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Christensen ASSOCIATES

2022 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report

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ABSTRACT

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2022. The report provides estimates of ex-post load impacts that occurred during events called in 2022 and an ex-ante forecast of load impacts for 2023 through 2033 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2022 program year.

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

PG&E and SCE both called three events in 2022 and SDG&E called no events. Both PG&E and SCE called their three events on September 5th, 6th, and 7th with varying event hours. September 5th was Labor Day, which falls on a Monday, and the September 6th and 7th events were on Tuesday and Wednesday, respectively.

Ex-post load impacts were estimated from regression analysis of customer-level hourly load data, where the equations modeled hourly load as a function of variables that control for factors affecting consumers' hourly demand levels. BIP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models.

The total program load impact for PG&E's September 6th typical event day was 149 MW, or 73 percent of enrolled load. This was 98 percent of the reduction required to meet the aggregate FSL, calculated as the estimated load impact divided by the load impact that would have occurred if customers had (in aggregate) exactly attained their FSL.

For SCE, the load impact was 463 MW during the September 6th event, representing a 78 percent decrease of the reference load. This was 99 percent of the reduction required to meet the aggregate FSL.

SDG&E did not call an event and has no ex-post load impacts for the 2022 program year.

EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2022. The report provides estimates of ex-post load impacts that occurred during events called in 2022 and an ex-ante forecast of load impacts for 2023 through 2033 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2022 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2022?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What are the ex-ante load impacts for 2023 through 2033?

ES.1 Resources Covered

Base Interruptible Program

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

There are a number of similarities and differences in the BIPs offered by the California investor-owned utilities ("IOUs"). The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand.

PG&E called three events in 2022. All three events were called as transmission emergencies in response to a heat wave in early September. The first event was called on Monday September 5th, which was Labor Day. The event lasted from 7:15 PM-9:18 PM. The second event was called from 6:00 PM-8:38 PM on Tuesday September 6th. The third event was called from 7:15 PM-8:02 PM on Wednesday September 7th.

SCE also called three events in 2022. The SCE events were also called in response to the heat wave that occurred in early September. The first event was called on Monday September 5th from 6:30 PM-8:12 PM which was Labor Day. The second event was called on Tuesday September 6th from 5:00 PM-8:43 PM. The third event was called on Wednesday September 7th from 6:15 PM-8:12 PM.

SDG&E did not call any events in 2022.

Enrollment

Enrollment in PG&E's BIP decreased relative to PY2021, from 309 to 258 customers. The sum of enrolled customers' coincident maximum demands was 230.8 MW, or 0.89 MW for the average service agreement during the September 6th event day.[1] The Manufacturing industry group contains 44 percent of the enrolled load. Figure ES.1 illustrates the distribution of BIP load across the indicated industry types.

Figure ES.1: Distribution of BIP Enrolled Load by Industry Type, PG&E

[redacted]

SCE's enrollment in BIP was 343 service accounts during the typical 2022 event day, which is a decrease relative to the 344 enrolled service accounts during PY2021. These accounted for a total of 623.7 MW of maximum demand, or 1.82 MW per service account during the September 6th event day. Manufacturers make up 60 percent of the enrolled load. Figure ES.2 illustrates the distribution of SCE's BIP load across the indicated industry types.

Figure ES.2: Distribution of BIP Enrolled Load by Industry Type, SCE

[redacted]

[1] A customer's coincident maximum demand ("Enrolled Load" in Figures ES.1 and ES.2) is defined as its demand during the hour with the highest aggregate demand on the typical event day, including the estimated load impacts (i.e., using the reference loads).

SDG&E had no service accounts enrolled during the 2022 program year and no events were called.

ES.2 Evaluation Methodology

We estimated ex-post load impacts using regression analysis of customer-level hourly load data. Individual-customer regression equations modeled hourly load as a function of several variables designed to control for factors affecting consumers' hourly demand levels, including:

- Seasonal and hourly time patterns (e.g., year, month, day-of-week, and hour, plus various hour/day-type interactions);
- Weather (e.g., cooling degree hours, including hour-specific weather coefficients);
- Event indicator (dummy) variables. A series of variables was included to account for each hour of each event day, allowing us to estimate the load impacts for each hour of each event day.

BIP load impacts for each event were obtained by summing the estimated hourly event coefficients from the customer-level regressions. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, by aggregating customer load impacts for the relevant industry group or local capacity area.

