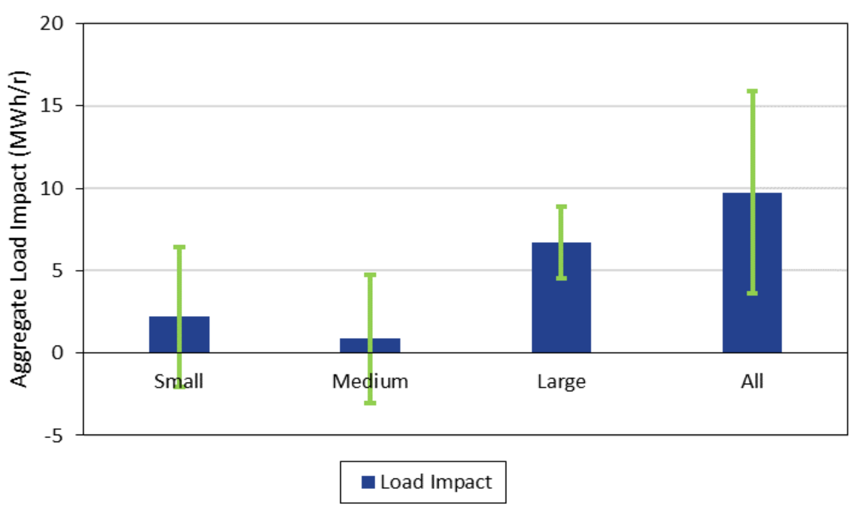
Figure ES.3 shows the ex-post load impacts for all SCE's CPP customers. Overall, SCE's customers had statistically significant load reductions on ten out of fifteen event days. The load impact averaged 9.76 MWh/hour across all event days, which is a 0.77 percent load reduction. Figure ES.3 also provides evidence of a relationship between load impacts and average temperatures. Specifically, load impacts decrease as temperatures increase. We find that this relationship is driven by large and medium CPP customers. The average 2021 weekday load impact and temperature are provided for comparison. The 2021 load impact was larger (16.3 MWh/hour) but with cooler temperatures (84.3 degrees).

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



Large customers had statistically significant load reductions on all but two event days (September 5th and 6th), ranging from 2 to 16 MWh/hour. The load impact averaged 6.71 MWh/hour across all non-holiday event days. Medium customers had statistically significant load reductions on four out of fifteen event days. The average event day load impact is 0.86 MWh/hour for medium customers but is not statistically significant. For small customers, seven events exhibit reductions in usage that are statistically significant. The average non-holiday weekday load impact of 2.19 MWh/hour is not statistically significant for small customers. Figure ES.4 shows the ex-post load impacts on the average weekday by customer size with 90 percent confidence intervals.

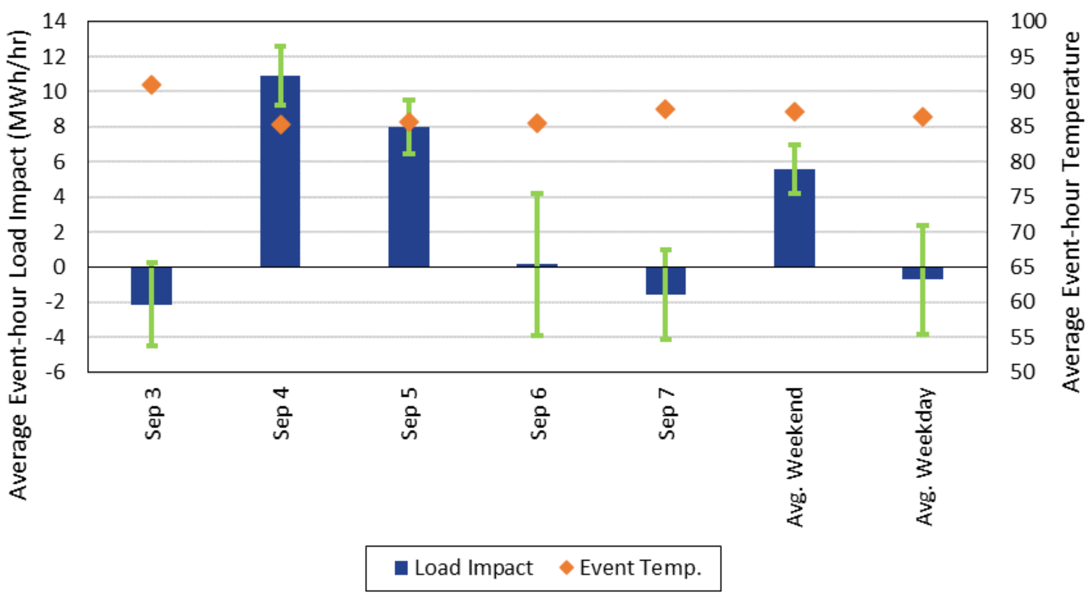
Figure ES.4: Average Event-Hour Load Impacts by Size on Average Weekday, SCE



ES.3.3 SDG&E

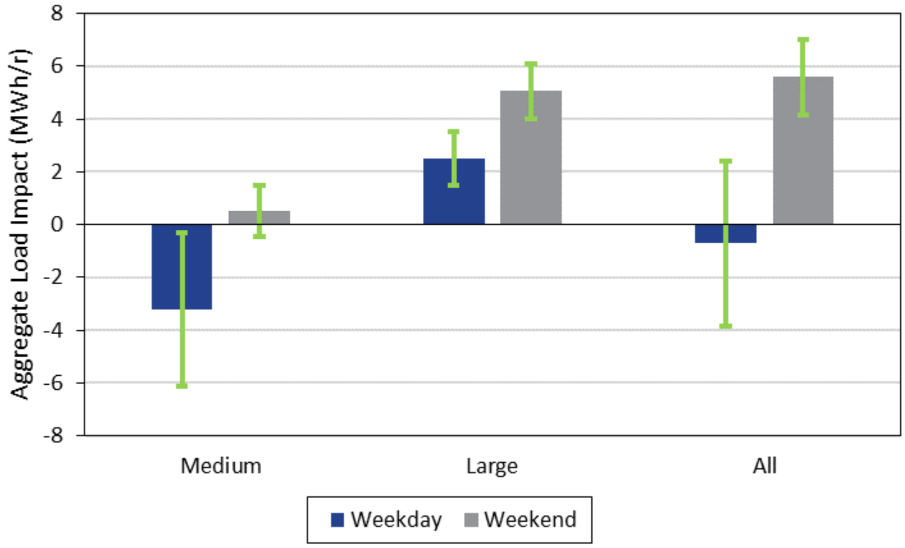
Figure ES.5 shows the ex-post load impacts for all SDG&E's CPP customers. Overall, SDG&E's customers had statistically significant load reductions on two out of five event days. The load impact averaged 5.6 MWh/hour across weekend event days and -0.7 MWh/hour over non-holiday weekday events. Figure ES.5 provides some evidence of a negative relationship between load impact and event temperature; however, there are not enough events to provide a clear picture of this relationship.

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



Large customers had statistically significant load reductions on all of the event days, ranging from 1.4 to 6.9 MWh/hour. The load impact averaged 5.1 MWh/hour and 2.5 MWh/hour across all weekend and non-holiday weekday events, respectively. Medium customers had reductions on two of the event days, September 4^{th} & 5^{th} (only September 4^{th} is statistically significant). The remaining event days do not indicate load reductions for medium customers. Figure ES.6 shows the ex-post load impacts for the average weekday and weekend events by customer size with 90 percent confidence intervals.

Figure ES.6: Average Event-Hour Load Impacts by Size on Average Weekday and Weekend, SDG&E



ES.4 Ex-Ante Load Impacts

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

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

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

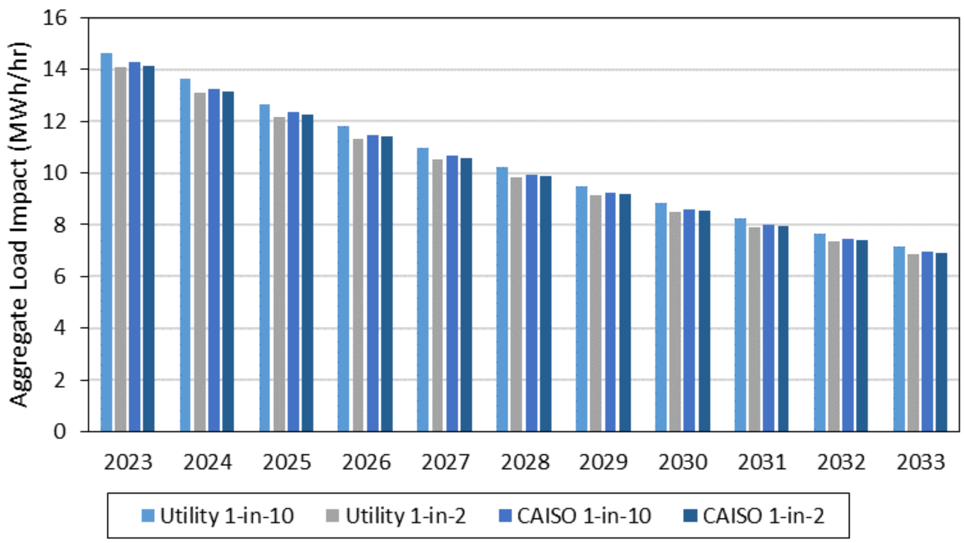
We conducted this process for each utility, size group (under 20 kW, 20 to 200 kW, and over 200 kW), and LCA. The load impacts are provided for the years 2023 through 2033, for various day types (monthly system peaks days) and weather scenarios (utility-specific and CAISO peaking conditions in both 1-in-2 and 1-in-10 scenarios).

ES.4.1 PG&E

Figures ES.7 summarizes ex-ante load impacts for all PG&E's PDP customers. The results reflect the Typical Event Day load impacts during the Resource Adequacy (RA) window from 4 to 9 p.m. at August enrollments. For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 PG&E and CAISO weather conditions). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

Load impacts decline after 2023 due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E's 1-in-10 weather conditions. The load impacts for each size group show a similar pattern.

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

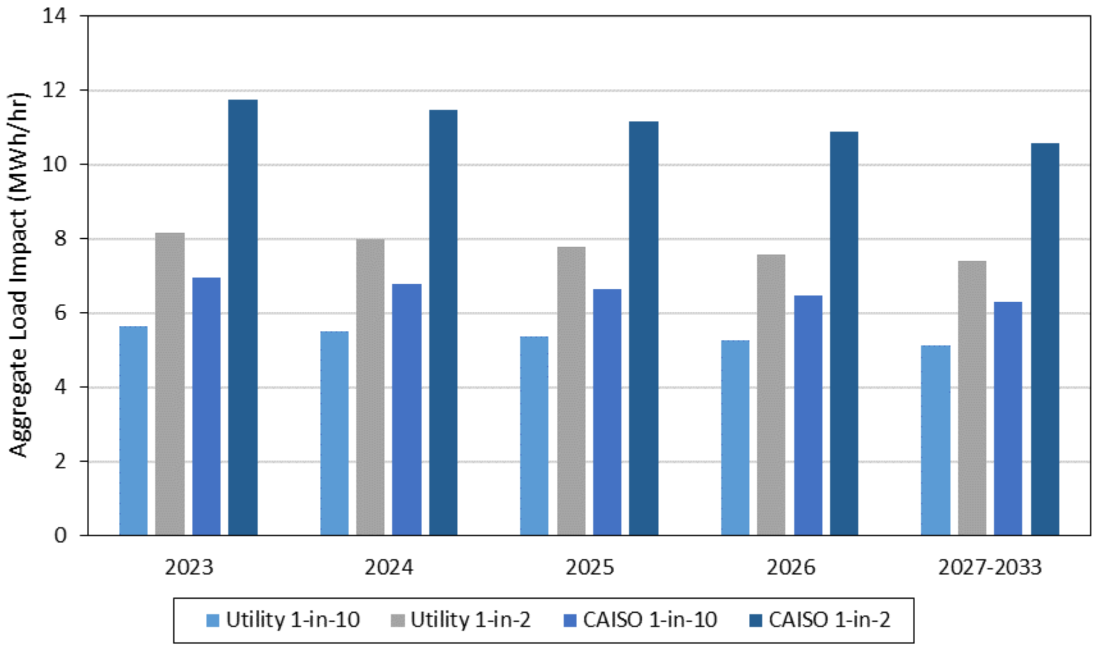


ES.4.2 SCE

Figures ES.8 summarizes the ex-ante load impact for all SCE's CPP customers. The results reflect the average weekday event day impacts during the RA window from 4 to 9 p.m. at August enrollments. For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 SCE and CAISO weather conditions). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

Enrollment is forecast to decrease by about 3 percent for each size group until 2027, where it remains constant for the remainder of the forecast. Ex-ante load impacts are negatively correlated with weather. Therefore, load impacts are smaller for weather scenarios with hotter temperatures. The load impacts for 1-in-10 scenarios are lower than 1-in-2 scenarios. The highest load impacts for each year occur under CAISO 1-in-2 weather conditions. The ex-ante load impacts of small customers do not follow this pattern since their ex-post load impacts did not have a statistically significant relationship with weather.

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

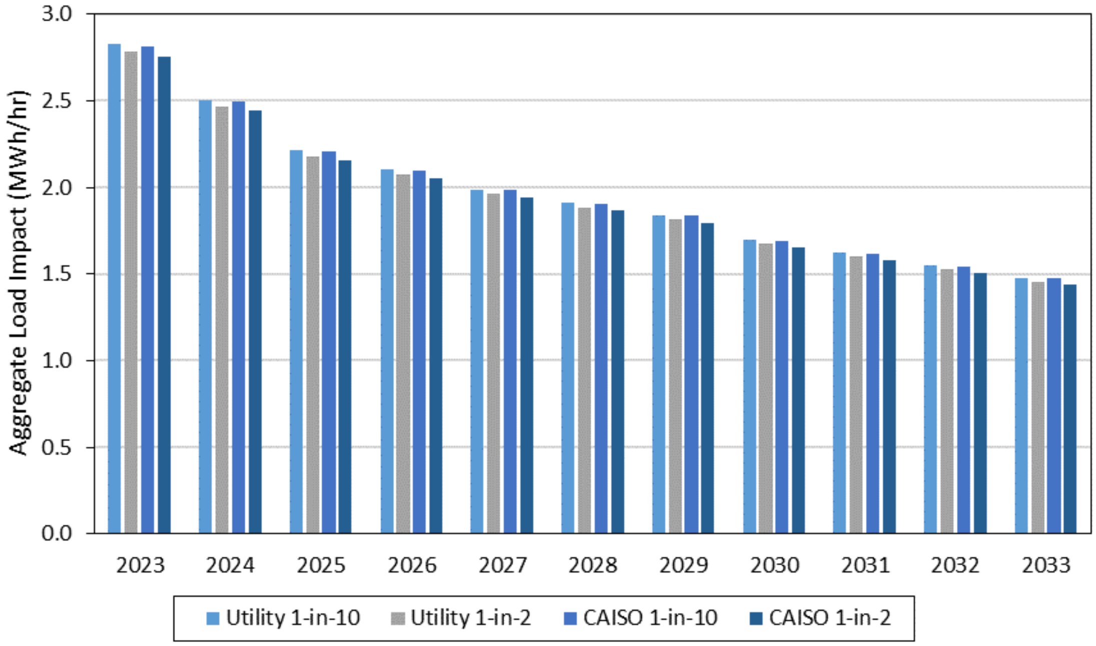


ES.4.3 SDG&E

Figures ES.9 summarizes the ex-ante load impact for all SDG&E's CPP customers. The results reflect the average weekday event day impacts during the RA window from 4 to 9 p.m. at August enrollments. For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 SDG&E and CAISO weather conditions). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

Load impacts decrease after each year because of reductions in enrollments. SDG&E anticipates the total number of customers to decreases sharply until 2025, and thereafter to decrease at a more moderate pace of about 5 percent each year. The load impacts of the 1-in-10 scenarios are slightly higher than 1-in-2 scenarios.

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



The load impacts of both large and medium customers decrease over time due to declining enrollments. For both large and medium customers, the largest load impacts occur for the SDG&E 1-in-10 weather year while the lowest load impacts occur during the CAISO 1-in-2 weather year.

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2022. The evaluation produces estimates of the ex-post load impacts for each hour of each of the utilities' CPP events called in 2022, and it develops ex-ante load impact forecasts of the programs through 2033.

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

PG&E, SCE, and SDG&E (henceforth the Joint Utilities) have implemented CPP as the default service for their non-residential customers (customers have the option to choose a different rate). PG&E began defaulting their large commercial and industrial (C&I) customers (over 200 kW) onto their CPP rates, called Peak Day Pricing (PDP), in 2010. Although PG&E began defaulting small and medium business (SMB) customers onto PDP in late 2014, they later delayed the process in anticipation of a change in TOU pricing periods and have since resumed defaulting customers onto PDP. SCE began defaulting their large C&I customers onto CPP rates in 2010 and their SMB customers in 2019. SDG&E began defaulting their large C&I customers onto CPP rates in 2009 and their SMB customers in 2018. SDG&E's small business CPP customer performance is analyzed in a separate evaluation and therefore will not be included in this evaluation. The Joint Utilities had the following enrollments in CPP on the typical event day in 2022:

Table 1.1: Enrollment by Group Included in the Study

Size Group	PG&E	SCE	SDG&E
Large (Over 200kW)	1,504	1,687	533
Medium (20 to 199kW)	17,723	22,119	4,324
Small (Under 20kW)	92,748	201,453	Excluded

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

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

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

1.1 Project Goals

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2022, by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2022 for each of the utilities' Automated Demand Response (Auto-DR) program for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2023 through 2033;[2]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

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

1.2 PY2022 Event Days

Table 1.3 summarizes the CPP events for the Joint Utilities. PG&E called twelve events, SCE fifteen events (the maximum number events allowed), and SDG&E five events. The bolded events were weekend or holiday events.

[2] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2022), with the values serving as weather-normalized versions of the ex-post load impacts.

Table 1.3: PY2022 CPP Event Dates by Utility

Date	Day of Week	PG&E	SCE	SDG&E
6/10/2022	Friday	X		
6/27/2022	Monday	X		
6/28/2022	Tuesday		X	
7/11/2022	Monday	X		
7/18/2022	Monday	X	X	
7/19/2022	Tuesday		X	
7/20/2022	Wednesday		X	
7/21/2022	Thursday	X		
8/4/2022	Thursday		X	
8/5/2022	Friday		X	
8/11/2022	Thursday		X	
8/12/2022	Friday		X	
8/15/2022	Monday		X	
8/16/2022	Tuesday	X		
8/17/2022	Wednesday	X	X	
8/19/2022	Friday	X		
9/1/2022	Thursday	X	X	
9/3/2022	**Saturday**			**X**
9/4/2022	**Sunday**			**X**
9/5/2022	**Monday**	**X**	**X**	**X**
9/6/2022	Tuesday	X	X	X
9/7/2022	Wednesday	X	X	X
9/8/2022	Thursday		X	

1.3 Report Organization

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

2 STUDY METHODOLOGY

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

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

2.1 Ex-post Load Impact Evaluation

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

2.1.1 Data

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

- *Customer* information for CPP customers (e.g., date of enrollment and de-enrollment, enrollment dates for other DR programs, LCA, climate zone, weather station, NAICS code, size category);
- Monthly usage from billing data for a 12-month period (used to validate the interval data);
- Billing-based *interval load data* on event and event-like non-event days;
- Billing-based *interval load data* for a sample of customers for a 12-month period (e.g., October 2021 through September 2022), used to simulate ex-ante reference loads;
- *Weather data* (i.e., hourly temperatures and other weather variables for each applicable weather station);
- *Program event data* (i.e., CPP and other demand response (DR) program event dates).

2.1.2 Event-Like Non-Event Day Selection

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

Figure 2.1-Figure 2.3 display the average event-hour temperature for all weekdays, weekends, and holidays between May and October 2022, for the Joint Utilities. Red diamond markers indicate weekend and holiday non-event days while blue circles indicate weekday non-event days. The red and blue filled-in markers represent selected event-like non-event days ("Hotdays") with relatively comparable temperatures to event days. The black filled-in markers are Flex Alert days, which are excluded from the set of possible Hotdays, similar to how other DR program event days are excluded. The red and blue "X" markers represent weekend/holiday and weekday event days, respectively. The event days were among the hottest days during 2022.

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

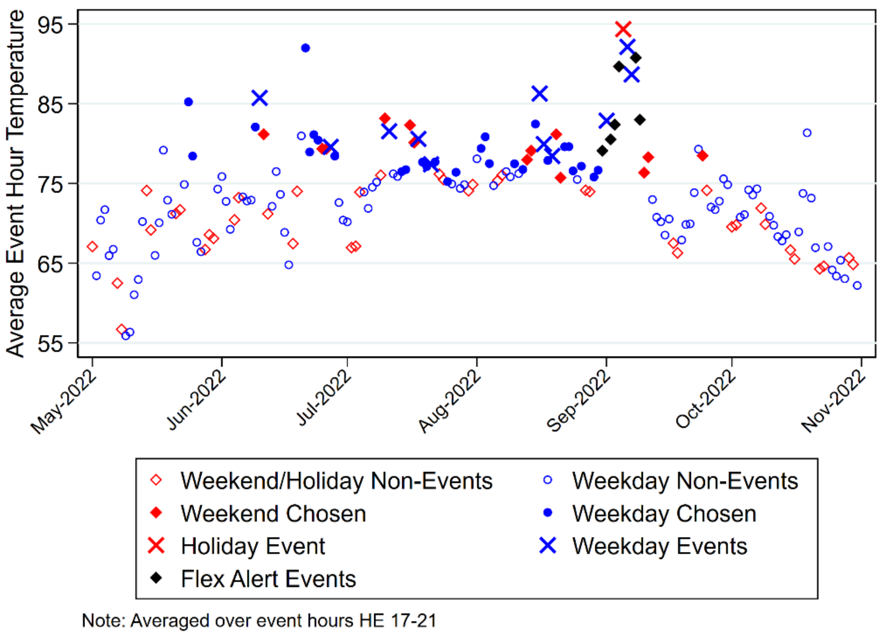


Figure 2.2: Average Event-Hour Temperatures, *SCE*

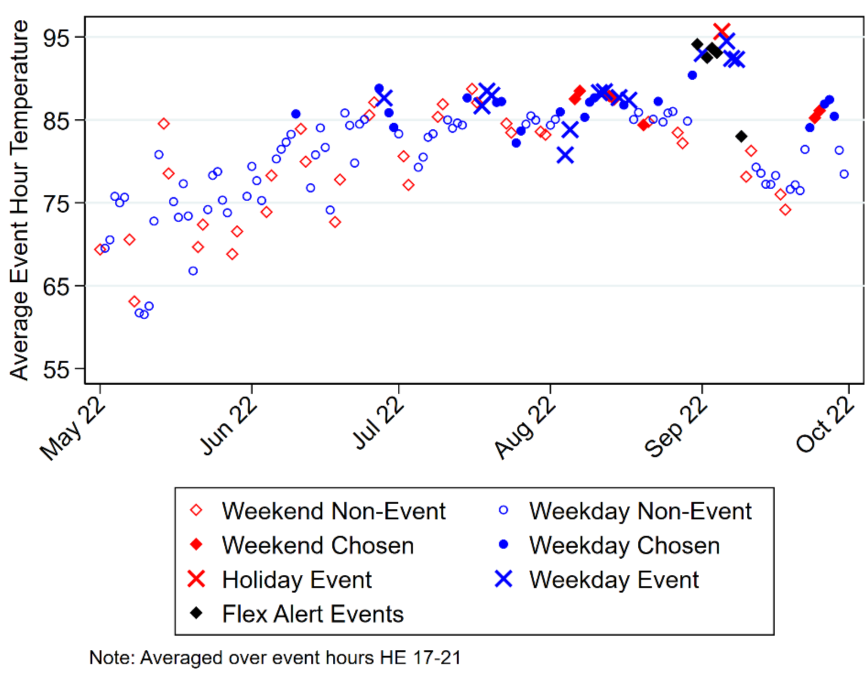
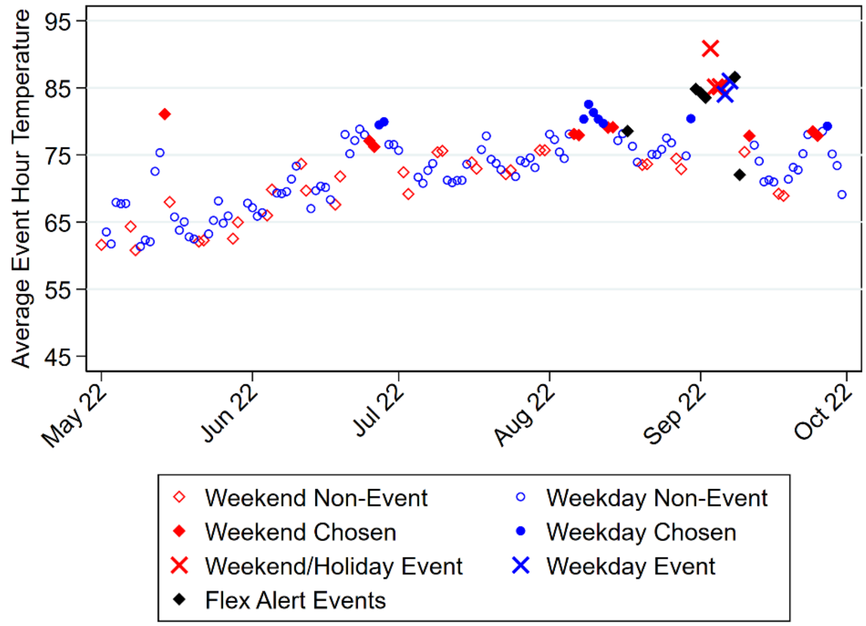


Figure 2.3: Average Event-Hour Temperatures, *SDG&E*



Note: Averaged over event hours HE 17-21

2.1.3 Model Validation Process

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

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

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

Table 2.1: Panel and Customer-Specific Regression Groups

Utility	Size	Panel	Customer-Specific
PG&E	Large	95% (<500 kWh/hour)	5% (≥ 500 kWh/hour)
	Medium	All	None
	Small	All	None
SCE	Large	95% (<600 kWh/hour)	5% (≥ 600 kWh/hour)
	Medium	All	None
	Small	All	None
SDG&E	Large	None	All
	Medium	All	None

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

Panel model specifications are evaluated for each utility and customer size. For the customer-specific models, we first classify customers according to whether or not their hourly loads are responsive to changes in weather conditions (weather-sensitive). Individual models for the largest customers are evaluated by utility, industry group, and weather sensitivity classification. We select specifications by customer group (i.e., sixteen groups, with eight industry groups for each of the non-weather-sensitive customers and weather-sensitive customers). This process and its results are explained in Appendix A.

2.1.4 Regression Model

A typical form for our within-subjects ex-post evaluation model is shown below. For customer-specific regressions, we estimate load impacts across all hours of the day by interacting these regression terms with the hour of the day. The model below is written to apply to a single customer; however, it can be modified to represent a panel model by adding customer fixed effects and customer subscripts to the appropriate variables. We estimate the panel models separately for each hour of the day and customer subgroup.[3] The specific form of the model varies across utilities and customer groups, as shown in Appendix A.

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

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

The variables are explained in Table 2.2.

Table 2.2: Regression Model Variables

Variable Name / Term	Variable / Term Description
Q_t	the customer's usage on day *t*
a and the various *b's*	the estimated parameters
CPP_t	an indicator variable for CPP event days
Wth_t	weather conditions on day *t* (e.g., measured by CDD, CDH, or THI)[4]
E	the number of event days that occurred during the program year
$MornLoad_t$	two separate variables equal to the average of the day's load in 1) hours-ending 1 through 7 and 2) hours-ending 8 through 14[5]
$DayType^j_t$	an indicator variable for day of week *j* on date *t*[6]
$Month^j_t$	a series of indicator variables for each month[7]
$OthDR_t$	a series of indicator variables representing event days for other DR programs in which the service account is enrolled
e_t	the error term.

The first term in the equation containing a summation sign is the component that allows estimation of event-specific load impacts for each hour of the day (the b^{Evt} coefficients). The CPP_t variable equals one if date *t* is a CPP event day and the customer is enrolled in CPP, and zero otherwise. The remaining terms in the equation are designed to control for weather and other periodic factors (e.g., days of the week and months of the year) that determine customers' loads. See Appendix A for a summary of the specifications considered for each size group and industry type.

The "morning load" variable is used in the same spirit as the optional day-of adjustment to the 10-in-10 baseline method currently used in some DR programs (e.g., CBP). That is, it is intended to adjust the reference load (the regression-based estimate of the loads that would have occurred in the absence of the event day) for unobserved exogenous factors that may affect customers' loads on a given day. The use of the morning load variable assumes that variations in the morning load are related to variations in reference loads later in the day; but that the changes in the morning load are not part of the

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[4] In this evaluation, we found it necessary to add additional daily weather variables to better control for event days during the September heat wave in which a series of CPP events were called in the context of high daily temperatures. For PG&E we added controls to for CDD60 and up to two daily lags of CDD60 to the models. For SCE and SDG&E we added average daily temperatures and up to two lags of daily temperature to models. These controls were in addition to the weather variables that were selected during the course of the model validation process and were only added to the panel models and the large customer models for weather sensitive large customers.
[5] The morning load variables differ for PG&E. The first morning load variable is the average daily load from hours-ending 1 through 10 and the second morning load variable covers hours-ending 11 through 15.
[6] In the panel models we only include indicator variables for Mondays and Fridays in the weekday models and Sundays in the weekend/holiday models.
[7] The month fixed effects are omitted from the PG&E panel models due to insufficient availability of hot non-event days in every month of the summer.

customer’s response to the event itself (e.g., pre-cooling the building in anticipation of an event).

Estimating distributions of load impacts for different customer segments

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

Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. Thus, in addition to producing point estimates of the ex-post load impacts, we produce *uncertainty-adjusted* program impacts for each event, which show the uncertainty around the estimated impacts, as required by the Protocols. These methods use the estimated load-impact parameter values and the associated variances to derive scenarios of hourly load impacts. We also report the uncertainty associated with the average event hour, both on an event-specific basis and for the typical event day, which are based on the standard errors from regression models that aggregate the corresponding load impacts (e.g., by estimating a single average event-hour load impact).

Validity assessment

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

2.2 Developing Ex-Ante Load Impacts

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

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

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

1. Utility program;

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

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

The load impacts are provided for the years 2023 through 2033[8], for a number of day types, and weather scenarios, including the following:

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

2.2.1 Reference Loads

The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios. The reference load regression models require a full year of load profile data (as opposed to the ex-post regression models, which include only event and event-like days), which we obtained for a representative sample of CPP customers.[9] Reference loads are simulated using the appropriate weather scenario data (i.e., the 1-in-2 and 1-in-10 weather-year conditions to be provided by the utilities) and event-day characteristics (e.g., weekday and weekend).

2.2.2 Per-customer Load Impacts

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

We investigate the effect of weather on estimated load impacts to determine whether a statistically significant relationship exists.[10] If so, then the ex-post percentage load

[8] PG&E and SDG&E requested the inclusion of a "back-cast" of 2022 load impacts, which we also provide.
[9] SDG&E provided a full year of interval load data for all enrolled customers.
[10] For SCE, we find a negative relationship between percentage load impacts and temperature. We discuss this analysis further in Section 4.1.8.

impacts that are applied to ex-ante reference loads are adjusted based on the ex-ante weather conditions. For example, if we find that percentage load impacts decrease as temperatures increase, then the ex-ante percentage load impact will also be lower for hotter ex-ante weather scenarios. Likewise, the load impact percentage would increase under cooler ex-ante weather scenarios. Where applicable, the method of weather adjusted load impact percentages is only applied to ex-ante reference loads during months that have temperatures that were observed in ex-post. For example, percentage load impacts are not adjusted for January because no ex-post events were called in that month.

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

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

3 PG&E

3.1 PG&E Ex-Post Load Impacts

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

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

3.1.1 All Customers

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

PG&E customers achieve statistically significant load reductions on ten out of twelve event days as well as on the typical event day. The load impact is highest on September 6th, which has the hottest temperature. The event on September 5th was a weekend event, which could explain the relatively low load impacts despite having the second hottest event temperatures of the 2022 events. Overall, Figure 3.1 does not show evidence of a relationship between load impacts and average event temperatures. The event on Aug 17th has the second highest load impact despite having one of the coolest event temperatures.

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

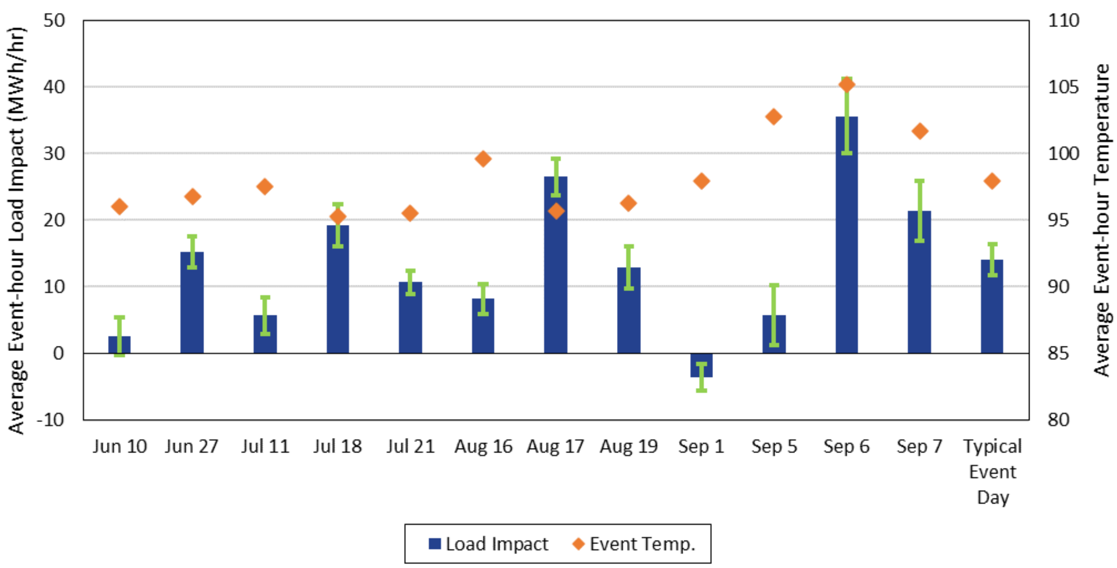


Table 3.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a decrease of more than 1,500 customers over the course of the season. Aggregate load impacts range from -3.6 MWh/hour on September 1st to 35.6 MWh/hour on September 6th. The estimated load reduction for the typical event day is 14.1 MWh/hour, which is a 1.4 percent load reduction[11]. Detailed results by hour, industry group and LCA are presented in subsequent subsections by size group.

[11] The typical event day represents a non-holiday, weekday impact and therefore excludes the holiday event on September 5th.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	113,005	935	2.7	8.3	0.02	0.3%	96.1
6/27/2022	112,748	943	15.2	8.4	0.14	1.6%	96.8
7/11/2022	112,430	939	5.7	8.4	0.05	0.6%	97.5
7/18/2022	112,267	949	19.3	8.5	0.17	2.0%	95.3
7/21/2022	112,182	940	10.7	8.4	0.10	1.1%	95.5
8/16/2022	111,589	999	8.2	9.0	0.07	0.8%	99.6
8/17/2022	111,584	986	26.5	8.8	0.24	2.7%	95.7
8/19/2022	111,564	968	12.9	8.7	0.12	1.3%	96.3
9/1/2022	111,455	990	-3.6	8.9	-0.03	-0.4%	98.0
9/5/2022	111,445	894	5.8	8.0	0.05	0.6%	102.8
9/6/2022	111,442	1,073	35.6	9.6	0.32	3.3%	105.2
9/7/2022	111,441	1,054	21.4	9.5	0.19	2.0%	101.7
Typical Event Day	**111,974**	**980**	**14.1**	**8.8**	**0.13**	**1.4%**	**98.0**

3.1.2 Large Customers

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

The ex-post load impacts for PG&E's large PDP customers are summarized for all twelve events in Figure 3.2. The blue bars indicate the magnitude of the aggregate load impact for the average event hour (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

Large customers had statistically significant load reductions on eight out of twelve event days. The event on September 5th was a holiday event, which could explain the lack of significant load impacts despite the high event temperatures. Figure 3.2 does not show evidence of a relationship between load impacts and event temperatures. The event with the second highest load impact on August 19th has a relatively low temperature, while the event on August 16th has less than half of the load impact despite a much hotter temperature. Moreover, September 6th has the highest load impact and hottest temperature, which suggests there is not a negative relationship between load impacts and average temperature.

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

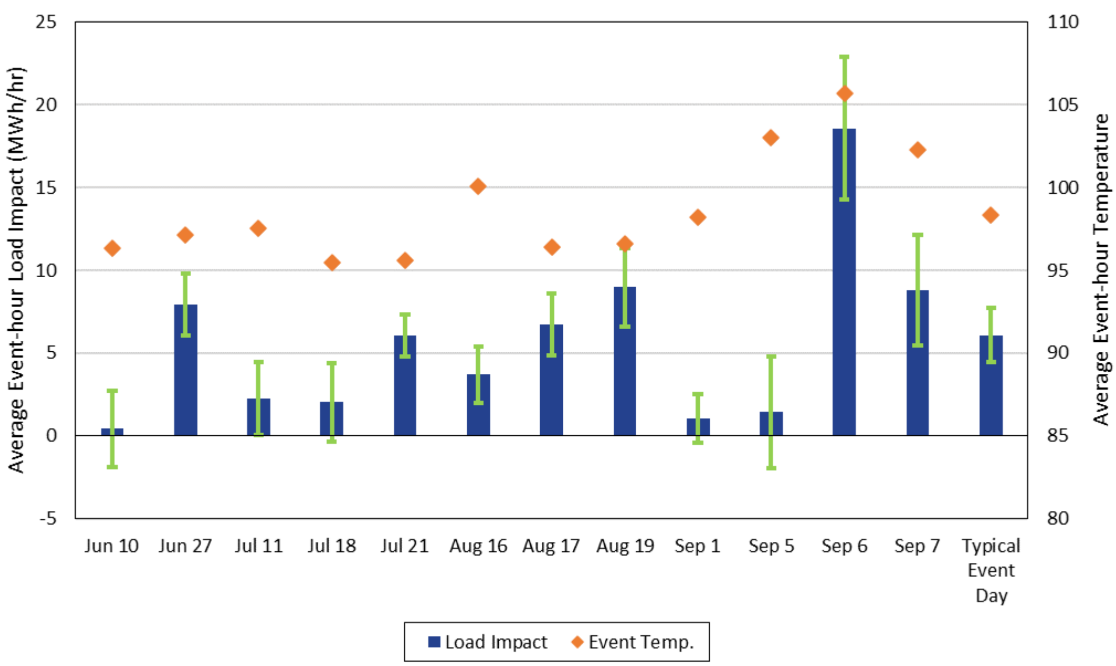


Table 3.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a slight decrease in large customer enrollments over the course of the season. Aggregate load impacts range from 0.4 MWh/hour on June 10th to 18.6 MWh/hour on September 6th. The estimated load reduction for the typical event day is 6.1 MWh/hour, which is a 1.7 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	1,526	343	0.4	224.5	0.3	0.1%	96.3
6/27/2022	1,516	346	7.9	228.1	5.2	2.3%	97.1
7/11/2022	1,503	341	2.3	226.8	1.5	0.7%	97.5
7/18/2022	1,503	344	2.0	229.2	1.3	0.6%	95.4
7/21/2022	1,500	338	6.1	225.3	4.0	1.8%	95.6
8/16/2022	1,500	370	3.7	246.7	2.5	1.0%	100.1
8/17/2022	1,500	366	6.7	244.0	4.5	1.8%	96.4
8/19/2022	1,500	359	9.0	239.0	6.0	2.5%	96.6
9/1/2022	1,498	372	1.0	248.5	0.7	0.3%	98.2
9/5/2022	1,498	323	1.4	215.5	1.0	0.4%	103.0
9/6/2022	1,498	387	18.6	258.4	12.4	4.8%	105.7
9/7/2022	1,498	378	8.8	252.3	5.9	2.3%	102.3
Typical Event Day	**1,504**	**359**	**6.1**	**238.5**	**4.0**	**1.7%**	**98.4**

Figure 3.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 3.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Notice that the highest load impact of 8.9 MWh/hour occurs in the first hour of the event (4 to 5 p.m.). The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are load impacts of approximately 5.8 MWh/hour in the hour immediately preceding (3 to 4 p.m.) and 3.2 MWh/hour in the hour following the event (9 to 10 p.m.). Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

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

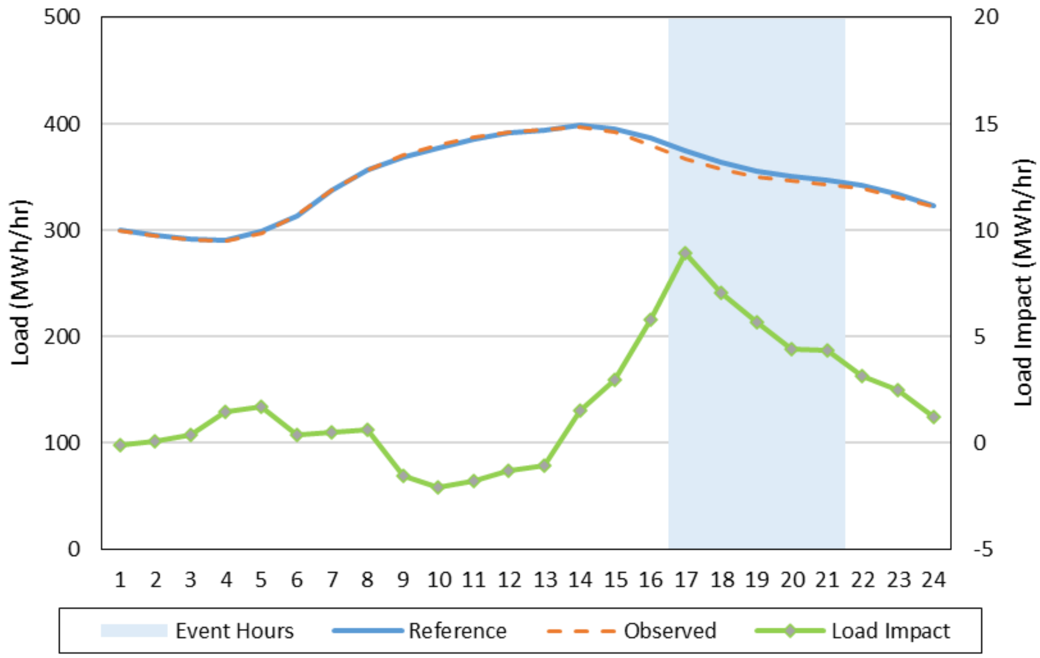


Table 3.3 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for large customers. The load impacts for large customers range from 4.3 MWh/hour (1.3 percent) in the fifth event hour to 8.9 MWh/hour (2.4 percent) in the first event hour.

Table 3.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	299.5	299.6	-0.1	0.0%	81.8	-1.1	-0.5	-0.1	0.3	0.9
2	295.4	295.3	0.1	0.0%	80.2	-0.8	-0.3	0.1	0.4	0.9
3	291.4	291.0	0.4	0.1%	78.4	-0.5	0.0	0.4	0.8	1.3
4	291.0	289.5	1.5	0.5%	76.9	0.7	1.1	1.5	1.8	2.2
5	299.2	297.6	1.7	0.6%	75.5	0.9	1.3	1.7	2.0	2.5
6	313.9	313.6	0.3	0.1%	74.4	-0.5	0.0	0.3	0.7	1.2
7	338.0	337.5	0.5	0.1%	73.9	-0.5	0.1	0.5	0.9	1.5
8	357.0	356.4	0.6	0.2%	75.8	-0.7	0.1	0.6	1.1	1.9
9	369.0	370.5	-1.5	-0.4%	79.8	-2.8	-2.1	-1.5	-1.0	-0.3
10	377.5	379.6	-2.1	-0.6%	84.2	-3.3	-2.6	-2.1	-1.6	-0.9
11	385.4	387.2	-1.8	-0.5%	88.5	-2.7	-2.2	-1.8	-1.4	-0.9
12	391.3	392.6	-1.3	-0.3%	92.3	-2.1	-1.6	-1.3	-1.0	-0.6
13	393.6	394.7	-1.1	-0.3%	95.3	-1.7	-1.3	-1.1	-0.8	-0.4
14	398.9	397.4	1.6	0.4%	97.8	0.8	1.2	1.6	1.9	2.3
15	395.2	392.2	3.0	0.8%	99.7	2.0	2.6	3.0	3.4	4.0
16	386.4	380.6	5.8	1.5%	101.0	4.4	5.2	5.8	6.3	7.1
17	375.2	366.3	8.9	2.4%	101.5	7.4	8.3	8.9	9.5	10.4
18	364.0	356.9	7.0	1.9%	101.0	5.5	6.4	7.0	7.7	8.6
19	356.0	350.3	5.7	1.6%	99.6	4.0	5.0	5.7	6.4	7.4
20	351.0	346.6	4.4	1.3%	96.7	2.9	3.8	4.4	5.1	6.0
21	347.3	343.0	4.3	1.3%	93.0	2.8	3.7	4.3	5.0	5.9
22	342.6	339.4	3.2	0.9%	89.9	1.5	2.5	3.2	3.8	4.8
23	333.2	330.7	2.5	0.8%	87.4	0.9	1.8	2.5	3.2	4.1
24	323.6	322.4	1.2	0.4%	84.6	-0.5	0.5	1.2	1.9	2.9
Daily	**8,375.7**	**8,331.0**	**44.7**	**0.5%**	**87.9**	**34.9**	**40.7**	**44.7**	**48.7**	**54.6**

Next, we look at PG&E large customer estimates by industry group. Table 3.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments and loads are concentrated in the Agriculture, Mining & Construction; Manufacturing; Wholesale, Transportation & Utilities; and Offices, Hotels, Health & Services industry groups, which represent a combined 84 percent of large customers and 85 percent of reference loads. Agriculture, Mining & Construction has the highest aggregate load impact (2.09 MWh/hour), but Other industries has the highest percentage load impact (4.0 percent). While all industry groups have positive load impacts, Agriculture, Mining & Construction and Wholesale, Transportation & Utilities are the only industry groups that achieve more than 1 MWh/hour of load impact.