ES.3 Ex-post Load Impacts

Table ES.1 summarizes the number of customers called, load impact, percentage load impact, and FSL achievement rate by event for PG&E. The total program load impact for PG&E's September 6th event averaged 149 MW, or 73 percent of enrolled load, representing 98 percent of the reduction required to meet the aggregate FSL across the 258 customers who were called for the event.

Table ES.1: Summary of Event-hour Load Impact by Event, *PG&E*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	9/5/2022	Mon.	258	109	68%	100%
2	9/6/2022	Tue.	258	149	73%	98%
3	9/7/2022	Wed.	258	163	74%	96%
Typical Event Day			**258**	**149**	**73%**	**98%**

Table ES.2 displays a summary of load impact results for each 2022 BIP event day for SCE. The total program load impacts for the September 6th event (which had the longest event window) was had a load impact of 463 MW, representing a 78 percent decrease relative to the reference load. This was 99 percent of the reduction required to meet the aggregate FSL.

Table ES.2: Summary of Event-hour Load Impact by Event, *SCE*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	9/5/2022	Mon.	343	341	76%	105%
2	9/6/2022	Tue.	343	463	78%	99%
3	9/7/2022	Wed.	343	490	82%	103%
Typical Event Day			**343**	**463**	**78%**	**99%**

SDG&E had no customers enrolled in BIP and did not call any events in PY2022.

ES.4 Ex-ante Load Impacts

Scenarios of ex-ante load impacts are developed by combining enrollment forecasts with per-customer reference loads and load impacts, which were developed using the results of the ex-post load impact evaluation.

PG&E forecasts constant enrollment of 240 customers from January of 2023 to the end of 2033. SCE predicts enrollments to remain constant at 332 service accounts from 2023 through 2033. SDG&E forecasts one BIP customer for the entire forecast period.

Figure ES.3 shows PG&E's ex-ante load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August event day, averaged over the resource adequacy window 4 to 9 p.m. The load impact is forecasted to increase slightly after 2025 when the ELRP pilot ends.[2] Figures ES.4 and ES.5 show the ex-ante load impacts for SCE and SDG&E, respectively. The ex-ante load impacts illustrate the lack of weather sensitivity at the aggregate level. Forecasts also remain constant as there are no forecasted changes in enrollment and weather patterns remain constant across years.[3]

[2] The BIP ex-post and ex-ante load impact is capped at a 100% FSL achievement rate for customers that are dually enrolled in BIP and ELRP. Any load impact above the 100% FSL achievement rate is credited towards ELRP. After the end of ELRP in November 2025, BIP load impacts are allowed to exceed the 100% FSL achievement rate for customers who have demonstrated the ability to surpass this threshold prior to enrollment in ELRP.

[3] For SDG&E, load impacts are set at 0.1 MWh/h during event hours for all weather scenarios and months over the forecast period. Further details are presented in the ex-ante methodology section.