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

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1.Agriculture, Mining, Construction	680	112	109	2.09	1.9%
2.Manufacturing	186	78	78	0.77	1.0%
3.Wholesale, Transportation, Utilities	213	49	48	1.71	3.5%
4.Retail Stores	[redacted]				
5.Offices, Hotels, Health, Services	189	64	64	0.50	0.8%
6.Schools	62	8	8	0.09	1.1%
7. Institutional/Government	[redacted]				
8.Other	24	4	3	0.14	4.0%

To better understand the distribution of results across industries, we look at the shares of estimated load impacts, reference loads, and enrollments by industry group in Figure 3.4. The load impacts for large customers are driven by three industry groups (Agriculture, Mining & Construction; Manufacturing and Wholesale, Transport & Utilities), which represent 78 percent of load impacts. Moreover, Wholesale, Transport & Utilities contributes a much higher share of the total load impacts (29 percent) compared to the share of enrollments (14 percent) and reference loads (14 percent).

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

[redacted]

Table 3.5 and Figure 3.5 provide the summaries like those above, by LCA. Large customers are concentrated in the Greater Fresno Area and Other LCA, which have reference loads of 109 MWh/hour and 138 MWh/hour, respectively. These two LCAs also account for the majority of the typical event day load impacts with a 1.25 MWh/hour (1.1 percent) load reduction for Greater Fresno Area and a 3.82 MWh/hour (2.8 percent) load reduction for Other LCA. Figure 3.5 reflects the prominence of these two LCAs, although Greater Fresno Area has a lower share (20 percent) of the load impacts compared to the share of customers and reference loads while Other LCA has a greater share (63 percent) of the load impacts compared to customers and reference loads.

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

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	82	26	26	0.02	0.1%
Greater Fresno	540	109	107	1.25	1.1%
Humboldt	[redacted]				
Kern	137	37	36	0.44	1.2%
North Coast/North Bay	[redacted]				
Other/Unknown	487	138	134	3.82	2.8%
Sierra	101	18	18	0.17	1.0%
Stockton	126	27	27	0.39	1.4%

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

[redacted]

3.1.3 Medium Customers

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

The ex-post load impacts for PG&E's medium PDP customers are summarized for all twelve events in Figure 3.6. Medium customers have statistically significant load reductions on ten out of twelve event days and during the typical event day. Figure 3.6 does not show evidence of a strong relationship between load impacts and average event temperature as two of the events with the highest load impacts on July 18th and August 17th have the coolest temperatures, while the event with the hottest temperature on September 6th has the second highest load impact.

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

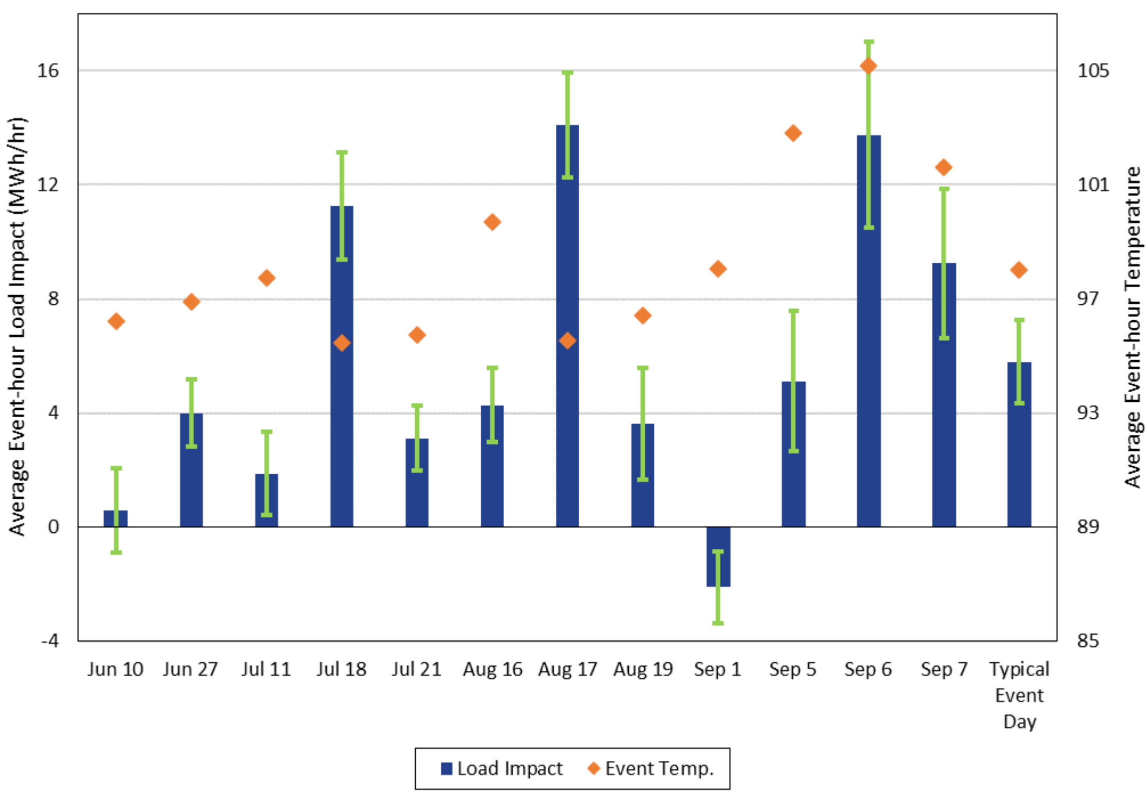


Table 3.6 summarizes enrollments, estimated load impacts, and reference loads for medium customers on each event day as well as for the typical event day. Enrollments decreased slightly over the season for medium customers. Aggregate load impacts range from -2.1 MWh/hour on September 1st to 14.1 MWh/hour on August 17th. The estimated load reduction for the typical event day is 5.8 MWh/hour, which is a 1.4 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	17,853	399	0.6	22.3	0.03	0.1%	96.2
6/27/2022	17,829	402	4.0	22.5	0.22	1.0%	96.9
7/11/2022	17,791	402	1.9	22.6	0.11	0.5%	97.7
7/18/2022	17,770	407	11.3	22.9	0.63	2.8%	95.5
7/21/2022	17,760	404	3.1	22.7	0.18	0.8%	95.7
8/16/2022	17,666	424	4.3	24.0	0.24	1.0%	99.7
8/17/2022	17,666	419	14.1	23.7	0.80	3.4%	95.5
8/19/2022	17,665	411	3.6	23.3	0.21	0.9%	96.4
9/1/2022	17,652	416	-2.1	23.5	-0.12	-0.5%	98.1
9/5/2022	17,649	391	5.1	22.2	0.29	1.3%	102.8
9/6/2022	17,649	461	13.8	26.1	0.78	3.0%	105.2
9/7/2022	17,649	455	9.2	25.8	0.52	2.0%	101.6
Typical Event Day	**17,723**	**418**	**5.8**	**23.6**	**0.33**	**1.4%**	**98.0**

Figure 3.7 plots aggregate loads for medium customers for the typical event day. Similar to large customers, the highest load impact of 7.4 MWh/hour occurs in the first hour of the event (4 to 5 p.m.) and the hourly load impact estimates do not show evidence of pre-cooling or post-event snapback. There are load impacts of approximately 3.7 MWh/hour in the hour immediately preceding (3 to 4 p.m.) and 2.9 MWh/hour in the hour following the event (9 to 10 p.m.). Overall, these results do not suggest that small customers are responding to events by shifting event-hour loads to hours outside the event window.

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

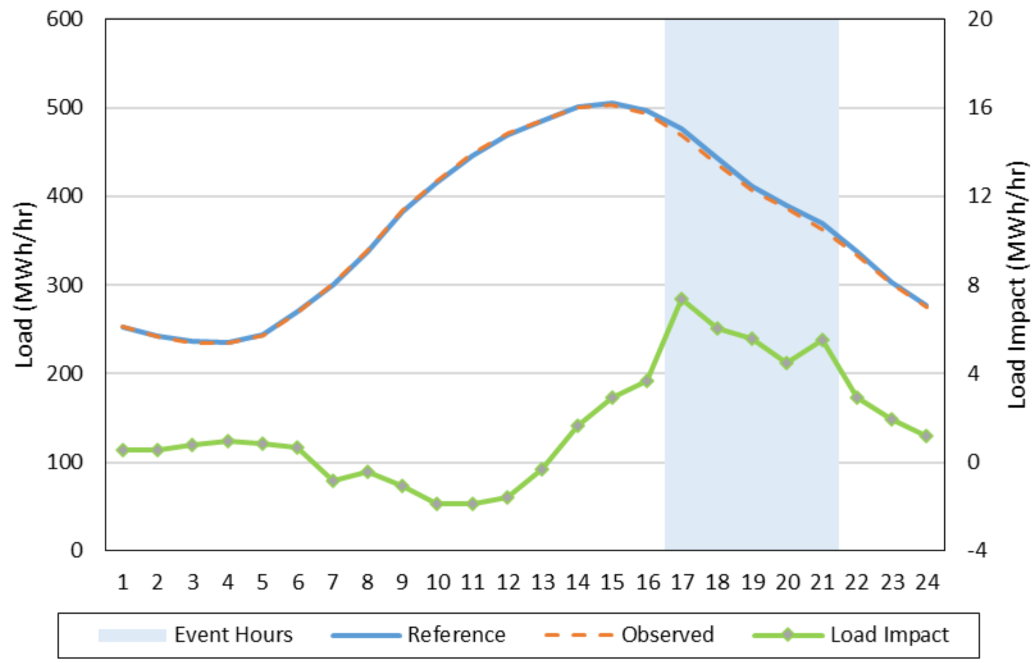


Table 3.7 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for medium customers. The load impacts for medium customers range from 4.5 MWh/hour (1.1 percent) in the fourth event hour to 7.4 MWh/hour (1.5 percent) in the first event hour.

Table 3.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	253.1	252.6	0.5	0.2%	80.3	-0.2	0.2	0.5	0.8	1.3
2	242.8	242.3	0.5	0.2%	78.7	0.0	0.3	0.5	0.8	1.1
3	236.0	235.2	0.8	0.3%	77.0	0.2	0.6	0.8	1.0	1.3
4	234.8	233.9	1.0	0.4%	75.4	0.5	0.7	1.0	1.2	1.5
5	244.5	243.6	0.9	0.4%	74.1	0.4	0.7	0.9	1.1	1.3
6	269.7	269.0	0.7	0.2%	73.0	0.1	0.4	0.7	0.9	1.2
7	299.6	300.4	-0.8	-0.3%	72.7	-1.8	-1.2	-0.8	-0.5	0.1
8	337.9	338.3	-0.4	-0.1%	75.0	-1.0	-0.7	-0.4	-0.2	0.1
9	383.2	384.3	-1.1	-0.3%	79.3	-1.9	-1.4	-1.1	-0.7	-0.2
10	416.3	418.2	-1.9	-0.5%	83.9	-2.9	-2.3	-1.9	-1.5	-0.9
11	445.7	447.5	-1.9	-0.4%	88.3	-2.8	-2.3	-1.9	-1.5	-0.9
12	469.2	470.8	-1.6	-0.3%	92.3	-2.3	-1.9	-1.6	-1.3	-0.8
13	485.1	485.4	-0.3	-0.1%	95.5	-0.6	-0.4	-0.3	-0.2	0.0
14	501.1	499.5	1.6	0.3%	98.1	1.1	1.4	1.6	1.9	2.2
15	505.6	502.7	2.9	0.6%	100.1	2.0	2.5	2.9	3.3	3.9
16	497.2	493.5	3.7	0.7%	101.4	2.5	3.2	3.7	4.2	4.8
17	476.2	468.8	7.4	1.5%	101.9	6.1	6.8	7.4	7.9	8.7
18	442.6	436.6	6.0	1.4%	101.2	4.8	5.5	6.0	6.5	7.3
19	412.0	406.4	5.6	1.4%	99.3	4.3	5.1	5.6	6.1	6.9
20	390.3	385.8	4.5	1.1%	95.9	3.2	4.0	4.5	5.0	5.7
21	369.0	363.5	5.5	1.5%	91.9	4.4	5.1	5.5	6.0	6.6
22	337.7	334.8	2.9	0.9%	88.6	1.5	2.3	2.9	3.5	4.4
23	303.0	301.1	2.0	0.6%	85.8	0.7	1.4	2.0	2.5	3.2
24	276.4	275.2	1.2	0.4%	83.1	-0.1	0.7	1.2	1.7	2.4
Daily	**8,828.9**	**8,789.2**	**39.7**	**0.4%**	**87.2**	**29.9**	**35.7**	**39.7**	**43.7**	**49.5**

Table 3.8 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 37 percent of enrollments and 181 MWh of reference load. However, this industry group only contributes 1.05 MWh/hour to the total load reduction, which is 20 percent of the total. Agriculture, Mining, & Construction and Wholesale, Transportation, & Utilities both contribute more than 1 MWh/hour of load reduction which is 7.6 percent and 2.8 percent of reference loads, respectively. Figure 3.8 illustrates that these two industries contribute a higher share of the total load impacts compared to enrollments and reference loads. In total, these two industry groups along with Offices, Hotel, Health & Services contribute 67 percent of the total load reduction.

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

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1.Agriculture, Mining, Construction	817	16	15	1.22	7.6%
2.Manufacturing	1,141	19	19	0.34	1.8%
3.Wholesale, Transportation, Utilities	2,357	44	43	1.23	2.8%
4.Retail Stores	2,647	77	76	0.59	0.8%
5.Offices, Hotels, Health, Services	6,580	181	180	1.05	0.6%
6.Schools	748	20	20	0.36	1.8%
7. Institutional/Government	3,105	54	53	0.42	0.8%
8.Other	328	6	6	0.01	0.1%

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

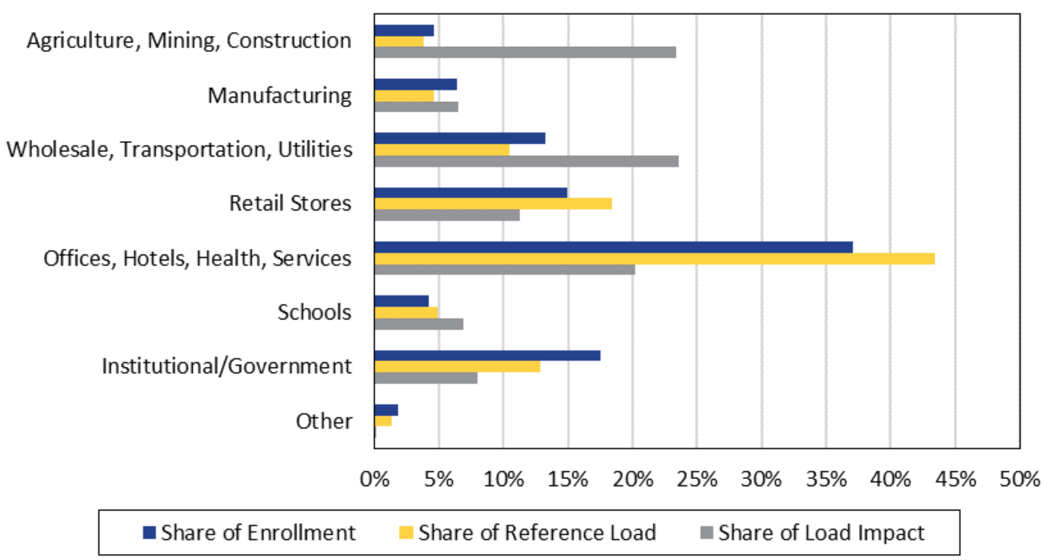
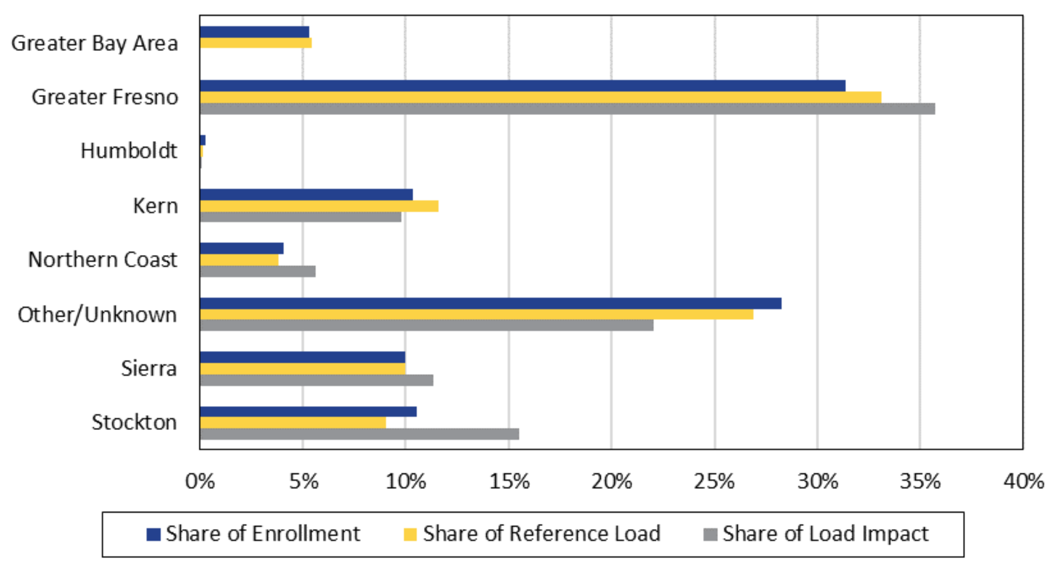


Table 3.9 and Figure 3.9 summarize the results by LCA for medium customers. As with the large customers, enrollments are concentrated in the Greater Fresno Area and Other LCA, which together contain 60 percent of medium customers and account for 139 MWh/hour and 113 MWh/hour of reference loads, respectively. Estimated load impacts are negative for Greater Bay Area, while Greater Fresno Area and Other LCA contribute 2.12 MWh/hour and 1.31 MWh/hour of load reduction, respectively. Figure 3.9 shows that Greater Fresno Area, Northern Coast, Sierra, and Stockton have larger shares of the total load impacts compared to the share of enrollments or reference loads.

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

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	941	23	23	-0.14	-0.6%
Greater Fresno	5,556	139	136	2.12	1.5%
Humboldt	43	0.56	0.56	0.00	0.5%
Kern	1,829	48	48	0.58	1.2%
North Coast/North Bay	719	16	16	0.34	2.1%
Other/Unknown	5,010	113	111	1.31	1.2%
Sierra	1,764	42	41	0.67	1.6%
Stockton	1,862	38	37	0.92	2.4%

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



3.1.4 Small Customers

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

The ex-post load impacts for PG&E's small PDP customers are summarized for all twelve events in Figure 3.10. The small customers have statistically significant positive load impacts on eight out of twelve event days and the typical event day. The event on September 5th was a holiday event, which could explain the negative and insignificant load impact despite the relatively high temperature. Figure 3.10 does not show evidence of a relationship between load impacts and average temperature. The events with the highest load impacts on July 18th and August 17th have the coolest temperatures, while the hottest events on September 6th and 7th have relatively high load impacts.

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

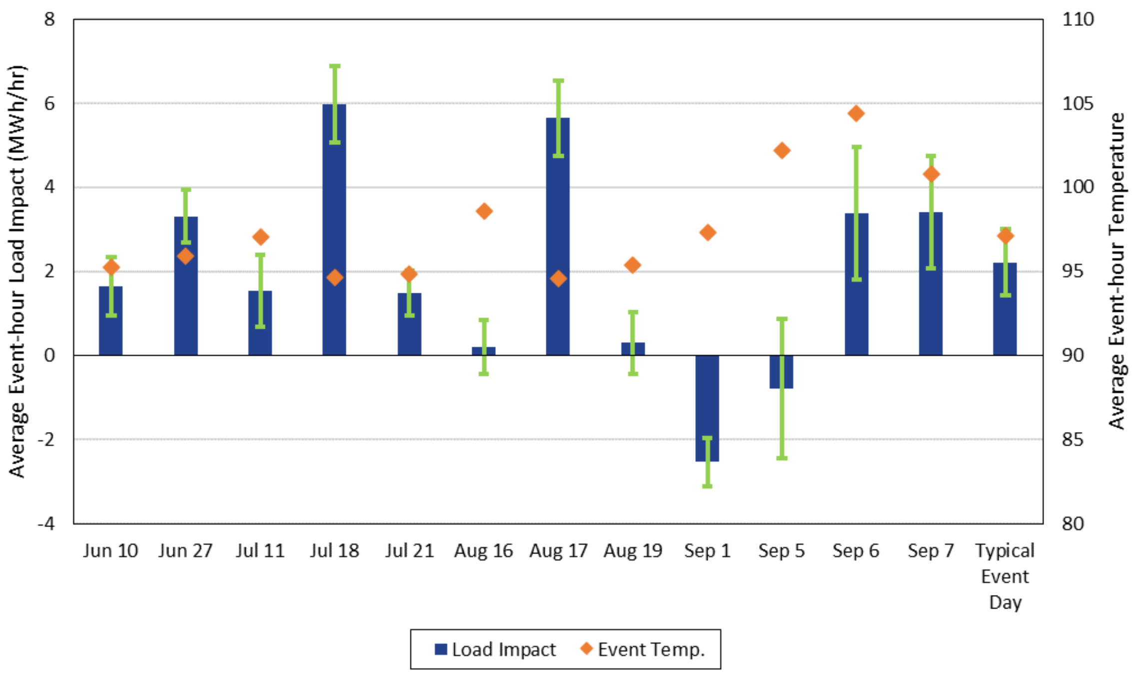


Table 3.10 summarizes enrollments, estimated load impacts, and reference loads for small customers on each event day as well as for the typical event day. Small customer enrollments decreased by more than 1,300 customers across the events in 2022. Aggregate load impacts range from -2.5 MWh/hour on September 1st to 6.0 MWh/hour on July 18th. The estimated load reduction for the typical event day is 2.2 MWh/hour, which is a 1.1 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	93,626	193.5	1.7	2.07	0.02	0.9%	95.3
6/27/2022	93,403	195.6	3.3	2.09	0.04	1.7%	95.9
7/11/2022	93,136	196.3	1.5	2.11	0.02	0.8%	97.0
7/18/2022	92,994	197.8	6.0	2.13	0.06	3.0%	94.7
7/21/2022	92,922	198.9	1.5	2.14	0.02	0.7%	94.9
8/16/2022	92,423	205.3	0.2	2.22	0.00	0.1%	98.6
8/17/2022	92,418	201.3	5.6	2.18	0.06	2.8%	94.6
8/19/2022	92,399	198.1	0.3	2.14	0.00	0.2%	95.4
9/1/2022	92,305	201.6	-2.5	2.18	-0.03	-1.3%	97.3
9/5/2022	92,298	181.6	-0.8	1.97	-0.01	-0.4%	102.2
9/6/2022	92,295	226.7	3.4	2.46	0.04	1.5%	104.4
9/7/2022	92,294	222.6	3.4	2.41	0.04	1.5%	100.8
Typical Event Day	**92,747**	**203.5**	**2.2**	**2.19**	**0.02**	**1.1%**	**97.1**

Figure 3.11 plots aggregate loads for small customers for the typical event day. Similar to medium and large customers, the highest load impact of 3.5 MWh/hour occurs in the first hour of the event (4 to 5 p.m.) and the hourly load impact estimates do not show evidence of pre-cooling or post-event snapback. There are load impacts of approximately 1.7 MWh/hour in the hour immediately preceding (3 to 4 p.m.) and 1.2 MWh/hour in the hour following the event (9 to 10 p.m.). Overall, these results do not suggest that medium customers are responding to events by shifting event-hour loads to hours outside the event window.

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

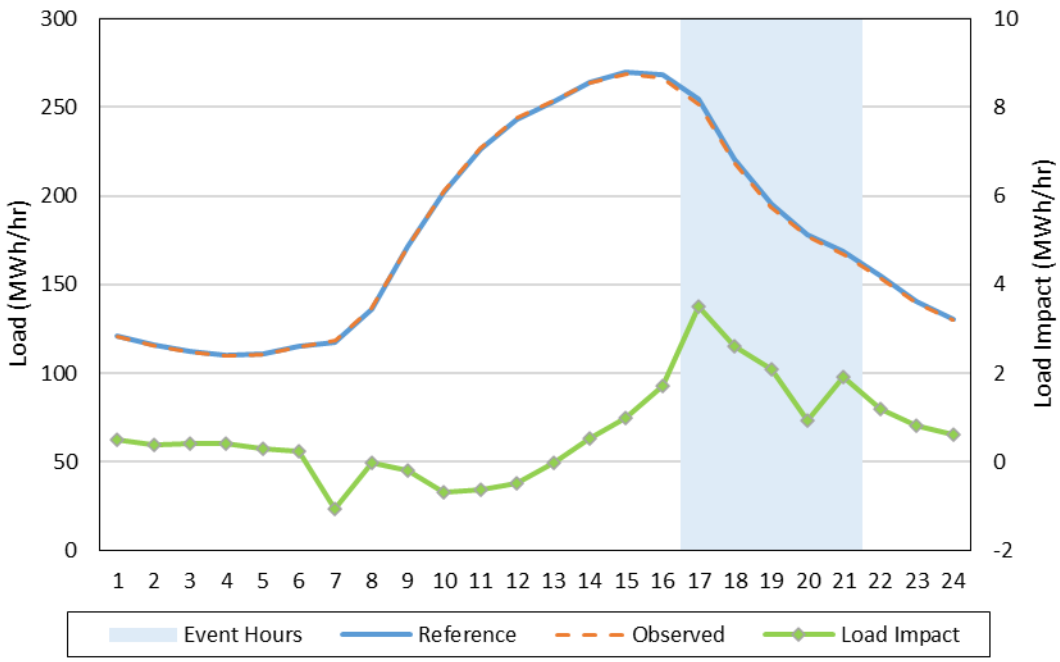


Table 3.11 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for small customers. The load impacts for small customers range from 0.9 MWh/hour (0.5 percent) in the fourth event hour to 3.5 MWh/hour (1.4 percent) in the first event hour.

Table 3.11: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Small*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	120.9	120.4	0.5	0.4%	79.3	0.2	0.4	0.5	0.6	0.8
2	116.0	115.6	0.4	0.3%	77.8	0.1	0.3	0.4	0.5	0.6
3	112.4	112.0	0.4	0.4%	76.1	0.2	0.3	0.4	0.5	0.6
4	110.4	110.0	0.4	0.4%	74.5	0.2	0.3	0.4	0.5	0.6
5	111.0	110.7	0.3	0.3%	73.3	0.1	0.2	0.3	0.4	0.5
6	115.1	114.8	0.2	0.2%	72.2	-0.2	0.1	0.2	0.4	0.7
7	117.0	118.1	-1.1	-0.9%	71.9	-1.8	-1.3	-1.1	-0.8	-0.4
8	136.3	136.3	0.0	0.0%	74.4	-0.3	-0.1	0.0	0.1	0.3
9	171.8	172.0	-0.2	-0.1%	79.0	-0.7	-0.4	-0.2	0.0	0.3
10	202.1	202.8	-0.7	-0.3%	83.7	-1.3	-1.0	-0.7	-0.4	-0.1
11	226.4	227.1	-0.6	-0.3%	88.2	-1.2	-0.9	-0.6	-0.4	0.0
12	243.3	243.8	-0.5	-0.2%	92.1	-0.9	-0.6	-0.5	-0.3	-0.1
13	253.4	253.4	0.0	0.0%	95.4	-0.2	-0.1	0.0	0.0	0.1
14	263.7	263.2	0.5	0.2%	97.9	0.3	0.4	0.5	0.6	0.8
15	269.9	268.9	1.0	0.4%	99.8	0.5	0.8	1.0	1.2	1.5
16	268.5	266.8	1.7	0.6%	101.1	1.1	1.5	1.7	2.0	2.3
17	254.6	251.1	3.5	1.4%	101.3	2.8	3.2	3.5	3.8	4.2
18	220.6	218.0	2.6	1.2%	100.5	1.9	2.3	2.6	2.9	3.3
19	195.7	193.6	2.1	1.1%	98.4	1.4	1.8	2.1	2.4	2.7
20	178.2	177.2	0.9	0.5%	94.8	0.2	0.6	0.9	1.2	1.6
21	168.4	166.4	1.9	1.1%	90.7	1.3	1.6	1.9	2.2	2.6
22	154.8	153.6	1.2	0.8%	87.4	0.6	0.9	1.2	1.4	1.8
23	140.3	139.4	0.8	0.6%	84.7	0.3	0.6	0.8	1.0	1.3
24	130.3	129.7	0.6	0.5%	82.1	0.1	0.4	0.6	0.8	1.1
Daily	**4,281.0**	**4,265.0**	**16.0**	**0.4%**	**86.5**	**10.8**	**13.9**	**16.0**	**18.1**	**21.2**

Table 3.12 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 36 percent of enrollments and 91 MWh/hour of reference loads. While no industry group achieves 1 MWh/hour of load reduction, Offices, Hotel, Health & Services has the highest load impact of 0.77 MWh/hour. Figure 3.12 illustrates the shares of enrollment, reference load, and load impact by industry group. Offices, Hotel, Health & Services and Retail Stores contribute the majority of the total load reduction at 58 percent and Retail Stores contributes a higher share of load impacts than their share of enrollments or reference loads.

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

Industry Type	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1. Agriculture, Mining, Construction	6,648	11	11	0.16	1.5%
2. Manufacturing	2,777	5	5	0.09	1.6%
3. Wholesale, Transportation, Utilities	15,899	20	19	0.24	1.2%
4. Retail Stores	8,831	31	30	0.43	1.4%
5. Offices, Hotels, Health, Services	33,326	91	91	0.77	0.8%
6. Schools	1,283	3	3	0.06	1.8%
7. Institutional/Government	18,420	33	33	0.24	0.7%
8. Other	5,564	8	7	0.09	1.2%

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

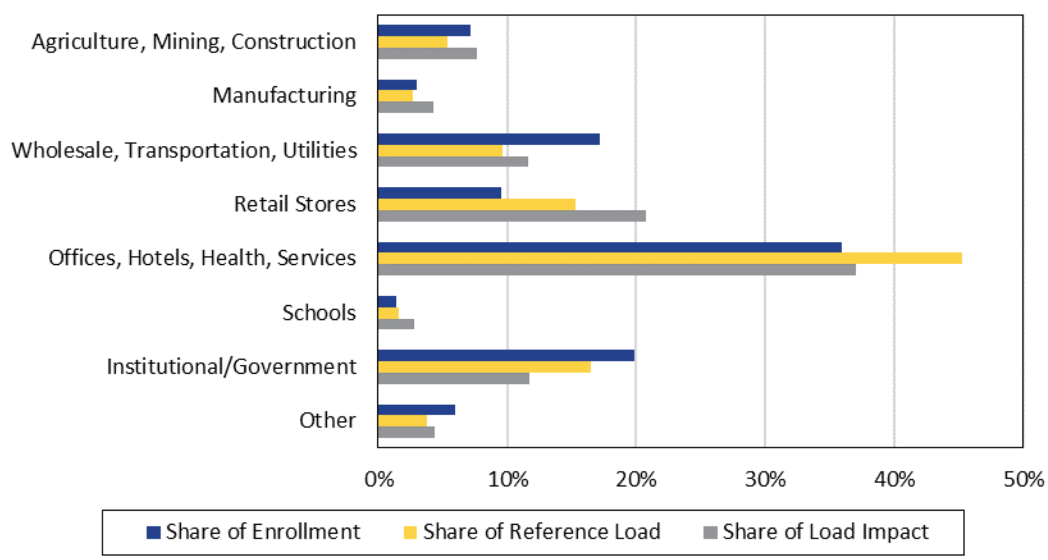
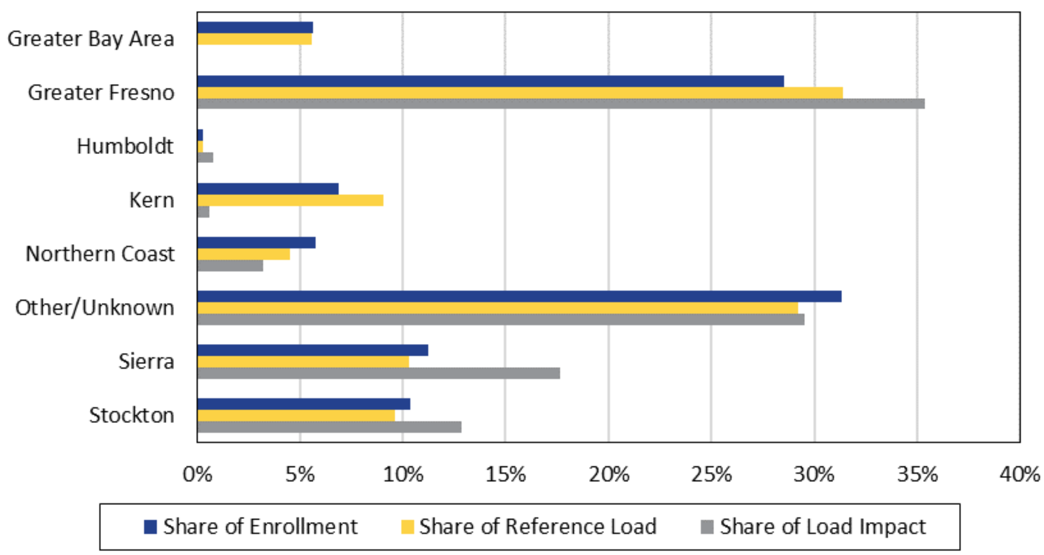


Table 3.13 and Figure 3.13 summarize the results by LCA for small customers. As with the large and medium customers, enrollments are concentrated in the Greater Fresno Area and Other LCA, which together contain 60 percent of small customers and account for 64 MWh/hour and 59 MWh/hour of reference loads. Together these two LCAs achieve a 1.47 MWh/hour load impact or 65 percent of the total load impacts, although no single LCA's load impact exceeds 1 MWh/hour. Similar to medium customers, the estimated load impacts for the Greater Bay Area are negative. Figure 3.13 shows that Greater Fresno Area, Sierra, and Stockton have a larger share of the total load reduction compared their share of enrollments and reference loads.

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

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	5,228	11	11	-0.05	-0.4%
Greater Fresno	26,445	64	63	0.80	1.3%
Humboldt	265	0.58	0.56	0.02	3.1%
Kern	6,402	18	18	0.01	0.1%
North Coast/North Bay	5,347	9	9	0.07	0.8%
Other/Unknown	29,033	59	59	0.67	1.1%
Sierra	10,405	21	21	0.40	1.9%
Stockton	9,622	20	19	0.29	1.5%

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



3.1.5 Dually Enrolled Customers

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

Table 3.14 summarizes average event-hour results for each event-day as well as the typical event day for customers who are dually enrolled in BIP and PDP, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). There are no reported results on September 5th, 6th, and 7th because these are dual event days—all load impacts for dually enrolled customers are attributed to BIP. [redacted]

Table 3.14: Average Event-Hour Load Impacts for PDP+BIP customers by Event, *PG&E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	[redacted]						
6/27/2022							
7/11/2022							
7/18/2022							
7/21/2022							
8/16/2022							
8/17/2022							
8/19/2022							
9/1/2022							
Typical Event Day							

3.1.6 AutoDR Customers

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

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

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

Table 3.15: Average Event-Hour Load Impacts for AutoDR Customers by Event, *PG&E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/10/2022	[redacted]						
6/27/2022							
7/11/2022							
7/18/2022							
7/21/2022							
8/16/2022							
8/17/2022							
8/19/2022							
9/1/2022							
9/5/2022							
9/6/2022							
9/7/2022							
Typical Event Day							

3.1.7 Notified vs. Non-Notified Customers

This section compares customers who receive notifications versus customers who do not receive notifications. Notifications are sent a day ahead of each event either by email, fax, phone, or SMS. We contrast average load impacts for the typical event day for customers that successfully receive notifications compared to those who do not by size group. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

While approximately 90 percent of PDP customers receive event notifications, an issue with missing contact information for some PDP customers led to a large share of customers not receiving event notifications for the first six events. For the first five events, approximately 70 percent of PDP customers received event notifications. A higher share of customers received event notifications for the sixth event on August 16th (86 percent). This issue may affect load impact performance for customers receiving notifications on the typical event day, which includes the first six events.

Table 3.16 summarizes aggregate event-hour results for the typical event day, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). 80 percent of customers successfully receive notifications on average, and these customers generate 84 percent of the aggregate load impacts. Large and medium customers who receive notifications have slightly lower per-customer load impacts, in contrast to the results presented in the PY2021 report. This could be impacted by the notification issues described above. None of the large BIP customers received notifications during these events, suggesting that the missing contact information did not impact a random selection of PDP customers who were signed up to receive notifications.

Table 3.16: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, PG&E

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	177	32.9	0.9	185.7	4.81	2.6%	96.5
	Medium	3,308	71.3	1.2	21.5	0.35	1.6%	98.3
	Small	19,066	38.1	0.3	2.0	0.01	0.7%	97.2
	All	**22,551**	**142.2**	**2.3**	**6.3**	**0.10**	**1.6%**	**97.6**
Yes	Large	1,328	326.0	5.3	245.5	3.96	1.6%	98.6
	Medium	14,415	345.5	4.7	24.0	0.32	1.4%	97.9
	Small	73,680	162.7	1.8	2.2	0.03	1.1%	97.1
	All	**89,423**	**834.1**	**11.8**	**9.3**	**0.13**	**1.4%**	**98.0**

3.1.8 ESS Customers

This section compares customers who receive enhanced in-season support (ESS) versus customers who do not receive enhanced support. ESS customers receive day-of event notifications, in addition to regular day-ahead notifications (for customers who are signed up for regular notifications), as well as a performance summary after each event. We contrast average load impacts for the typical event day for customers in the ESS program compared to those who do not by size group. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.17 summarizes aggregate event-hour results for the typical event day, including the number of enrolled customers, the reference loads, and the estimated load impacts (in MWh/hour, kWh/customer/hour, and as a percentage of reference loads). 37 percent of customers receive enhanced support; however, these customers only generate 33 percent of the aggregate load impacts. Large and medium ESS customers have lower per-customer load impacts compared to customers who do not receive enhanced support. However, this result does not provide conclusive evidence that the ESS program is not effective at improving PDP customer response. Because PDP customers must opt into the ESS program, comparing load impacts between ESS and non-ESS customers may not show the true impact of ESS on PDP customer performance due to self-selection bias. For example, none of the large BIP customers, which tend to have higher per-customer load impacts, are in the ESS program, which would downward bias the effect of ESS on PDP customer performance when derived from a comparison of load impacts between ESS and non-ESS customers.

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

ESS Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	632	118.2	4.1	187.0	6.44	3.4%	97.4
	Medium	10,466	234.5	4.1	22.4	0.39	1.7%	98.3
	Small	59,025	123.2	1.3	2.1	0.02	1.1%	97.2
	All	**70,123**	**475.9**	**9.4**	**6.8**	**0.13**	**2.0%**	**97.8**
Yes	Large	872	240.6	2.0	275.9	2.32	0.8%	98.7
	Medium	7,257	183.5	1.8	25.3	0.24	1.0%	97.8
	Small	33,722	80.3	0.9	2.4	0.03	1.1%	97.0
	All	**41,851**	**504.4**	**4.7**	**12.1**	**0.11**	**0.9%**	**98.1**

To better assess the impact of the ESS program on PDP customers performance, we estimate a regression model on the sample of ESS customers that compares the load impacts for these customers in 2021, before enhanced support was provided, to their load impacts in 2022, when enhanced support is provided. We estimate a model similar to the one described in Section 2.1.4, but which adds an interaction term between the average event load impact and the effect of joining ESS in 2022. This term estimates the incremental effect of joining ESS for customers in the ESS program.[12] We also include additional controls in the model for the impact of customers successfully receiving standard event notifications and customers who participate in the BES/CRS program.

Figure 3.14 summarizes the average incremental load impact for customers that joined ESS in 2022. The blue bars indicate the incremental load impacts during the common event hours from 5-8 p.m. on non-holiday weekday events as a percentage of ESS customer reference loads in 2022. The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes). These results suggest that ESS led to an incremental increase in load impacts of 1.4 percent and this result is statically significant. The incremental load impacts for large customers are 1.2 percent, but this estimate is not statistically different from zero. In contrast, the incremental load impacts for small and medium customers are 2 percent and 1.6 percent, respectively, and are statistically significant.

These results suggest that the ESS program may be more impactful for small and medium customers compared to large customers. This could be due to the higher share of large customers that participate in the BES/CRS program compared to small and medium customers as discussed in the next section. To determine the extent to which ESS customer incremental load impacts are driven by participation in BES/CRS, we

[12] This estimate is not necessarily representative of the effect of the average PDP customer joining ESS. This model only estimates the impact of the ESS program for the customers that have decided to join ESS in 2022.

estimate a model that further decomposes the ESS incremental load impact into BES and no BES customers.

Figure 3.14: Incremental Load Impacts for Customers that Join ESS in 2022 during HE 18-20 on Non-Holiday, Weekday events by Size, *PG&E*

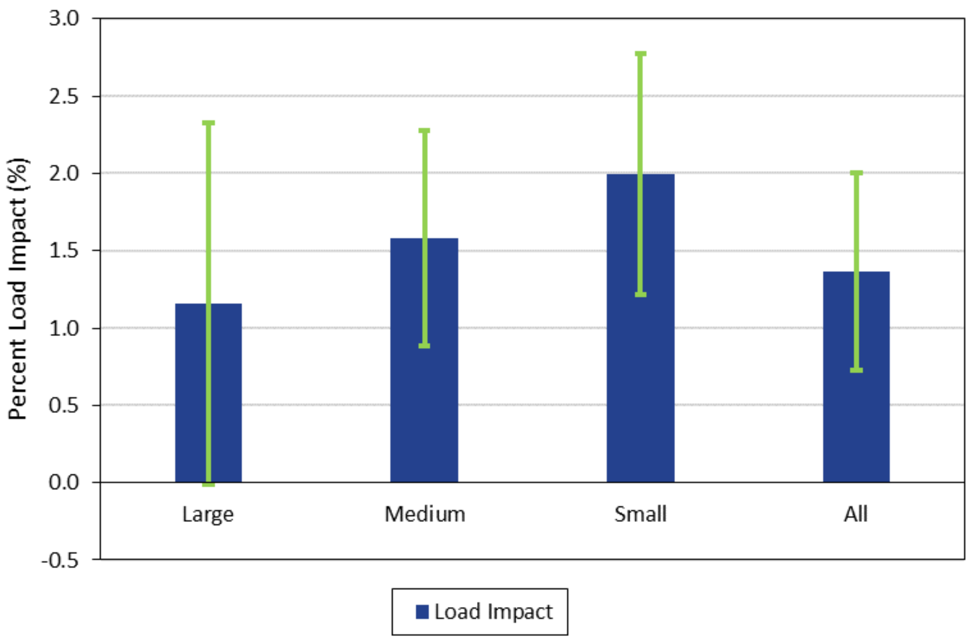


Table 3.18 contrasts the results from the basic ESS model (as summarized in Figure 3.14) with the results from the model that decomposes the incremental ESS load impacts into no BES versus BES customers. We present results for the incremental per-customer load impacts and as a percent of customer reference loads in 2022 for each relevant group.[13] The stars indicate results that are significant at the 10 percent level. The results from the BES Interacted Model suggest that the incremental load impacts for ESS, no BES customers are positive for all size groups and significant for small and medium customers and overall. The incremental load impacts for small and medium ESS and BES customers are not significant. These results further support the notion that ESS may be more impactful for small and medium customers, who are less likely to be enrolled in BES compared to large customers. The ESS and BES incremental load impact for large customers is not significant, however the effect is larger in magnitude than the incremental effect for no BES large customers, which suggests that BES may be playing a larger role in the estimated incremental effects for large ESS customers.

[13] The incremental load impacts summarized in Table 3.18 only show the incremental change in load impacts for ESS customers in 2022 relative to the average load impacts in 2021. These incremental effects do not show ESS customer performance in 2021, before enhanced support was available. The full regression results (not depicted in the report) show that load impacts for these customers in 2021 were not statistically significant, suggesting that customers who enroll in ESS in 2022 were not highly responsive PDP customers in 2021.

Table 3.18: Incremental Load Impacts for ESS Customers during HE 18-20 on Non-Holiday, Weekday events in 2021-2022 by Size, PG&E

Model	Group	Size	# Enrolled	Incremental Load Impact		Avg. Temp.
				kWh/customer/hour	%	
ESS Model	ESS	Large	464	2.52	1.2%	99.3
		Medium	4,421	0.39*	1.6%	98.6
		Small	19,874	0.04*	2.0%	97.8
		All	**24,759**	**0.14***	**1.4%**	**98.7**
ESS, BES Interacted Model	ESS, No BES	Large	226	1.03	0.7%	99.9
		Medium	3,266	0.54*	2.4%	98.5
		Small	16,858	0.05*	2.3%	97.8
		All	**20,349**	**0.13***	**1.9%**	**98.6**
	ESS and BES	Large	238	3.6	1.2%	99.0
		Medium	1,155	0.01	0.0%	98.9
		Small	3,017	0.00	-0.2%	97.4
		All	**4,410**	**0.18**	**0.7%**	**98.9**

3.1.9 Other Subgroup Results

This section summarizes the average load impacts for customers in the agricultural, commercial, and government rate classes, customers who received Business Energy Support (BES/CRS), and NEM customers. We present results for the average event-hour for the typical event day by size group. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

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

The results for the rate classes show that most customers (97 percent) are on a commercial/industrial rate class, however 38 percent of large customers are on an agricultural rate class. The agricultural rate class has higher load impacts both in per-customer terms (1.7 kWh/customer/hour) and as a percent of reference loads (3.5 percent) and generates 23 percent of the load impacts despite having only 2 percent of customers. The commercial rate class has the highest aggregate load impacts at 10.5 MWh/hour.

The results for BES/CRS customers show that this customer support program is highly targeted towards large customers: 47 percent of large customers have BES/CRS compared to 23 percent of medium customers and 14 percent of small customers (16 percent of all customers). Large and medium BES/CRS customers generate higher per-customer load impacts, leading to this group representing a larger share of large and medium load impacts compared to the share of enrollments. Customers receiving

BES/CRS support generate 39 percent of aggregate load impacts compared to 16 percent of enrollments.