Figure ES.3: Average August Ex-Ante Load Impacts by Year and Scenario, *PG&E*

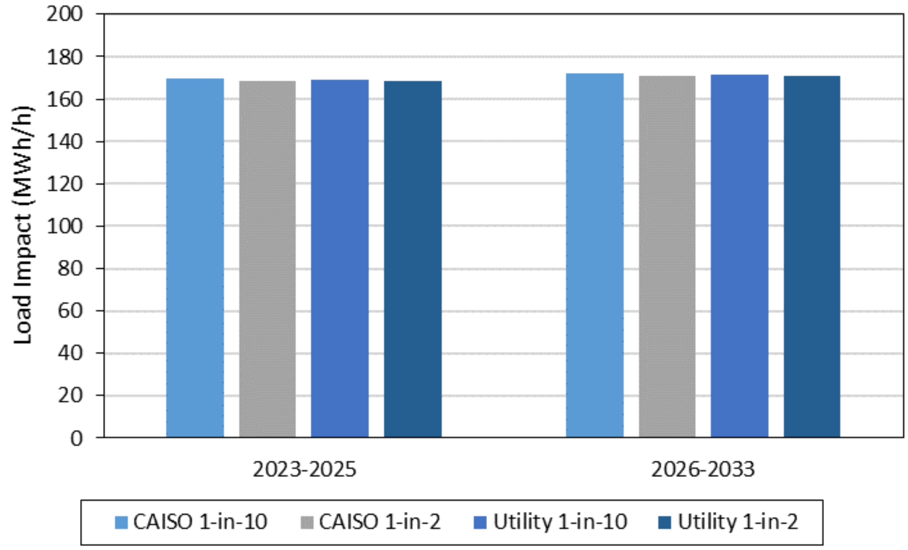


Figure ES.4: Average August Ex-Ante Load Impacts by Year and Scenario, *SCE*

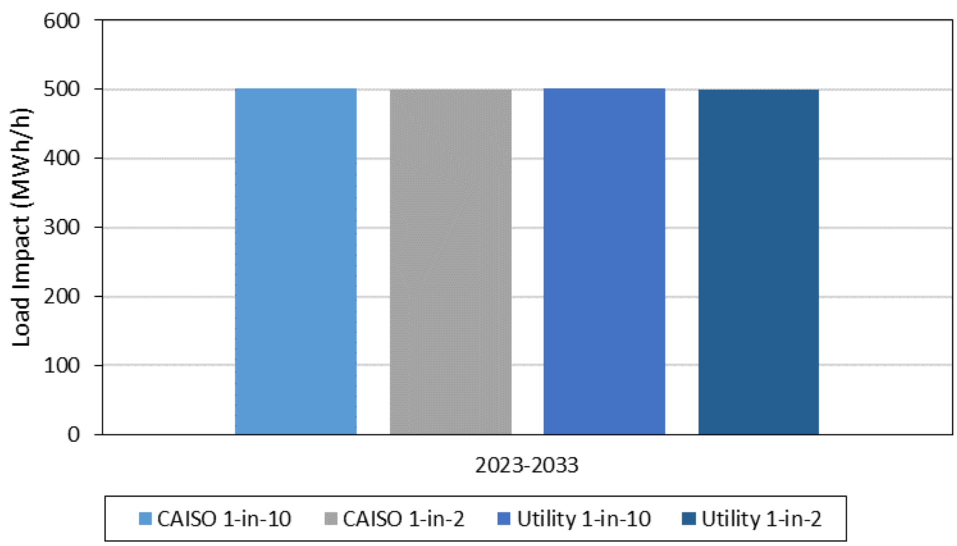


Figure ES.5: Average August Ex-Ante Load Impacts by Scenario, *SDG&E*

[redacted]

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2022. The report provides estimates of ex-post load impacts that occurred during events called in 2022 and an ex-ante forecast of load impacts for 2023 through 2033 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2022 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2022?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What are the ex-ante load impacts for 2023 through 2033?

The report is organized as follows. Section 2 contains a description of the programs, the enrolled customers, and the events called; Section 3 describes the methods used in the study; Section 4 contains the detailed ex-post load impact results; Section 5 describes the ex-ante load impact forecast; Section 6 contains descriptions of differences in various scenarios of ex-post and ex-ante load impacts; and Section 7 provides recommendations. Appendix A contains an assessment of the validity of the study. Appendix B shows the FSL achievement rate by industry group.

2. DESCRIPTION OF RESOURCES COVERED IN THE STUDY

This section provides details on the Base Interruptible Programs, including the characteristics of the participants enrolled in the programs and the events called in 2022.

2.1 Program Descriptions

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

There are a number of similarities and differences in the BIPs offered by the California investor-owned utilities ("IOUs"). The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand. Descriptions of each utility's BIP are provided below.

SCE's Base Interruptible Program

SCE's BIP is designed for customers and aggregators with demands of 200 kW and above. The program includes two participation options:

- Option A, which requires a customer or Aggregated Group to reduce its demand to its FSL within 15 minutes of a Notice of Interruption; or
- Option B, which requires a customer or Aggregated Group to reduce its demand to its FSL within 30 minutes of a Notice of Interruption.

Excess energy charges are applied when a customer is unable to reduce its demand to its FSL during events. Interruption events for an individual BIP customer or aggregated group are limited to no more than one event per day (lasting no more than 6 hours), ten in any calendar month, and a total of 180 hours per calendar year.

An interruption event may be called by the California Independent System Operator ("CAISO") or SCE at any time during the year.

PG&E's Base Interruptible Program

PG&E's BIP, a tariff-based program, is designed to provide load reductions on PG&E's system on a day-of basis when the CAISO issues a curtailment notice or in the event of a transmission or distribution system contingency. Customers must be notified at least 30 minutes prior to the event. BIP events can be operated year-round, with a maximum of one event per day and six hours per event. The program cannot exceed ten events during a calendar month or 180 hours per calendar year.