The results for NEM customers suggest that across all sizes, NEM customers do not make load reductions during PDP events. Only 2 percent of PDP customers are NEM customers, but the share of medium and large customers is higher at 4 and 8 percent, respectively.

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

Subgroup	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Agricultural Rate Class	Large	566	82.9	2.4	146.47	4.22	2.9%	101.9
	Medium	215	7.4	0.9	34.22	4.09	12.0%	101.8
	Small	1,115	1.9	0.0	1.68	-0.04	-2.6%	99.8
	All	**1,897**	**92.2**	**3.2**	**48.60**	**1.70**	**3.5%**	**101.9**
Commercial/ Industrial Rate Class	Large	925	265.1	3.4	286.55	3.72	1.3%	97.6
	Medium	17,303	406.1	4.8	23.47	0.28	1.2%	98.0
	Small	90,643	199.5	2.2	2.20	0.02	1.1%	97.1
	All	**108,871**	**870.7**	**10.5**	**8.00**	**0.10**	**1.2%**	**97.7**
ST/GOV Rate Class	Large	[redacted]						
	Medium	205	4.6	0.1	22.39	0.50	2.2%	97.6
	Small	988	2.0	0.0	2.06	0.01	0.5%	96.9
	All	[redacted]						
BES/CRS	Large	708	238.9	3.7	337.37	5.19	1.5%	97.9
	Medium	3,988	127.6	1.8	31.99	0.45	1.4%	98.2
	Small	13,402	27.5	0.1	2.05	0.01	0.3%	96.2
	All	**18,099**	**394.0**	**5.5**	**21.77**	**0.31**	**1.4%**	**97.9**
NEM	Large	117	30.7	-0.5	262.71	-4.09	-1.6%	96.6
	Medium	696	17.6	-0.5	25.28	-0.66	-2.6%	96.9
	Small	941	2.8	-0.1	2.96	-0.09	-3.1%	97.0
	All	**1,755**	**51.2**	**-1.0**	**29.20**	**-0.59**	**-2.0%**	**96.8**
All Customers	Large	1,504	358.7	6.1	238.50	4.05	1.7%	98.4
	Medium	17,723	418.0	5.8	23.59	0.33	1.4%	98.0
	Small	92,747	203.5	2.2	2.19	0.02	1.1%	97.1
	All	**111,974**	**980.3**	**14.1**	**8.75**	**0.13**	**1.4%**	**98.0**

3.1.10 Capacity Reservation Level (CRL) Analysis

This section analyzes the impact of the Capacity Reservation Level (CRL) on customer loads during PDP events and dual PDP and ELRP events. The CRL is a fixed level of capacity (KW) that large commercial and agricultural customers designate to be protected from the PDP rate during events. While PDP customers do not have any incentive beyond the retail rate to lower consumption below their designated CRL during events, ELRP customers receive a credit for the full amount of their load reduction during ELRP events, including dual PDP and ELRP events.

To examine the extent to which PDP customer usage drops below their CRL, we estimate a regression model on the sample of PDP customers that have a designated CRL. We estimate a model similar to the model described in 2.1.4, but instead of customer usage in kWh as the dependent variable, we use a binary variable that indicates whether a customer's usage level is below their CRL. We examine whether dual PDP and ELRP customers respond to the additional incentive provided by the ELRP program by estimating a difference-in-differences (DID) model that estimates the probability that a customer drops below their CRL during a given event hour including the following regression terms: 1) the difference for dual PDP and ELRP customers on PDP-only events, 2) the difference for PDP-only customers on dual PDP and ELRP events, and 3) the difference for dual PDP and ELRP customers during dual PDP and ELRP events.[14] The coefficient of interest is the third term in the DID model, which indicates whether there is an incremental increase in the probability of dual customers dropping below their CRL during dual PDP and ELRP events.

Figure 3.15 summarizes the DID estimate—the incremental change in the probability of dropping below the CRL for dual customers during dual events. The blue bars indicate the change in probability of a customer dropping below their CRL for the average event hour on non-holiday weekday events. The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes).

Overall, these results suggest that dual PDP and ELRP customers are not statistically more likely to drop below their CRL on dual events compared to PDP-only customers. [redacted] These results suggest that there is not convincing evidence that ELRP customers respond to the additional incentive to lower their usage below their CRL during dual PDP and ELRP events.

[14] We estimate a linear probability model, which allows for a direct interpretation of the estimated coefficients.

Figure 3.15: Incremental Change in the Probability of Customer Usage Below CRL for Dually Enrolled Customers during Dual Events by Size, *PG&E*

[redacted]

3.2 PG&E Ex-Ante Load Impacts

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

As described in Section 2.2, *per-customer load impacts* are derived from analysis of current and previous ex-post load impacts. We investigated the effect of weather on estimated load impacts (and percentage load impacts) and found that there was not a strong relationship between load impacts and weather conditions for most customer groups. Therefore, we simulate ex-ante load impacts by multiplying forecasted reference loads and ex-post percentage load impacts (by size, LCA, and hour of the day).

3.2.1 All Customers

Figure 3.16 summarizes the overall trend of PG&E's enrollment forecast. PG&E anticipates a 1 percent increase in total enrollment from 2022 to 2023 due to customer defaults into the PDP program. After 2023, an annual attrition of 7 percent is expected.

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

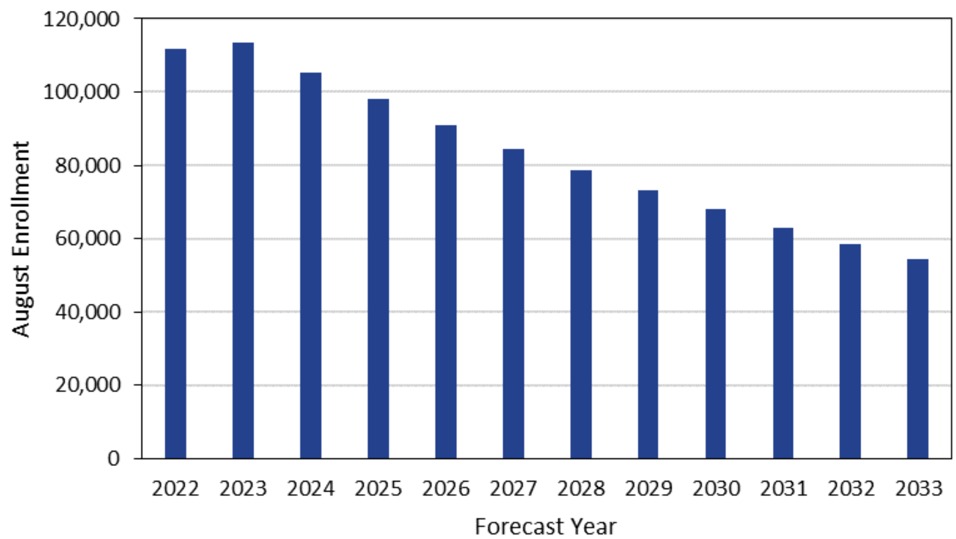
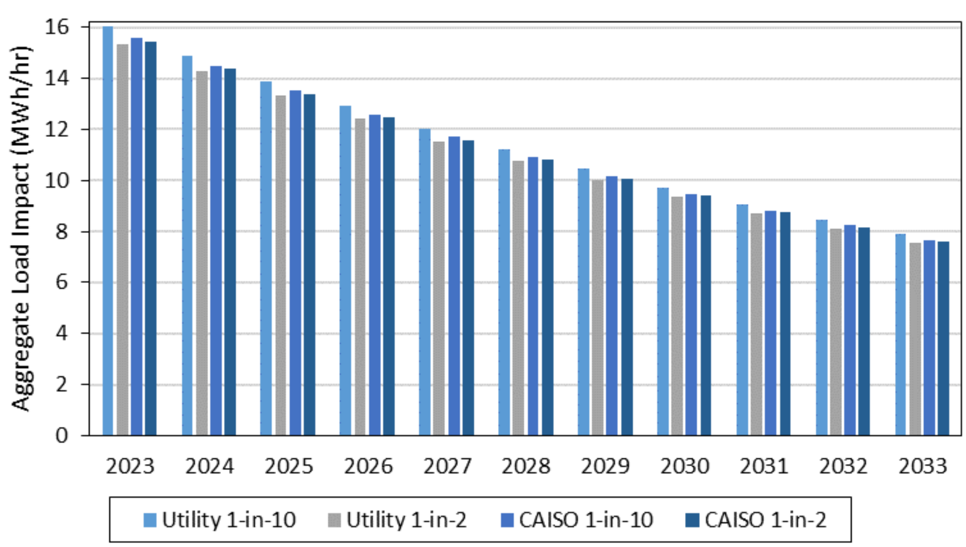


Figure 3.17 shows the change in program load impacts for PDP over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average Resource Adequacy (RA) window hour of the typical event day. Load impacts decline over time due to program attrition. The highest load impacts for each year occur under the PG&E 1-in-10 weather conditions. There are relatively minor differences between load impacts across the weather scenarios. Additional summaries of the ex-ante forecast are presented by size group.

Figure 3.17: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E All*



3.2.2 Large Customers

Figure 3.18 summarizes PG&E's enrollment forecast for large customers. PG&E anticipates a 27 percent increase in large customer enrollments from 2022 to 2023 due to customer defaults into the PDP program, including a default of large agricultural customers in March of 2023. After 2023, annual customer attrition of 7 percent is expected.

Figure 3.18: PDP Enrollments, *PG&E Large*

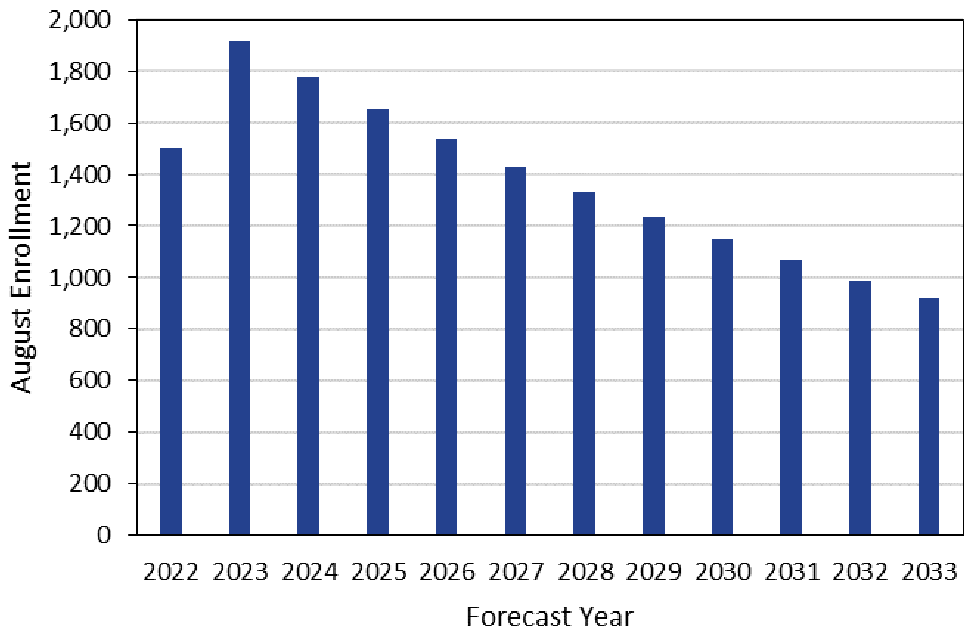


Figure 3.19 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The RA window load impacts have similar shape as the ex-post results in Figure 3.3, but the ex-ante load impacts are larger in magnitude due to higher enrollments. The average RA window load impact is 7.2 MWh/hour, or 1.6 percent of the reference loads.

Figure 3.19: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

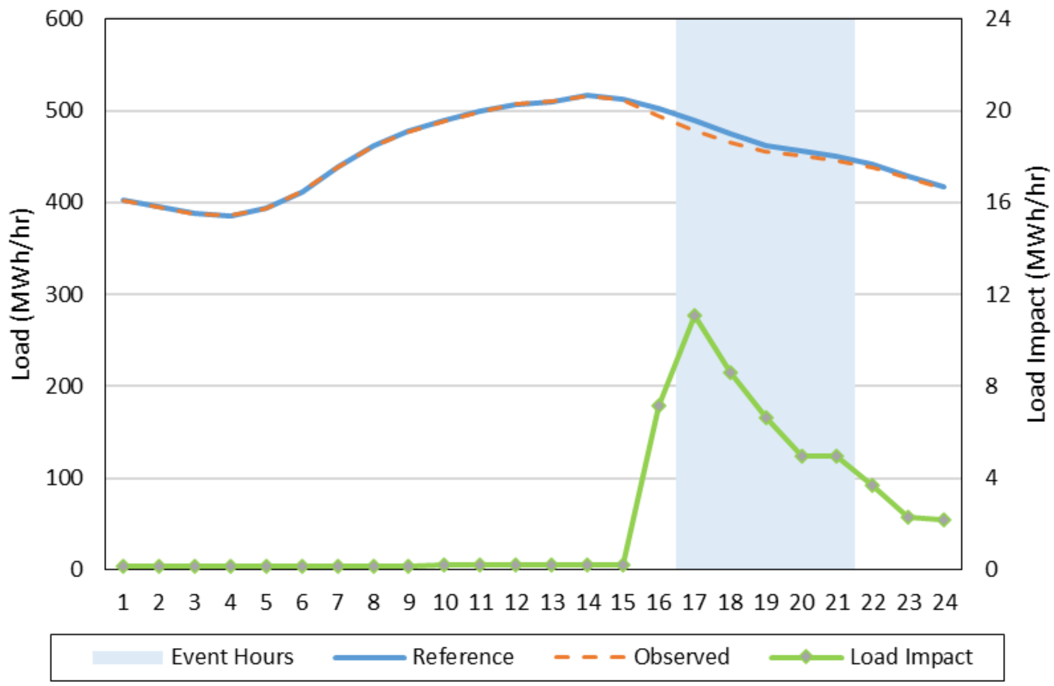


Figure 3.20 shows the forecasted share of load impacts by LCA during the average event hour on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Other LCA has the largest share of load impacts. Greater Fresno Area and Kern have the second and third largest shares of load impacts. In total, the three LCAs contribute 88 percent of load impacts in the forecast. The top three LCAs in terms of the share of load impacts are the same as the ex-post results presented in Figure 3.5. The share of Other LCA is 4.6 percent lower than ex-post. Declines in enrollment and per-customer load impacts in Other LCA contribute to this change. Enrollment in Other LCA drops 1.6 percent in the ex-ante forecast, including the de-enrollment of one large BIP customer, which lowers the per-customer load impacts.

Figure 3.20: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

[redacted]

Figure 3.21 illustrates the seasonality in the forecasted load impacts for large customers by comparing aggregate load impacts for the average hour in the RA window in 2024, after large customer defaults have been completed, across months for PG&E’s 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March and April, when it is 5 to 10 p.m. The load impact is highest in August (6.8 MWh/hour) and lowest in December (3.7 MWh/hour). In the PY2021 evaluation, the peak load impact occurred in June. The peak month changes to August in the PY2022 forecast due to changes in the weather scenarios. The load impacts are lower from November to March because the reference loads are lower in those months. Additionally, in March and April, the average load impacts over the RA window include one non-event hour, which further decreases the load impacts.

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

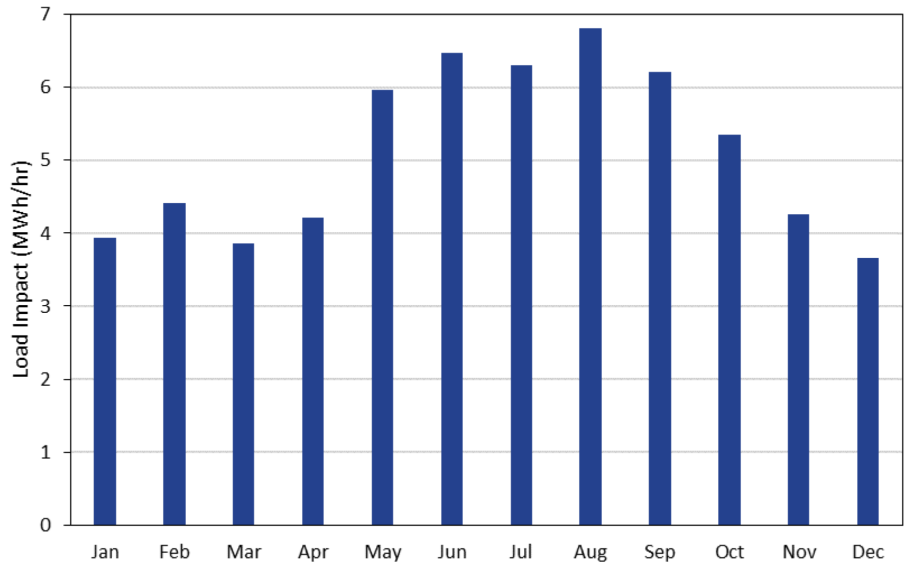
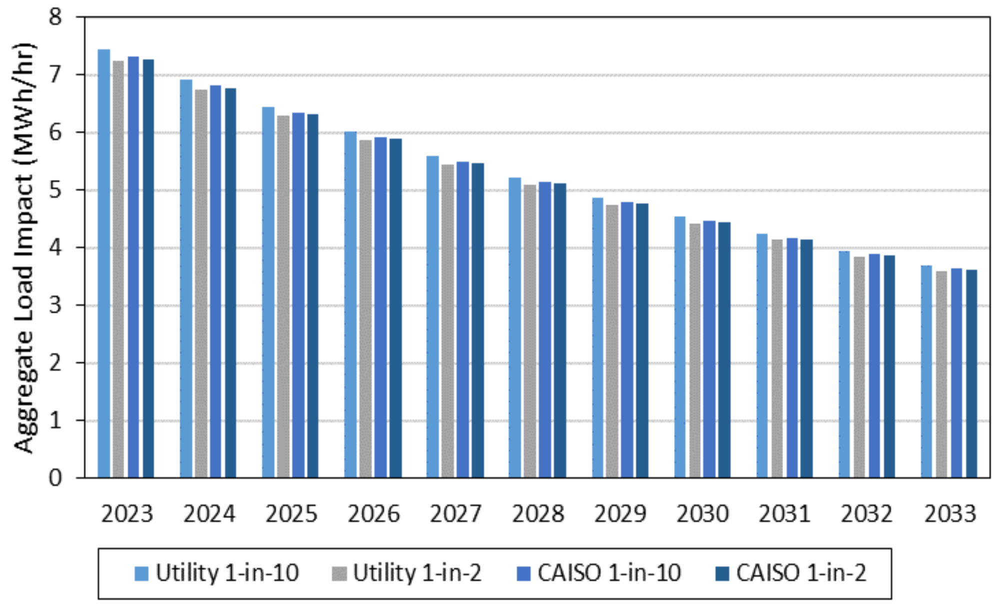


Figure 3.22 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window hour of the typical event day. Aggregate load impacts decline over time due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.22: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Large*



3.2.3 Medium Customers

Figure 3.23 summarizes PG&E's enrollment forecast for medium customers. PG&E anticipates a 1 percent increase in medium customer enrollments from 2022 to 2023 due to customer defaults in the PDP program. From 2023 onward, medium customer enrollments are expected to decline by 7 percent per year due to customer attrition.

Figure 3.23: PDP Enrollments, *PG&E Medium*

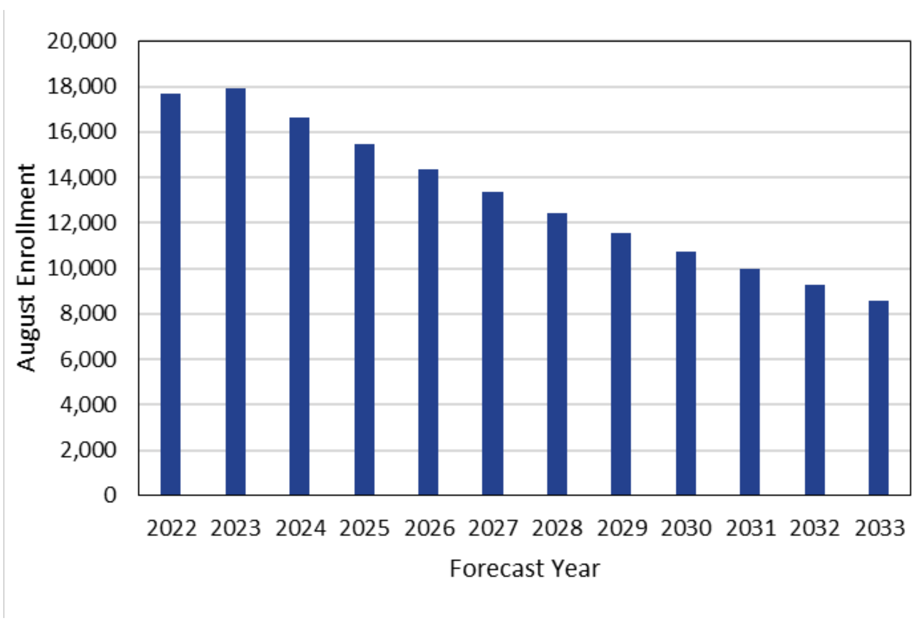


Figure 3.24 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The RA window load impacts have similar shape and magnitude as the ex-post results in Figure 3.7. The forecast predicts an average load impact of 5.9 MWh/hour, or 1.4 percent of the reference loads.

Figure 3.24: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

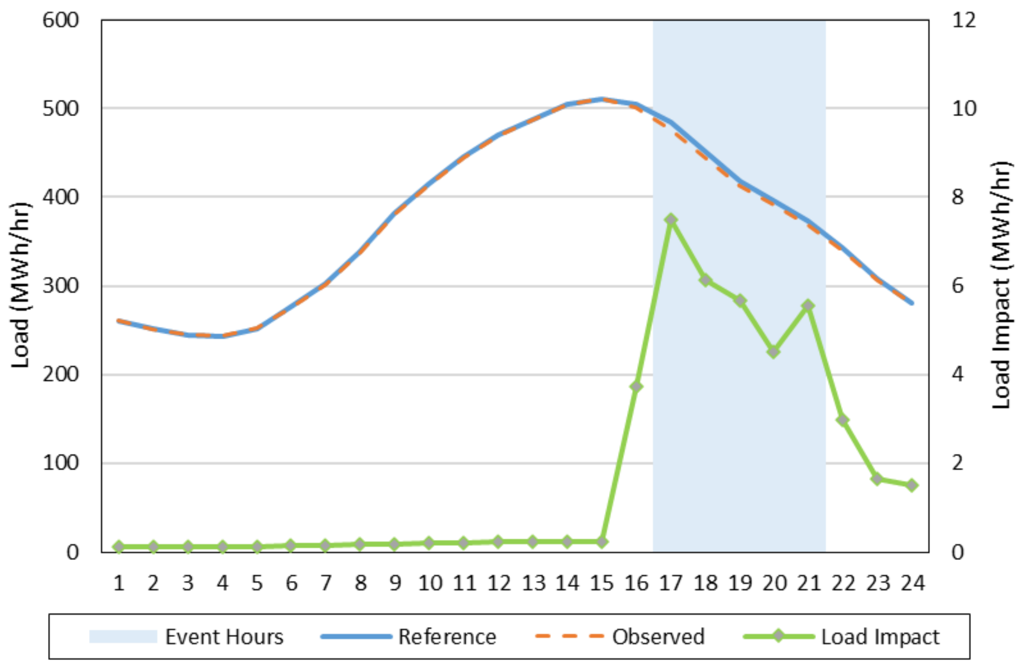


Figure 3.25 shows the forecasted share of load impacts for medium customers by LCA, based on the load impacts during the average RA window on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Greater Fresno Area, Other LCA, and Stockton are the top three LCAs contributing to medium customer load reductions, similar to the ex-post results presented in Figure 3.9.

Figure 3.25: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

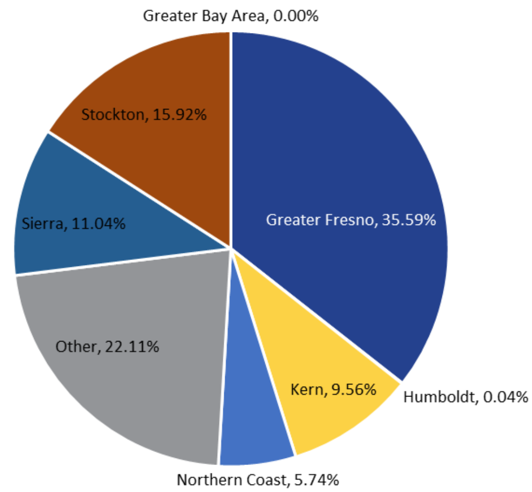


Figure 3.26 illustrates the seasonality in the forecasted load impacts for medium customers by comparing aggregate load impacts for the average hour in the RA window in 2024 across months for PG&E's 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March and April, when it is 5 to 10 p.m. The load impact is highest in August (5.5 MWh/hour) and lowest in December (3.0 MWh/hour). In the PY2021 evaluation, the peak load impact occurred in July. The peak month changes to August in the PY2022 forecast due to changes in the weather scenarios. The load impacts are lower from November to March because the reference loads are lower in those months. Additionally, in March and April, the average load impacts over the RA window include one non-event hour, which further decreases the load impacts.

Figure 3.26: Aggregate Load Impacts by Month over RA Window in 2023 for *PG&E 1-in-2 Peak Day, PG&E Medium*

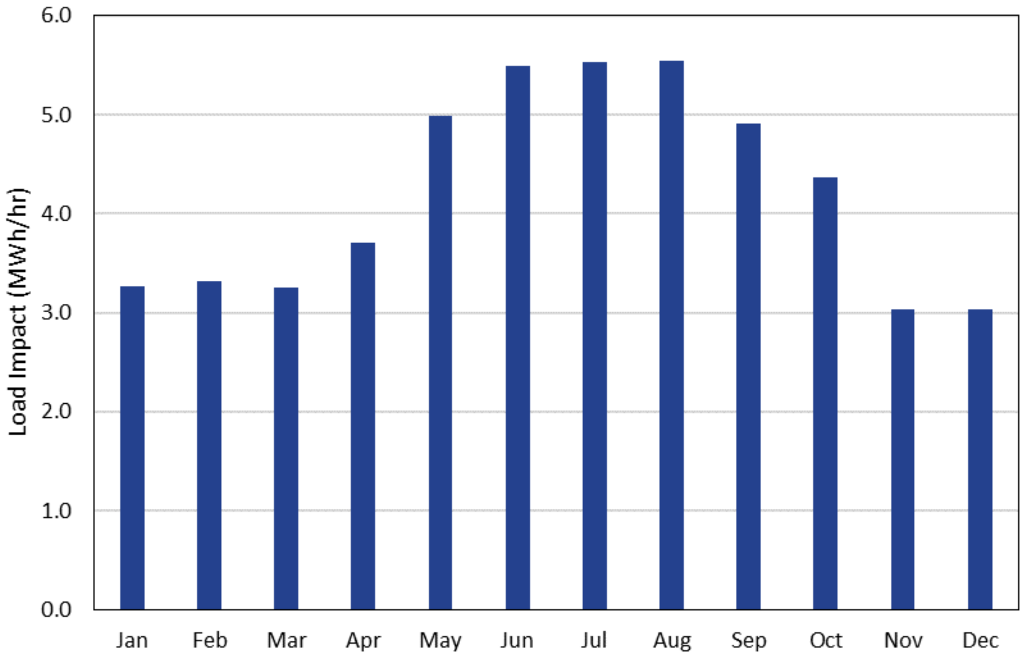
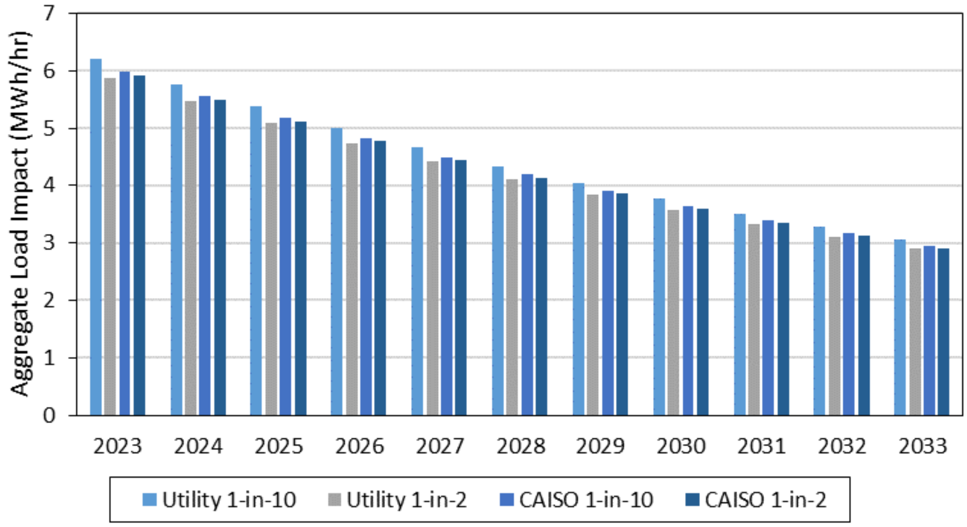


Figure 3.27 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window hour of the typical event day. Aggregate load impacts decline over time due to program attrition. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The load impacts are highest for the PG&E 1-in-10 weather conditions.

Figure 3.27: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Medium*



3.2.4 Small Customers

Figure 3.28 summarizes PG&E's enrollment forecast for small customers. PG&E anticipates a 1 percent increase in medium customer enrollments from 2022 to 2023 due to customer defaults into the PDP program. After 2023, enrollments decrease by 7 percent annually due to customer attrition.

Figure 3.28: PDP Enrollments, *PG&E Small*

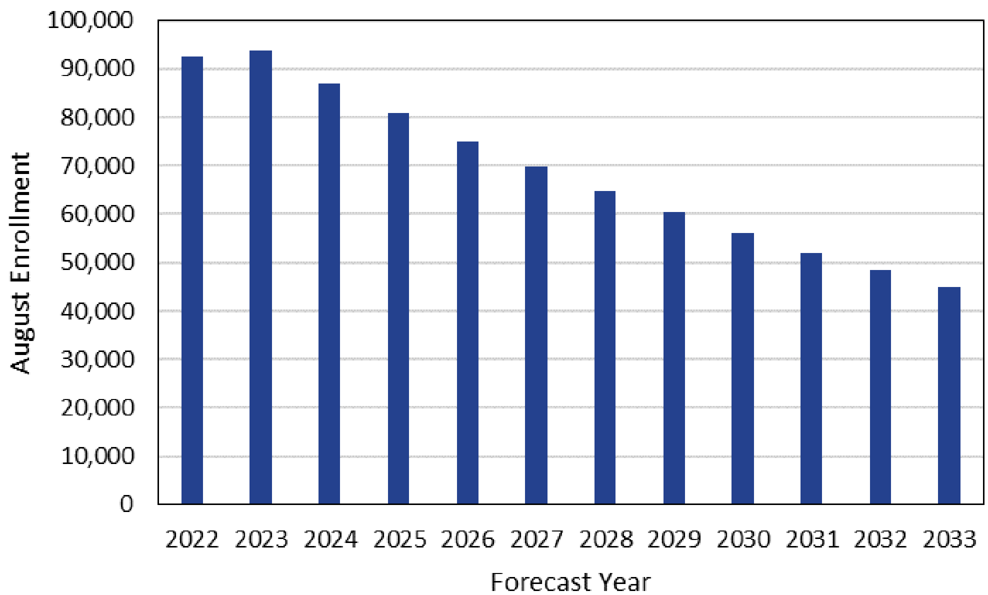


Figure 3.29 illustrates the aggregate reference loads, observed loads, and load impacts for small customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The RA window load impacts have similar shape and magnitude as the ex-post results as shown in Figure 3.11. The forecast predicts an average load impact of 2.2 MWh/hour, or 1.1 percent of reference loads.

Figure 3.29: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

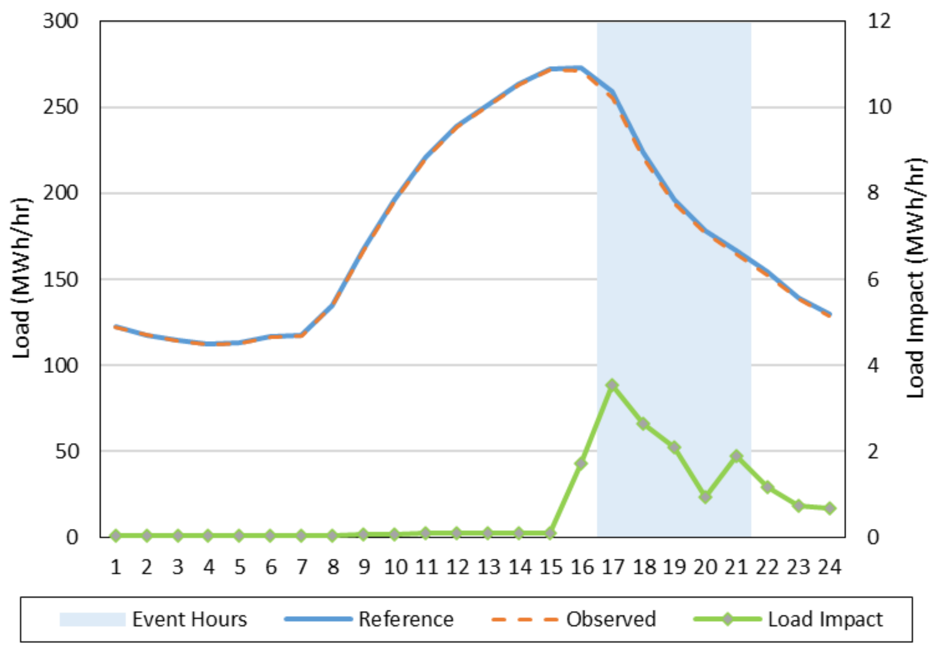


Figure 3.30 shows the forecasted share of load impacts for small customers by LCA, based on the load impacts during the average RA window on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Greater Fresno Area, Other LCA, Sierra, and Stockton contribute most of the aggregate load reduction. The shares of aggregate load impacts in the forecast are consistent with the ex-post estimates presented in Figure 3.13.

Figure 3.30: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

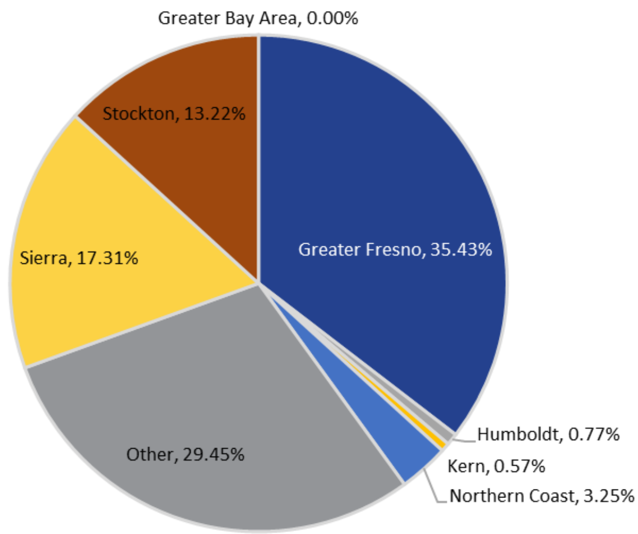


Figure 3.31 illustrates the seasonality in the forecasted load impacts for small customers by comparing aggregate load impacts for the average hour in the RA window in 2024 across months for PG&E's 1-in-2 peak day weather scenarios. The RA window is 4 to 9 p.m. for all months except for March and April, when it is 5 to 10 p.m. The load impact is highest in August (2.1 MWh/hour) and lowest in March (1.1 MWh/hour). In the PY2021 evaluation, the peak load impact occurred in July. The peak month changes to August in the PY2022 forecast due to changes in the weather scenarios. The load impacts are lower from November to March because the reference loads are lower in those months. Additionally, in March and April, the average load impacts over the RA window include one non-event hour, which further decreases the load impacts.

Figure 3.31: Aggregate Load Impacts by Month over RA Window in 2023 for *PG&E 1-in-2 Peak Day, PG&E Small*

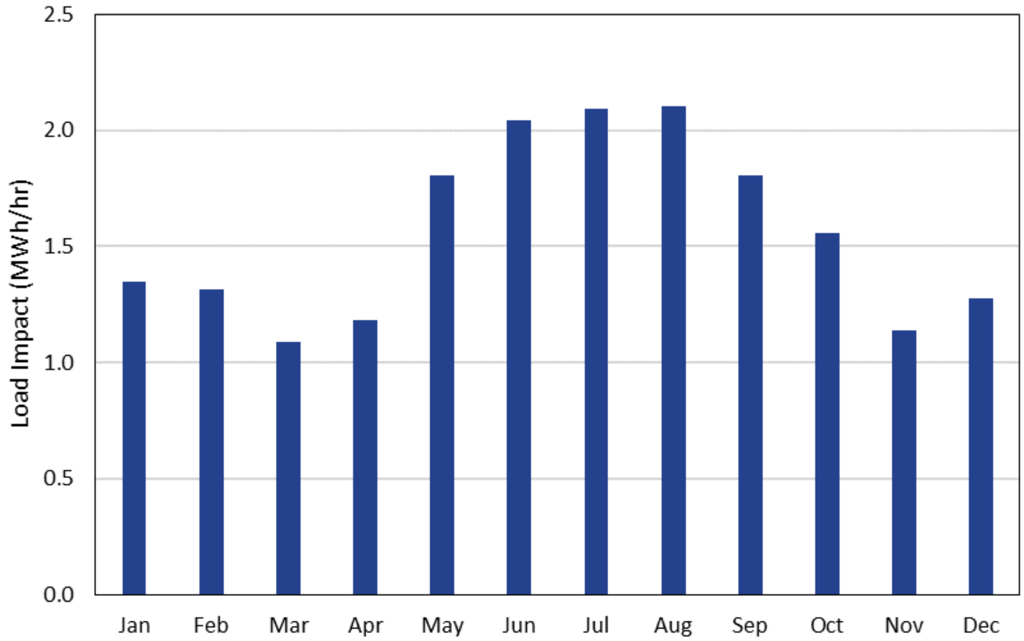
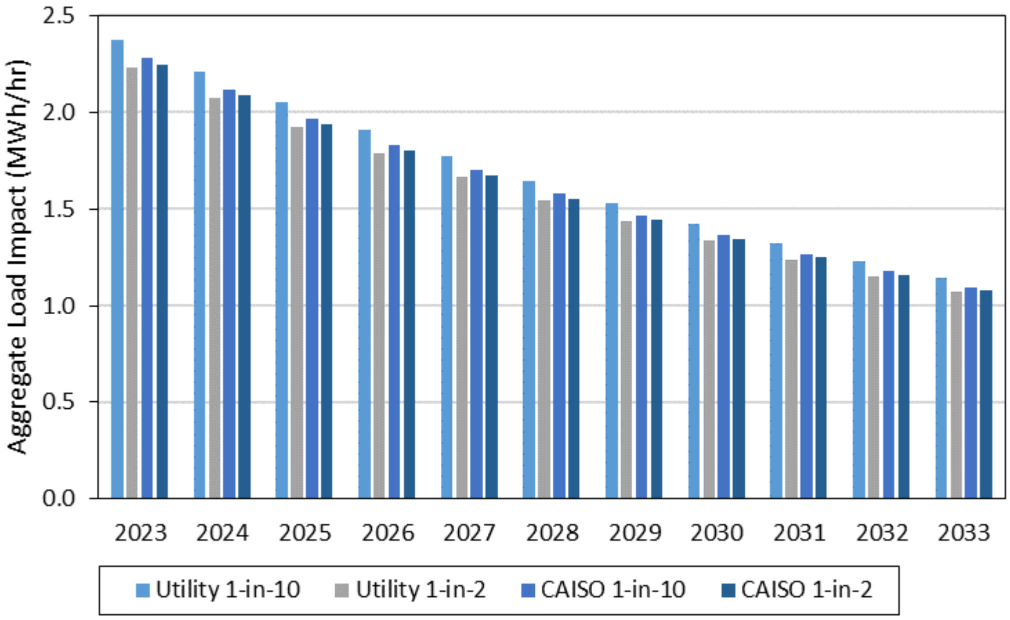


Figure 3.32 shows the change in load impacts over the years of the forecast and across weather scenarios. Each bar is the aggregate load impact during the average RA window hour of the typical event day. Aggregate load impacts decline over time due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.32: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Small*



3.3 PG&E Load Impact Reconciliations

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

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

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2022. The term "previous" refers to revised findings from the PY2021 evaluation. We revised the ex-post load impacts and ex-ante forecast in response to an error in the load interval data that was discovered after the original reports were submitted to the CPUC. Appendix B provides summaries of the revised PY2021 results. In the final comparison above, we illustrate the linkage between the PY2022 ex-post load impacts and the ex-ante forecast of the typical event day for 2022.

3.3.1 All Customers

Previous vs. Current Ex-Post

Table 3.20 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. We restrict the comparison to the event hours from PY2021 (5 to 8 p.m.). Enrollments increased in PY2022 by 4,531 customers. Per-customer reference loads are 13 percent higher in PY2022, which may be related to the minor increase in average event temperatures. Per-customer load impacts are also 42 higher in 2022. As a result, percentage load impacts are 0.2 percentage points higher. Aggregate load impacts are 49 percent higher in PY2022 due to better per-customer performance combined with increased enrollments.

Table 3.20: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day (5-8 p.m.), *PG&E All*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	107,443	111,974
	Reference (MW)	823	970
	Load Impact (MW)	8.7	13.0
	Avg. Temp.	97.8	98.7
Per SAID	Reference (kW)	7.7	8.7
	Load Impact (kW)	0.08	0.12
	% Load Impact	1.1%	1.3%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2021 ex-ante forecast to the ex-ante forecast contained in the current study. Table 3.21 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2023. Per-customer load impacts increase by 44 percent between PY2021 and PY2022, consistent with the comparison of ex-post results between the two years. Enrollments increase by more than 10,000 customers between the two forecasts. This 10 percent increase in enrollments in the PY2022 forecast leads to aggregate load impacts that are 58 percent higher.

Table 3.21: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, PG&E All*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	103,361	113,501
	Reference (MW)	879	1,096
	Load Impact (MW)	9.7	15.4
	Avg. Temp.	96.7	96.9
Per SAID	Reference (kW)	8.5	9.7
	Load Impact (kW)	0.09	0.14
	% Load Impact	1.1%	1.4%

3.3.2 Large Customers

Previous vs. Current Ex-Post

Table 3.22 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. We restrict the comparison to the event hours from PY2021 (5 to 8 p.m.). Enrollments increased in PY2022 by 269 customers, while 3 large BIP customers de-enrolled from the PDP program. De-enrollments of large BIP customers and lower load impacts of most existing BIP customers contribute to the decrease of per-customer load impacts between PY2021 and PY2022. Per-customer reference loads are 20 percent higher in PY2022, which may be related to the minor increase in average event temperatures. Percentage load impacts are also 1.1 percentage points lower in PY2022, which results from lower load impacts combined with higher reference loads. Aggregate load impacts are 5 percent lower in PY2022 despite increased enrollments.

Table 3.22: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day (5-8 p.m.), *PG&E Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	1,235	1,504
	Reference (MW)	245	357
	Load Impact (MW)	6.1	5.7
	Avg. Temp.	98.2	99.0
Per SAID	Reference (kW)	198.1	237.4
	Load Impact (kW)	4.9	3.8
	% Load Impact	2.5%	1.6%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2021 ex-ante forecast to the ex-ante forecast contained in the current study. Table 3.23 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2023. The per-customer load impacts decrease by 13 percent between PY2021 and PY2022. Enrollments are 21 percent higher in the PY2022 forecast, which leads to aggregate load impacts that are 5 percent higher.

Table 3.23: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, PG&E Large*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,587	1,916
	Reference (MW)	321	466
	Load Impact (MW)	6.9	7.2
	Avg. Temp.	96.4	97.0
Per SAID	Reference (kW)	202.3	243.5
	Load Impact (kW)	4.4	3.8
	% Load Impact	2.2%	1.6%

Previous Ex-Ante vs. Current Ex-Post

Table 3.24 provides a comparison of the average event-hour load impacts from the PY2021 ex-ante forecast of 2022 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The PY2021 load impact forecast is in line with the ex-post results in the current study in terms of per-customer load impacts which are 4.8 kWh/customer/hour compared to 4.0 kWh/customer/hour in the forecast. Reference loads are higher than forecasted, leading to percentage load impacts in 2022 that are lower than forecasted—2.4 percent compared to 1.7 percent of reference loads. The aggregate load impacts are 9 percent lower in 2022 despite higher enrollments than forecasted.

Table 3.24: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Large*

Level	Outcome	Ex-ante for 2022 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	1,385	1,504
	Reference (MW)	276	359
	Load Impact (MW)	6.7	6.1
	Avg. Temp.	97.3	98.3
Per SAID	Reference (kW)	199.6	238.5
	Load Impact (kW)	4.8	4.0
	% Load Impact	2.4%	1.7%

Current Ex-Post vs. Current Ex-Ante

Table 3.25 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent a typical event day in 2023 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Per-customer and percentage load impacts are slightly lower in the ex-ante forecast for 2023, which may be related to the de-enrollments of three large BIP customers. Aggregate load impacts increase from 6.1 MWh/hour to 7.2 MWh/hour in 2023, due to additional large customer defaults lead that increase enrollments.

Table 3.25: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Large*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,504	1,916
	Reference (MW)	359	466
	Load Impact (MW)	6.1	7.2
	Avg. Temp.	98.3	97.0
Per SAID	Reference (kW)	238.5	243.5
	Load Impact (kW)	4.0	3.8
	% Load Impact	1.7%	1.6%

Table 3.26 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The biggest driver of differences is the 27 percent increase in customer enrollments (which scales the aggregate load impact up by a commensurate amount) and lower percentage load impact (from de-enrollment of three BIP customers).

Table 3.26: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 98.3°F during the typical event day.	Average event-hour temperature of 97.0°F during the PG&E 1-in-2 Typical Event Day.	Lower ex-ante temperatures would decrease the per-customer load impacts (ceteris paribus) via lower reference loads.
Event window	HE17-HE21.	RA window (HE17-HE21).	None.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	1,504 service accounts (7 BIP customers).	1,916 service accounts (4 BIP customers).	Higher ex-ante enrollments lead to higher aggregate load impacts. De-enrollments of BIP customers may reduce percentage load impacts.
Methodology	Large individual customer models and panel models by LCA with customer fixed effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

3.3.3 Medium Customers

Previous vs. Current Ex-Post

Table 3.27 shows the average event-hour reference loads and load impacts during 5 to 8 p.m. on the typical event day of the current and previous program years. Customer defaults also led enrollments to increase in 2022 by 1,321 customers. There was a dramatic increase in per-customer load impacts from 0.09 to 0.30 kWh/customer/hour. Together with the increase in enrollments, this leads to an increase in aggregate load impacts from 1.5 to 5.4 MWh/hour. The percentage load impact increases from 0.4 to 1.3 percent, suggesting an improvement in medium customer performance.

Table 3.27: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day *(5-8 p.m.), PG&E Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	16,402	17,723
	Reference (MW)	389	415
	Load Impact (MW)	1.5	5.4
	Avg. Temp.	97.9	98.8
Per SAID	Reference (kW)	23.7	23.4
	Load Impact (kW)	0.09	0.30
	% Load Impact	0.4%	1.3%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2021 and PY2022 ex-ante forecasts. Table 3.28 reports the average RA window load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2023. The aggregate load impacts increase dramatically between PY2021 and PY2022 from 1.6 to 5.9 MWh/hour, driven by the improvement in medium customer performance during PDP events in 2022 as shown in the comparison of the ex-post results in both years. Enrollments are forecast to increase by 14 percent in PY2022 compared to the PY2021 forecast due to further customer defaults, which also contributes to the increase of aggregate load impact in this year's forecast.

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

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	15,649	17,914
	Reference (MW)	373	424
	Load Impact (MW)	1.6	5.9
	Avg. Temp.	97.0	97.0
Per SAID	Reference (kW)	23.8	23.7
	Load Impact (kW)	0.10	0.33
	% Load Impact	0.4%	1.4%

Previous Ex-Ante vs. Current Ex-Post

Table 3.29 provides a comparison of the average event-hour load impacts from the PY2021 ex-ante forecast of 2022 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day during PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The ex-post load impacts are 0.22 kWh/customer/hour higher than forecast in PY2021, reflecting the improvement in medium customer performance. Percentage load impacts increase by 1 percentage point, reflecting the comparable per-customer reference loads. Ex-post aggregate load impacts increase by 4.5 MWh/hour compared to the forecast, reflecting the higher per-customer load impacts and enrollments.

Table 3.29: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Medium*

Level	Outcome	Ex-ante for 2022 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	14,439	17,723
	Reference (MW)	344	418
	Load Impact (MW)	1.5	5.8
	Avg. Temp.	97.0	98.0
Per SAID	Reference (kW)	23.8	23.6
	Load Impact (kW)	0.11	0.33
	% Load Impact	0.4%	1.4%

Current Ex-Post vs. Current Ex-Ante

Table 3.30 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts represent a typical event day in 2023 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Load impacts (aggregate, per-customer, and percentage) are similar in 2022 and 2023. Customer defaults cause a 1 percent increase in enrollments.

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

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	17,723	17,914
	Reference (MW)	418	424
	Load Impact (MW)	5.8	5.9
	Avg. Temp.	98.0	97.0
Per SAID	Reference (kW)	23.6	23.7
	Load Impact (kW)	0.33	0.33
	% Load Impact	1.4%	1.4%

Table 3.31 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The aggregate and per-customer load impacts are similar in 2022 and 2023.

Table 3.31: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 98.0°F during the typical event day.	Average event-hour temperature of 97.0°F during the PG&E 1-in-2 Typical Event Day.	Lower ex-ante temperatures would decrease the per-customer load impacts (ceteris paribus) via lower reference loads.
Event window	HE17-HE 21.	RA window (HE17-HE21).	None.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	17,723 service accounts.	17,914 service accounts.	Increased enrollments should lead to higher aggregate load impacts.
Methodology	Panel models by LCA with customer fixed effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

3.3.4 Small Customers

Previous vs. Current Ex-Post

Table 3.32 shows the average event-hour reference loads and load impacts for the typical event day during 5 to 8 p.m. of the current and previous program years. Customer defaults also led small customer enrollments to increase in PY2022 by 2,941 customers. Small customers had an improvement in customer performance like medium customers. Per-customer load impacts increase from 0.01 to 0.02 kWh/customer/hour. As a result, aggregate load impacts increase from 1.2 to 1.9 MWh/hour. Per-customer reference loads are slightly higher which may be driven by average temperatures being slightly higher. Percentage load impacts increase from 0.6 to 0.9 percent of reference loads.

Table 3.32: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day *(5-8 p.m.)*, *PG&E Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	89,806	92,747
	Reference (MW)	190	198
	Load Impact (MW)	1.2	1.9
	Avg. Temp.	97.1	97.9
Per SAID	Reference (kW)	2.11	2.14
	Load Impact (kW)	0.01	0.02
	% Load Impact	0.6%	0.9%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2021 and PY2022 ex-ante forecasts. Table 3.33 reports the RA window average load impacts for the typical event day under PG&E 1-in-2 weather conditions in 2023. Aggregate load impacts increase between PY2021 and PY2022 from 1.2 to 2.2 MWh/hour, consistent with the improvement in small customer performance and increased enrollments presented in the previous section. The per-customer load impacts increase by 0.01 kWh/customer/hour from PY2021 to PY2022, while the percentage load impacts increase from 0.7 to 1.1 percent.

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

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	86,125	93,671
	Reference (MW)	186	205
	Load Impact (MW)	1.2	2.2
	Avg. Temp.	96.3	96.6
Per SAID	Reference (kW)	2.16	2.19
	Load Impact (kW)	0.01	0.02
	% Load Impact	0.7%	1.1%

Previous Ex-Ante vs. Current Ex-Post

Table 3.34 provides a comparison of the average event-hour load impacts from the PY2021 ex-ante forecast of 2022 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under PG&E 1-in-2 weather conditions. The ex-post load impacts are based on the typical event day. The ex-post load impacts are twice as high as the forecast in PY2021, due to higher per-customer and percentage load impacts and enrollments. Percentage load impacts increase from 0.6 to 1.1 percent of reference loads.

Table 3.34: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Small*

Level	Outcome	Ex-ante for 2022 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	78,905	92,747
	Reference (MW)	170	203
	Load Impact (MW)	1.1	2.2
	Avg. Temp.	96.3	97.1
Per SAID	Reference (kW)	2.15	2.19
	Load Impact (kW)	0.01	0.02
	% Load Impact	0.6%	1.1%

Current Ex-Post vs. Current Ex-Ante

Table 3.35 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent a typical event day in 2023 under PG&E 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Load impacts (aggregate, per-customer, and percentage) are similar in 2022 and 2023. Customer defaults cause a 1 percent increase in enrollments.

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

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	92,747	93,671
	Reference (MW)	203	205
	Load Impact (MW)	2.2	2.2
	Avg. Temp.	97.1	96.6
Per SAID	Reference (kW)	2.19	2.19
	Load Impact (kW)	0.02	0.02
	% Load Impact	1.1%	1.1%

Table 3.36 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The aggregate and per-customer load impacts are similar in 2022 and 2023.

Table 3.36: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 97.1°F during the typical event day.	Average event-hour temperature of 96.6°F during the PG&E 1-in-2 Typical Event Day.	Lower ex-ante temperatures would decrease the per-customer load impacts (ceteris paribus) via lower reference loads.
Event window	HE17-HE 21.	RA window (HE17-HE21).	None.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	92,747 service accounts.	93,671 service accounts.	Slightly higher ex-ante enrollments should lead to higher aggregate load impacts.
Methodology	Panel models by LCA with customer fixed effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

4 SCE

4.1 SCE Ex-Post Load Impacts

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

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

4.1.1 All Customers

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

SCE customers have statistically significant load reductions on ten out of fifteen event days. The highest load reduction is 53 MWh/hour on August 4th. The load impact averaged 10 MWh/hour across all event days. Figure 4.1 provides evidence of a relationship between load impact and event temperature. Specifically, load impacts are lower when event temperatures are higher. We provide more details regarding this relationship in Section 4.1.8.

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

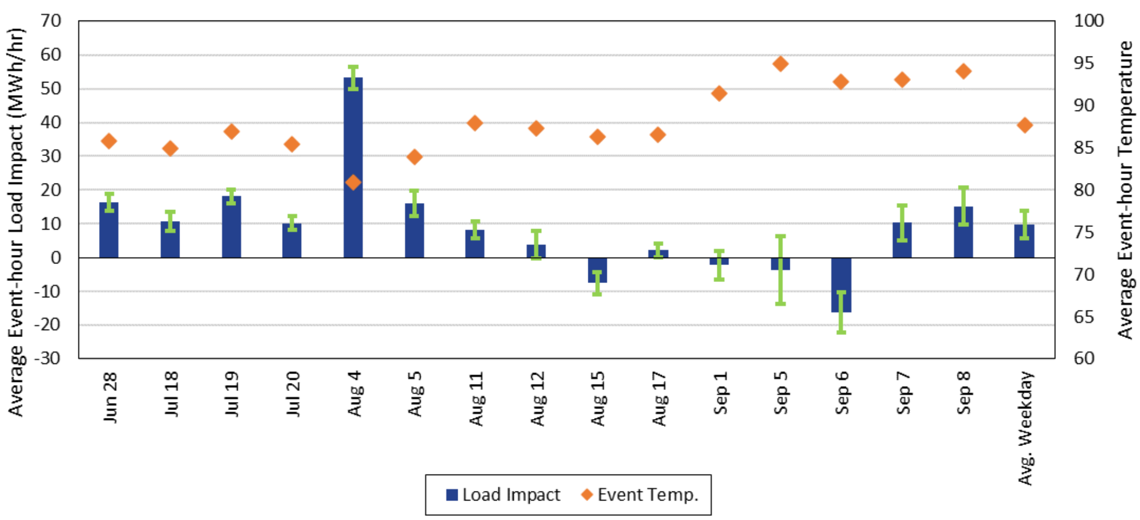


Table 4.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for all SCE customers. Estimated load impacts averaged 0.04 kWh/hour per customer across event days, which amounts to a 0.8 percent load reduction. Detailed results by hour, industry group and LCA are presented in subsequent subsections by size group.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	227,524	1,253	16.3	5.5	0.07	1.3%	85.8
7/18/2022	226,478	1,235	10.6	5.5	0.05	0.9%	84.9
7/19/2022	226,423	1,261	18.2	5.6	0.08	1.4%	86.9
7/20/2022	226,347	1,247	10.1	5.5	0.04	0.8%	85.4
8/4/2022	225,471	1,217	53.2	5.4	0.24	4.4%	80.9
8/5/2022	225,411	1,208	15.9	5.4	0.07	1.3%	83.9
8/11/2022	225,212	1,274	8.2	5.7	0.04	0.6%	87.9
8/12/2022	225,140	1,240	3.9	5.5	0.02	0.3%	87.3
8/15/2022	225,062	1,242	-7.5	5.5	-0.03	-0.6%	86.3
8/17/2022	224,957	1,270	2.1	5.6	0.01	0.2%	86.5
9/1/2022	224,136	1,328	-2.3	5.9	-0.01	-0.2%	91.4
9/5/2022	223,922	1,072	-3.7	4.8	-0.02	-0.3%	94.9
9/6/2022	223,876	1,339	-16.2	6.0	-0.07	-1.2%	92.8
9/7/2022	223,818	1,362	10.3	6.1	0.05	0.8%	93.1
9/8/2022	223,749	1,346	15.2	6.0	0.07	1.1%	94.0
Typical Event Day	**225,258**	**1,274**	**9.8**	**5.7**	**0.04**	**0.8%**	**87.6**

4.1.2 Large Customers

This section summarizes results for all large SCE customers, defined as customers with maximum demand over 200 kW.[15] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impacts for SCE's large CPP customers are summarized for all 15 events in Figure 4.2. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

These results indicate that large customers had statistically significant load reductions on all but the September 5th and 6th event days, ranging from 2 to 16 MWh/hour. The load impact averaged 7 MWh/hour across all non-holiday event days. Figure 4.2 provides

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

evidence of a relationship between load impact and event temperature. Specifically, load impacts are lower when event temperatures are higher. We provide more details regarding this relationship in Section 4.1.8.

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

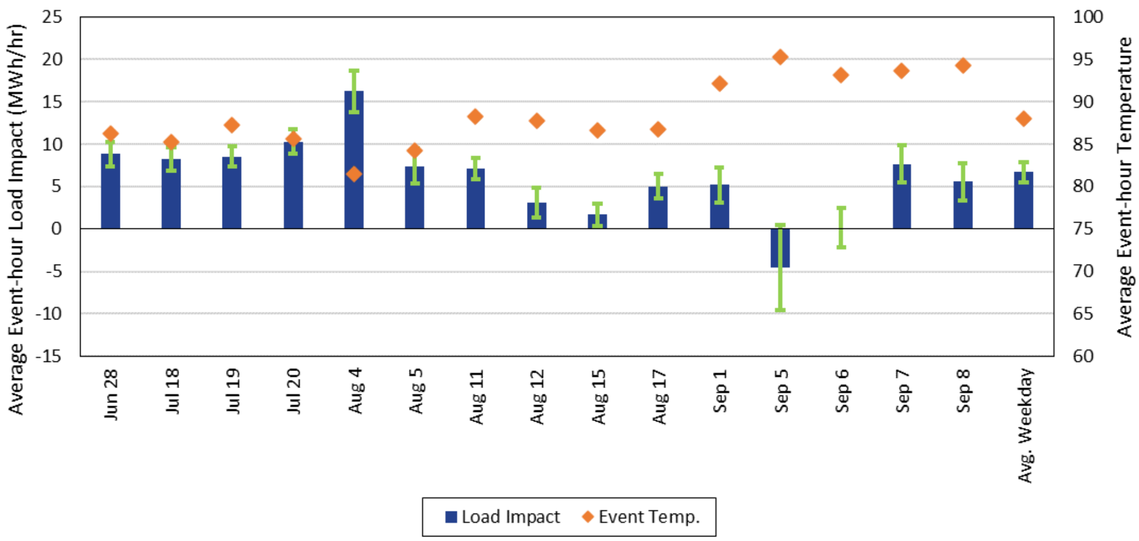


Table 4.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Estimated load reductions averaged 4 kWh/hour per customer across event days, which amounts to a 1.8 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	1,691	365	8.9	215.6	5.2	2.4%	86.2
7/18/2022	1,708	364	8.2	213.0	4.8	2.3%	85.2
7/19/2022	1,705	369	8.6	216.4	5.0	2.3%	87.2
7/20/2022	1,704	368	10.3	216.0	6.0	2.8%	85.6
8/4/2022	1,694	364	16.2	214.9	9.6	4.5%	81.5
8/5/2022	1,694	350	7.4	206.8	4.4	2.1%	84.2
8/11/2022	1,691	372	7.1	219.9	4.2	1.9%	88.2
8/12/2022	1,691	356	3.1	210.4	1.8	0.9%	87.8
8/15/2022	1,691	367	1.7	217.2	1.0	0.5%	86.6
8/17/2022	1,690	374	5.0	221.0	3.0	1.3%	86.7
9/1/2022	1,681	380	5.2	226.0	3.1	1.4%	92.1
9/5/2022	1,649	268	-4.6	162.4	-2.8	-1.7%	95.3
9/6/2022	1,647	375	0.1	227.5	0.1	0.0%	93.2
9/7/2022	1,649	379	7.7	229.6	4.7	2.0%	93.6
9/8/2022	1,662	379	5.6	227.9	3.3	1.5%	94.3
Typical Event Day	**1,687**	**369**	**6.7**	**218.9**	**4.0**	**1.8%**	**88.0**

Figure 4.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 4.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are smaller load impacts in the hours immediately following (6.4 MWh from 9 to 10 p.m.) the event. Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

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

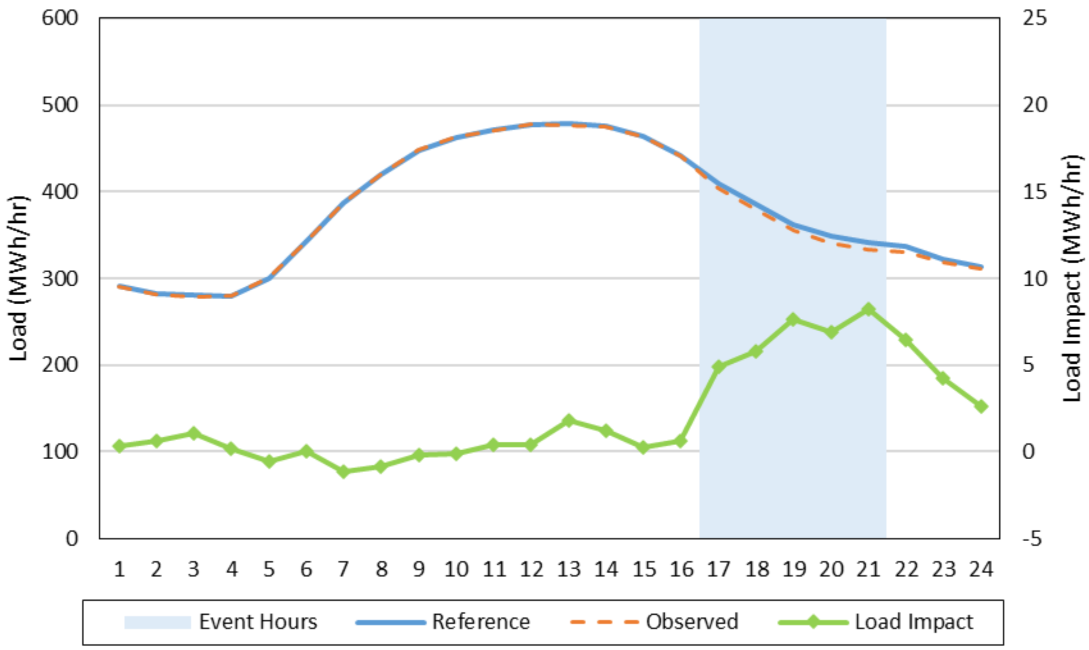


Table 4.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	290.8	290.4	0.4	0.1%	77.1	-1.0	-0.2	0.4	0.9	1.7
2	282.5	281.9	0.7	0.2%	75.9	-0.5	0.2	0.7	1.1	1.8
3	280.2	279.1	1.0	0.4%	74.9	0.2	0.7	1.0	1.4	1.9
4	279.6	279.4	0.2	0.1%	74.2	-0.7	-0.2	0.2	0.6	1.1
5	299.7	300.3	-0.6	-0.2%	73.4	-1.4	-0.9	-0.6	-0.3	0.2
6	342.8	342.7	0.0	0.0%	72.7	-1.0	-0.4	0.0	0.5	1.0
7	387.0	388.1	-1.1	-0.3%	72.3	-2.6	-1.8	-1.1	-0.5	0.3
8	419.7	420.5	-0.9	-0.2%	72.7	-2.7	-1.6	-0.9	-0.1	1.0
9	448.4	448.5	-0.2	0.0%	74.6	-1.6	-0.8	-0.2	0.4	1.2
10	463.0	463.1	-0.1	0.0%	77.8	-1.3	-0.6	-0.1	0.4	1.1
11	471.4	470.9	0.4	0.1%	81.3	-0.7	0.0	0.4	0.9	1.6
12	478.0	477.6	0.4	0.1%	84.5	-1.1	-0.2	0.4	1.0	1.8
13	478.3	476.6	1.8	0.4%	87.2	0.2	1.1	1.8	2.4	3.3
14	476.5	475.3	1.2	0.2%	89.2	-0.7	0.4	1.2	1.9	3.0
15	463.9	463.6	0.3	0.1%	90.5	-1.8	-0.6	0.3	1.1	2.4
16	441.5	440.8	0.6	0.1%	91.2	-1.4	-0.2	0.6	1.5	2.7
17	409.0	404.1	4.9	1.2%	91.2	3.2	4.2	4.9	5.6	6.7
18	385.6	379.7	5.8	1.5%	90.4	4.0	5.1	5.8	6.6	7.6
19	362.5	354.9	7.7	2.1%	88.9	5.5	6.8	7.7	8.5	9.8
20	348.2	341.3	6.9	2.0%	86.4	4.7	6.0	6.9	7.8	9.1
21	340.9	332.6	8.3	2.4%	83.3	6.4	7.5	8.3	9.0	10.1
22	336.7	330.2	6.4	1.9%	80.8	4.4	5.6	6.4	7.3	8.5
23	322.9	318.6	4.2	1.3%	79.2	2.3	3.4	4.2	5.0	6.1
24	313.4	310.8	2.6	0.8%	77.9	0.5	1.7	2.6	3.4	4.7
Daily	9,122	9,071	51	0.6%	81.2	40.9	46.8	50.9	55.0	60.9

Next, we look at SCE large customer estimate by industry group. Table 4.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments have 65 percent concentration in three industry groups: Manufacturing; Offices, Hotels, Health, & Services; and Wholesale, Transportation, & Utilities. The estimated reference loads are 95, 82, and 75 MWh/hour for these groups, respectively. The load impact is even more concentrated with 65 percent (4.66 MW) of the total load impact coming from two industry groups: Manufacturing and Wholesale, Transportation, & Utilities.

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

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	132	21	20	0.73	3.5%
2. Manufacturing	432	95	91	3.34	3.5%
3. Wholesale, Transportation, Utilities	326	75	74	1.32	1.8%
4. Retail Stores	102	26	26	0.12	0.5%
5. Offices, Hotels, Health, Services	335	82	82	0.32	0.4%
6. Schools	149	26	26	-0.07	-0.3%
7. Institutional/Government	110	27	25	1.08	4.1%
8. Other	101	19	19	0.23	1.2%

To better understand the distribution of results across industries, we look at the shares of estimated positive load impacts, reference loads, and enrollments by industry group in Figure 4.4. Manufacturing represents such a large share of the load impact. Most other industry groups, with the exception of Agricultural, Mining, Construction and Institutional/Government, have lower shares of the load impact than the shares of enrolled customers.

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

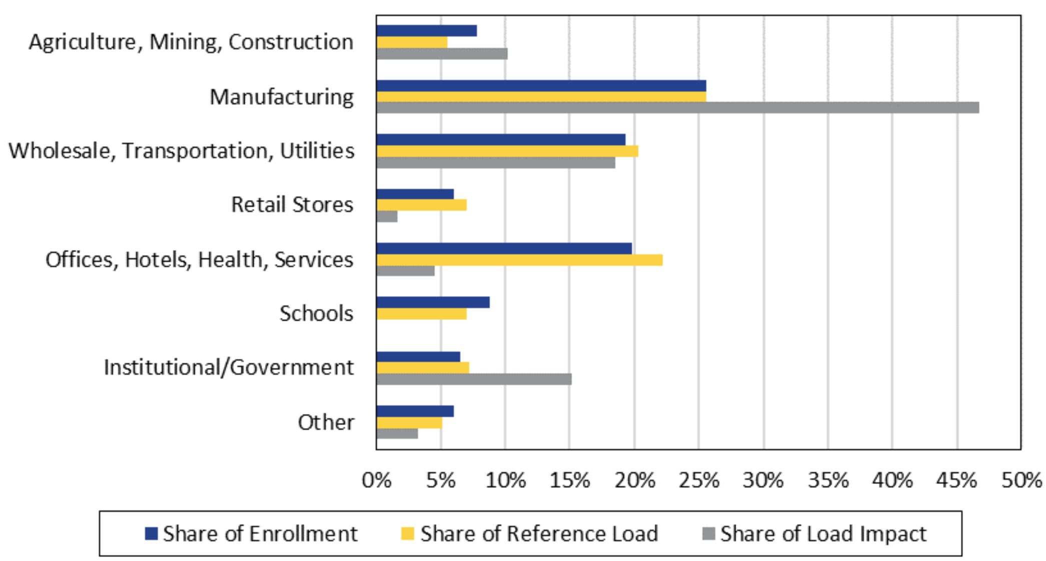
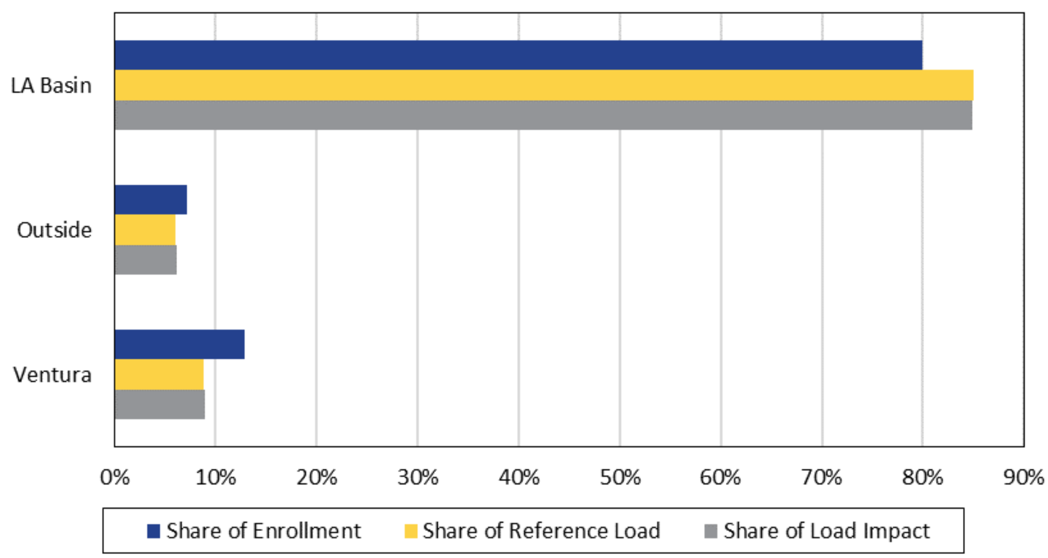


Table 4.5 and Figure 4.5 provide the same summaries as above by LCA. SCE's large CPP customers are concentrated in the LA Basin, which has a combined reference load of 314 MWh/hour. This LCA also accounts for the largest load impact of 5.9 MWh/hour. We can see in Figure 4.5 that the LA Basin's share of customers, reference loads, and positive load impacts all exceed 80 percent.

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

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin	1,348	314	308	5.92	1.9%
Outside Basin	122	23	22	0.41	1.8%
Ventura	217	33	32	0.38	1.1%

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



4.1.3 Medium Customers

This section summarizes results for all medium SCE customers, defined as customers with maximum demand between 20 and 199.99 kW.[16] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers presented in successive sub-sections.

[16] Medium CPP customers were identified using rate codes provided by SCE. The majority (99.4 percent) of Medium CPP customers are on rate TOU-GS-2-D.

The ex-post load impacts for SCE's medium CPP customers are summarized for all 15 events in Figure 4.6. Four of the events days (June 28th, July 19th, August 4th, and August 5th) have estimated load reductions that are statistically significant. The average weekday event day load impact of 0.9 MWh/hour is not statistically significant. Figure 4.6 provides evidence of a relationship between load impact and event temperature. Specifically, load impacts are lower when event temperatures are higher. We provide more details regarding this relationship in Section 4.1.8.

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

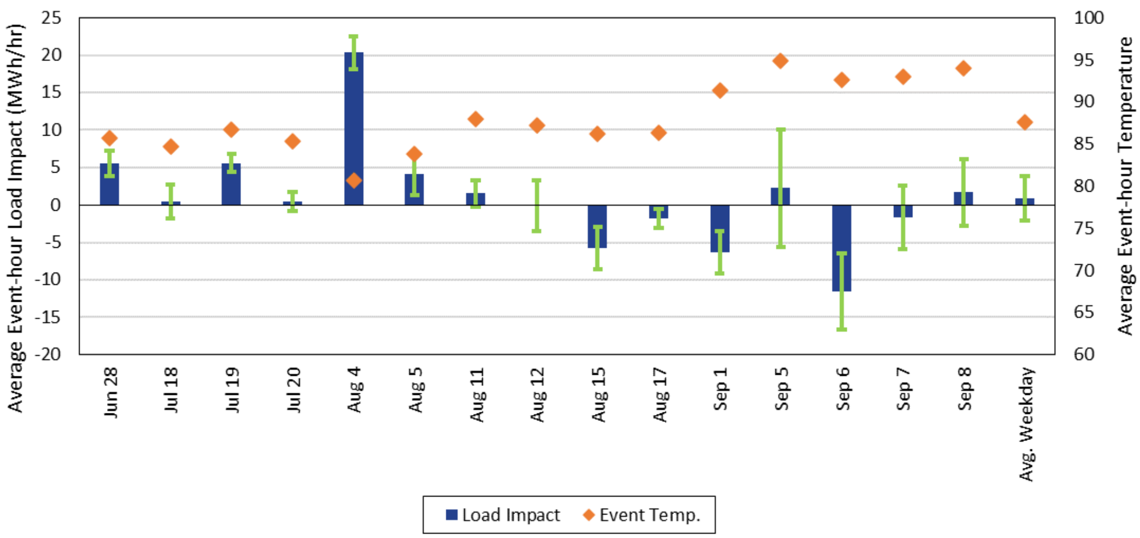


Table 4.6 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Overall, medium customers had an aggregate load impact of 0.9 MWh/hour, which is 0.04 kWh/hour per customer on average, or about a 0.1 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	22,381	589	5.5	26.3	0.2	0.9%	85.7
7/18/2022	22,260	580	0.4	26.0	0.0	0.1%	84.7
7/19/2022	22,254	591	5.6	26.6	0.3	0.9%	86.8
7/20/2022	22,253	583	0.4	26.2	0.0	0.1%	85.3
8/4/2022	22,133	565	20.3	25.5	0.9	3.6%	80.7
8/5/2022	22,132	569	4.1	25.7	0.2	0.7%	83.9
8/11/2022	22,108	598	1.5	27.0	0.1	0.3%	87.9
8/12/2022	22,096	586	-0.2	26.5	0.0	0.0%	87.3
8/15/2022	22,089	583	-5.8	26.4	-0.3	-1.0%	86.2
8/17/2022	22,081	594	-1.8	26.9	-0.1	-0.3%	86.4
9/1/2022	21,998	626	-6.4	28.4	-0.3	-1.0%	91.3
9/5/2022	21,970	549	2.2	25.0	0.1	0.4%	94.9
9/6/2022	21,967	635	-11.5	28.9	-0.5	-1.8%	92.7
9/7/2022	21,961	646	-1.7	29.4	-0.1	-0.3%	93.0
9/8/2022	21,953	636	1.7	29.0	0.1	0.3%	94.0
Typical Event Day	**22,119**	**599**	**0.9**	**27.1**	**0.04**	**0.1%**	**87.5**

Figure 4.7 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for medium customers. Table 4.7 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The highest load impacts of 2.1 MWh/hour occurred in the first event hour (4 to 5 p.m.). There appears to be is no evidence of pre-cooling or post-event snapback, and in fact, there are load impacts in the hours directly preceding the event.

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

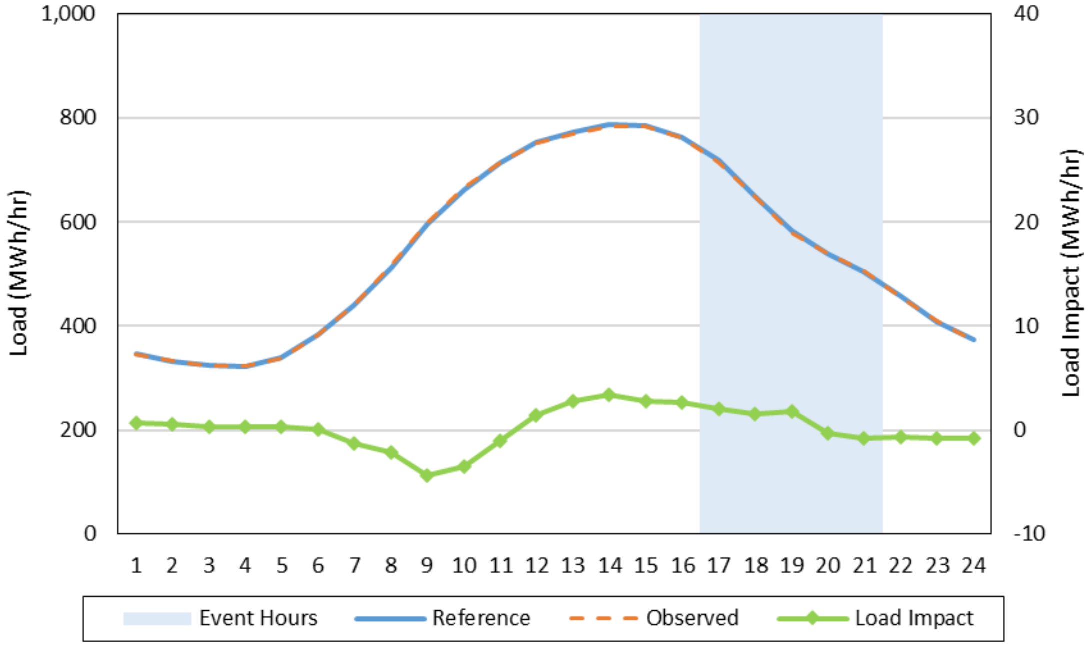


Table 4.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	346.4	345.7	0.7	0.2%	76.7	-0.1	0.3	0.7	1.0	1.5
2	332.6	332.0	0.6	0.2%	75.6	0.0	0.3	0.6	0.8	1.2
3	324.5	324.2	0.4	0.1%	74.7	0.0	0.2	0.4	0.5	0.8
4	323.0	322.7	0.3	0.1%	74.0	0.1	0.2	0.3	0.4	0.6
5	339.3	338.9	0.4	0.1%	73.3	0.1	0.3	0.4	0.5	0.6
6	383.6	383.6	0.1	0.0%	72.6	-0.4	-0.1	0.1	0.3	0.5
7	441.4	442.7	-1.3	-0.3%	72.2	-2.5	-1.8	-1.3	-0.9	-0.2
8	512.2	514.3	-2.1	-0.4%	72.5	-3.7	-2.8	-2.1	-1.5	-0.5
9	594.3	598.6	-4.3	-0.7%	74.4	-5.9	-5.0	-4.3	-3.7	-2.8
10	661.2	664.7	-3.4	-0.5%	77.6	-4.9	-4.0	-3.4	-2.8	-2.0
11	714.5	715.5	-1.0	-0.1%	81.1	-1.7	-1.3	-1.0	-0.7	-0.3
12	752.0	750.7	1.4	0.2%	84.3	0.1	0.8	1.4	1.9	2.7
13	772.4	769.6	2.8	0.4%	86.9	1.0	2.1	2.8	3.6	4.6
14	787.6	784.2	3.4	0.4%	89.0	1.0	2.5	3.4	4.4	5.8
15	786.1	783.4	2.7	0.3%	90.3	0.2	1.7	2.7	3.8	5.2
16	763.7	761.1	2.6	0.3%	90.9	-0.4	1.4	2.6	3.8	5.6
17	717.4	715.3	2.1	0.3%	90.9	-1.6	0.6	2.1	3.6	5.7
18	649.7	648.2	1.6	0.2%	90.0	-1.7	0.2	1.6	2.9	4.9
19	582.2	580.4	1.8	0.3%	88.4	-1.2	0.6	1.8	3.0	4.8
20	539.5	539.9	-0.3	-0.1%	85.7	-2.7	-1.3	-0.3	0.6	2.0
21	505.1	505.9	-0.8	-0.2%	82.7	-2.4	-1.5	-0.8	-0.2	0.8
22	456.7	457.4	-0.7	-0.2%	80.3	-2.3	-1.4	-0.7	0.0	0.9
23	407.9	408.6	-0.8	-0.2%	78.8	-2.2	-1.4	-0.8	-0.2	0.7
24	372.7	373.5	-0.8	-0.2%	77.5	-2.0	-1.3	-0.8	-0.3	0.4
Daily	**13,066**	**13,061**	**5**	**0.0%**	**80.8**	**-16.5**	**-3.7**	**5.2**	**14.0**	**26.9**

Next, we look at SCE medium customer estimates by industry group. Table 4.8 summarizes the aggregate average event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services has the largest number of enrollments, reference load and load impacts (1.01 MW). The Agricultural, Mining, Construction industry group has the largest percentage load impact of 1 percent.

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

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1. Agriculture, Mining, Construction	650	13	13	0.13	1.0%
2. Manufacturing	2,202	50	50	0.38	0.8%
3. Wholesale, Transportation, Utilities	2,187	52	52	-0.27	-0.5%
4. Retail Stores	3,004	93	93	0.22	0.2%
5. Offices, Hotels, Health, Services	9,979	286	285	1.01	0.4%
6. Schools	608	18	18	0.12	0.7%
7. Institutional/Government	2,203	53	52	0.17	0.3%
8. Other	1,286	35	35	-0.09	-0.3%

Figure 4.8 shows the shares of enrollments, reference loads, and load impacts by industry group. The load impacts are concentrated in Offices, Hotels, Health, & Services, which realizes 47 percent of the total load impact.

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

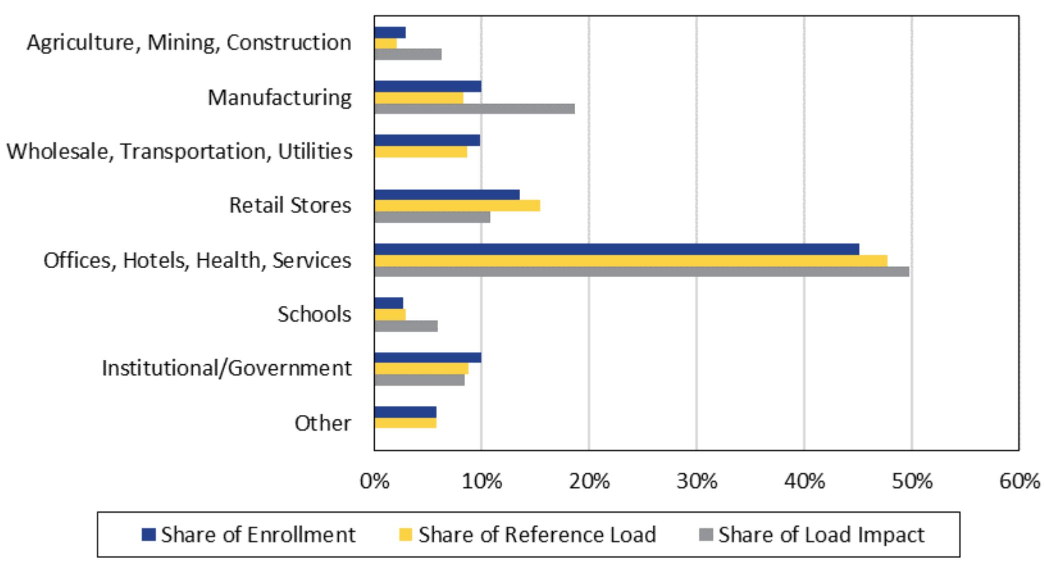


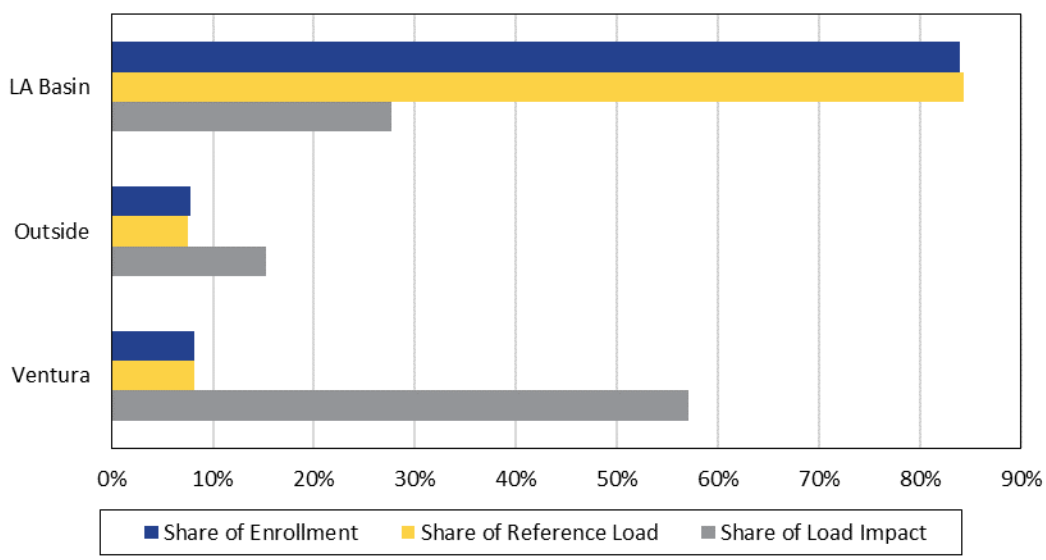
Table 4.9 and Figure 4.9 provide the same summaries as above but by LCA instead of industry group. Enrollments and reference loads are highly concentrated in LA Basin,

accounting for over 80 percent. Nonetheless, the Ventura LCA accounts for the majority of the 2022 typical event day load impacts.

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

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	18,581	505	505	0.24	0.0%
Outside Basin	1,727	45	45	0.13	0.3%
Ventura	1,811	49	48	0.49	1.0%

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



4.1.4 Small Customers

This section summarizes results for SCE small CPP customers, defined as customers with maximum demand less than 20 kW.[17] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impacts for SCE's small CPP customers are summarized for all 15 events in Figure 4.10. Seven of the twelve events have statistically significant load impacts at the 90 percent confidence level (represented by the green bars). Seven events exhibit reductions in usage that are statistically significant (June 28th, July 18th, 19th, August 4th, 5th, September 7th, and 8th). The average non-holiday weekday event of 2.2 MWh/hour (0.7 percent) is not statistically significant. Small CPP customers do not show a strong

[17] Small CPP customers were identified using rate codes provided by SCE. The majority (99.96 percent) of Small CPP customers are on rate TOU-GS-1-E.

relationship between load impacts and temperature. We provide more details regarding this relationship in Section 4.1.8.

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

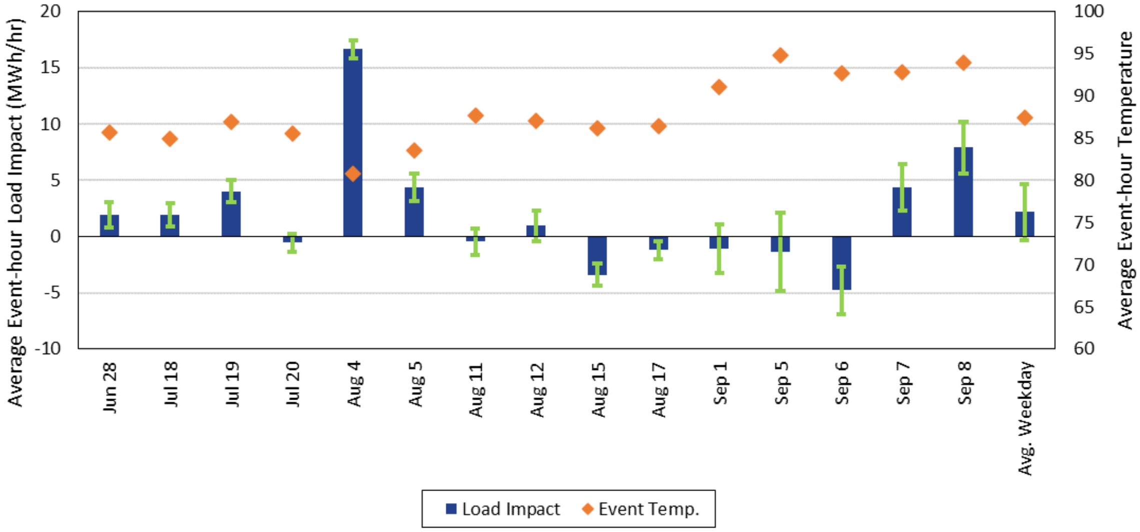


Table 4.10 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Enrollment of small customers in CPP were fairly consistent over the course of the season. Overall, small CPP customers had an aggregate load impact of 2.2 MWh/hour, which is 0.011 kWh/hour per customer on average, or about a 0.7 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	203,452	299	1.9	1.5	0.01	0.6%	85.7
7/18/2022	202,510	291	1.9	1.4	0.01	0.7%	84.9
7/19/2022	202,464	301	4.0	1.5	0.02	1.3%	86.9
7/20/2022	202,390	296	-0.6	1.5	0.00	-0.2%	85.5
8/4/2022	201,644	288	16.6	1.4	0.08	5.8%	80.7
8/5/2022	201,585	288	4.4	1.4	0.02	1.5%	83.6
8/11/2022	201,413	305	-0.5	1.5	0.00	-0.1%	87.7
8/12/2022	201,353	298	1.0	1.5	0.00	0.3%	87.1
8/15/2022	201,282	292	-3.4	1.4	-0.02	-1.2%	86.1
8/17/2022	201,186	302	-1.2	1.5	-0.01	-0.4%	86.5
9/1/2022	200,457	323	-1.1	1.6	-0.01	-0.3%	91.0
9/5/2022	200,303	255	-1.4	1.3	-0.01	-0.5%	94.8
9/6/2022	200,262	329	-4.8	1.6	-0.02	-1.4%	92.7
9/7/2022	200,208	337	4.4	1.7	0.02	1.3%	92.8
9/8/2022	200,134	331	7.9	1.7	0.04	2.4%	93.9
Typical Event Day	**201,453**	**306**	**2.2**	**1.5**	**0.011**	**0.7%**	**87.5**

Figure 4.11 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for small CPP customers. Table 4.11 contains the hourly typical event day results, including hourly temperatures and uncertainty adjusted load impacts. The largest load impact of 3.4 MWh/hour occurred during the first event hour.