Participants who do not comply with the curtailment order are subject to a substantial excess energy charge on any power used above their contracted amount, or FSL. This potential energy charge has resulted in a high compliance rate. PG&E may require a customer that fails to reduce its load down to or below its FSL to re-test, modify its FSL, de-enroll from the program, or successfully comply with the re-test.

Directly-enrolled customers may participate in PG&E's Underfrequency Relay (UFR) Program. The UFR Program is not available to customers enrolled through aggregators. Under the UFR Program, customers agree to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E. PG&E may require up to 3-years' written notice for termination of participation in the UFR Program. Customers participating in the UFR program will receive a demand credit on a monthly basis based on their average monthly on-peak period demand in the summer and their average monthly partial-peak demand in the winter.

SDG&E's Base Interruptible Program

SDG&E's BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. Non-residential customers who can commit to curtail 15 percent of monthly peak demand are eligible for the program. Customers are notified no later than 20 minutes before the event. The monthly incentive payments in 2022 were $6.30 per kW during January through December months. Curtailment events for an individual BIP customer are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

Recent year participation in SDG&E's program has been low, consistent with the California Public Utilities Commission ("Commission" or "CPUC") direction to focus marketing efforts on price responsive programs. There were no participants in 2022.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

In order to assess differences in load impacts across customer types, the program participants were categorized according to eight industry types. The industry groups are defined according to their applicable two-digit North American Industry Classification System (NAICS) codes:

1. Agriculture, Mining and Oil and Gas, Construction: 11, 21, 23
2. Manufacturing: 31-33
3. Wholesale, Transport, other Utilities: 22, 42, 48-49
4. Retail stores: 44-45
5. Offices, Hotels, Finance, Services: 51-56, 62, 72
6. Schools: 61
7. Entertainment, Other services and Government: 71, 81, 92
8. Other or unknown.

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[4]

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows BIP enrollment by industry group for PG&E during the typical event day. Enrollment in PG&E's BIP decreased relative to PY2021, from 310 to 258.[5] The sum of enrolled customers' coincident maximum demands[6] was 230.8 MW, or 0.89 MW for the average service agreement. The manufacturing industry group contains 44 percent of the enrolled load.

[4] Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently seven LCAs within PG&E's service area, 3 in SCE's service territory, and 1 representing SDG&E's entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA.
[5] "Enrollment" is defined as the enrollment on the (July 9th) typical event day in PY2021 compared to the September 6th typical event day in PY2022.
[6] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 3—demand during the hour with the highest aggregate demand that day—including the estimated load impacts (i.e., using the reference loads).

Table 2.1: BIP Enrollees by Industry Group, *PG&E*

Industry	Enrolled	Sum of Max MWh/h[7]	Percent of Max MWh/h	Average Max MWh/h[8]
Agriculture, Mining & Construction	101	[redacted]	[redacted]	[redacted]
Manufacturing	70	101.0	43.8%	1.44
Wholesale, Transport, other utilities	77	39.7	17.2%	0.52
Retail stores	4	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	3	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]
Other or unknown	2	[redacted]	[redacted]	[redacted]
Total	**258**	**230.8**	**-**	**0.89**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 343 service accounts on the September 6, 2022 event day, which is a decrease relative to the 344 enrolled service accounts during PY2021. These accounted for a total of 623.7 MW of maximum demand, or 1.82 MW per service account. Manufacturers make up 60 percent of the enrolled load.

Table 2.2: BIP Enrollees by Industry Group, *SCE*

Industry	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
Agriculture, Mining & Construction	30	[redacted]	[redacted]	[redacted]
Manufacturing	232	372.0	59.7%	1.60
Wholesale, Transport, other utilities	60	[redacted]	[redacted]	[redacted]
Retail stores	2	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	5	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]
Institutional/Government	1	[redacted]	[redacted]	[redacted]
Other (or unknown)	12	[redacted]	[redacted]	[redacted]
Total	**343**	**623.7**	**-**	**1.82**

SDG&E did not have any customers enrolled on BIP in 2022.

Tables 2.3 and 2.4 show BIP enrollment by local capacity area for PG&E and SCE, respectively. The greatest portion of PG&E's enrolled load is in the "Kern" LCA category. For SCE, 71.5% percent of enrolled load is in the LA Basin.