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

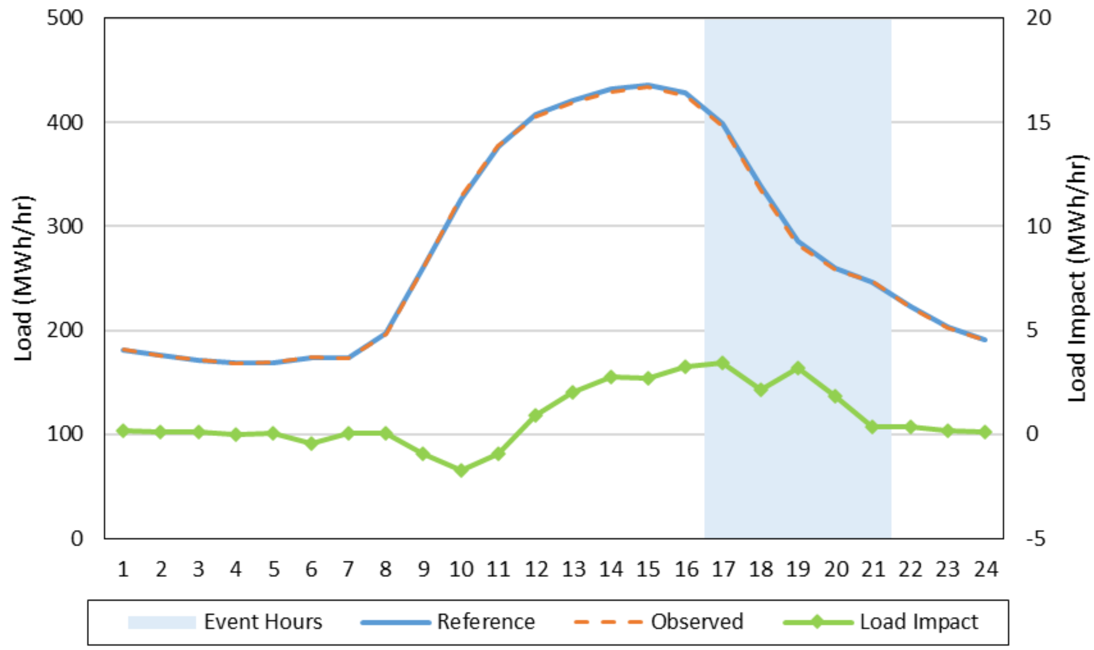


Table 4.11: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Small*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	181.5	181.3	0.2	0.1%	76.7	-0.3	0.0	0.2	0.4	0.7
2	175.8	175.6	0.1	0.1%	75.6	-0.3	-0.1	0.1	0.3	0.5
3	171.4	171.3	0.1	0.1%	74.7	-0.3	0.0	0.1	0.3	0.5
4	168.7	168.7	0.0	0.0%	74.0	-0.4	-0.2	0.0	0.1	0.3
5	169.2	169.2	0.0	0.0%	73.2	-0.3	-0.1	0.0	0.2	0.4
6	174.2	174.7	-0.4	-0.3%	72.6	-0.9	-0.6	-0.4	-0.3	0.0
7	173.0	173.0	0.0	0.0%	72.2	-1.8	-0.7	0.0	0.8	1.9
8	197.0	197.0	0.0	0.0%	72.7	-0.6	-0.2	0.0	0.3	0.6
9	259.5	260.5	-1.0	-0.4%	74.6	-1.8	-1.3	-1.0	-0.6	-0.1
10	326.1	327.8	-1.7	-0.5%	77.8	-2.6	-2.1	-1.7	-1.4	-0.9
11	376.2	377.2	-0.9	-0.2%	81.2	-1.4	-1.1	-0.9	-0.7	-0.4
12	407.0	406.2	0.9	0.2%	84.3	0.2	0.6	0.9	1.2	1.6
13	421.5	419.5	2.0	0.5%	87.0	0.9	1.6	2.0	2.5	3.2
14	431.8	429.1	2.7	0.6%	89.0	1.3	2.2	2.7	3.3	4.1
15	436.5	433.8	2.7	0.6%	90.3	0.8	1.9	2.7	3.5	4.6
16	428.8	425.6	3.3	0.8%	91.0	0.5	2.1	3.3	4.4	6.0
17	399.1	395.7	3.4	0.9%	90.9	0.1	2.1	3.4	4.8	6.7
18	338.2	336.0	2.2	0.6%	90.0	-0.8	1.0	2.2	3.4	5.1
19	285.7	282.5	3.2	1.1%	88.3	0.9	2.2	3.2	4.1	5.4
20	259.4	257.6	1.8	0.7%	85.6	-0.6	0.8	1.8	2.8	4.2
21	246.8	246.4	0.4	0.1%	82.5	-0.6	0.0	0.4	0.7	1.3
22	223.0	222.6	0.4	0.2%	80.2	-0.6	0.0	0.4	0.8	1.3
23	203.1	202.9	0.2	0.1%	78.8	-0.6	-0.2	0.2	0.5	0.9
24	190.5	190.4	0.1	0.1%	77.4	-0.5	-0.1	0.1	0.4	0.8
Daily	6,644	6,624	20	0.3%	80.9	4.7	13.5	19.6	25.7	34.5

Next, we look at SCE small CPP customer estimates by industry group. Table 4.12 summarizes the aggregate event-hour results for the typical event day for each industry group, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). About 46 percent of enrollments, reference loads, and load impacts come from the Offices, Hotels, Health, & Services industry group.

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

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	8,762	12	12	0.29	2.5%
2.Manufacturing	6,754	9	9	0.14	1.5%
3.Wholesale, Transportation, Utilities	11,100	15	15	0.22	1.4%
4.Retail Stores	14,651	40	40	0.19	0.5%
5.Offices, Hotels, Health, Services	92,347	140	138	1.09	0.8%
6.Schools	2,374	6	6	-0.01	-0.1%
7. Institutional/Government	28,645	44	44	0.11	0.2%
8.Other	36,819	40	39	0.26	0.6%

Figure 4.12 shows the shares of enrollments, reference loads, and positive load impacts by industry group.

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

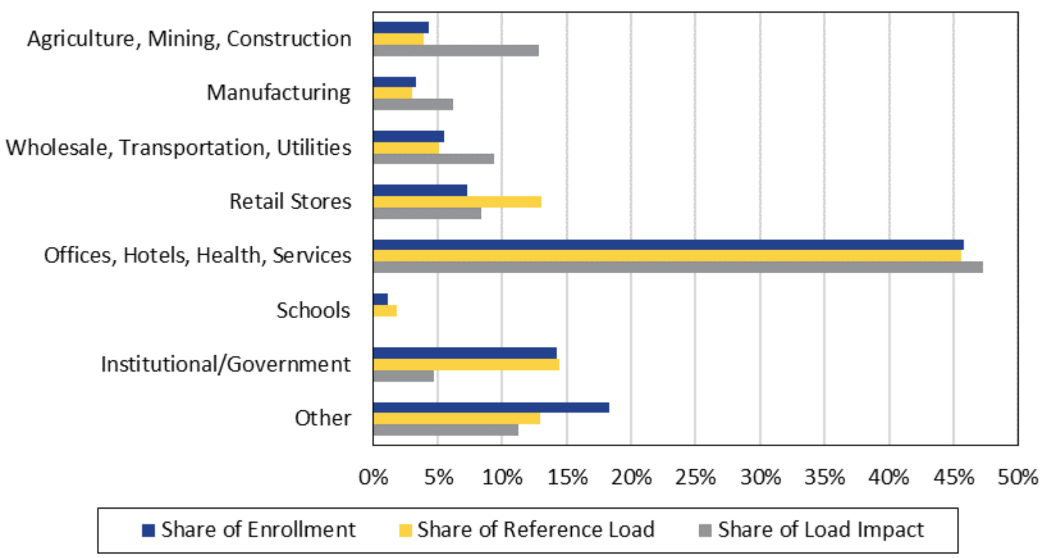
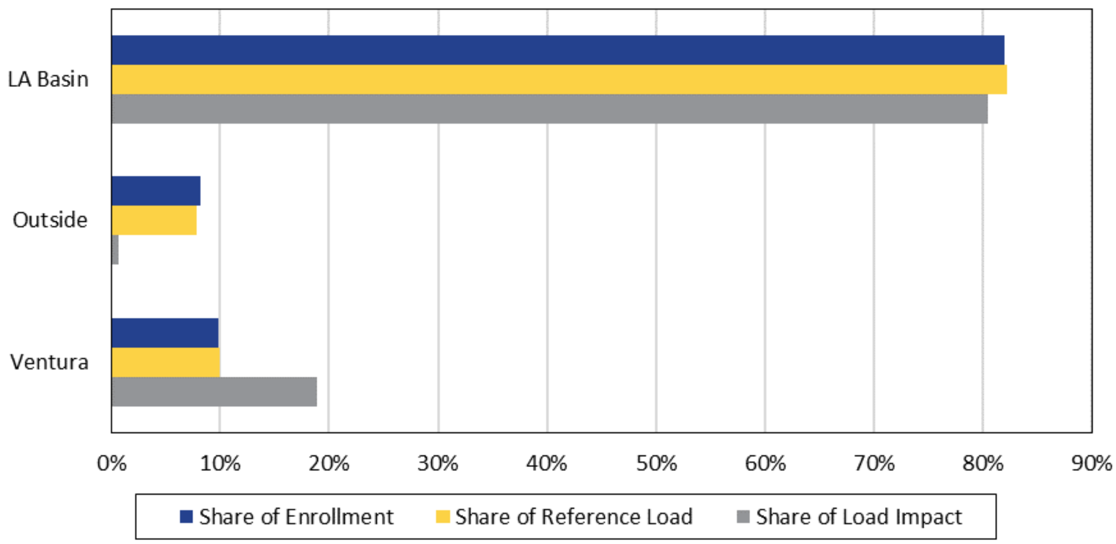


Table 4.13 and Figure 4.13 provide the same summaries as above but by LCA instead of industry group. Enrollments, reference loads, and positive load impacts are highly concentrated in LA Basin, accounting for over 80 percent of small CPP customers.

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

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	165,106	251	250	1.76	0.7%
Outside	16,523	24	24	0.02	0.1%
Ventura	19,825	30	30	0.41	1.4%

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



4.1.5 Dually Enrolled Customers

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

Table 4.14 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who are dually enrolled in CPP. Load impacts are not counted for CPP customers dually enrolled in BIP or SDP when a BIP or SDP event is called on the same day as a CPP event; these customer load impacts are accounted for in the BIP and SDP evaluations. The average dually enrolled customer has a reference load of 101.9 kWh/hour. Dually enrolled customers provided a load impact of 1.2 MWh/hour, or 6.7 percent of their reference load.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	144	15.1	2.0	105.1	14.1	13.4%	82.4
7/18/2022	181	17.6	1.6	97.4	9.1	9.3%	82.7
7/19/2022	181	18.1	1.1	100.2	6.1	6.1%	84.7
7/20/2022	181	18.0	1.2	99.23	6.42	6.5%	82.9
8/4/2022	181	18.2	1.9	100.3	10.8	10.7%	79.3
8/5/2022	181	17.4	2.1	96.3	11.4	11.9%	83.1
8/11/2022	181	19.0	1.7	105.0	9.1	8.7%	86.8
8/12/2022	181	18.2	1.2	100.7	6.5	6.4%	85.9
8/15/2022	181	18.6	1.7	102.6	9.6	9.4%	83.8
8/17/2022	180	18.4	0.5	102.0	2.8	2.7%	83.6
9/1/2022	181	20.5	0.6	113.0	3.1	2.7%	88.6
9/5/2022	131	10.9	-0.3	83.0	-2.3	-2.8%	91.8
9/6/2022	131	12.1	0.1	92.6	0.6	0.7%	89.9
9/7/2022	131	12.2	0.0	92.9	0.2	0.3%	90.4
9/8/2022	144	16.4	1.0	113.8	6.8	6.0%	93.5
Typical Event Day	**169**	**17.2**	**1.2**	**101.9**	**6.8**	**6.7%**	**85.7**

4.1.6 AutoDR Customers

This section summarizes results for CPP customers who participated in Automated Demand Response (AutoDR) programs. The AutoDR program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention. We present results for the average event-hour for each event day and for the average event. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report. Table 4.15 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who participated in the AutoDR program. There were 53 SCE CPP customers enrolled in AutoDR. Their combined load impact was 0.6 MWh/hour (6.3 percent) for the typical event day.

Table 4.15: Average Event-Hour Load Impacts for AutoDR Customers by Event, SCE

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/28/2022	53	8.6	0.7	161.5	14.10	8.7%	87.1
7/18/2022	53	8.7	0.6	163.6	10.38	6.3%	86.3
7/19/2022	53	8.7	0.6	164.3	11.19	6.8%	88.0
7/20/2022	53	8.5	0.9	160.5	17.38	10.8%	86.8
8/4/2022	53	8.6	0.8	162.3	15.31	9.4%	82.7
8/5/2022	53	8.4	0.7	157.9	12.84	8.1%	84.9
8/11/2022	53	8.9	0.9	167.4	16.32	9.7%	89.1
8/12/2022	53	8.5	0.6	160.7	11.77	7.3%	88.6
8/15/2022	53	8.7	0.7	164.8	12.86	7.8%	87.1
8/17/2022	53	9.1	0.9	172.4	16.90	9.8%	88.1
9/1/2022	53	9.3	0.0	175.8	0.93	0.5%	93.8
9/5/2022	53	7.3	-0.7	138.0	-13.79	-10.0%	96.3
9/6/2022	53	9.7	0.0	183.1	-0.79	-0.4%	95.3
9/7/2022	53	9.7	0.3	183.9	6.38	3.5%	95.1
9/8/2022	53	9.5	0.2	179.1	3.90	2.2%	95.3
Typical Event Day	**53**	**8.9**	**0.6**	**168.4**	**10.68**	**6.3%**	**89.2**

4.1.7 Notified vs. Non-Notified Customers

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

Table 4.16 summarizes enrollments, average event-hour load impacts, and reference loads for the average event day by size and notification status. About 67 percent of all customers were notified during events. Large CPP customers have the greatest proportion of notified customers (77 percent). Additionally, Large CPP customers exhibited the largest difference in percentage load impacts between notified and non-notified customers: 2.2 and 0.3 percent, respectively.

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

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	391	84	0.3	214.0	0.70	0.3%	89.3
	Medium	6,234	170	0.1	27.2	0.01	0.0%	87.4
	Small	66,739	109	0.3	1.6	0.00	0.3%	87.4
	All	**73,364**	**362**	**0.7**	**4.9**	**0.01**	**0.2%**	**87.8**
Yes	Large	1,296	286	6.4	220.3	4.94	2.2%	87.6
	Medium	15,885	429	0.8	27.0	0.05	0.2%	87.6
	Small	134,714	197	1.9	1.5	0.01	1.0%	87.5
	All	**151,894**	**911**	**9.1**	**6.0**	**0.06**	**1.0%**	**87.6**

4.1.8 Load Impact and Weather Relationship

Figure 4.14 through Figure 4.16 demonstrate the relationship between percentage load impacts and weather for large, medium, and small CPP customers, respectively. Orange and blue points represent the average event-hour load impact percentages and temperatures for each event in PY21 and PY22, respectively.[18] Each line represents the linear relationship between load impact percentages and weather. The solid dashed line indicates the relationship looking at both program years, while the orange and blue dotted lines indicate the linear relationships separately for PY21 and PY22 events, respectively. A decreasing slope of the linear relationship indicates that events with hotter temperatures tend to have lower percentage load impacts. The events in PY22 generally had hotter temperatures than PY21 events. However, the relationship between weather and load impact appears to be consistent between years as evidenced by similar slopes.[19]

While the relationship between temperatures and load impacts exists for large and medium customers, there is no statistically significant relationship for small customers. We estimate the magnitude of the effect of temperature on percentage load impacts via a regression for each size and LCA. Statistically significant estimates of the load impact percentage and weather relationship are used in the ex-ante analysis to adjust the

[18] Holiday events (e.g., Labor Day) are excluded from each figure. However, the load impact percentage and weather relationships are similar if holiday events were included.
[19] It is important to acknowledge that there could be other elements, unobserved by the researcher, which are correlated with higher temperatures and cause a reduction in load impacts. For example, event-day fatigue that results in reduced load impacts for consecutive event days could be misattributed to weather if consecutive events were only called during hot events. However, we do not believe that is the case here since the load impacts and weather relationship remains when consecutive events days are removed. As well, consecutive event days also occurred when temperatures were moderate.

percentage load impacts that are applied to ex-ante reference loads that differ by weather scenario.

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

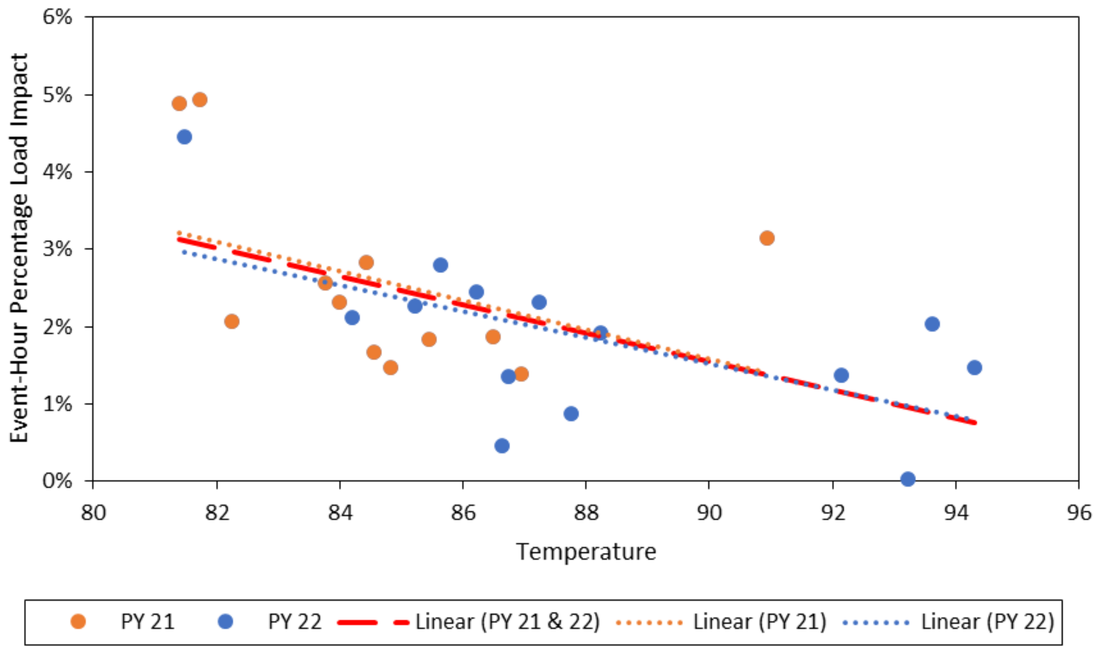


Figure 4.15: Load Impact Percentage and Weather Relationship, *SCE Medium*

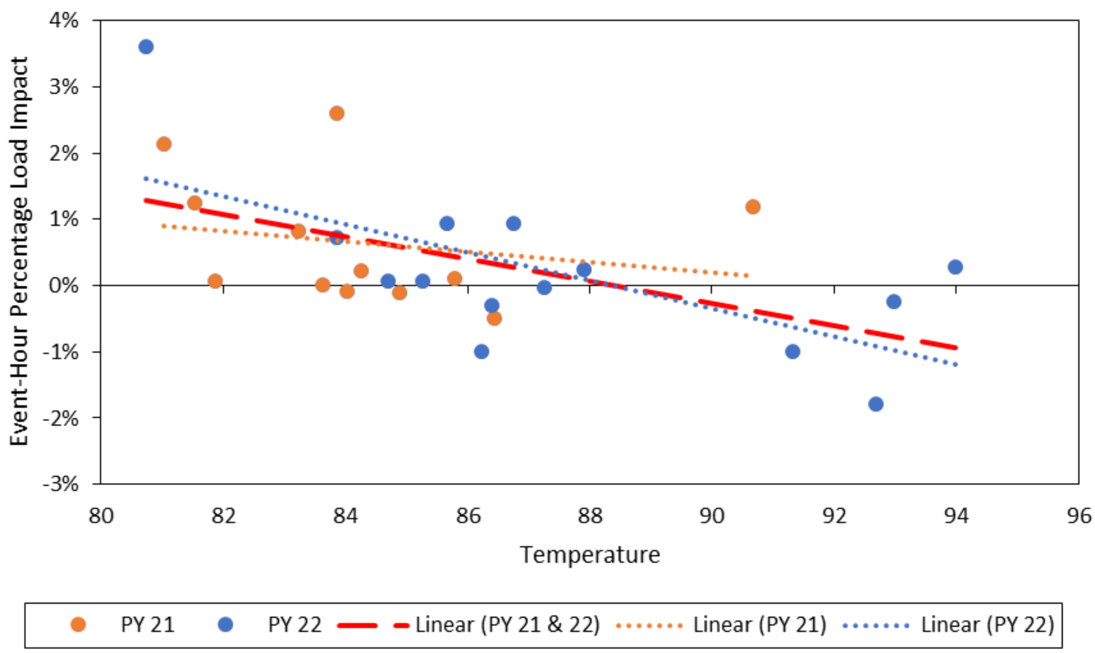
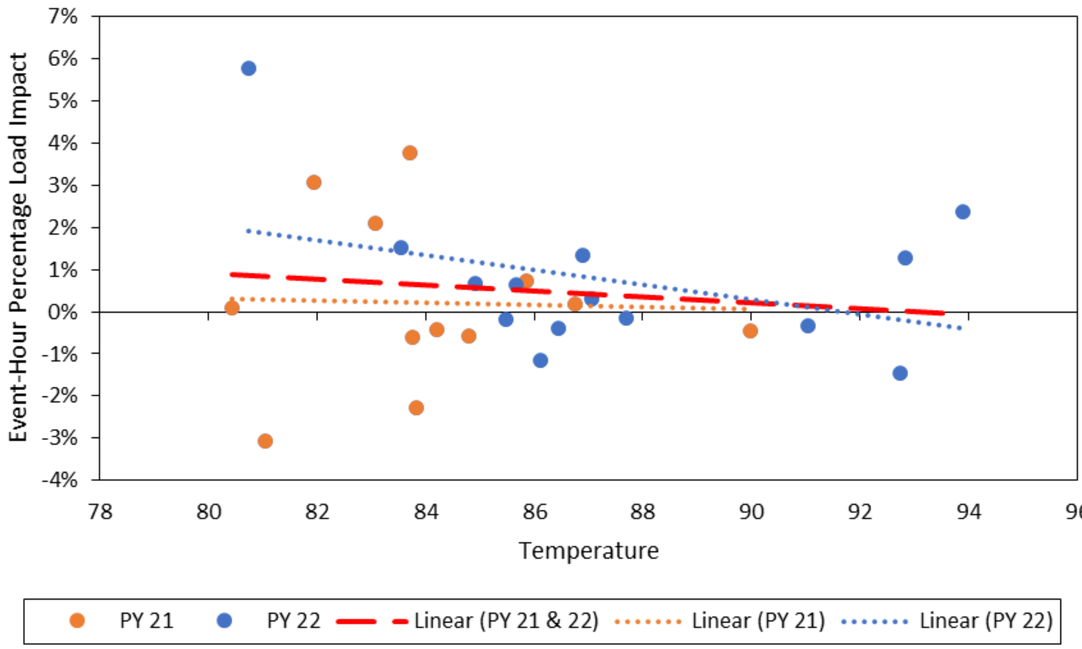


Figure 4.16: Load Impact Percentage and Weather Relationship,
SCE Small



4.2 SCE Ex-Ante Load Impacts

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

As described in Section 2.2, per-customer load impacts are derived from analysis of current and previous ex-post load impacts. As demonstrated in Section 4.1.8, we investigated the effect of weather on estimated load impacts and found that there exists a negative relationship for large and medium, but not small customers. The ex-ante load impacts are simulated by multiplying forecast reference loads by the ex-post percentage load impacts (by size, LCA, and hour of the day). The ex-post percentage load impact is adjusted based on ex-ante weather scenarios for large and medium customers.[20]

Another assumption made in these forecasts is that the share of enrollments by LCA within each size group remains constant over time. This was necessary to produce

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

forecasts at the LCA level from SCE's enrollment forecasts, which vary by size group but not by LCA.

4.2.1 All Customers

Figure 4.17 summarizes the overall trend of SCE's enrollment forecast. SCE anticipates that the total number of CPP customers decreases by about 3 percent each year until 2027, where it will remain constant at 185,923 customers.

Figure 4.17: CPP Enrollments, *SCE All*

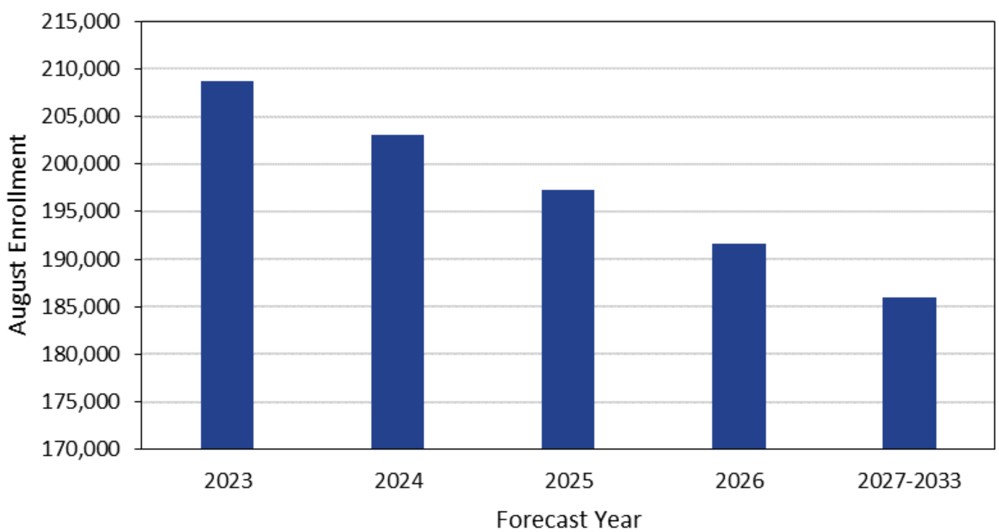
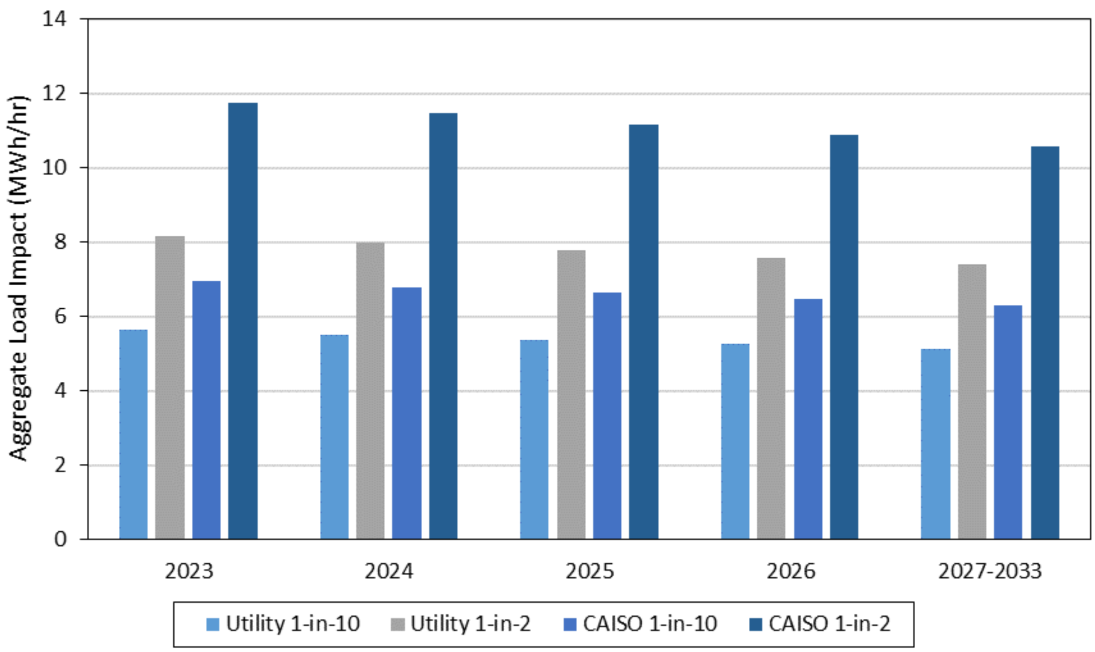


Figure 4.18 shows the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts reduce slightly over time due to the decrease in forecasted total enrollment. Aggregate load impacts have a negative relationship with weather; therefore, weather scenarios with hotter temperatures have lower load impacts. For instance, the load impacts for 1-in-2 scenarios are higher than 1-in-10 scenarios, and the largest difference of load impacts between 1-in-2 and 1-in-10 scenarios is about 6.1 MWh/hour. The highest load impacts for each year occur under CAISO-specific 1-in-2 weather conditions. Additional results of ex-ante load impacts are presented in the subsequent sections by size group.

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



4.2.2 Large Customers

Figure 4.19 summarizes SCE's enrollment forecast for large CPP customers. SCE anticipates that Large CPP customer enrollment decreases by about 3 percent each year until 2027, where it will remain constant at 1,479 customers.

Figure 4.19: CPP Enrollments, *SCE Large*

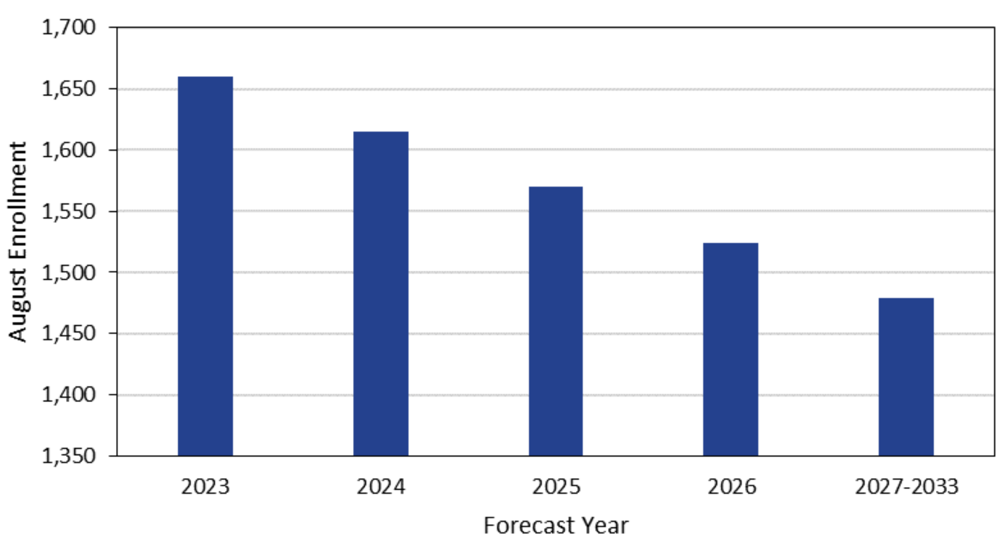


Figure 4.20 illustrates the aggregate reference load, observed load, and load impact for large customers on the typical event day in 2023 for the SCE 1-in-2 weather scenario. The average event-hour load impact is 5.4 MWh/hour, or 1.4 percent of the reference

load. The shape of the ex-ante loads and load impacts is similar to the ex-post results in Figure 4.3.

Figure 4.20: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Large*

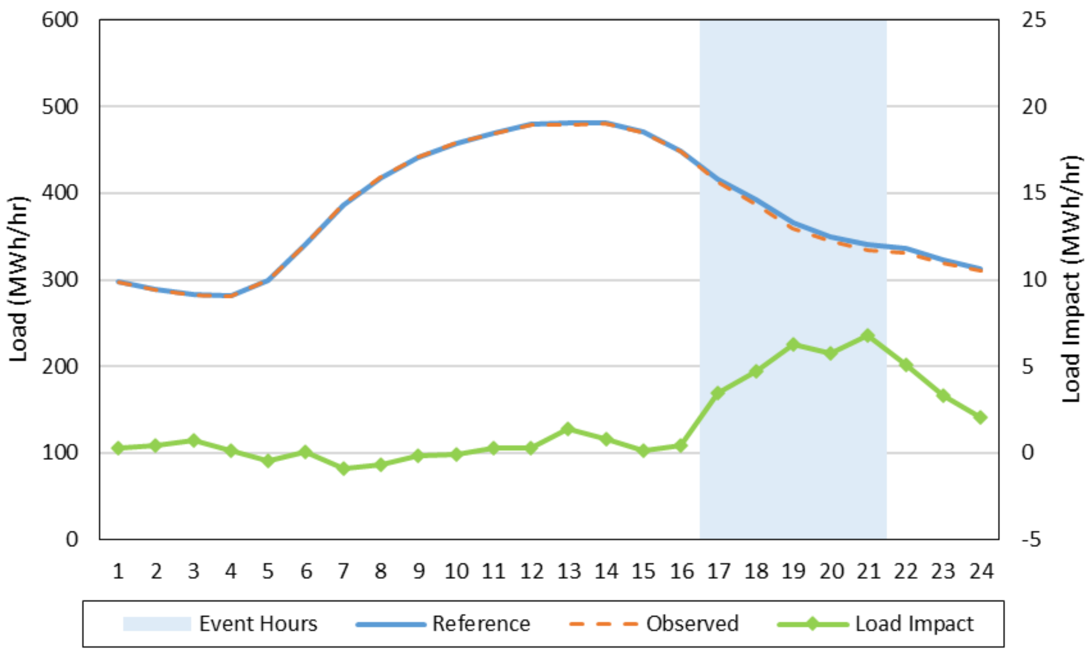


Figure 4.21 shows the forecasted share of large customer load impacts by LCA during the average event hour on the typical event day in 2023 under SCE's 1-in-2 weather scenario. As expected, the LA Basin accounts for 87 percent of the total load impact.

Figure 4.21: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Large*

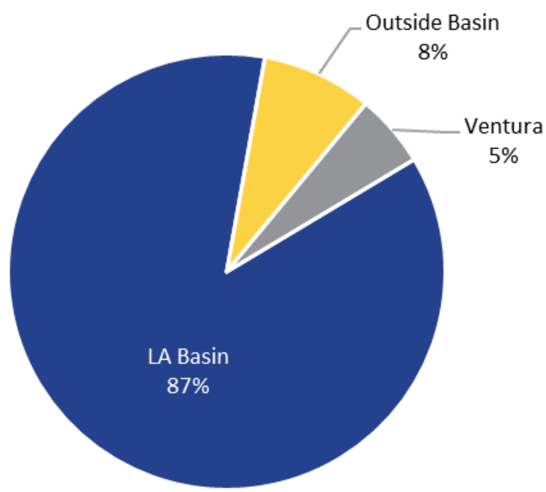


Figure 4.22 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the RA window in 2023 across months for SCE's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. for all months except for March and April, when it is from 5 to 10 p.m. The load impact is highest in June (6.7 MWh/hour) and then decreases over the summer period as temperatures rise. The lowest load impacts occur in September at 3.7 MWh/hour.

Figure 4.22: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day, SCE Large*

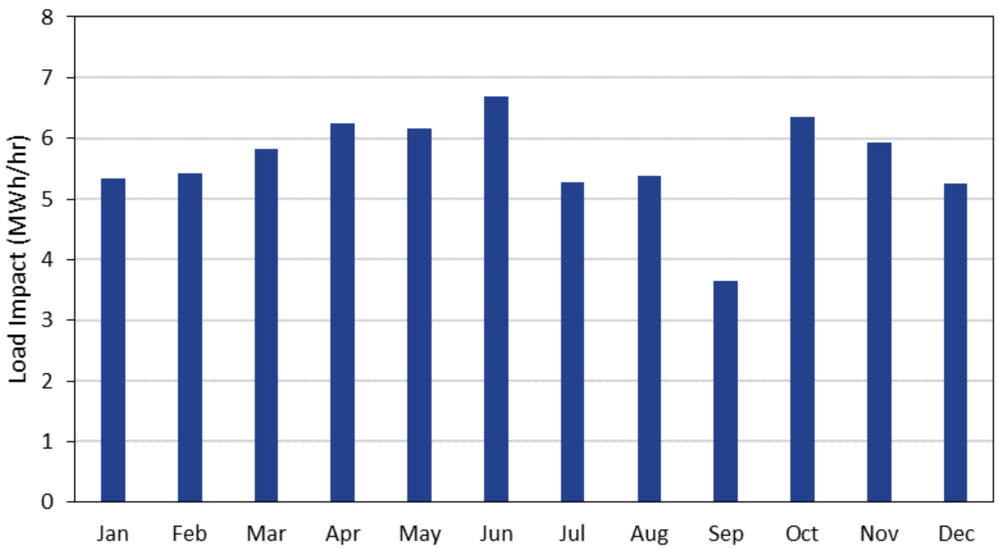
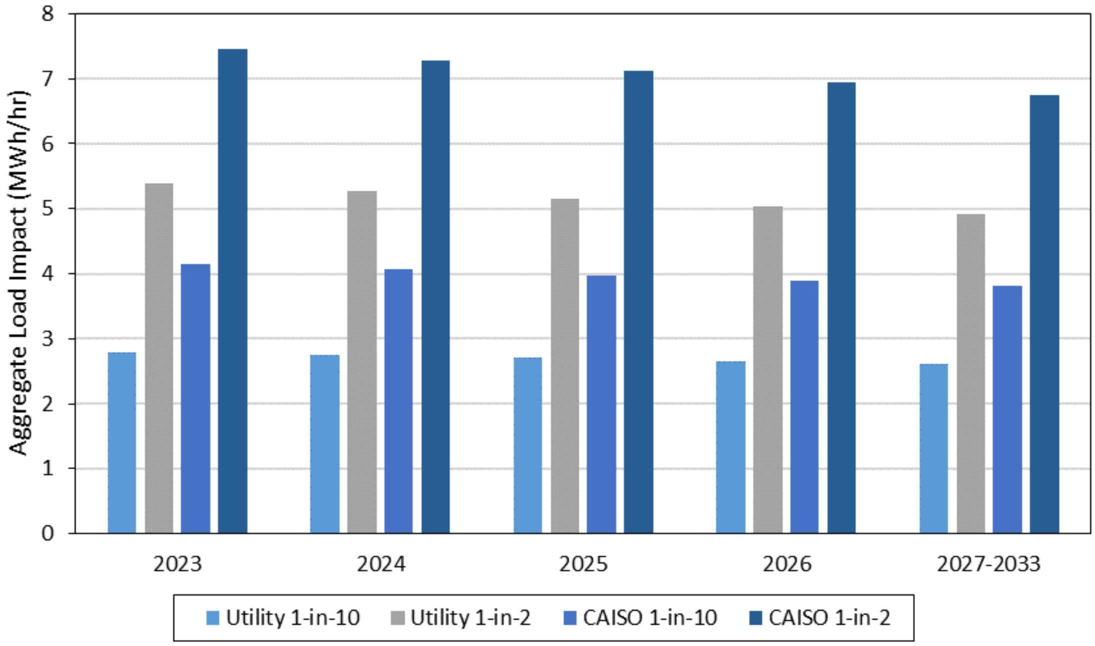


Figure 4.23 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. The load impact decreases over time, within a specific weather scenario, as enrollment numbers decrease. The hottest weather scenarios have relatively lower load impacts. For example, SCE weather scenarios are hotter than CAISO weather scenarios and thus have lower load impacts. Similarly, 1-in-10 weather scenarios are hotter than 1-in-2 weather scenarios and thus have lower load impacts. The largest load impact (7.46 MWh/hour in 2023) occurs under the CAISO 1-in-2 weather condition when temperatures are relatively lower.

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



4.2.3 Medium Customers

Figure 4.24 summarizes SCE's enrollment forecast for medium CPP customers. SCE anticipates that Medium CPP customer enrollment decreases by about 3 percent each year until 2027, where it will remain constant at 17,980 customers.

Figure 4.24: CPP Enrollments, *SCE Medium*

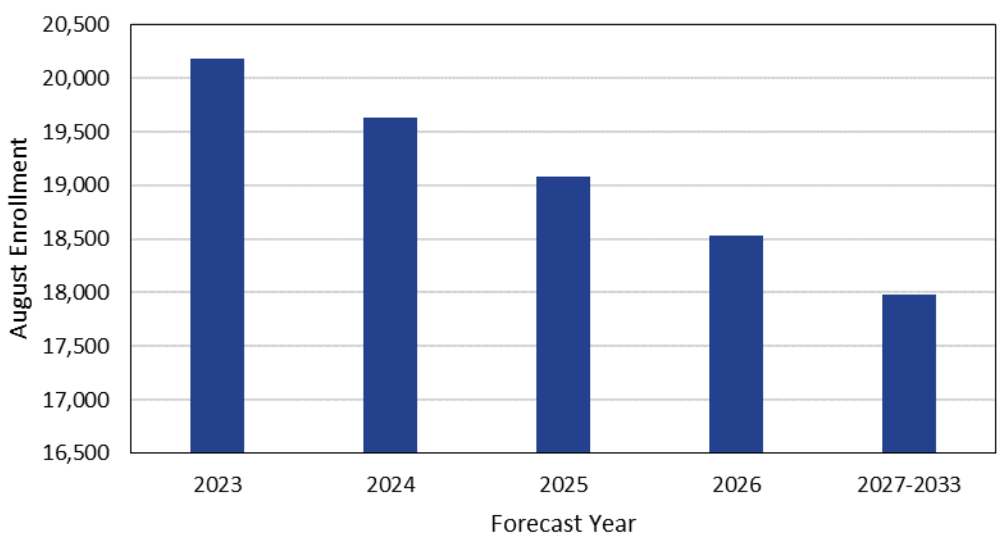


Figure 4.25 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August in 2023 for the SCE 1-in-2

weather scenario. The forecast predicts an average load impact of 0.64 MWh/hour for Medium CPP customers on the typical event day in 2023, which is a 0.1 percent reduction in reference loads.

Figure 4.25: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Medium*

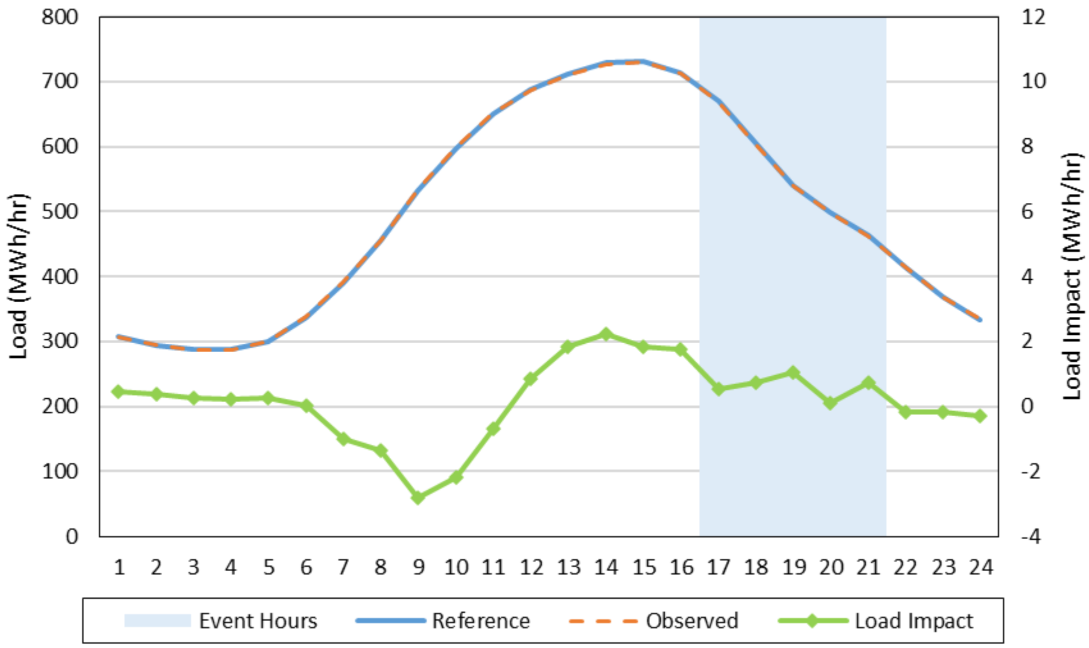


Figure 4.26 shows the forecasted share of load impacts for medium CPP customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under SCE's 1-in-2 weather scenario. Ventura is expected to have the largest share of load impacts at 69 percent, followed by Outside Basin at 19 percent, then LA Basin at 12 percent.

Figure 4.26: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Medium*

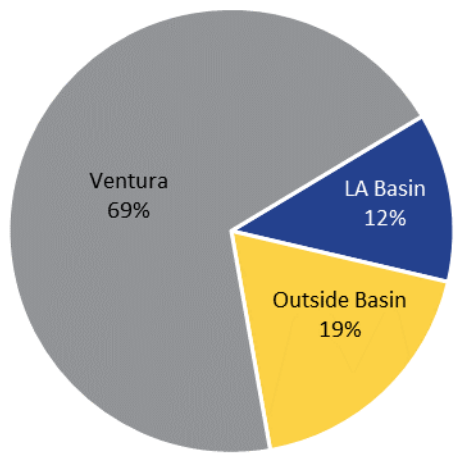


Figure 4.27 shows the seasonality of the forecasted load impacts for medium CPP customers based on the 2023 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The RA window is 4 to 9 p.m. in all months except for March and April when it is 5 to 10 p.m. The load impact is highest in June (0.8 MWh/hour) and lowest in March (0.1 MWh/hour). The lower load impacts in March and April are due to the later RA window hours which include one hour that is not an event hour (9 to 10 p.m.) Over the summer period, load impacts decrease as weather temperatures rise because of the observed negative relationship between temperatures and load impacts in the ex-post analysis for medium customers.