[7] "Sum of Max MW" is defined as the sum of the event-day coincident maximum demands across service accounts. The reported values include the estimated load impacts.
[8] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

Table 2.3: BIP Enrollees by Local Capacity Area, *PG&E*

Local Capacity Area	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
Greater Bay Area	32	[redacted]	[redacted]	[redacted]
Greater Fresno Area	74	17.6	7.6%	0.24
Humboldt	2	[redacted]	[redacted]	[redacted]
Kern	27	[redacted]	[redacted]	[redacted]
North Coast / North Bay	8	[redacted]	[redacted]	[redacted]
Other	79	54.0	23.4%	0.68
Sierra	20	[redacted]	[redacted]	[redacted]
Stockton	16	[redacted]	[redacted]	[redacted]
Total	**258**	**230.8**	**-**	**0.89**

Table 2.4: BIP Enrollees by Local Capacity Area, *SCE*

Local Capacity Area	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
LA Basin	280	446.0	71.5%	1.59
Outside Basin	15	[redacted]	[redacted]	[redacted]
Ventura	48	[redacted]	[redacted]	[redacted]
Total	**343**	**623.7**	**-**	**1.82**

2.3 Event Days

Table 2.5 lists BIP event days and hours for the three IOUs in 2022. PG&E called three transmission emergency events, which occurred on September 5th, 6th, and 7th. SCE also called three consecutive events over September 5-7. SDG&E did not call any events.

Table 2.5: BIP Event Days

Date	Day of Week	PG&E	SCE	SDG&E
9/5/2022	Monday	Transmission Emergency 7:15 – 9:18 p.m.	Transmission Emergency 6:30 – 8:12 p.m.	
9/6/2022	Tuesday	Transmission Emergency 6:00 – 8:38 p.m.	Transmission Emergency 5:00 – 8:43 p.m.	
9/7/2022	Wednesday	Transmission Emergency 7:15 – 8:02 p.m.	Transmission Emergency 6:15 – 8:12 p.m.	

3. STUDY METHODOLOGY

3.1 Overview

We estimated ex-post hourly load impacts using regression equations applied to customer-level 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., year, month, day-of-week, and hour, plus various hour/day-type interactions);
- Weather, including hour-specific weather coefficients;
- Event variables. A series of dummy variables was included to account for each hour of each event day, allowing us to estimate the load impacts for all hours across the event days.

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each enrolled customer. As a result, the coefficients on the event day/hour variables are direct estimates of the ex-post load impacts. For example, a BIP hour 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Both PG&E and SCE called September 5th, Labor Day, as a BIP event. Holidays have load profiles that are more similar to weekends than weekdays. Separate weekday and holiday/weekend models were estimated for PG&E and SCE to provide load impact estimates for both weekday and weekend/holiday events.

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. Each customer was first classified according to whether it is weather-sensitive. We then selected specifications by customer group, defined by industry group and weather sensitivity (i.e., sixteen groups, with eight industry groups for each of the non-weather-sensitive customers and weather-sensitive customers). This process is done separately for weekday and weekend/holiday models and its results are explained in Appendix A.

3.2 Description of Methods

3.2.1 Regression Model

The following is a general form of the model that was separately estimated for each enrolled BIP customer. The specific form of the model varied across utilities and customer groups, as shown in Appendix A. Table 3.1 below describes the terms included in this equation for the observed demand in a given hour h and date d:

$$
\begin{aligned}
Q_t \; = \; & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=1}^{24}(b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t}) \\
& + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{i=6}^{10}(b_i^{MONTH} \times MONTH_{i,t}) + \sum_{i=2}^{24}(b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + e_t
\end{aligned}
$$

Table 3.1: Descriptions of Variables included in the Ex-post Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a BIP customer
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, …)
$Weather_t$	the weather variables selected using our model screening process
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10 (may be excluded via model screening)
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday (Sunday hourly indicator variables are included in models that include weekend dates)
$MONTH_{j,t}$	a series of indicator variables for each month (model screening may include separate hourly profiles by month)
$SUMMER_t$	an indicator variable for the summer pricing season[9]
e_t	the error term

The *OtherEvt* variables help the model explain load changes that occur on event days for programs in which the BIP customers are dually enrolled. (In the absence of these variables, any load reductions that occur on such days may be falsely attributed to other included variables, such as weather conditions or day type variables.) The "morning load" variables are included in the same spirit as the day-of adjustment to the 10-in-10 baseline settlement method used in some DR programs. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of

[9] The summer pricing season is June through September for SCE. PGE has two separate summer definitions which varies by rate: May through October and June through September.

an event) for factors that affect pre-event usage but are not accounted for by the other included variables.[10]

The model allows for the hourly load profile to differ by time periods, which can vary across specifications selected for each customer group. The time-based patterns reflect day of week, with separate profiles for Monday, Tuesday through Thursday, and Friday; month of year; and pricing season (i.e., summer versus winter), to account for potential customer load changes in response to seasonal changes in rates.