Figure 4.27: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day, SCE Medium*

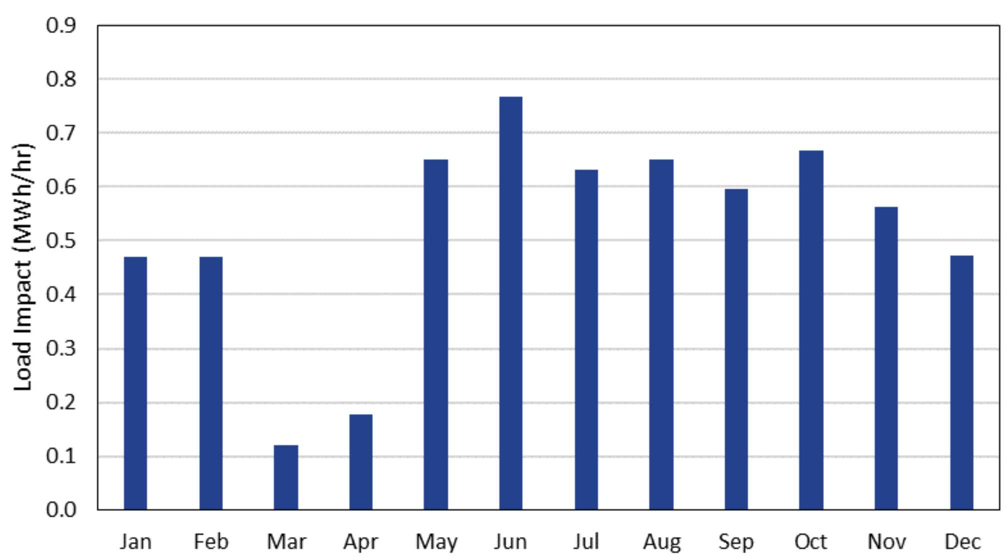
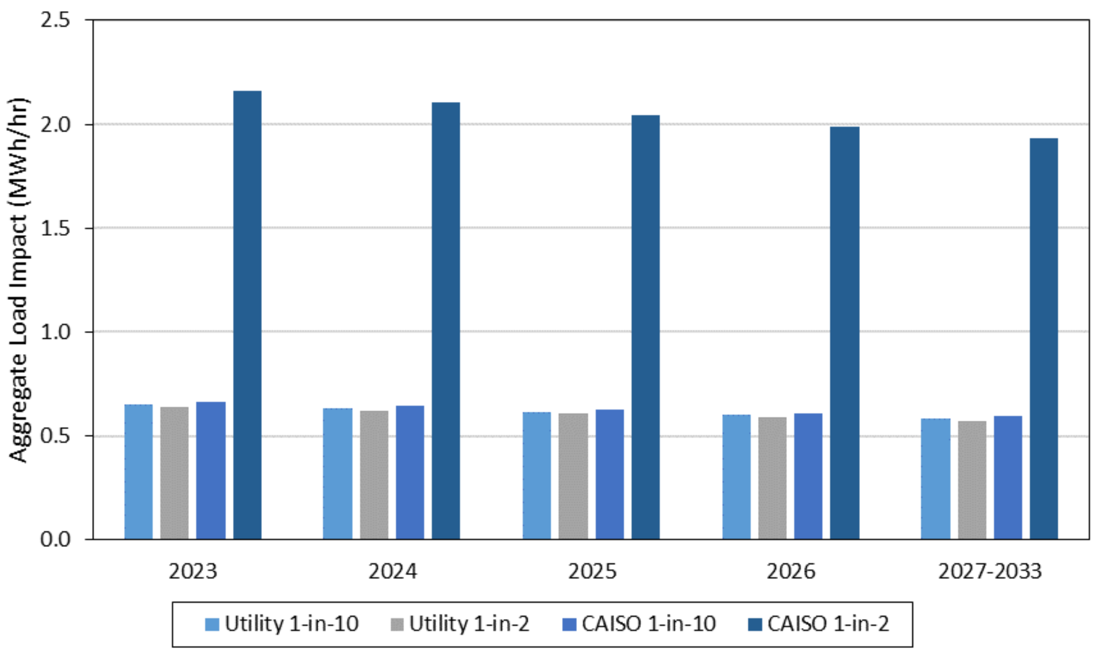


Figure 4.28 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. The CAISO 1-in-2 weather scenario has the largest load impact of 2.2 MWh/hour in 2023 when temperatures are relatively cooler. The other weather scenarios in 2023 exhibit load impacts around 0.65 MWh/hour. These scenarios have hotter temperatures than the CAISO 1-in-2 scenario which result in lower load impacts. There is less variation for these scenarios because weather adjusted load impacts are capped at a lower bound.[21]

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



4.2.4 Small Customers

Figure 4.29 summarizes SCE's enrollment forecast for small CPP customers. SCE anticipates that small CPP customer enrollment decreases by about 3 percent until 2027, where it will remain constant at 166,464 customers.

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

Figure 4.29: CPP Enrollments, *SCE Small*

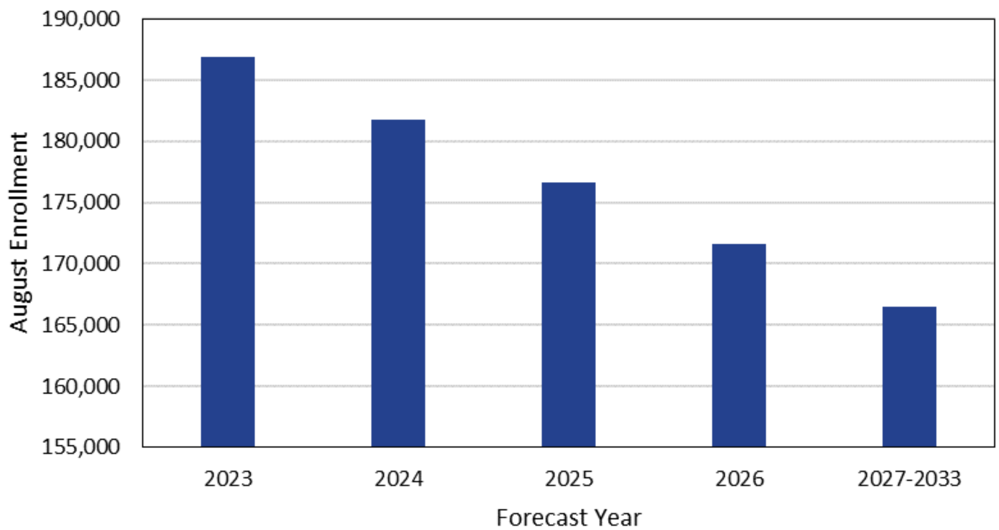


Figure 4.30 illustrates the aggregate reference loads, observed loads, and load impacts for small CPP customers on the typical event day in August in 2023 for the SCE 1-in-2 weather scenario. The forecast predicts an average load impact of 2.1 MWh/hour for small CPP customers on the typical event day in 2023 for the SCE 1-in-2 weather scenario, which is a 0.7 percent reduction in reference loads.

Figure 4.30: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Small*

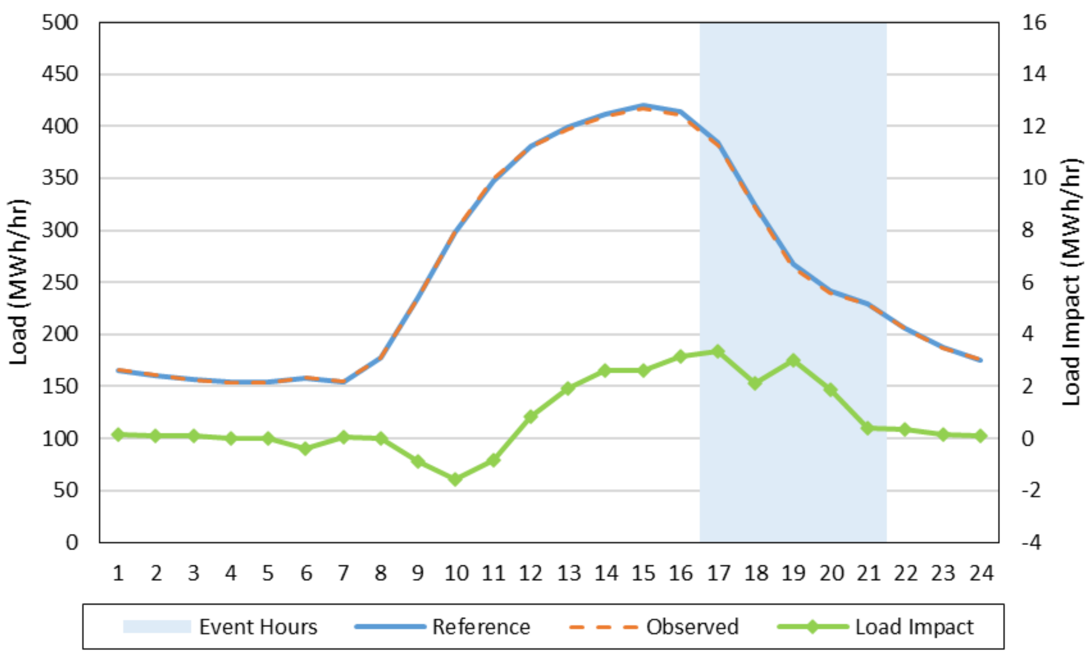


Figure 4.31 shows the forecasted share of load impacts for small customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under

SCE's 1-in-2 weather scenario. LA Basin has the largest share of load impacts at 78 percent, followed by Ventura at 18 percent, then Outside Basin at 4 percent.

Figure 4.31: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Small*

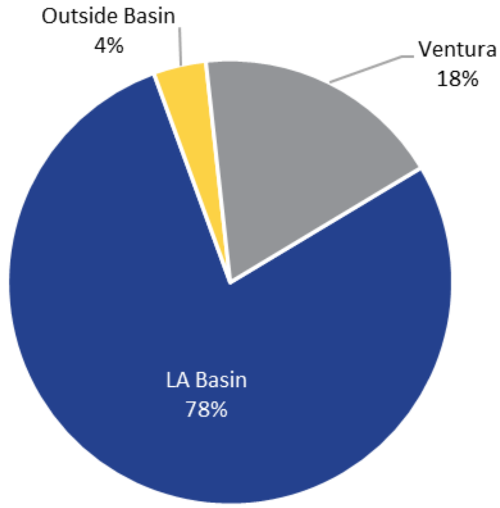


Figure 4.32 shows the seasonality of the forecasted load impacts for small CPP customers based on the 2023 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The load impact is highest in September at 2.2 MWh/hour. The load impact is lowest in March at 1.0 MWh/hour, driven by differences in the March and April RA window (i.e., RA window is 5 to 10 p.m. in March and April and 4 to 9 p.m. in all other months). The peak load impact in September is driven by higher references loads.[22]

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

Figure 4.32: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day, SCE Small*

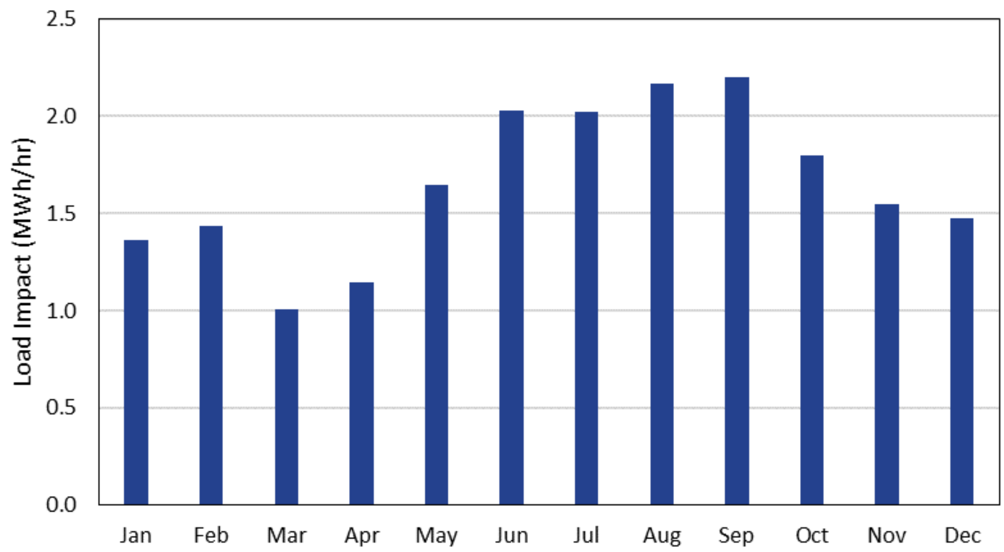
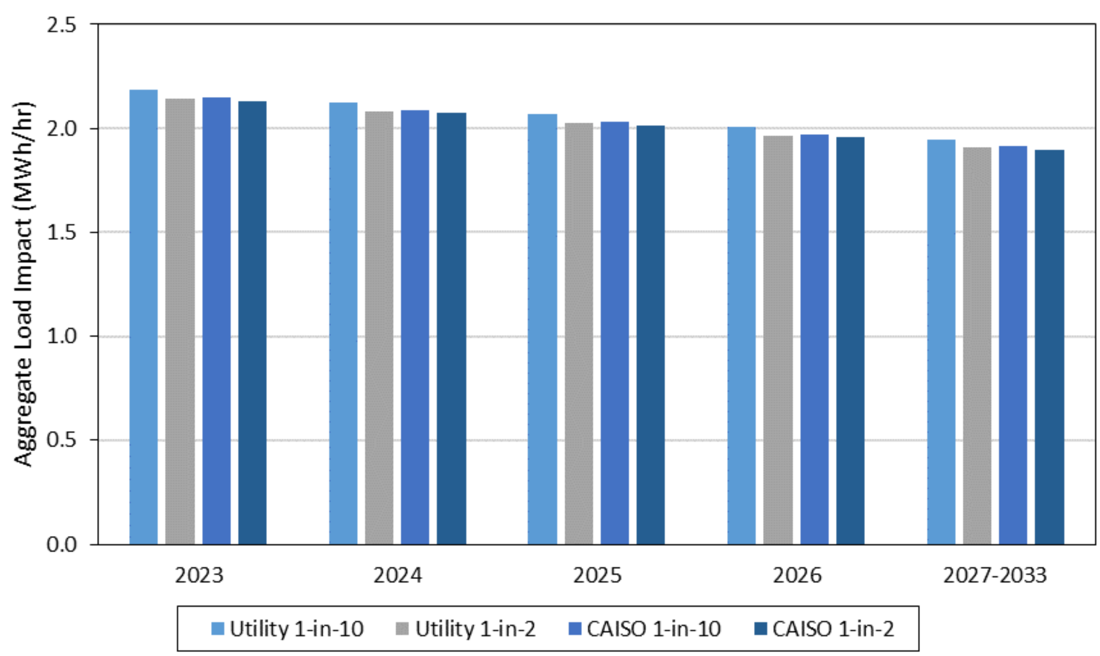


Figure 4.33 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast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

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



4.3 SCE Load Impact Reconciliations

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

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

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2022. The term "previous" refers to findings in reports for PY2021.

4.3.1 Large Customers

Previous vs. Current Ex-Post

Table 4.17 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The total load impact is decreased in the current study (6.7 MWh/hour vs. 10.9 MWh/hour in the previous study). This is partly due to a combination of lower enrollments and per-customer reference loads. The per-customer reference load decreased slightly from 222 kWh/hour to 219 kWh/hour. The percentage load impacts also decreased in the current study. As discussed previously, there appears to be a negative relationship between load impacts and weather for large CPP customers. Specifically, load impacts decrease when temperatures increase. The table below reflects this relationship as the current study has lower percentage load impacts and higher temperatures than the previous study.

Table 4.17: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	1,915	1,687
	Reference (MW)	425	369
	Load Impact (MW)	10.9	6.7
	Avg. Temp.	84.7	88.0
Per SAID	Reference (kW)	221.8	218.9
	Load Impact (kW)	5.7	4.0
	% Load Impact	2.6%	1.8%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.18 reports the average event-hour load impacts for a typical event day in 2023 under SCE 1-in-2 weather conditions. The forecast load impact is lower in the current study (5.4 MWh/hour vs. 10.7 MWh/hour in the previous study). Lower enrollments only partially cause the lower load impacts. More importantly, the current study forecast accounts for the negative relationship between ex-post load impacts and weather by allowing load impacts to decrease as temperatures rise. The previous study forecast did not have enough information to model this relationship, thus allowing load impacts to rise with temperatures as a constant percentage of the increased reference load. Temperatures in the current study forecast are also slightly larger.

Table 4.18: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, SCE Large*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,793	1,660
	Reference (MW)	407	373
	Load Impact (MW)	10.7	5.4
	Avg. Temp.	87.7	89.7
Per SAID	Reference (kW)	227	225
	Load Impact (kW)	5.9	3.2
	% Load Impact	2.6%	1.4%

Previous Ex-Ante vs. Current Ex-Post

Table 4.19 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post typical event day load impacts are based on the average non-holiday weekday event. The ex-ante forecast in the previous study predicted higher enrollments and reference loads. The per-customer reference load in the current study is slightly lower due to a compositional change since customers remaining on the CPP are slightly smaller. The current study ex-post results exhibited lower load impacts with higher temperatures. The previous year forecast did not have enough information to model this relationship and therefore forecasted constant percentage loads impacts. As a result, load impacts would rise with temperatures as reference loads increased.

Table 4.19: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Large*

Level	Outcome	Ex-Ante for 2022 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	1,808	1,687
	Reference (MW)	410	369
	Load Impact (MW)	10.7	6.7
	Avg. Temp.	87.7	88.0
Per SAID	Reference (kW)	227	219
	Load Impact (kW)	5.9	4.0
	% Load Impact	2.6%	1.8%

Current Ex-Post vs. Current Ex-Ante

Table 4.20 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2023 under SCE 1-in-2 weather conditions. Reference loads are slightly larger in ex-ante due to hotter temperatures, even with a decreased enrollment forecast. Conversely, the load impact and percentage load impact are smaller in ex-ante because of the hotter temperatures.

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

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	1,687	1,660
	Reference (MW)	369	373
	Load Impact (MW)	6.7	5.4
	Avg. Temp.	88.0	89.7
Per SAID	Reference (kW)	219	225
	Load Impact (kW)	4.0	3.2
	% Load Impact	1.8%	1.4%

Table 4.21 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 4.21: Comparison of Ex-Post and Ex-Ante Factors, *SCE Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 88.0 °F during the average event day.	Average event-hour temperature of 89.7 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load but decrease the load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	1,687 service accounts.	1,660 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.2 Medium Customers

Previous vs. Current Ex-Post

Table 4.22 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load impact is smaller in the current study (0.9 MWh/hour vs. 4.6 MWh/hour in the previous study). Enrollments are lower in the current study which impact the aggregate reference loads. The per-customer reference loads, however, were slightly higher. As was discussed previously, higher temperatures during events are associated with lower load impacts for medium customers. This relationship is demonstrated here with higher temperatures and lower load impacts in the current ex-post study.

Table 4.22: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	27,503	22,119
	Reference (MW)	721	599
	Load Impact (MW)	4.6	0.9
	Avg. Temp.	84.3	87.5
Per SAID	Reference (kW)	26.2	27.1
	Load Impact (kW)	0.17	0.04
	% Load Impact	0.6%	0.1%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.23 reports the average event-hour load impacts for a typical event day in 2023 under SCE 1-in-2 weather conditions. The per-customer reference load is slightly larger in the current study as a result of hotter temperatures. The current study also models load impacts to decrease with higher temperatures during the summer months, resulting in a lower percentage load impact. Additionally, the current study enrollment forecast is less than the previous study, which reduces aggregate reference loads and load impacts.

Table 4.23: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 August Typical Event Day, SCE Medium*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	24,560	20,185
	Reference (MW)	655	555
	Load Impact (MW)	4.2	0.6
	Avg. Temp.	87.6	89.2
Per SAID	Reference (kW)	26.7	27.5
	Load Impact (kW)	0.17	0.03
	% Load Impact	0.6%	0.1%

Previous Ex-Ante vs. Current Ex-Post

Table 4.24 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post load impacts are based on the average non-holiday weekday event. The ex-post enrollments in the current study are lower than what was forecast. Per-customer reference loads, however, are similar between studies. The load impact was forecasted to be larger from the previous study because the percentage load impact was assumed to be constant as reference loads changed, thereby increasing load impacts as reference loads increased with temperatures. However, a negative relationship between load impacts and weather was observed as a larger sample of events over hotter temperatures occurred in the current ex-post study.

Table 4.24: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Medium*

Level	Outcome	Ex-Ante for 2022 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	24,766	22,119
	Reference (MW)	661	599
	Load Impact (MW)	4.2	0.9
	Avg. Temp.	87.6	87.5
Per SAID	Reference (kW)	26.7	27.1
	Load Impact (kW)	0.17	0.04
	% Load Impact	0.6%	0.1%

Current Ex-Post vs. Current Ex-Ante

Table 4.25 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2023 under SCE 1-in-2 weather conditions. Enrollments decrease in ex-ante, resulting in lower aggregate reference loads and load impacts. Per-customer reference loads are slightly higher while per-customer load impacts are slightly lower in ex-ante due to higher forecasted temperatures.

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

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	22,119	20,185
	Reference (MW)	599	555
	Load Impact (MW)	0.9	0.6
	Avg. Temp.	87.5	89.2
Per SAID	Reference (kW)	27.1	27.5
	Load Impact (kW)	0.04	0.03
	% Load Impact	0.1%	0.1%

Table 4.26 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.26: Comparison of Ex-Post and Ex-Ante Factors, *SCE Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 87.5 °F during the average event day.	Average event-hour temperature of 89.2 °F during the SCE 1-in-2 August peak day.	Higher temperatures result in larger reference loads but lower load impacts.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	22,119 service accounts.	20,185 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.3 Small Customers

Previous vs. Current Ex-Post

Table 4.27 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load impact is 0.8 MWh/hour in the previous study and 2.2 MWh/hour in the current study. Enrollment numbers decreased in the current study but were offset by higher per-customer load impacts. Higher per-customer reference loads in the current study are a result of hotter event day temperatures. Small customer ex-post load impacts exhibited little relationship with weather and thus maintained a higher percentage load impact with hotter temperatures, unlike the large and medium CPP customers.

Table 4.27: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	229,582	201,453
	Reference (MW)	337	306
	Load Impact (MW)	0.8	2.2
	Avg. Temp.	84.1	87.5
Per SAID	Reference (kW)	1.47	1.52
	Load Impact (kW)	0.003	0.011
	% Load Impact	0.2%	0.7%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.28 reports the average event-hour load impacts for a typical event day in 2023 under SCE 1-in-2 weather conditions. Enrollments decreased in the current study forecast, resulting in lower aggregate reference loads. Per-customer reference loads are slightly higher in the current study due to hotter forecasted temperatures. The forecasted percentage load impact is larger in the current study due to ex-post percentage load impacts being larger than percentage impacts from during PY2021 events.

Table 4.28: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, SCE Small*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	212,422	186,878
	Reference (MW)	320	289
	Load Impact (MW)	0.7	2.1
	Avg. Temp.	87.3	89.2
Per SAID	Reference (kW)	1.51	1.55
	Load Impact (kW)	0.004	0.011
	% Load Impact	0.2%	0.7%

Previous Ex-Ante vs. Current Ex-Post

Table 4.29 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SCE 1-in-2 weather conditions. The ex-post load impacts are based on the average non-holiday weekday event. Enrollments decreased in the current ex-post study resulting in lower aggregate reference loads. Nevertheless, the aggregate load impact was larger in the current study due to higher percentage load impacts during PY2022 events. Per-customer reference loads are similar between the previous forecast and the current ex-post analysis.

Table 4.29: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Small*

Level	Outcome	Ex-Ante for 2022 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	214,202	201,453
	Reference (MW)	322	306
	Load Impact (MW)	0.8	2.2
	Avg. Temp.	87.3	87.5
Per SAID	Reference (kW)	1.51	1.52
	Load Impact (kW)	0.004	0.011
	% Load Impact	0.2%	0.7%

Current Ex-Post vs. Current Ex-Ante

Table 4.30 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2023 under SCE 1-in-2 weather conditions. The ex-post percentage load impacts were applied to ex-ante reference loads, resulting in equivalent percentage load impacts. The constant percentage load impact was applied to reference load for small customers since there was not a strong relationship between ex-post load impacts and weather. The per-customer ex-ante reference loads are higher due to hotter event hour-temperatures. The aggregate reference load and load impact is lower in ex-ante due to decreased enrollment numbers.

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

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	201,453	186,878
	Reference (MW)	306	289
	Load Impact (MW)	2.2	2.1
	Avg. Temp.	87.5	89.2
Per SAID	Reference (kW)	1.52	1.55
	Load Impact (kW)	0.011	0.011
	% Load Impact	0.7%	0.7%

Table 4.31 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.31: Comparison of Ex-Post and Ex-Ante Factors, *SCE Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 87.5 °F during the average event day.	Average event-hour temperature of 89.2 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	201,453 service accounts.	186,878 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

5 SDG&E

5.1 SDG&E Ex-Post Load Impacts

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

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

5.1.1 All Customers

This section summarizes results for all SDG&E customers. The average ex-post load impacts are summarized for all five events as well as the average weekday and weekend events in Figure 5.1.[23] The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

SDG&E customers have statistically significant load reductions on two out of five event days. The highest load reduction is 10.9 MWh/hour on September 4th. The load impact averaged 5.6 MWh/hour across all weekend events and -0.7 MWh/hour over weekday event. Figure 5.1 provides some evidence of a negative relationship between load impact and event temperature; however, there are not enough events to provide a clear picture of this relationship.

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

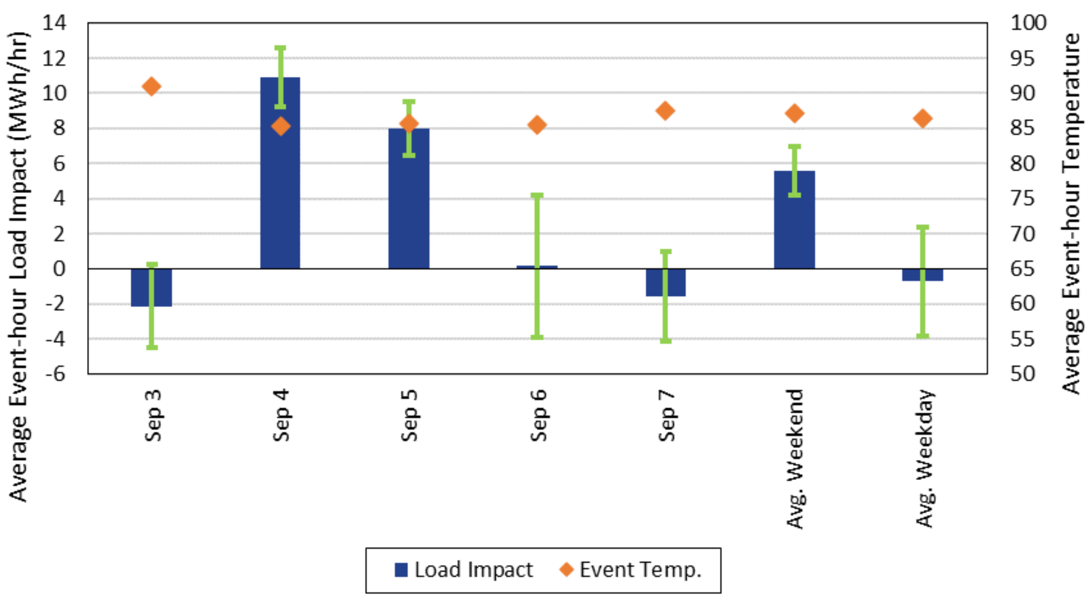


Table 5.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average weekday and weekend events for all SDG&E customers. Estimated load impacts averaged 1.1 kWh/hour per customer across weekend event days (e.g., September 3rd through 5th), which amounts to a 2.7 percent load reduction. Estimated load impacts were not statistically significant over the weekday events. Detailed results by hour and industry group are presented in subsequent subsections by size group.

[23] Labor Day, September 5th, is included in the average weekend load impact results since holiday loads more closely resemble weekend loads.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
9/3/2022	4,860	204	-2.1	41.9	-0.4	-1.0%	91.0
9/4/2022	4,858	202	10.9	41.6	2.2	5.4%	85.4
9/5/2022	4,858	203	8.0	41.9	1.6	3.9%	85.7
9/6/2022	4,857	235	0.1	48.4	0.0	0.1%	85.5
9/7/2022	4,856	245	-1.6	50.5	-0.3	-0.6%	87.4
Avg. Weekend Event	**4,859**	**208**	**5.6**	**42.8**	**1.1**	**2.7%**	**87.2**
Avg. Weekday Event	**4,857**	**240**	**-0.7**	**49.5**	**-0.1**	**-0.3%**	**86.5**

5.1.2 Large Customers

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

The ex-post load impacts for SDG&E's large CPP customers are summarized for all five events in Figure 5.2. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

These results indicate that large customers had statistically significant load reductions on all of the event days, ranging from 1.4 to 6.9 MWh/hour. The load impact averaged 5.1 MWh/hour and 2.5 MWh/hour across all weekend and non-holiday weekday events, respectively. Figure 5.2 suggests a negative correlation between load impact and event temperature; however, there are not enough events to provide conclusive evidence of this relationship.

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

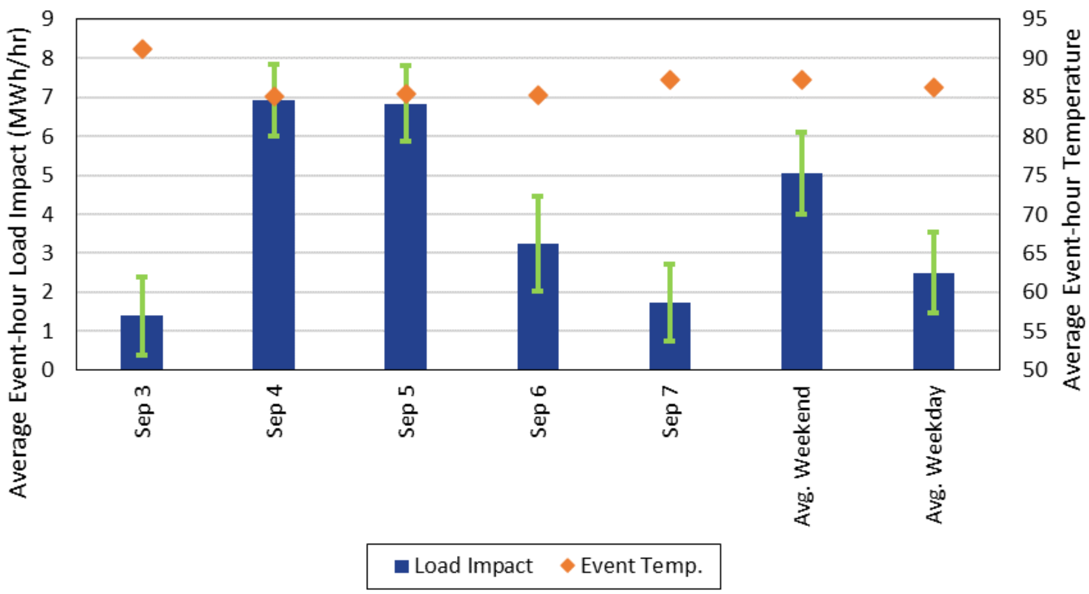


Table 5.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average weekend and weekday event. Per-Customer estimated load reductions averaged 9.4 kWh/hour across weekend event days, which amounts to a 5.7 percent load reduction. Estimated load reductions averaged and 4.7 kWh/hour per customer across weekday events, which amounts to a 2.2 percent load reduction.

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

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
9/3/2022	535	88	1.4	165.0	2.6	1.6%	91.1
9/4/2022	534	87	6.9	163.3	13.0	8.0%	85.2
9/5/2022	534	91	6.8	170.6	12.8	7.5%	85.4
9/6/2022	533	108	3.3	203.2	6.1	3.0%	85.3
9/7/2022	533	114	1.7	213.8	3.2	1.5%	87.3
Avg. Weekend Event	**535**	**89**	**5.1**	**166.1**	**9.4**	**5.7%**	**87.3**
Avg. Weekday Event	**533**	**111**	**2.5**	**208.5**	**4.7**	**2.2%**	**86.3**

Figure 5.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day (defined as the average non-holiday weekday event). Table 5.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. The hourly load impact estimates do not show evidence of significant pre-cooling but there

does appear to be some snapback, as evidenced by a load increase in the hours following the event.

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

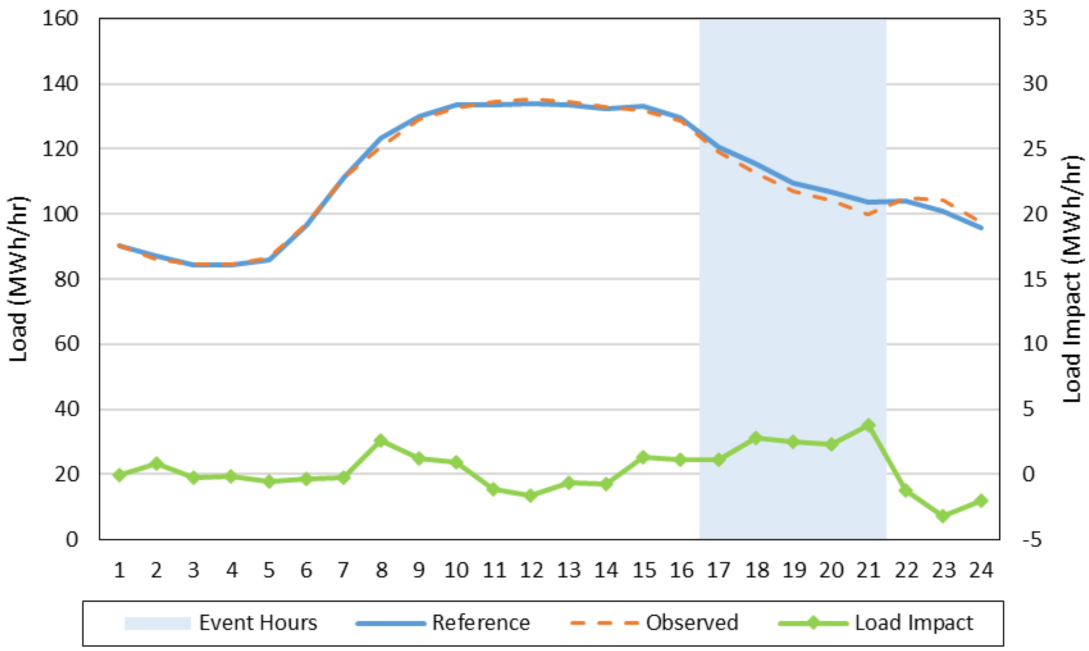


Table 5.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	90.4	90.5	-0.1	-0.1%	73.6	-1.2	-0.6	-0.1	0.4	1.0
2	87.0	86.2	0.8	1.0%	72.4	0.2	0.6	0.8	1.1	1.4
3	84.1	84.4	-0.3	-0.3%	72.0	-0.9	-0.5	-0.3	0.0	0.3
4	84.4	84.6	-0.2	-0.2%	71.0	-0.9	-0.5	-0.2	0.1	0.5
5	85.8	86.3	-0.5	-0.6%	70.1	-1.4	-0.9	-0.5	-0.2	0.3
6	96.4	96.8	-0.3	-0.3%	70.3	-1.3	-0.7	-0.3	0.0	0.6
7	110.9	111.2	-0.3	-0.3%	70.2	-1.4	-0.8	-0.3	0.2	0.8
8	123.4	120.9	2.5	2.1%	71.1	1.4	2.1	2.5	3.0	3.7
9	130.1	128.9	1.2	0.9%	76.1	0.0	0.7	1.2	1.7	2.4
10	133.4	132.5	0.9	0.7%	82.4	-0.2	0.5	0.9	1.4	2.0
11	133.5	134.6	-1.1	-0.9%	87.6	-2.1	-1.5	-1.1	-0.8	-0.2
12	133.9	135.5	-1.7	-1.2%	91.4	-2.7	-2.1	-1.7	-1.2	-0.6
13	133.7	134.4	-0.7	-0.5%	92.0	-1.8	-1.2	-0.7	-0.3	0.4
14	132.3	133.2	-0.8	-0.6%	91.7	-2.5	-1.5	-0.8	-0.1	0.9
15	133.2	131.9	1.3	1.0%	91.7	-0.3	0.7	1.3	2.0	3.0
16	129.8	128.7	1.1	0.9%	92.5	-0.4	0.5	1.1	1.8	2.7
17	120.5	119.4	1.1	0.9%	92.1	-0.4	0.5	1.1	1.8	2.7
18	115.4	112.7	2.7	2.4%	90.5	1.2	2.1	2.7	3.4	4.3
19	109.7	107.1	2.5	2.3%	86.6	0.8	1.8	2.5	3.2	4.2
20	106.6	104.3	2.3	2.2%	82.5	0.5	1.6	2.3	3.1	4.2
21	103.5	99.8	3.8	3.6%	79.8	1.8	3.0	3.8	4.5	5.7
22	104.0	105.2	-1.2	-1.2%	78.2	-3.5	-2.1	-1.2	-0.3	1.0
23	100.9	104.2	-3.3	-3.2%	76.7	-5.8	-4.3	-3.3	-2.3	-0.8
24	95.7	97.7	-2.0	-2.1%	76.2	-4.4	-3.0	-2.0	-1.0	0.4
Daily	**2,679**	**2,671**	**8**	**0.3%**	**80.8**	**-2.5**	**3.6**	**7.8**	**12.1**	**18.2**

Typical Event Day results based on only non-holiday weekday event.

Next, we look at SDG&E large customer estimates by industry group. Table 5.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). The Offices, Hotels, Health, Services industry group have the largest number of enrolled customers (123 service accounts) and reference load (35 MWh/hour).

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

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	[redacted]				
2. Manufacturing	97	15	16	-0.44	-2.9%
3. Wholesale, Transportation, Utilities	103	21	18	2.74	13.1%
4. Retail Stores	27	6	6	-0.17	-2.8%
5. Offices, Hotels, Health, Services	123	35	33	2.23	6.3%
6. Schools	107	11	13	-1.68	-15.4%
7. Institutional/Government	59	19	20	-0.12	-0.6%
8. Other	[redacted]				

To better understand the distribution of results across industries, we look at the shares of estimated positive load impacts, reference loads, and enrollments by industry group in Figure 5.4. [redacted]

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

[redacted]

Table 5.5 summarizes SDG&E large customers estimated load impacts by industry group for the average weekend/holiday event. The average reference load is lower for each industry group on the weekend. Like the typical event day results, the Offices, Hotels, Health, Services industry group has the largest number of enrolled customers and reference load. The load impact is also highest for this industry group (3.11 MWh/hour).

Table 5.5: Average Weekend/Holiday Event-Hour Load Impacts by Industry Group, *SDG&E Large*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	[redacted]				
2. Manufacturing	97	5	5	0.06	1.1%
3. Wholesale, Transportation, Utilities	104	18	17	1.36	7.4%
4. Retail Stores	27	5	5	-0.07	-1.4%
5. Offices, Hotels, Health, Services	124	34	30	3.11	9.3%
6. Schools	107	6	6	-0.07	-1.2%
7. Institutional/Government	59	18	18	0.53	2.9%
8. Other	[redacted]				

Figure 5.5 illustrates the shares of estimated positive load impacts, reference loads, and enrollments by industry group for the average weekend/holiday event. The Offices, Hotels, Health, Services industry group accounts for 59 percent of the load reductions while the Wholesale, Transportation, Utilities industry group accounts for 26 percent of load reduction. The next largest proportion or load reduction, 10 percent, comes from the Institutional/Government industry group.

Figure 5.5: Average Weekend/Holiday Event-Hour Load Impacts by Industry Group, *SDG&E Large*

[redacted]

5.1.3 Medium Customers

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

The ex-post load impacts for SDG&E's medium CPP customers are summarized for all five events in Figure 5.6. Two event days, September 4th and 5th, have estimated load reductions; however, only September 4th is statistically significant. The remaining event days do not indicate load reductions. Figure 5.6 provides evidence of a relationship between load impact and event temperature. Specifically, load impacts are lower when event temperatures are higher. However, five events split between weekday and weekends are not sufficient to provide conclusive evidence of this relationship.

Figure 5.6: Average Event-Hour Load Impacts by Event, *SDG&E Medium*

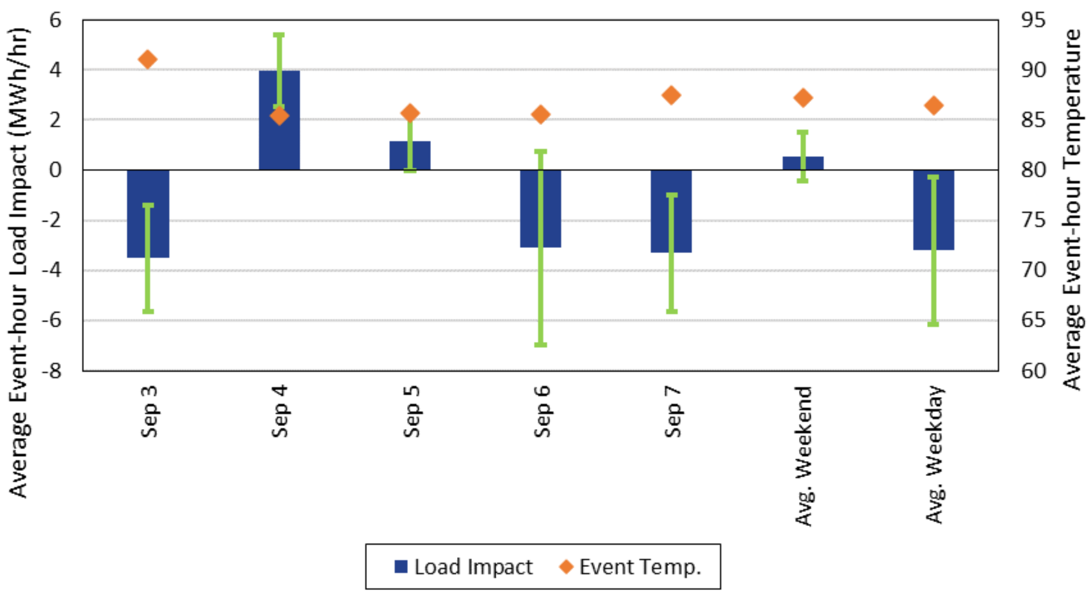


Table 5.6 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Overall, medium customers had an aggregate load impact of 0.1 MWh/hour over weekend/holiday events but no reduction over non-holiday weekday events.

Table 5.6: Average Event-Hour Load Impacts by Event, *SDG&E Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
9/3/2022	4,325	115	-3.5	26.7	-0.8	-3.1%	91.0
9/4/2022	4,324	115	4.0	26.6	0.9	3.4%	85.4
9/5/2022	4,324	112	1.1	26.0	0.3	1.0%	85.7
9/6/2022	4,324	127	-3.1	29.3	-0.7	-2.5%	85.6
9/7/2022	4,323	131	-3.3	30.4	-0.8	-2.5%	87.5
Avg. Weekend Event	**4,324**	**119**	**0.5**	**27.5**	**0.1**	**0.4%**	**87.2**
Avg. Weekday Event	**4,324**	**129**	**-3.2**	**29.9**	**-0.7**	**-2.5%**	**86.5**

Figure 5.7 illustrates the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day (defined as the average non-holiday weekday event) for medium customers. Table 5.7 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. There was not a reduction in usage for medium customers on the typical event day. Temperatures for the typical event day were hotter than other days, as shown in Figure 2.3, which contributed to higher usage on events.

Figure 5.7: Typical Event Day Reference Loads and Load Profile, *SDG&E Medium*

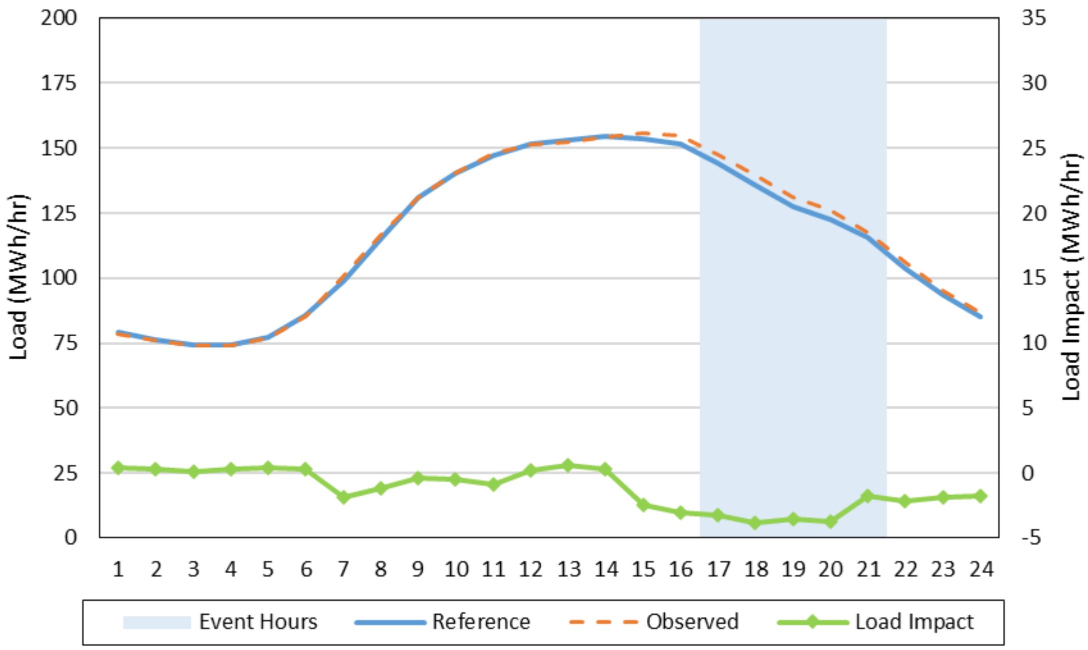


Table 5.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (^{o}F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	79.0	78.7	0.4	0.5%	73.8	-0.5	0.0	0.4	0.7	1.2
2	76.1	75.8	0.3	0.3%	72.7	-0.4	0.0	0.3	0.5	1.0
3	74.1	73.9	0.1	0.2%	72.2	-0.3	0.0	0.1	0.3	0.6
4	74.4	74.1	0.3	0.4%	71.5	-0.1	0.1	0.3	0.5	0.7
5	77.2	76.8	0.4	0.5%	70.6	-0.1	0.2	0.4	0.6	0.9
6	85.7	85.4	0.3	0.3%	70.7	-0.2	0.1	0.3	0.5	0.8
7	98.8	100.7	-1.8	-1.9%	70.6	-3.4	-2.5	-1.8	-1.2	-0.3
8	115.4	116.5	-1.2	-1.0%	71.1	-2.8	-1.8	-1.2	-0.5	0.5
9	130.9	131.3	-0.4	-0.3%	75.9	-1.3	-0.8	-0.4	-0.1	0.5
10	140.1	140.6	-0.5	-0.4%	82.1	-1.1	-0.8	-0.5	-0.2	0.1
11	147.1	147.9	-0.8	-0.6%	87.3	-2.0	-1.3	-0.8	-0.4	0.3
12	151.7	151.5	0.2	0.1%	91.1	-0.6	-0.1	0.2	0.5	0.9
13	152.9	152.3	0.6	0.4%	91.7	0.0	0.3	0.6	0.8	1.2
14	154.4	154.2	0.3	0.2%	91.5	-1.2	-0.3	0.3	0.9	1.7
15	153.4	155.8	-2.4	-1.6%	91.7	-4.5	-3.3	-2.4	-1.6	-0.3
16	151.6	154.6	-3.1	-2.0%	92.6	-6.4	-4.4	-3.1	-1.7	0.3
17	144.3	147.5	-3.2	-2.2%	92.0	-6.4	-4.5	-3.2	-1.9	-0.1
18	135.8	139.6	-3.8	-2.8%	90.4	-7.1	-5.2	-3.8	-2.5	-0.5
19	127.5	131.1	-3.6	-2.8%	87.0	-6.5	-4.8	-3.6	-2.4	-0.7
20	122.5	126.2	-3.7	-3.1%	82.9	-5.1	-4.3	-3.7	-3.2	-2.4
21	115.4	117.1	-1.7	-1.5%	80.2	-3.1	-2.3	-1.7	-1.2	-0.3
22	103.8	106.0	-2.2	-2.1%	78.6	-3.6	-2.8	-2.2	-1.6	-0.8
23	93.2	95.1	-1.9	-2.0%	77.0	-3.3	-2.5	-1.9	-1.3	-0.4
24	85.3	87.0	-1.7	-2.0%	76.5	-3.1	-2.3	-1.7	-1.1	-0.3
Daily	**2,790**	**2,820**	**-29**	**-1.1%**	**80.9**	**-47.5**	**-36.8**	**-29.4**	**-22.0**	**-11.3**

Typical Event Day results based on only non-holiday weekday event.