In PY2022, we treat the September 5th event as a weekend event day since it was Labor Day, and the holiday load shapes were more like weekends than weekdays. Therefore, we run separate weekend/holiday regression specifications for the September 5th event. The weekend/holiday regression specification differs only by the inclusion of the appropriate day type indicator variables (e.g., Sunday). We treat September 5th as a Sunday and September 6th as a Monday in order to account for load shape patterns that differ around holidays (i.e., September 5th and 6th have load profiles that more similarly resemble Sunday and Monday load profiles, respectively).

Separate models were estimated for each customer. The load impacts were aggregated across customer accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group, local capacity area (LCA), notification type (applicable for SCE), and SubLAP (provided in Protocol Tables).

A parallel set of winter models was estimated for each customer, which were used to simulate ex-ante reference loads for those months.[11] The structure matches the model described above, with the appropriate month indicators substituted in. A separate model selection process was conducted for the winter models.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of ex-post load impacts, the parameters that constitute the load impact estimates are not estimated with certainty. We base the uncertainty-adjusted load impacts on the variances associated with the estimated load impact coefficients.

Specifically, we added the variances of the estimated load impacts across the customers who are called during the event in question. These aggregations were performed at either the program level, by industry group, by LCA, or by SubLAP, as appropriate. The uncertainty-adjusted scenarios were then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of

[10] Events that occur later in the day can have load impacts that carry over into the next day, affecting the next day's morning load. As a result, a consecutive event day that has lower morning loads, caused by the previous event day's load impact, can result in estimating lower reference loads during later hours of the day. Underestimating the reference load will also lead to underestimating the load impact for the consecutive event day. Since multiple BIP events were consecutive events in PY2022, we did not use the morning load variable for weekday events for all PG&E and most SCE customers.

[11] The summer models were estimated over the months May through for September for each utility. The ex-ante winter models cover all other months.

the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

In order to develop the uncertainty-adjusted load impacts associated with the average event hour (i.e., the bottom rows in the tables produced by the ex-post table generator), we estimated an additional set of customer-specific regression models in which each event day's average event-hour load impact is estimated using a single variable (rather than the hour-specific variables used in the primary model described above). The standard error associated with these event-specific coefficients serves as the basis of the average event-hour uncertainty-adjusted load impacts for each ex-post event day. The standard errors are used to develop the uncertainty-adjusted scenarios in the same manner as the hour-specific standard errors in the primary model.

4. DETAILED STUDY FINDINGS

The primary objective of the ex-post evaluation is to estimate the aggregate and per-customer BIP event-day load impacts for each utility. In this section we first summarize the estimated BIP load impacts for each of the utilities using a metric of estimated *average hourly load impacts* by event and for the average event. We also report average hourly load impacts for the average event by industry type and local capacity area. We then present tables of *hourly* load impacts for an *average event* (also referred to as a "typical event day") in the format required by the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in Decision (D.) 08-04-050 ("the Protocols"), including risk-adjusted load impacts at different probability levels, and figures that illustrate the reference loads, observed loads and estimated load impacts.

PG&E and SCE each called three events in 2022. On a summary level for the typical event day, the average event-hour load impact per enrolled customer was 577 kWh/h for PG&E and 1,349 kWh/h for SCE.

4.1 PG&E Load Impacts

4.1.1 Average Event-hour Load Impacts by Industry Group and LCA

Table 4.1 summarizes average event-hour reference loads and load impacts at the program level for each of PG&E's 2022 events.[12] Each of the events was called as an emergency event. The highest load impacts are observed on September 7th. The typical event day is defined as September 6th as it is the only weekday event with full event hours. On the typical event day, the average estimated reference load across event hours was 203 MWh/h. The load impact was 149 MWh/h, resulting in a percentage load impact of 73 percent. There were 258 customers called for each event.

[12] Results are averaged over full event hours only, i.e., partial event hours are omitted. The September 7th event has no full event hours, so we report results during the longest partial event hour (HE 20).