Next, we look at SDG&E medium customer estimates by industry group. Table 5.8 summarizes the aggregate average event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services has the largest number of enrollments and reference load but did not exhibit a load reduction during weekday events.

Table 5.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *SDG&E Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	191	4	4	-0.49	-13.7%
2. Manufacturing	461	11	11	-0.31	-2.9%
3. Wholesale, Transportation, Utilities	313	9	9	0.34	3.7%
4. Retail Stores	584	21	21	-0.67	-3.2%
5. Offices, Hotels, Health, Services	1,679	56	57	-1.52	-2.7%
6. Schools	249	7	7	-0.35	-4.9%
7. Institutional/Government	769	21	21	0.08	0.4%
8. Other	79	2	2	-0.07	-4.5%

Figure 5.8 shows the shares of enrollments, reference loads, and load impacts by industry group. The non-holiday weekday load impacts are concentrated in the Wholesale, Transportation, Utilities industry group, which realizes 81 percent of the total load impact. The remaining 19 percent of load reduction comes from the Institutional/Government industry group.

Figure 5.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *SDG&E Medium*

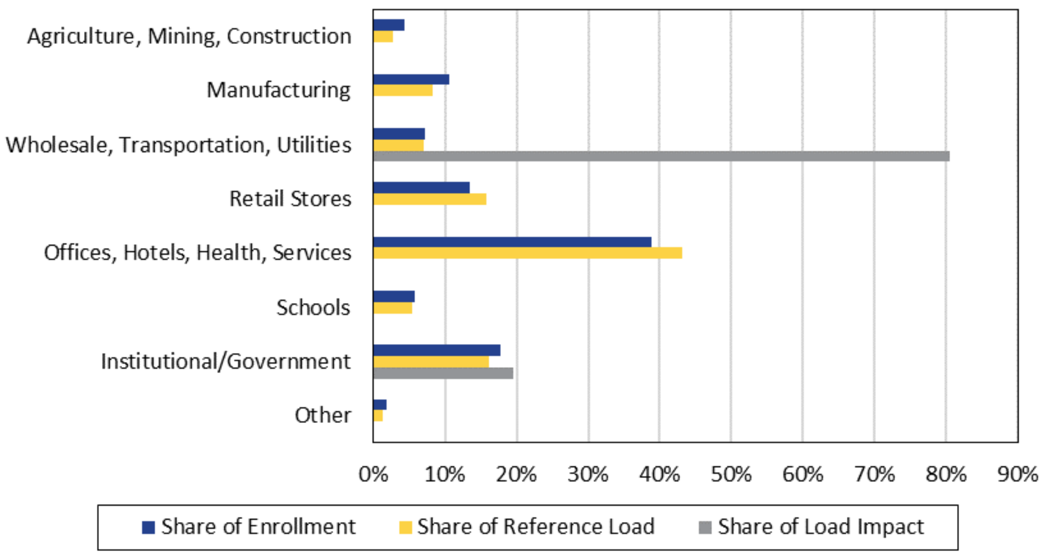


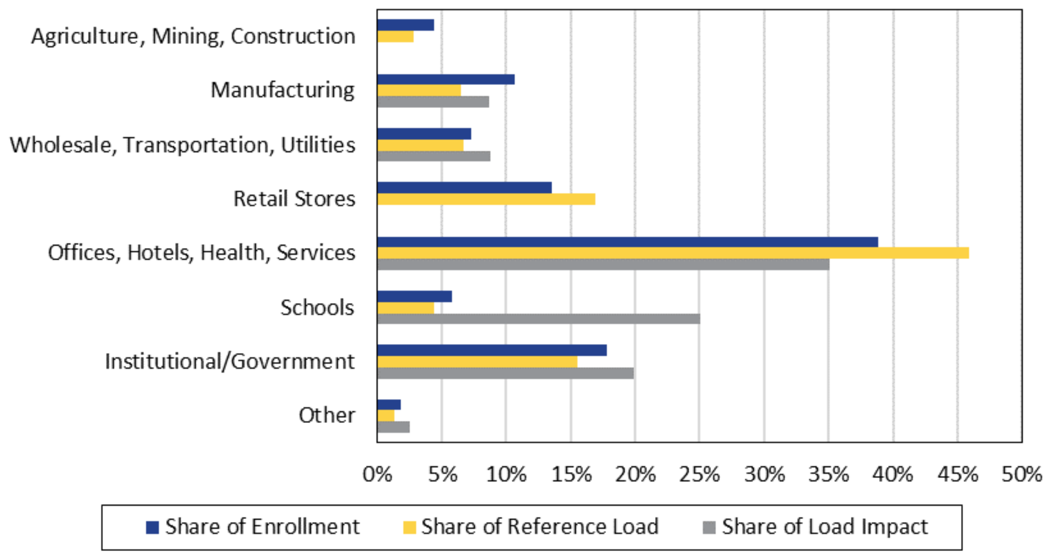
Table 5.9 summarizes SDG&E medium customers estimated load impacts by industry group for the average weekend/holiday event. The average reference load is lower for each industry group on the weekend. The Offices, Hotels, Health, Services industry group has the largest number of enrolled customers, reference load, and load impact (0.35 MWh/hour).

Table 5.9: Average Weekend/Holiday Event-Hour Load Impacts by Industry Group, *SDG&E Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/ hour)	Observed Load (MWh/ hour)	Estimated Load Impact (MWh/ hour)	% LI
1. Agriculture, Mining, Construction	191	3	3	-0.08	-2.3%
2. Manufacturing	461	8	8	0.09	1.1%
3. Wholesale, Transportation, Utilities	313	8	8	0.09	1.1%
4. Retail Stores	584	20	20	-0.04	-0.2%
5. Offices, Hotels, Health, Services	1,678	55	54	0.35	0.6%
6. Schools	249	5	5	0.25	4.7%
7. Institutional/Government	769	18	18	0.20	1.1%
8. Other	79	2	2	0.03	1.7%

Figure 5.9 illustrates the shares of estimated positive load impacts, reference loads, and enrollments by industry group for the average weekend/holiday event. The Offices, Hotels, Health, Services industry group accounts for 35 percent of the load reductions. Schools account for 25 percent of the load reduction and the Institutional/Government industry group accounts for 20 percent.

Figure 5.9: Average Weekend/Holiday Event-Hour Load Impacts by Industry Group, *SDG&E Medium*



5.1.4 Dually Enrolled Customers

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

Table 5.10 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average weekday and weekend events for customers who are dually enrolled in CPP. The average dually enrolled customer had a reference load of 56.5 kWh/hour during weekday events and 36.6 kWh/h during weekend events. Dually enrolled customers provided a load impact of 1.6 MWh/hour, or 9.5 percent of their reference load during weekday events. Their load impact for weekend events was 3.1 MWh/hour, or 28.9 percent of reference loads.

Table 5.10: Average Event-Hour Load Impacts for Dually Enrolled Customers by Event, *SDG&E*

Size	Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
All	9/3/2022	295	10.5	2.7	35.5	9.00	25.4%	92.4
	9/4/2022	295	9.6	2.4	32.4	8.14	25.1%	88.3
	9/5/2022	295	11.3	4.3	38.5	14.52	37.8%	84.8
	9/6/2022	295	15.8	1.6	53.5	5.59	10.4%	87.5
	9/7/2022	295	17.6	1.5	59.5	5.14	8.6%	89.0
	Avg. Weekend Event	**295**	**10.8**	**3.1**	**36.6**	**10.56**	**28.9%**	**89.3**
	Avg. Weekday Event	**295**	**16.7**	**1.6**	**56.5**	**5.36**	**9.5%**	**88.3**
Large	9/3/2022	60	4.8	2.8	80.2	46.40	57.9%	95.3
	9/4/2022	60	3.8	2.2	63.0	36.45	57.8%	100.9
	9/5/2022	60	5.7	4.3	95.2	72.33	76.0%	99.2
	9/6/2022	60	9.2	2.0	153.9	33.06	21.5%	91.9
	9/7/2022	60	10.8	1.9	179.5	31.77	17.7%	91.6
	Avg. Weekend Event	**60**	**4.8**	**3.1**	**79.5**	**51.72**	**65.1%**	**96.6**
	Avg. Weekday Event	**60**	**10.0**	**1.9**	**166.7**	**32.41**	**19.4%**	**91.7**
Medium	9/3/2022	235	5.7	-0.1	24.1	-0.54	-2.3%	91.8
	9/4/2022	235	5.8	0.2	24.6	0.91	3.7%	86.0
	9/5/2022	235	5.6	-0.1	24.0	-0.24	-1.0%	86.3
	9/6/2022	235	6.5	-0.3	27.9	-1.42	-5.1%	86.6
	9/7/2022	235	6.8	-0.4	28.9	-1.66	-5.8%	88.4
	Avg. Weekend Event	**235**	**6.0**	**0.0**	**25.6**	**0.04**	**0.2%**	**87.9**
	Avg. Weekday Event	**235**	**6.7**	**-0.4**	**28.4**	**-1.54**	**-5.4%**	**87.5**

5.1.5 Notified vs. Non-Notified Customers

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

Table 5.11 summarizes enrollments, average event-hour load impacts, and reference loads for the average weekday and weekend/holiday event day by size and notification status. About 57 percent of all customers were notified during weekday and weekend/holiday events. Medium CPP customers have the greatest proportion of notified customers (58 percent on weekdays and 59 percent on weekends/holidays). The weekend to weekday notification rate increased from 40 to 53 percent for large customers.

For both the large and medium customers, the notified customers, on average, had smaller reference loads and provided less reduction during the average weekday event. For example, large customers that were notified had a 1.1 percent load impact while non-notified customers had a 3.4 percent load impact. Large customers that were notified, however, did provide larger percentage load impacts for the event days, September 3rd and 5th. Large, notified customers had a reduction of 3.8 percent on September 3rd while non-notified customers had a slight increase of 0.7 percent. By September 7th, however, large, notified customers had a reduction of 0.1 percent while non-notified customers had a reduction of 2.8 percent. This could suggest that notified customers have event fatigue during consecutive event days quicker than non-notified customers since they become aware of events first.

Table 5.11: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, *SDG&E*

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Average Weekday Event								
No	Large	252	54	1.8	214.1	7.29	3.4%	85.8
	Medium	1,830	58	-1.1	31.7	-0.61	-1.9%	86.4
	All	**2,082**	**112**	**0.7**	**53.8**	**0.34**	**0.6%**	**86.4**
Yes	Large	281	57	0.7	203.5	2.33	1.1%	86.8
	Medium	2,494	71	-2.1	28.5	-0.84	-2.9%	86.6
	All	**2,775**	**128**	**-1.4**	**46.2**	**-0.52**	**-1.1%**	**86.6**
Average Weekend/Holiday Event								
No	Large	323	47	3.1	146.8	9.49	6.5%	87.0
	Medium	1,782	52	0.0	29.1	0.02	0.1%	87.2
	All	**2,105**	**99**	**3.1**	**47.2**	**1.48**	**3.1%**	**87.2**
Yes	Large	212	41	2.0	195.4	9.37	4.8%	87.6
	Medium	2,542	67	0.5	26.3	0.19	0.7%	87.1
	All	**2,754**	**108**	**2.5**	**39.3**	**0.90**	**2.3%**	**87.2**

5.2 SDG&E Ex-Ante Load Impacts

This section provides the ex-ante CPP load impact forecasts based on an enrollment forecast provided by SDG&E. Results are presented by size group. First, the enrollment forecast provided by SDG&E is summarized in figures on an annual basis. Second, results for all hours for the average weekday event in 2023 are illustrated in figures to convey the shape of ex-ante reference loads. Finally, forecasted ex-ante load impacts are summarized in figures by month and forecast year. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, per-customer load impacts are derived from analysis of current ex-post load impacts. We investigated the effect of weather on estimated load impacts (and percentage load impacts) and found that there was not enough evidence of a strong relationship between load impacts and weather conditions. Therefore, we simulate ex-ante load impacts by multiplying forecasted reference loads and ex-post percentage load impacts (by size and hour of the day). Ex-post load increases of medium customers are set to a minimum reduction of 0.01 percent during event hours.

5.2.1 All Customers

Figure 5.10 summarizes the trend of SDG&E's enrollment forecast for medium and large customers combined. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[24] SDG&E anticipates the total number of customers to decreases sharply until 2025, and thereafter to decrease at a more moderate pace of about 5 percent each year.

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

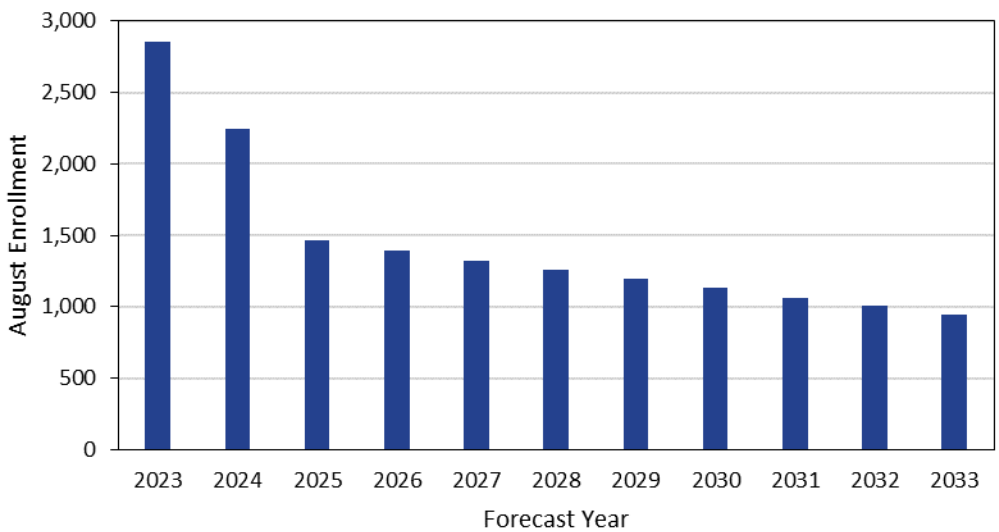
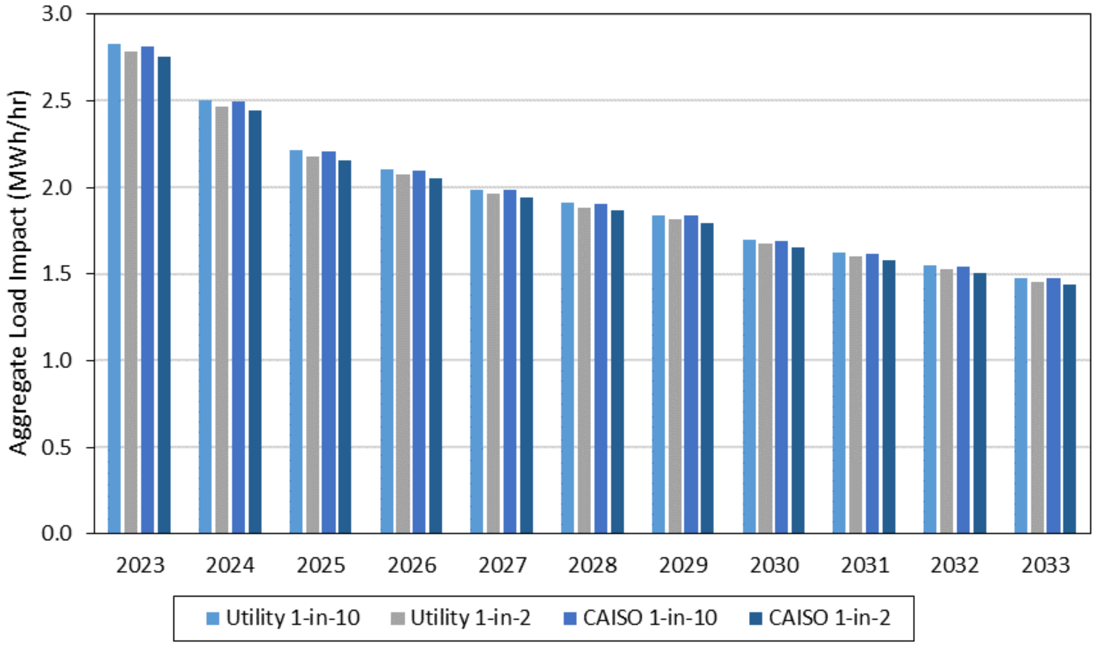


Figure 5.11 shows the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease each year because of reductions in enrollments. The load impacts of the 1-in-10 scenarios are higher than 1-in-2 scenarios by about 0.05 MWh/hour. Additional results of ex-ante load impacts are presented in the subsequent sections by size group.

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

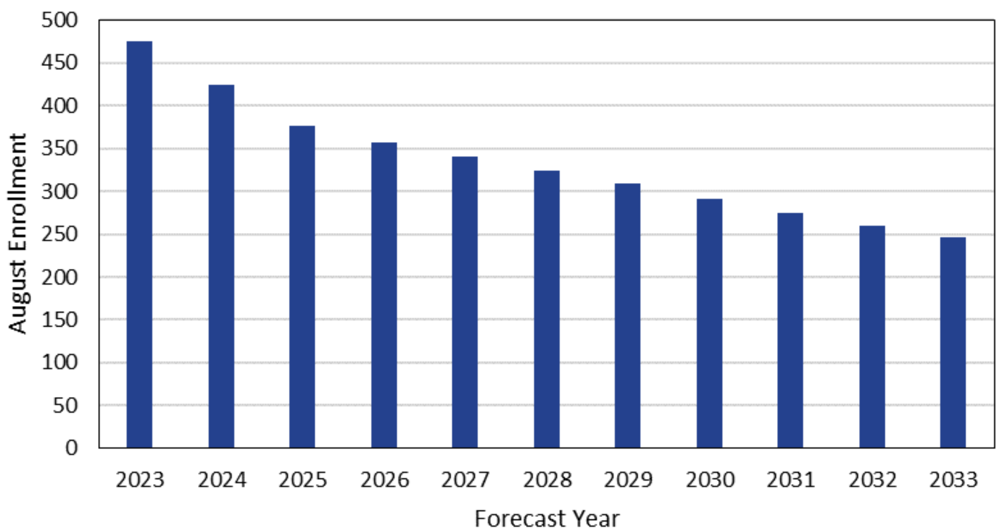
Figure 5.11: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E All*



5.2.2 Large Customers

Figure 5.12 summarizes SDG&E's enrollment forecast for large customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[25] SDG&E anticipates an average decrease in large customers of 11 percent in the first two years and then about 5 percent each year thereafter.

Figure 5.12: CPP Enrollments, *SDG&E Large*



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

Figure 5.13 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in August of 2023 for the SDG&E 1-in-2 weather scenario. The shape follows that of the ex-post load impact, exhibiting reduction in usage during event hours and a slight snapback following the event hours. The forecast predicts an average load impact of 2.8 MWh/hour for large customers on the average weekday event in 2023 for the SDG&E 1-in-2 weather scenario, which is a 2.8 percent reduction in reference loads.

Figure 5.13: Aggregate Hourly Loads and Load Impacts in 2023 for *SDG&E 1-in-2 Typical Event Day, SDG&E Large*

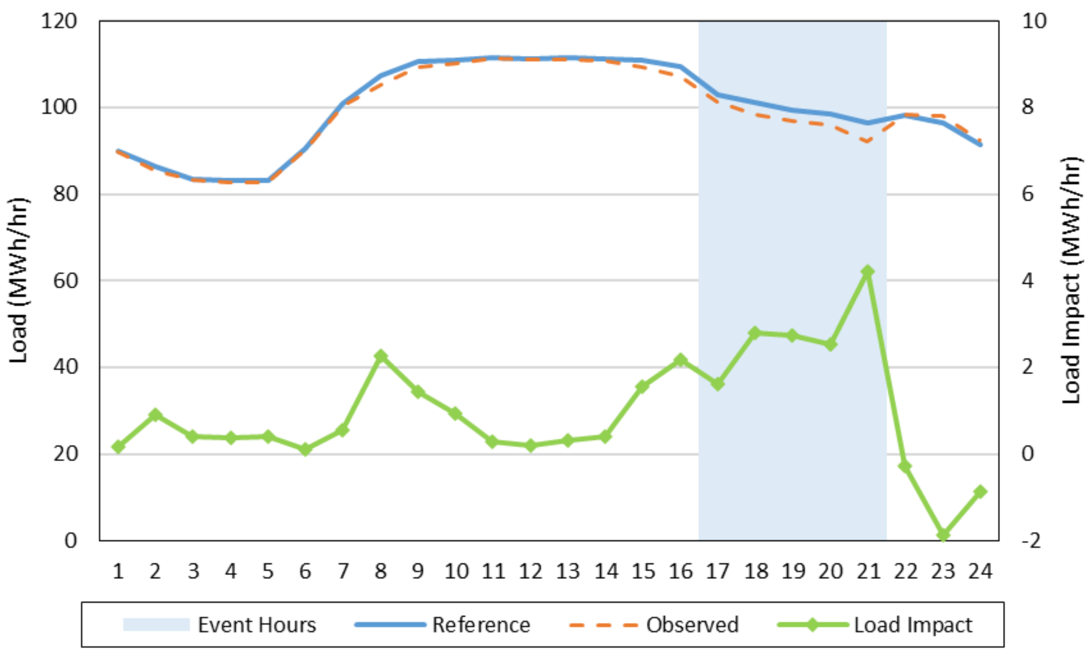


Figure 5.14 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the RA window in 2023 across months for SDG&E's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. for all months except March and April, when it is 5 to 10 p.m. The load impact is highest in September (2.9 MWh/hour) and lowest in March (2.0 MWh/hour).

Figure 5.14: Aggregate Load Impacts by Month over RA Window in 2023 for *SDG&E 1-in-2 Peak Day, SDG&E Large*

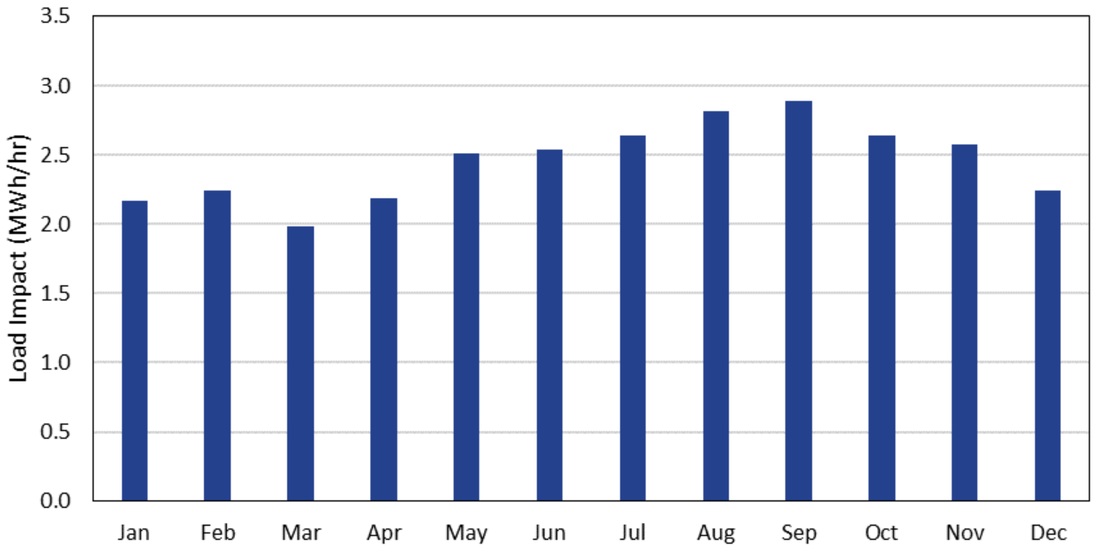
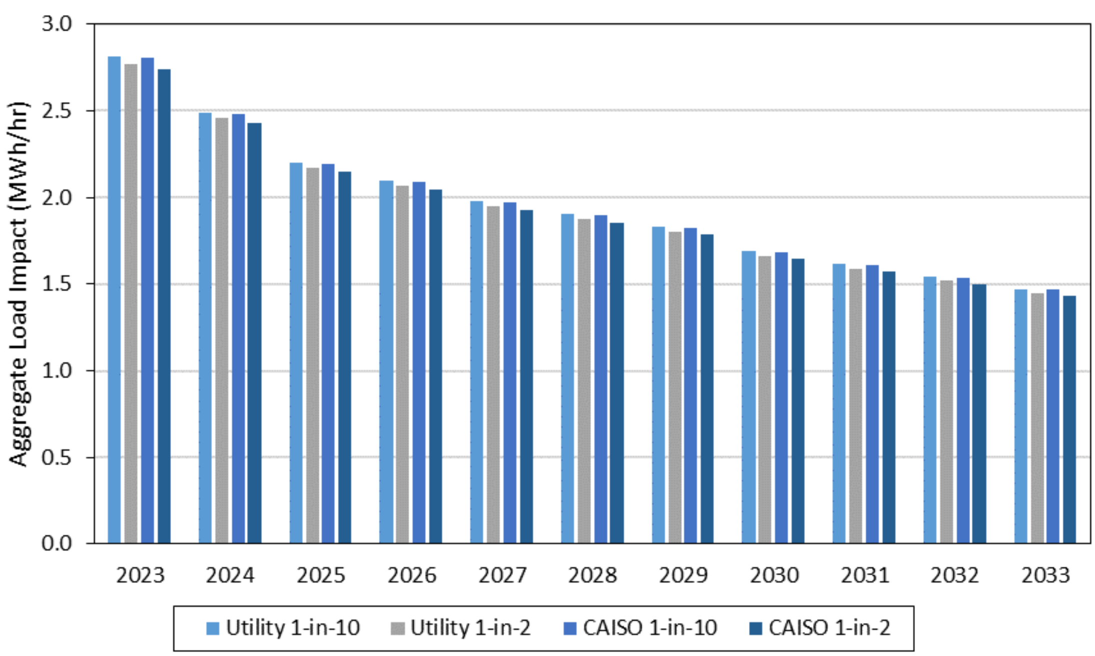


Figure 5.15 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease over time because of reductions in enrollments. As expected, the largest load impacts occur for the SDG&E 1-in-10 weather year while the lowest load impacts occur during the CAISO 1-in-2 weather year because of reference loads being increases/decreasing with hotter/cooler temperatures. The range of difference in load impacts between weather scenarios is about 0.08 MWh/hour.

Figure 5.15: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Large*



5.2.3 Medium Customers

Figure 5.16 summarizes SDG&E's enrollment forecast for medium customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[26] SDG&E anticipates large enrollment decreases until 2025, and then a steady reduction each year afterwards of about 5 percent.

Figure 5.16: CPP Enrollments, *SDG&E Medium*

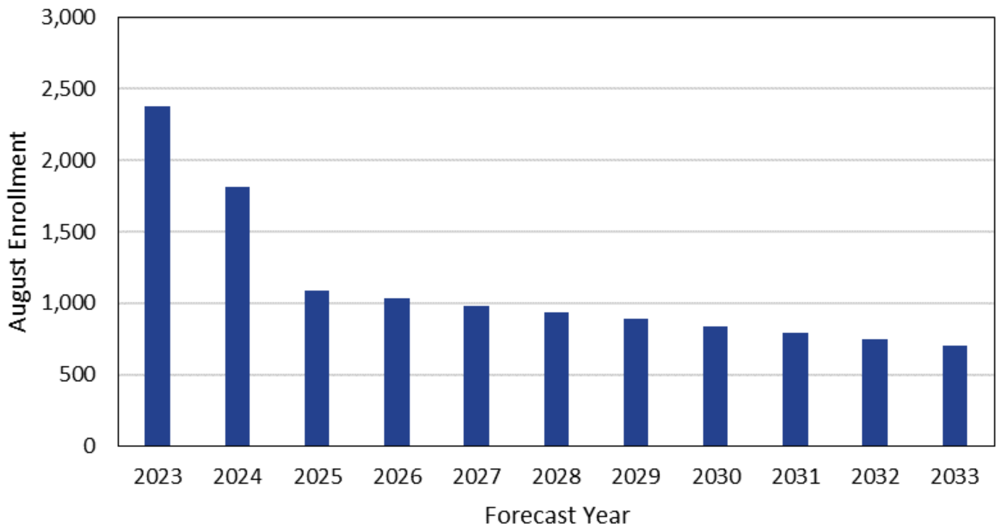


Figure 5.17 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August of 2023 for the SDG&E 1-in-2 weather scenario. The load reduction is minimized at 0.01 percent during event hours that had an increase in usage during ex-post.[27] Load reduction beyond 0.01 percent are provided by customers that were evaluated in ex-post with customer specific regressions. Non-event hours load impacts are set at zero by design since ex-post estimates did not find any significant results during these hours. The forecast predicts an average load impact of 0.01 MWh/hour, or 0.02 percent of the reference load.

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

[27] Load reductions beyond 0.01 percent, such as in HE 19, stem from dually enrolled customers that were analyzed on a per-customer basis in the ex-post analysis because they contained a generation component as part of their industry code.

Figure 5.17: Aggregate Hourly Loads and Load Impacts in 2023 for
SDG&E 1-in-2 Typical Event Day, SDG&E Medium

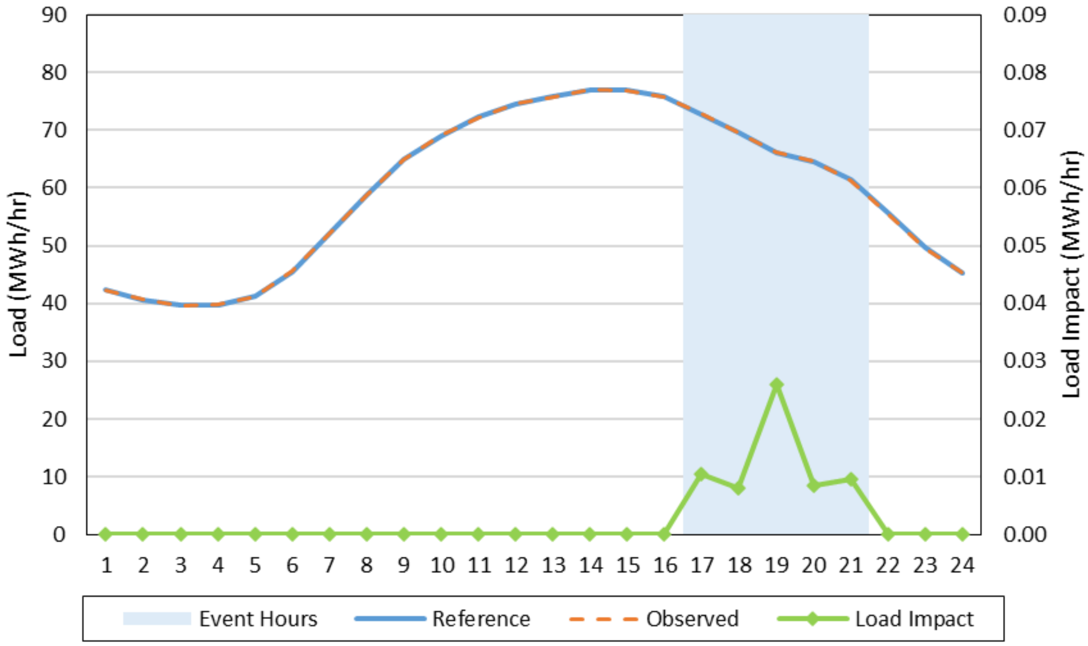


Figure 5.18 shows the seasonality of the forecasted load impacts for medium customers based on the 2023 aggregate load impacts for the average hour in the RA window for SDG&E's 1-in-2 weather scenario. As with the large customers, the load impacts follow the seasonal pattern of reference loads over the RA window (4 to 9 p.m. for all months except March and April, when it is 5 to 10 p.m.). The load impact is highest in September (0.0129 MWh/hour) and lowest in March (0.0098 MWh/hour).

Figure 5.18: Aggregate Load Impacts by Month over RA Window in 2023 for
SDG&E 1-in-2 Peak Day, SDG&E Medium

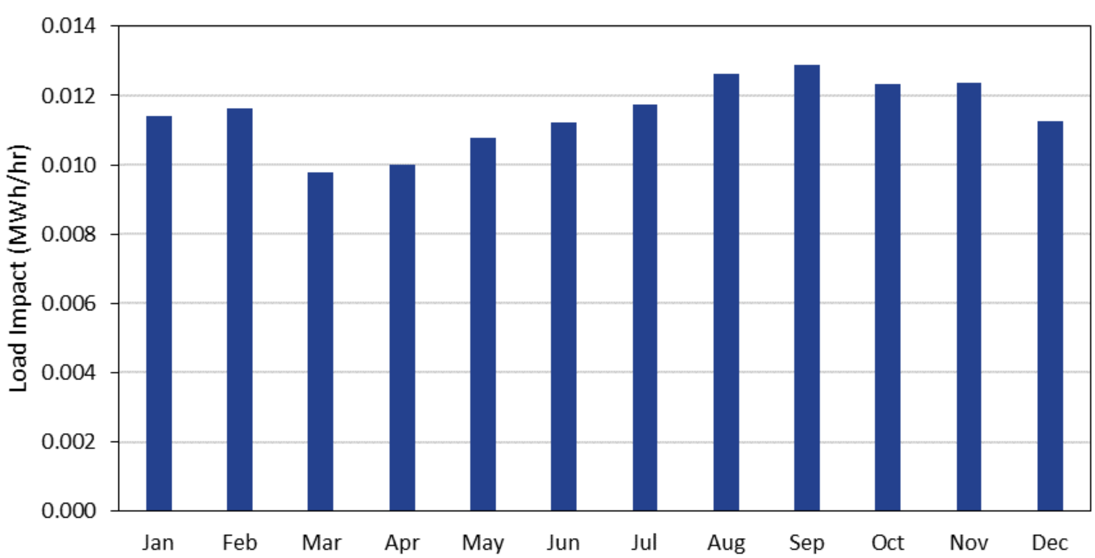
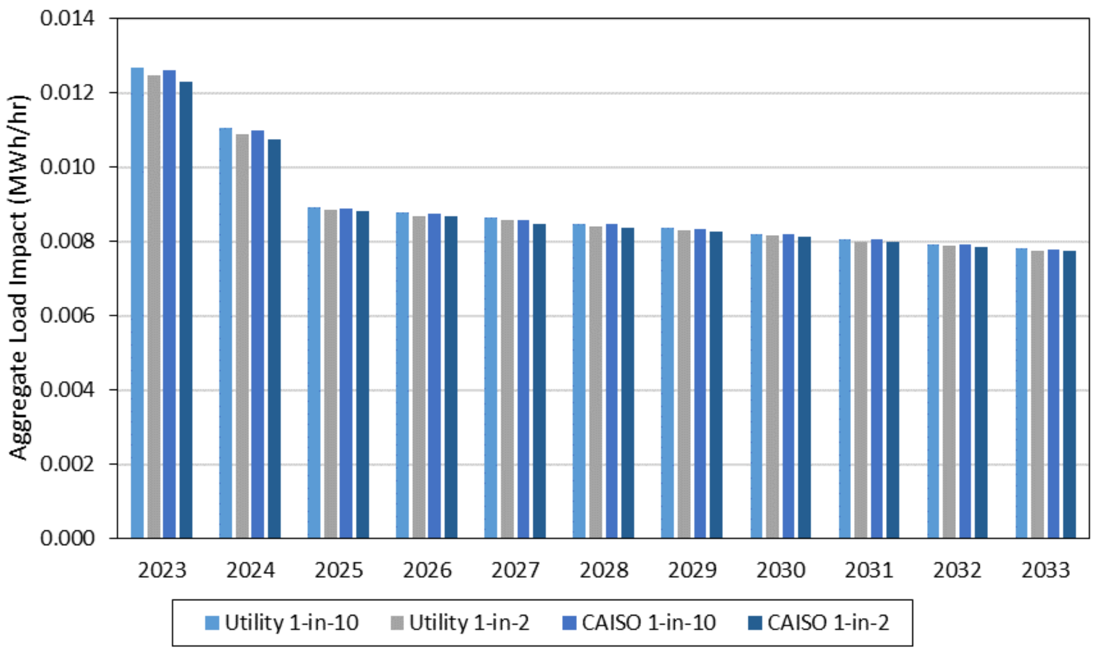


Figure 5.19 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease over time because of the reduction in forecast enrollments. Reference loads are largest for the SDG&E and CAISO 1-in-10 weather scenarios, resulting in higher load impacts for the 1-in-10 scenarios relative to 1-in-2 scenarios.

Figure 5.19: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Medium*



5.3 SDG&E Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares findings from this study to those of the previous study. Because there SDG&E did not call any CPP events during the previous program year, we cannot provide a comparison of the previous versus current ex-post results. In the text below, the term "current" refers to the present study while the term "previous" refers to findings from PY2021.

5.3.1 Large Customers

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 5.12 reports the average weekday event-hour load impacts for a typical event day in 2023 under SDG&E 1-in-2 weather conditions. The current study forecasts more customers than the previous study, resulting in larger aggregate reference loads and load impacts. At a per-customer level, the current study load impacts (5.8 kW) are higher than the previous study (4.5 kW).

Table 5.12: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 2023 Typical Event Day, SDG&E Large*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	379	475
	Reference (MW)	87	100
	Load Impact (MW)	1.7	2.8
	Avg. Temp.	81.5	82.5
Per SAID	Reference (kW)	228	210
	Load Impact (kW)	4.5	5.8
	% Load Impact	1.9%	2.8%

Previous Ex-Ante vs. Current Ex-Post

Table 5.13 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SDG&E 1-in-2 weather conditions. The ex-post typical event day load impacts are based on the average non-holiday weekday event.

The ex-ante forecast in the previous study had predicted a decrease in enrollments, but enrollments did not reduce as much as expected. The per-customer reference load in the current study is slightly lower due to a compositional change since customers remaining on the CPP are slightly smaller. Nevertheless, the aggregate reference load is larger due to higher enrollment numbers as well as hotter temperatures in the current study forecast. The per-customer load impacts and percentage load impacts are similar between studies, albeit slightly higher in the current study (4.5 kW vs. 4.7 kW).

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

Level	Outcome	Ex-Ante for 2022 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	417	533
	Reference (MW)	95	111
	Load Impact (MW)	1.9	2.5
	Avg. Temp.	81.5	86.3
Per SAID	Reference (kW)	228	209
	Load Impact (kW)	4.5	4.7
	% Load Impact	1.9%	2.2%

Current Ex-Post vs. Current Ex-Ante

Table 5.14 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2023 under SDG&E 1-in-2 weather conditions. The ex-ante enrollment forecasts a decrease in enrollments resulting in lower aggregate reference loads. Lower temperatures result in lower reference loads; however, the per-customer ex-ante reference loads are higher than ex-post, despite lower weather, because the ex-post typical event day loads were slightly lower than the average weekday because they occurred right after Labor Day. The ex-ante percentage load impact is based on the percentage load impact from ex-post. The percentage load impacts are slightly higher in ex-ante because of the composition changes of customers between ex-post and ex-ante.[28]

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

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	533	475
	Reference (MW)	111	100
	Load Impact (MW)	2.5	2.8
	Avg. Temp.	86.3	82.5
Per SAID	Reference (kW)	209	210
	Load Impact (kW)	4.7	5.8
	% Load Impact	2.2%	2.8%

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

[28] Ex-post percentage load impacts are applied separately for dually enrolled and non-dually enrolled customers since dually enrolled customers have larger ex-post load impacts. The increased percentage load impact in ex-ante is driven by a slightly higher proportion of dually enrolled customers in ex-ante as non-dually enrolled customer counts decrease in the enrollment forecast.

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

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 86.3 °F during the average event day.	Average event-hour temperature of 82.5 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
Day of Week	September 6th & 7th	Average Weekday	September 6th was a Tuesday following a Holiday which results in lower loads relative to the average weekday, after controlling for weather differences. Therefore, simulated average weekday loads would be higher than ex-post loads (*ceteris paribus*).
% of resource dispatched	100 percent	100 percent	None.
Enrollment	533 service accounts.	475 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

5.3.2 Medium Customers

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 5.16 reports the average weekday event-hour load impacts for a typical event day in 2023 under SDG&E 1-in-2 weather conditions. The enrollment forecast is lower in the current study resulting in lower aggregate reference loads. The per-customer reference load, however, is nearly identical between years. The current study has lower load impacts and percentage load impacts than the previous study.

Table 5.16: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 2023 Typical Event Day, SDG&E Medium*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	3,440	2,381
	Reference (MW)	96	67
	Load Impact (MW)	0.4	0.01
	Avg. Temp.	81.3	82.5
Per SAID	Reference (kW)	28.0	28.1
	Load Impact (kW)	0.11	0.01
	% Load Impact	0.4%	0.02%

Previous Ex-Ante vs. Current Ex-Post

Table 5.17 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents a typical event day under SDG&E 1-in-2 weather conditions. The ex-post typical event day load impacts are based on the average non-holiday weekday event. The ex-ante forecast in the previous study had predicted a decrease in enrollments, but enrollments did not reduce as much as expected. The per-customer reference load in the current study is slightly higher due to hotter temperatures. Medium customers in the current study did not exhibit any load reduction during the non-holiday weekday ex-post events in 2022, while the previous study forecast a reduction of 0.4 percent.

Table 5.17: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SDG&E Medium*

Level	Outcome	Ex-Ante for 2022 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	3,950	4,324
	Reference (MW)	111	129
	Load Impact (MW)	0.4	-3.2
	Avg. Temp.	81.3	86.5
Per SAID	Reference (kW)	28.0	29.9
	Load Impact (kW)	0.11	-0.74
	% Load Impact	0.4%	-2.5%

Current Ex-Post vs. Current Ex-Ante

Table 5.18 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent a typical event day in 2023 under SDG&E 1-in-2 weather conditions. The medium customer enrollment is forecasted to decrease from 4,324 customers in 2022 to 2,381 customers in 2023. The reduction in enrollments numbers significantly reduces the aggregate reference load of the program. The per-customer reference load is lower in ex-ante due to lower temperatures. Overall, medium customers did not exhibit a load reduction during the ex-post events; nevertheless, the ex-ante forecast assumes a load reduction for future events of 0.02 percent.

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

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	4,324	2,381
	Reference (MW)	129	67
	Load Impact (MW)	-3.2	0.01
	Avg. Temp.	86.5	82.5
Per SAID	Reference (kW)	29.9	28.1
	Load Impact (kW)	-0.74	0.01
	% Load Impact	-2.5%	0.02%

Table 5.19 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 5.19: Comparison of Ex-Post and Ex-Ante Factors, *SDG&E Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 86.5 °F during the average event day.	Average event-hour temperature of 82.5 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	4,324 service accounts.	2,381 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

6 RECOMMENDATIONS

For PG&E, we note that dually enrolled BIP customers play a reduced role in driving customer performance during PDP events, although these customers still outperform other large PDP customers. Recruiting and retaining more BIP customers may improve PDP load impacts.

For SCE, we found a negative relationship between ex-post load impacts and weather. In other words, hotter temperature events were associated with lower load impacts. We suggest continuing to call events under different weather conditions in order to provide more evidence of this relationship.

For SDG&E, five events were called during the September heat wave, including weekends. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures and months.

APPENDICES

The following Appendices accompany this report. Appendix A presents the model validity assessment associated with our ex-post load impact evaluation. Appendix B documents PG&E's Revised Estimates from the PY2021 Evaluation. The additional appendices consist of Excel files that can produce the tables required by the Protocols.

Appendix C	7a. PGE_2022_CPP_Ex_Post
Appendix D	7b. PGE_2022_CPP_Ex_Ante
Appendix E	PY2022_SCE_NRCPP_Ex_Post_Load_Impacts
Appendix F	PY2022_SCE_NRCPP_Ex_Ante_Load_Impacts
Appendix G	SDG&E PY22 NonResCPP Ex-Post Load Impact Tables
Appendix H	SDG&E PY22 NonResCPP Ex-Ante Load Impact Tables

Appendix A. Model Validity Assessment

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

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

To select event-like non-event days, we create an average weather profile using the load-weighted average temperature across customers, each of which is associated with a weather station.

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

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

PG&E		SCE		SDG&E	
Weekday	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
5/24/2022	6/11/2022	6/10/2022	8/6/2022	6/27/2022	5/14/2022
5/25/2022	6/25/2022	6/27/2022	8/7/2022	6/28/2022	6/25/2022
6/9/2022	6/26/2022	6/29/2022	8/13/2022	8/8/2022	6/26/2022
6/21/2022	7/10/2022	6/30/2022	8/14/2022	8/9/2022	8/6/2022
6/22/2022	7/16/2022	7/15/2022	8/20/2022	8/10/2022	8/7/2022
6/23/2022	7/17/2022	7/21/2022	9/24/2022	8/11/2022	8/13/2022
6/24/2022	8/13/2022	7/22/2022	9/25/2022	8/12/2022	8/14/2022
6/28/2022	8/14/2022	7/25/2022		8/30/2022	9/11/2022
7/14/2022	8/20/2022	7/26/2022		9/27/2022	9/24/2022
7/15/2022	8/21/2022	8/3/2022			9/25/2022
7/19/2022	9/10/2022	8/8/2022			
7/20/2022	9/11/2022	8/9/2022			
7/22/2022	9/24/2022	8/10/2022			
7/25/2022		8/16/2022			
7/27/2022		8/23/2022			
8/2/2022		8/30/2022			
8/3/2022		9/23/2022			
8/4/2022		9/26/2022			
8/10/2022		9/27/2022			
8/12/2022		9/28/2022			
8/15/2022					
8/18/2022					
8/22/2022					
8/23/2022					
8/24/2022					
8/26/2022					
8/29/2022					
8/30/2022					

A.2 Model Specification Tests

Customer-Specific Models

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

The basic structure of the model for weather-sensitive customers is shown in Section 2.1.4. The weather variables include: temperature-humidity index (THI)[29]; heat index (HI)[30]; cooling degree hours (CDH)[31], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[32], including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we test for weather-sensitive customers is provided in Table A.2, including 17 specifications for the individual customer ex-post analysis.[33]

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

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

The model specifications for non-weather sensitive customers do not include any weather variables but have different combinations of non-weather-related variables. The variables include combinations of indicator variables with interactions between month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is

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

[30] HI = $c_1 + c_2T + c_3R + c_4TR + c_5T^2 + c_6R^2 + c_7T^2R + c_8TR^2 + c_9T^2R^2 + c_{10}T^3 + c_{11}R^3 + c_{12}T^3R + c_{13}TR^3 + c_{14}T^3R^2 + c_{15}T^2R^3 + c_{16}T^3R^3$, where T = ambient dry-bulb temperature in degrees Fahrenheit and R = relative humidity (where 10 percent is expressed as "10"). The values for the various c's may be found here: http://en.wikipedia.org/wiki/Heat_index.

[31] Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

[32] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.

[33] Humidity data for PG&E was not available in PY2022. Therefore, the set of specifications we test for PG&E excludes the entries that require humidity.

shown in Table A.3, where an "X" between two variables represents the interaction of these two variables. Each specification includes the following variables in common: hour indicators, day type indicators, and events interacted with hour indicators. For the ex-ante analysis, we exclude the specifications with the morning load variable.

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

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

Panel Models

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

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

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

Validation Test

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

A.3 Results from Tests of Alternative Weather Specifications

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

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

Tables A.5 through A.10 summarize for the Joint Utilities the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for both customer the customer-specific and panel models, bifurcated by weekday and weekend.

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

Weekday

Group	Industry Type	Selected Specification	Event-Hour		Number of Customers
			MPE	MAPE	
Weather Sensitive	1. Agriculture, Mining, Construction	17	4.7%	13.7%	7
	2. Manufacturing	16	0.4%	3.7%	10
	3. Wholesale, Transportation, Utilities	17	-0.3%	1.9%	7
	4. Retail	16	1.2%	4.9%	3
	5. Offices, Hotels, Health, Services	17	-0.1%	1.4%	16
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	17	0.3%	2.0%	5
	8. Other or unknown	N/A	N/A	N/A	N/A
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	1.4%	5.5%	6
	2. Manufacturing	5	-0.2%	3.9%	18
	3. Wholesale, Transportation, Utilities	3	-0.6%	5.1%	5
	4. Retail	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	2	-1.1%	2.3%	1
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	4	4.5%	9.8%	2
	8. Other or unknown	N/A	N/A	N/A	N/A

Weekend

Group	Industry Type	Selected Specification	Event-Hour		Number of Customers
			MPE	MAPE	
Weather Sensitive	1. Agriculture, Mining, Construction	17	8.4%	15.8%	4
	2. Manufacturing	17	-0.3%	4.8%	11
	3. Wholesale, Transportation, Utilities	4	-0.6%	2.9%	9
	4. Retail	3	2.4%	4.5%	3
	5. Offices, Hotels, Health, Services	16	0.4%	1.7%	17
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	3	0.3%	2.1%	4
	8. Other or unknown	N/A	N/A	N/A	N/A
Non-Weather Sensitive	1. Agriculture, Mining, Construction	4	-1.6%	3.3%	10
	2. Manufacturing	3	-0.1%	2.7%	17
	3. Wholesale, Transportation, Utilities	4	1.0%	1.7%	3
	4. Retail	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	3	0.7%	1.2%	1
	6. Schools	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	4	0.7%	16.1%	2
	8. Other or unknown	N/A	N/A	N/A	N/A

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

Day Type	Size	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weekday	Large	8	0.0%	1.3%	0.0%	1.2%	1,440
	Medium	8	0.0%	1.1%	0.0%	1.1%	17,835
	Small	8	0.0%	1.3%	0.0%	1.0%	88,702
Weekend	Large	10	-0.3%	2.4%	-0.2%	1.7%	1,439
	Medium	3	0.1%	1.3%	0.1%	1.2%	17,835
	Small	3	0.3%	2.1%	0.2%	1.8%	88,702

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

Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	3	0.5%	4.3%	2
	2. Manufacturing	3	-0.7%	2.7%	14
	3. Wholesale, Transportation, Utilities	6	-0.6%	6.2%	11
	4. Retail	16	1.7%	3.8%	2
	5. Offices, Hotels, Health, Services	6	-0.7%	2.3%	22
	6. Schools	16	1.3%	5.5%	4
	7. Entertainment, Other Services, Government	5	0.7%	6.8%	8
	8. Other or unknown	3	0.1%	2.4%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	14.9%	30.3%	3
	2. Manufacturing	5	1.0%	2.5%	23
	3. Wholesale, Transportation, Utilities	3	-0.6%	5.7%	9
	4. Retail	5	0.7%	5.0%	2
	5. Offices, Hotels, Health, Services	5	-0.9%	6.6%	3
	6. Schools	3	0.0%	5.4%	2
	7. Entertainment, Other Services, Government	3	7.4%	19.9%	1
	8. Other or unknown	5	0.6%	6.3%	2

Weekend

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	3	1.9%	3.9%	2
	2. Manufacturing	3	2.6%	4.3%	9
	3. Wholesale, Transportation, Utilities	6	-0.3%	3.8%	6
	4. Retail	4	-0.6%	3.4%	3
	5. Offices, Hotels, Health, Services	2	0.9%	2.6%	21
	6. Schools	11	1.1%	2.7%	3
	7. Entertainment, Other Services, Government	7	0.1%	7.7%	7
	8. Other or unknown	11	0.1%	2.8%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	2.3%	26.4%	3
	2. Manufacturing	2	1.5%	5.8%	28
	3. Wholesale, Transportation, Utilities	4	0.2%	5.6%	14
	4. Retail	4	-29.2%	207.6%	1
	5. Offices, Hotels, Health, Services	4	1.0%	7.6%	4
	6. Schools	4	-4.4%	5.9%	3
	7. Entertainment, Other Services, Government	3	9.7%	19.6%	2
	8. Other or unknown	5	-3.7%	4.8%	2

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

Day Type	Size	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weekday	Large	1	0.00%	0.80%	0.01%	1.22%	1,601
	Medium	3	0.02%	0.81%	0.01%	0.75%	22,426
	Small	1	-0.02%	1.17%	-0.02%	0.94%	203,554
Weekend	Large	7	-0.02%	1.11%	0.02%	2.33%	1,590
	Medium	1	0.02%	0.99%	0.02%	0.91%	22,174
	Small	8	-0.08%	0.95%	-0.64%	2.85%	201,675

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

Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	3	-0.3%	5.1%	1
	2. Manufacturing	5	1.1%	16.3%	7
	3. Wholesale, Transportation, Utilities	17	112.4%	145.5%	1
	5. Offices, Hotels, Health, Services	16	-0.2%	1.6%	3
	7. Entertainment, Other Services, Government	12	1.3%	3.7%	4
	99. Generation	16	-2.0%	7.4%	21
Non-Weather Sensitive	2. Manufacturing	5	1.9%	6.6%	2
	3. Wholesale, Transportation, Utilities	4	0.6%	13.9%	4
	5. Offices, Hotels, Health, Services	5	-2.5%	4.9%	1
	7. Entertainment, Other Services, Government	4	-2.6%	5.8%	3
	99. Generation	5	6.8%	13.9%	23

Weekend

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	3	0.1%	4.8%	1
	2. Manufacturing	7	1.2%	8.7%	4
	5. Offices, Hotels, Health, Services	1	0.1%	1.8%	3
	7. Entertainment, Other Services, Government	4	0.0%	2.9%	5
	99. Generation	7	0.6%	8.6%	14
Non-Weather Sensitive	2. Manufacturing	3	-23.0%	6.5%	5
	3. Wholesale, Transportation, Utilities	4	-1.0%	10.1%	5
	5. Offices, Hotels, Health, Services	3	-4.3%	5.9%	1
	7. Entertainment, Other Services, Government	4	-2.7%	17.0%	2
	99. Generation	4	3.2%	17.9%	30

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

Day Type	Size	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weekday	Large	8	0.46%	10.27%	-1.57%	13.20%	483
	Medium	8	17.89%	21.27%	1.81%	10.10%	4,308
Weekend	Large	10	-0.70%	3.19%	1.36%	5.94%	484
	Medium	8	0.36%	2.00%	0.33%	2.07%	4,308

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

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.1 through A.6 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen for each customer or group. In each figure, the solid line represents the observed load, and the dashed line represents the load predicted by the statistical model. Figures A.1 and A.2 provide weekday load profiles for PG&E while figures A.3 and A.4 provide weekend load profiles. Figures A.1 and A.3 (PG&E), A.5 and A.7 (SCE), and A.9 and A.11 (SDG&E) compare predicted and observed loads for large customers, separating the results for customers included in the customer-specific or panel models. Figures A.2 and A.4 (PG&E), A.6 and A.8 (SCE), and A.10 and A.12 (SDG&E) compare predicted and observed loads separately for small (PG&E and SCE only) and medium customers, both of which were estimated using panel models. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

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

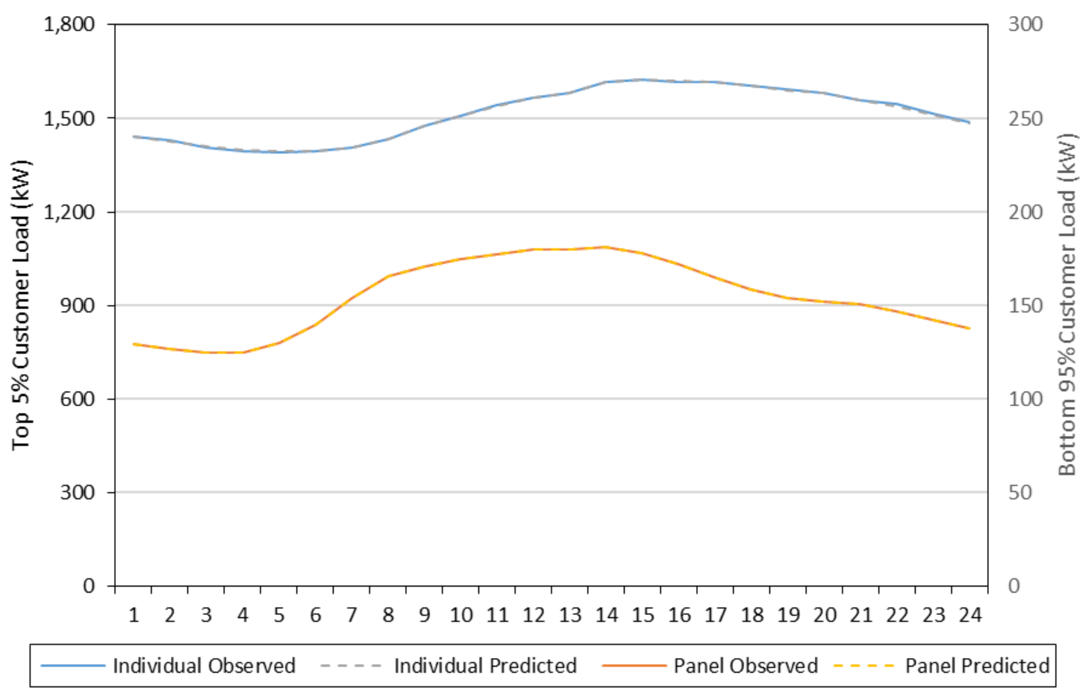


Figure A.2: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers*, PG&E*

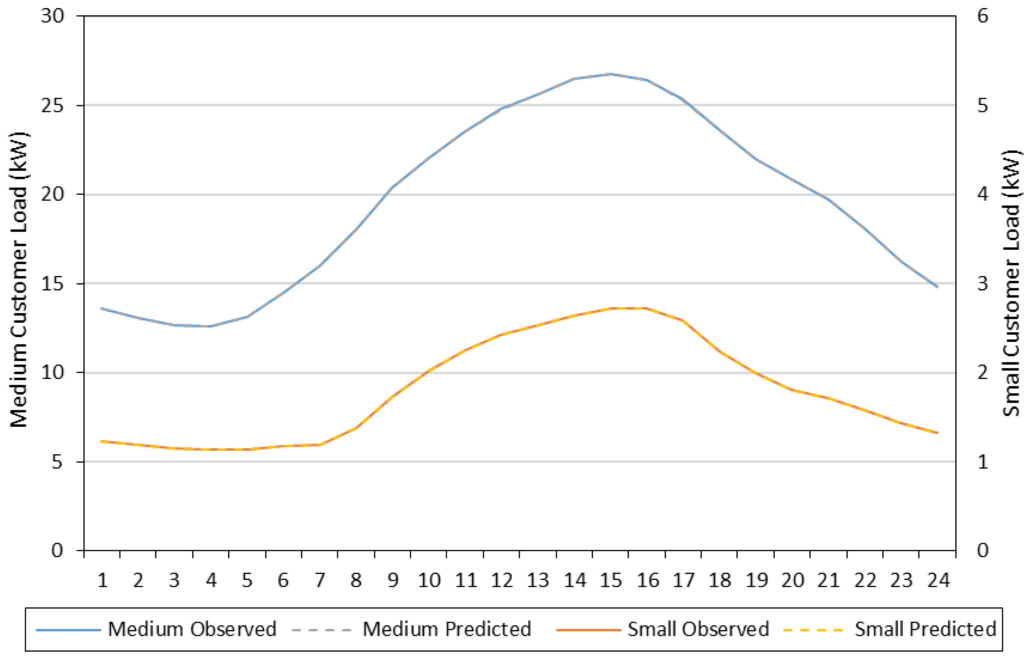


Figure A.3: Average Observed & Predicted Loads on Weekend Event-Like Days, Large Customers, *PG&E*

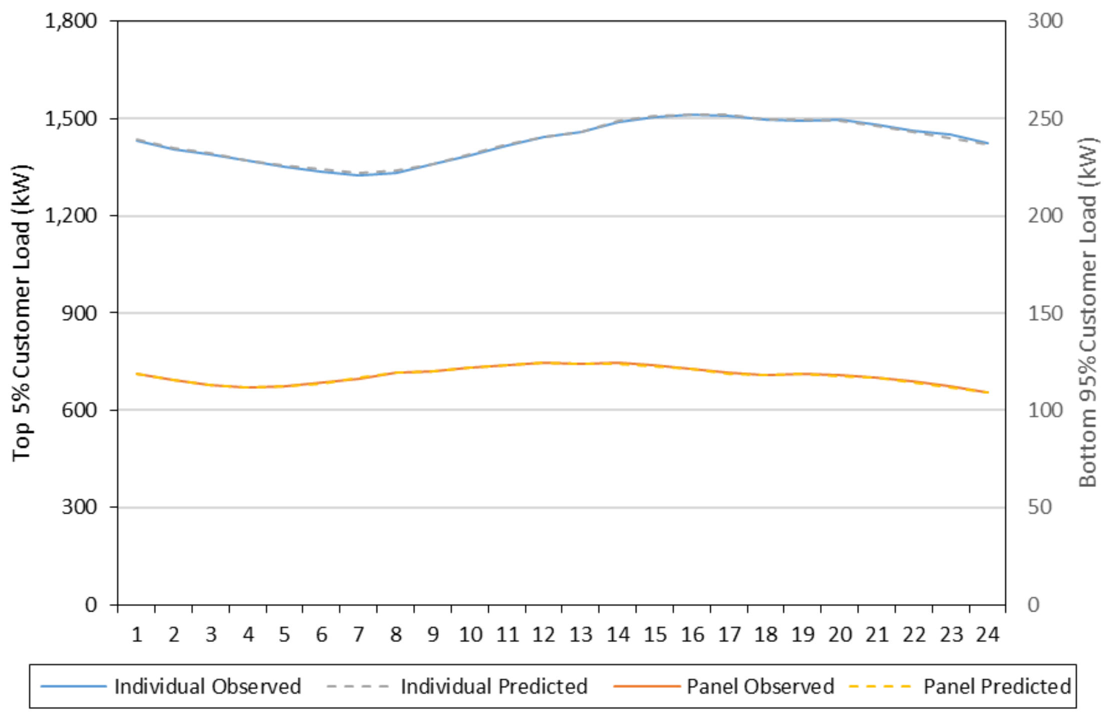


Figure A.4: Average Observed & Predicted Loads on Weekend Event-Like Days, Small and Medium Customers*, PG&E*

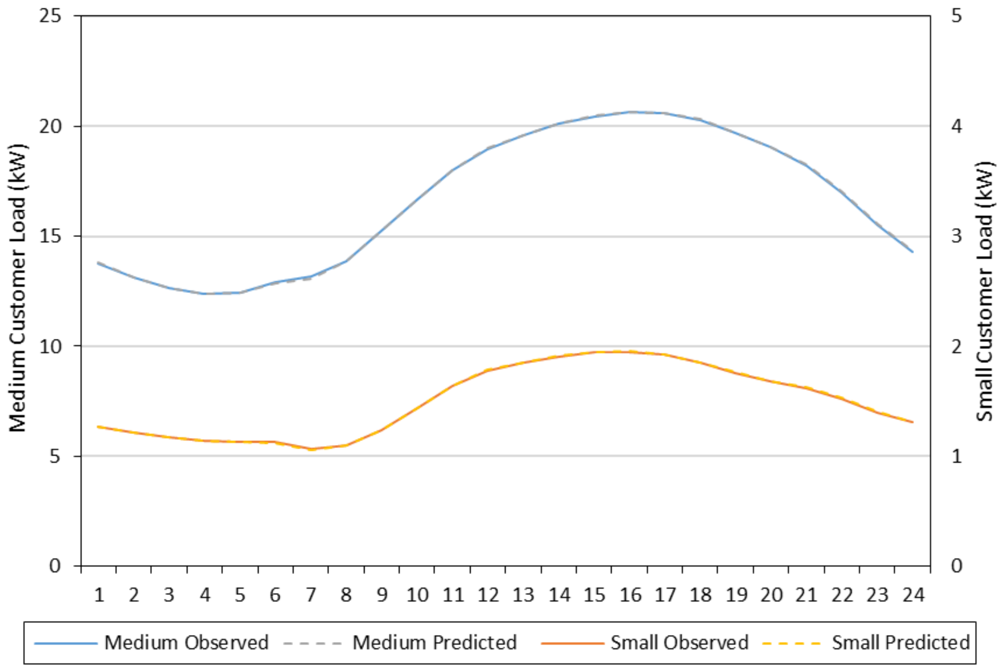


Figure A.5: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *SCE*

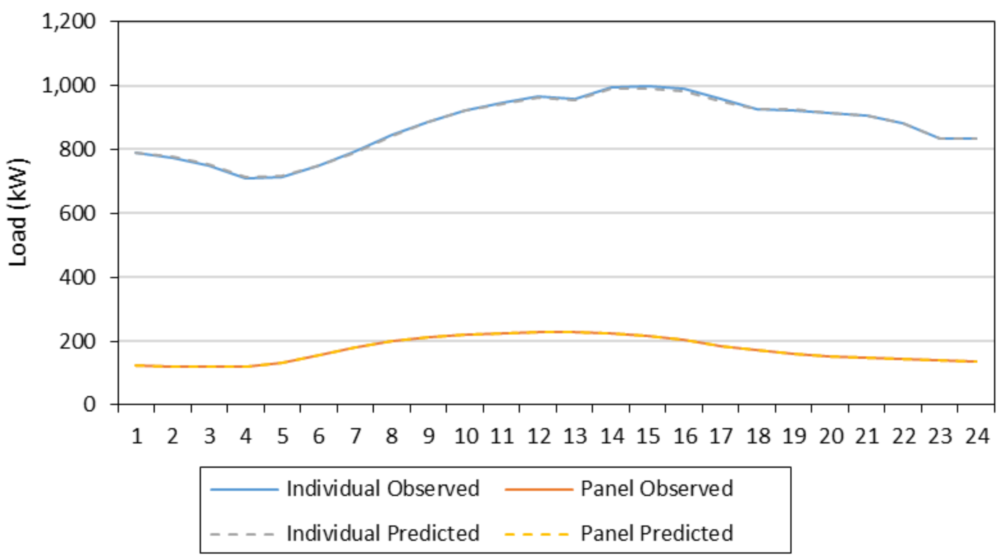


Figure A.6: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers*, SCE*

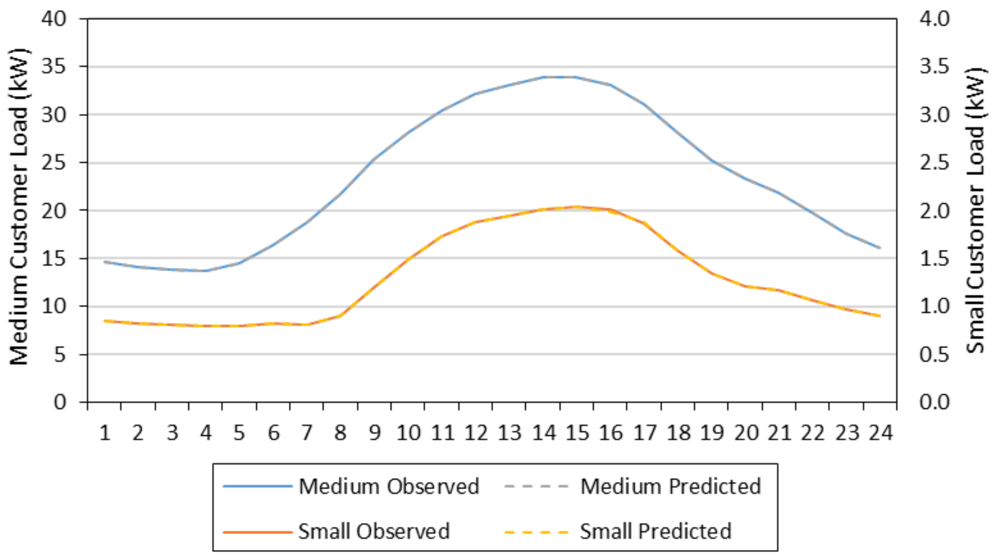


Figure A.7: Average Observed & Predicted Loads on Weekend Event-Like Days, Large Customers, *SCE*

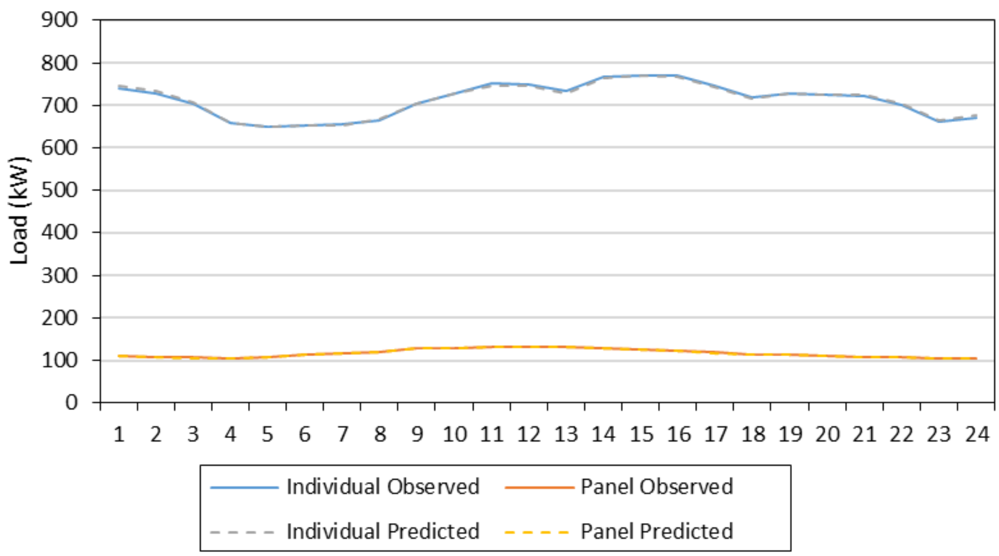


Figure A.8: Average Observed & Predicted Loads on Weekend Event-Like Days, Small and Medium Customers*, SCE*

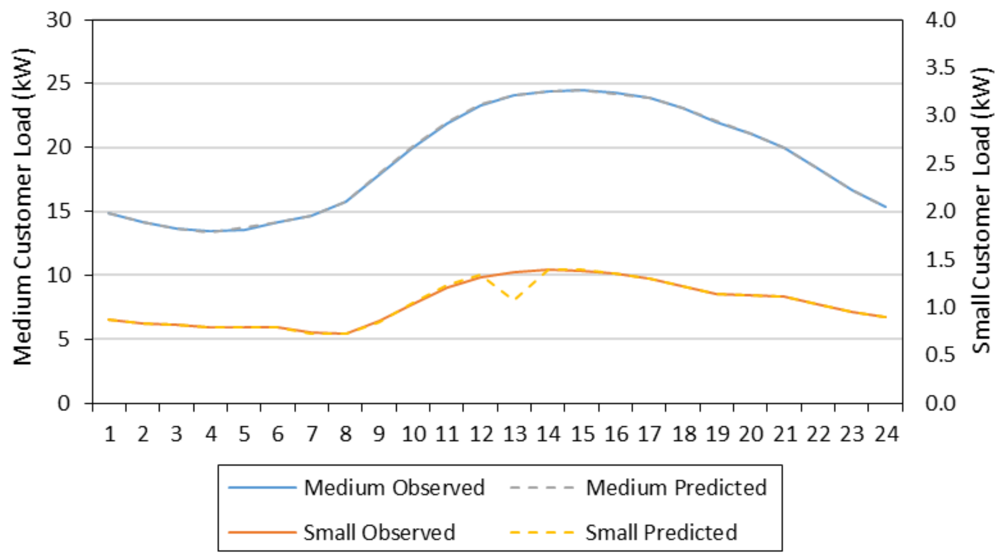


Figure A.9: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *SDG&E*

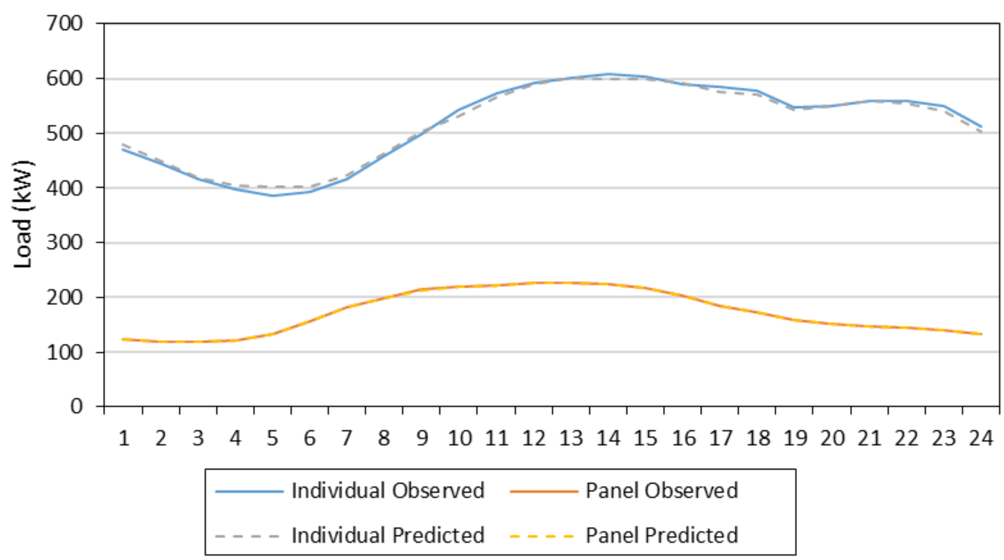


Figure A.10: Average Observed & Predicted Loads on Weekday Event-Like ADays, Medium Customers*, SDG&E*

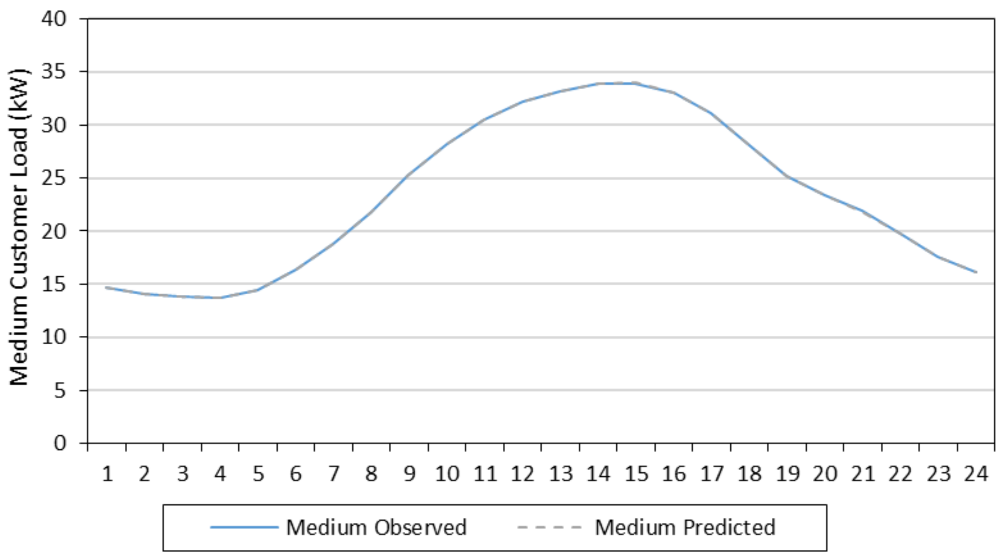


Figure A.11: Average Observed & Predicted Loads on Weekend Event-Like Days, Large Customers, *SCE*

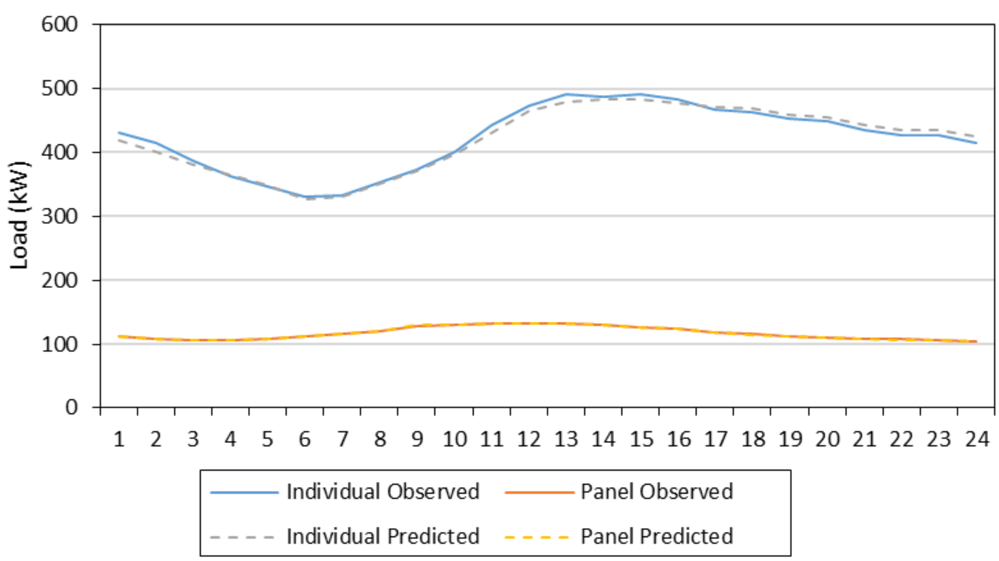
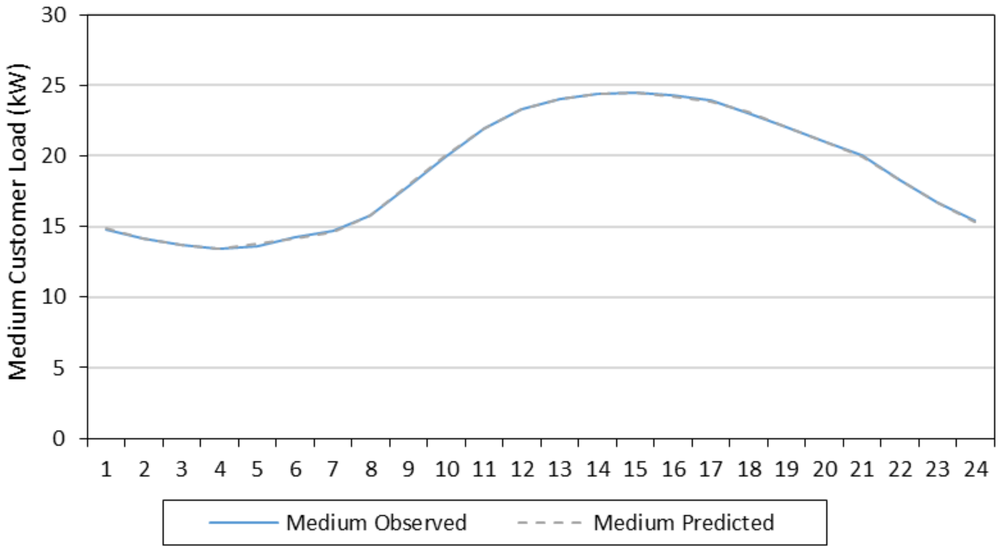


Figure A.12: Average Observed & Predicted Loads on Weekend Event-Like Days, Small and Medium Customers*, SCE*



Appendix B. PG&E's Revised PY2021 Load Impact Evaluation

This appendix summarizes results for the revised load impact estimates and ex-ante forecast for PG&E for PY2021. These revisions are in response to an error in the load interval data that was discovered after the original reports were submitted to the CPUC.

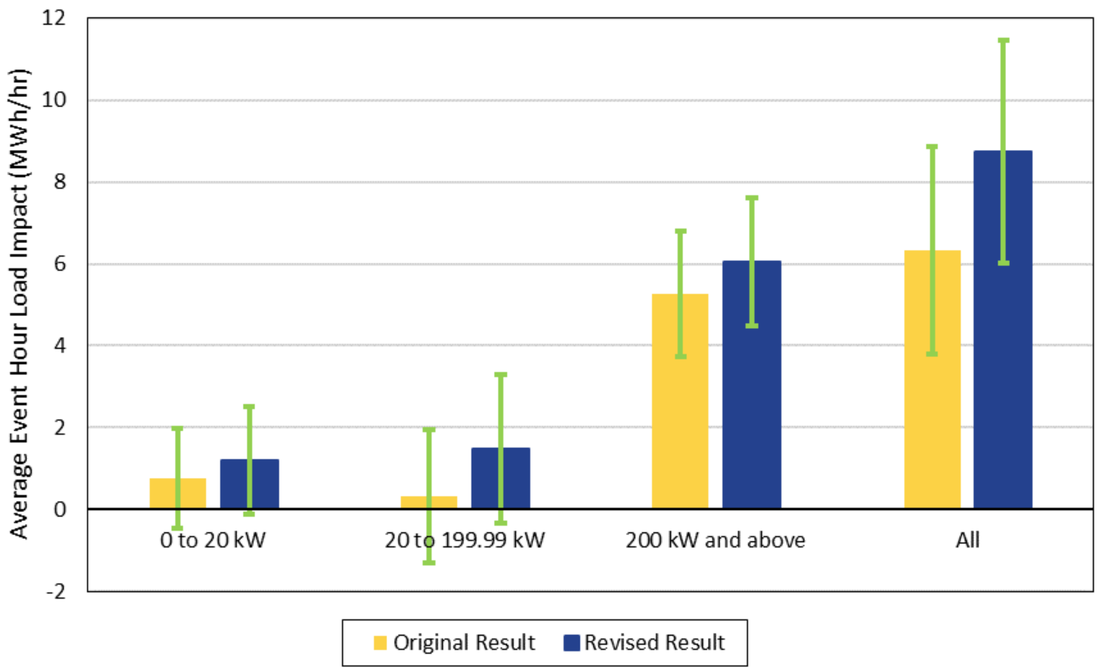
B.1 Ex-Post Load Impacts

This section summarizes the revised PY2021 load impact estimates for PG&E, overall and for each size group. First, we compare the original and revised estimates for the typical event day. We then present the revised estimates by event and for the typical event day by size group.

The original and revised ex-post load impacts are summarized for the typical event day, for each size group and overall, in Figure B.1. The blue bars indicate the magnitude of the aggregate load impacts (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes).

Figure B.1 shows that the revised load impacts are larger in magnitude for all size groups. The increase in aggregate load impacts is the greatest for medium customers. Although these results suggest improved load impacts on the typical event day for small and medium customers, the estimates are still not statistically significant for the revised results. Large customers had statistically significant load reductions of approximately 6 MWh/hour on the typical event day in the revised estimates, nearly a 1 MWh/hour increase. Overall, load impacts increase by 2.4 MWh/hour.

Figure B.1: Comparison of Typical Event Day Load Impacts by Size, PG&E Original and Revised PY2021 Estimates



Tables B.1-B.4 summarize enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day, for all customers and by size group.

For all customers, there were load reductions on six out of nine events ranging between 2.3 MWh/hour on September 8th and 22.1 MWh/hour on July 9th. The first two events had issues with dispatching customer notifications before the events and the event on July 10th was a weekend event. The estimated load reduction for the typical event day is 8.7 MWh/hour, which is a 1.1 percent load reduction.

Table B.1: Revised PY2021 Average Event-Hour Load Impacts by Event, *PG&E All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	108,869	830	-2.0	7.6	0.0	-0.2%	100.2
7/8/2021	108,167	821	-0.3	7.6	0.0	0.0%	100.0
7/9/2021	108,150	859	22.1	7.9	0.2	2.6%	103.4
7/10/2021	108,149	786	-0.8	7.3	0.0	-0.1%	104.6
7/28/2021	107,523	812	6.8	7.6	0.1	0.8%	96.9
7/29/2021	107,502	828	2.5	7.7	0.0	0.3%	97.8
8/12/2021	107,145	812	17.3	7.6	0.2	2.1%	94.2
8/16/2021	107,095	811	10.5	7.6	0.1	1.3%	95.7
9/8/2021	106,511	817	2.3	7.7	0.0	0.3%	96.9
Typical Event Day	**107,443**	**823**	**8.7**	**7.7**	**0.1**	**1.1%**	**97.8**

Large customers had load reductions on all nine events ranging between 0.1 MWh/hour during the weekend event (July 10th) and 11.8 MWh/hour on July 28th. The estimated load reduction for the typical event day is 6.1 MWh/hour, which is a 2.5 percent load reduction.

Table B.2: Revised PY2021 Average Event-Hour Load Impacts by Event, *PG&E Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	1,256	251	1.4	199.6	1.1	0.6%	99.9
7/8/2021	1,241	248	3.7	199.7	3.0	1.5%	100.3
7/9/2021	1,241	247	8.5	198.6	6.9	3.5%	103.8
7/10/2021	1,245	212	0.1	170.3	0.1	0.0%	104.7
7/28/2021	1,237	246	11.8	199.0	9.6	4.8%	97.0
7/29/2021	1,237	246	3.7	198.8	3.0	1.5%	98.2
8/12/2021	1,234	243	4.1	197.0	3.3	1.7%	95.2
8/16/2021	1,233	243	3.0	196.9	2.4	1.2%	96.1
9/8/2021	1,218	243	7.5	199.1	6.2	3.1%	97.1
Typical Event Day	**1,235**	**245**	**6.1**	**198.1**	**4.9**	**2.5%**	**98.2**

Medium customers had load reductions on three out of the nine events ranging between 3.9 MWh/hour on August 16th and 9.2 MWh/hour on July 9th. The estimated load reduction for the typical event day is 1.5 MWh/hour, which is a 0.4 percent load reduction.

Table B.3: Revised PY2021 Average Event-Hour Load Impacts by Event, *PG&E Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	16,568	389	-1.2	23.5	-0.07	-0.3%	100.6
7/8/2021	16,474	385	-1.4	23.4	-0.08	-0.4%	100.2
7/9/2021	16,473	411	9.2	25.0	0.56	2.2%	103.6
7/10/2021	16,473	384	-1.5	23.3	-0.09	-0.4%	104.9
7/28/2021	16,420	381	-3.1	23.2	-0.19	-0.8%	97.1
7/29/2021	16,419	390	-0.9	23.8	-0.06	-0.2%	97.9
8/12/2021	16,370	382	7.0	23.3	0.43	1.8%	94.1
8/16/2021	16,360	384	3.9	23.5	0.24	1.0%	95.8
9/8/2021	16,296	386	-4.3	23.7	-0.26	-1.1%	97.0
Typical Event Day	**16,402**	**389**	**1.5**	**23.7**	**0.09**	**0.4%**	**97.9**

Small customers had load reductions on four out of the nine events ranging between 0.6 MWh/hour on July 10th and 6.2 MWh/hour on August 12th. The estimated load reduction for the typical event day is 1.2 MWh/hour, which is a 0.6 percent load reduction.

Table B.4: Revised PY2021 Average Event-Hour Load Impacts by Event, *PG&E Small*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	91,045	189.9	-2.3	2.09	-0.02	-1.2%	100.0
7/8/2021	90,452	188.3	-2.6	2.08	-0.03	-1.4%	99.4
7/9/2021	90,436	203.5	4.4	2.25	0.05	2.1%	102.7
7/10/2021	90,431	189.6	0.6	2.10	0.01	0.3%	103.9
7/28/2021	89,866	185.2	-1.9	2.06	-0.02	-1.0%	96.3
7/29/2021	89,846	191.9	-0.3	2.14	0.00	-0.1%	97.1
8/12/2021	89,541	186.4	6.2	2.08	0.07	3.3%	93.2
8/16/2021	89,502	184.4	3.6	2.06	0.04	2.0%	94.8
9/8/2021	88,997	188.5	-0.9	2.12	-0.01	-0.5%	96.2
Typical Event Day	**89,806**	**189.7**	**1.2**	**2.11**	**0.013**	**0.6%**	**97.1**

B.2 Ex-Ante Forecast

This section summarizes the revised PY2021 ex-ante forecast for PG&E. We present the forecast for the typical event day for each weather scenario over the forecast period from 2022 to 2032. The results are summarized for each size group and for the PDP program overall. Aggregate load impacts increase in 2023 relative to 2022 commensurate with defaulting of customers onto PDP, which increases enrollments in that year. After 2023, enrollments decline due to attrition as do aggregate load impacts.

Table B.5: Revised PY2021 Ex-Ante Forecast by Year and Weather Scenario for a Typical Event Day by Size, *PG&E*

Size	Year	# Enrolled	RA Window Load Impact (MWh/Hour)			
			PG&E 1-in-10	PG&E 1-in-2	CAISO 1-in-10	CAISO 1-in-2
Large	2022	1,385	6.7	6.7	6.7	6.6
	2023	1,587	6.9	6.9	6.9	6.9
	2024	1,487	6.7	6.6	6.6	6.6
	2025	1,393	6.4	6.4	6.4	6.3
	2026	1,306	6.2	6.2	6.2	6.1
	2027	1,224	5.9	5.9	5.9	5.9
	2028	1,148	5.7	5.7	5.7	5.7
	2029	1,076	5.6	5.5	5.5	5.5
	2030	1,008	5.4	5.4	5.4	5.3
	2031	945	5.2	5.2	5.2	5.2
	2032	885	5.0	5.0	5.0	5.0
Medium	2022	14,439	1.3	1.3	1.3	1.3
	2023	15,649	1.4	1.4	1.4	1.4
	2024	14,664	1.3	1.3	1.3	1.3
	2025	13,740	1.2	1.2	1.2	1.2
	2026	12,874	1.2	1.1	1.1	1.1
	2027	12,064	1.1	1.1	1.1	1.0
	2028	11,303	1.0	1.0	1.0	1.0
	2029	10,592	1.0	0.9	0.9	0.9
	2030	9,924	0.9	0.9	0.9	0.9
	2031	9,299	0.8	0.8	0.8	0.8
	2032	8,714	0.8	0.8	0.8	0.8
Small	2022	78,905	1.1	1.1	1.1	1.1
	2023	86,125	1.2	1.2	1.2	1.2
	2024	80,697	1.2	1.1	1.1	1.1
	2025	75,611	1.1	1.1	1.1	1.0
	2026	70,848	1.0	1.0	1.0	1.0

Size	Year	# Enrolled	RA Window Load Impact (MWh/Hour)			
			PG&E 1-in-10	PG&E 1-in-2	CAISO 1-in-10	CAISO 1-in-2
	2027	66,382	0.9	0.9	0.9	0.9
	2028	62,199	0.9	0.9	0.9	0.8
	2029	58,280	0.8	0.8	0.8	0.8
	2030	54,608	0.8	0.8	0.8	0.7
	2031	51,165	0.7	0.7	0.7	0.7
	2032	47,942	0.7	0.7	0.7	0.6
All	2022	94,729	9.1	9.1	9.1	8.9
	2023	103,361	9.6	9.5	9.5	9.4
	2024	96,848	9.1	9.1	9.1	9.0
	2025	90,744	8.7	8.7	8.7	8.6
	2026	85,028	8.3	8.3	8.3	8.2
	2027	79,670	8.0	7.9	7.9	7.8
	2028	74,650	7.6	7.6	7.6	7.5
	2029	69,948	7.3	7.3	7.3	7.2
	2030	65,540	7.0	7.0	7.0	6.9
	2031	61,409	6.8	6.7	6.7	6.7
	2032	57,541	6.5	6.5	6.5	6.4