Table 4.1: Average Event-hour Load Impacts by Event, *PG&E*

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI[13]
1	9/5/2022	Mon.	258	160	51	109	68%
2	9/6/2022	Tue.	258	203	54	149	73%
3	9/7/2022	Wed.	258	220	58	163	74%
Typical Event Day			**258**	**203**	**54**	**149**	**73%**

Table 4.2 compares the observed loads and FSLs for each event. Event-day performance at the program level is shown in the rightmost column, as measured by the ratio of the estimated load impact (shown in Table 4.1) to the load impact that would have occurred if customers had (in aggregate) exactly attained their FSL. That is, a 100% value in that column would indicate that observed loads exactly matched the FSL (in aggregate, when averaged across event hours). A value less than 100% indicates aggregate under-performance (i.e., observed loads above the FSL). The FSL achievement rate was 98% on September 6th and 96% on September 7th. September 5th had the highest FSL achievement rate which is common on weekend/holiday events because some customers can have reference loads below their FSLs which contributes to a lower overall FSL achievement rate.

Table 4.2: Average Event-hour Observed Loads and FSLs by Event, *PG&E*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	9/5/2022	Mon.	51	51	100%
2	9/6/2022	Tue.	54	51	98%
3	9/7/2022	Wed.	58	51	96%
Typical Event Day			**54**	**51**	**98%**

Table 4.3 summarizes average event-hour BIP load impacts by industry group for the typical event day. The Manufacturing industry group accounted for the largest share of the load impacts, with a 66 MW average event-hour load reduction.

[13] The percentage load impact is calculated as the load impact divided by the reference load.

Table 4.3: Typical Event Day Load Impacts – *PG&E, by Industry Group*

Industry Group	# of Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	70	83.0	16.9	66.1	79.7%
Wholesale, Transport, Other Utilities	77	38.0	8.9	29.1	76.7%
Retail	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Schools	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other or Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**258**	**203.0**	**54.03**	**148.9**	**73.4%**

Table 4.4 summarizes the typical event day load impacts by local capacity area (LCA), showing that the highest share of the load impacts came customers in the Kern LCA (47.6 MW).

Table 4.4: Typical Event Day Load Impacts – *PG&E, by LCA*

Local Capacity Area	# of Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Greater Bay Area	32	[redacted]	[redacted]	[redacted]	[redacted]
Greater Fresno	74	15.0	4.4	10.5	70.3%
Humboldt	2	[redacted]	[redacted]	[redacted]	[redacted]
Kern	27	[redacted]	[redacted]	[redacted]	[redacted]
Northern Coast	8	[redacted]	[redacted]	[redacted]	[redacted]
Other	79	46.1	14.3	31.8	69.0%
Sierra	20	[redacted]	[redacted]	[redacted]	[redacted]
Stockton	16	[redacted]	[redacted]	[redacted]	[redacted]
Total	**258**	**203.0**	**54.0**	**148.9**	**73.4%**

4.1.2 Hourly Load Impacts

Table 4.5 presents hourly PG&E BIP load impacts at the program level in the manner required by the Protocols. BIP load impacts were estimated from the individual customer regressions for customers enrolled at the time of the event. The table reflects the September 6th event when 258 customers were called.

Table 4.5: BIP Hourly Load Impacts for the Typical Event Day, *PG&E*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	189.5	141.3	48.2	81.2	45.7	47.2	48.2	49.2	50.7
2	190.0	143.3	46.7	80.3	44.4	45.8	46.7	47.7	49.1
3	189.3	144.3	45.1	79.5	43.0	44.2	45.1	45.9	47.1
4	190.1	150.7	39.4	79.2	37.3	38.5	39.4	40.2	41.4
5	195.2	166.7	28.4	77.9	26.8	27.8	28.4	29.1	30.0
6	203.6	184.4	19.1	77.4	17.2	18.3	19.1	19.9	21.1
7	213.9	198.8	15.1	76.6	13.2	14.3	15.1	15.8	16.9
8	220.3	212.0	8.3	80.2	6.2	7.4	8.3	9.1	10.3
9	222.1	218.7	3.5	86.0	1.5	2.6	3.5	4.3	5.4
10	224.5	222.5	2.0	92.5	0.0	1.2	2.0	2.8	4.0
11	225.9	225.1	0.8	97.7	-1.6	-0.2	0.8	1.8	3.2
12	227.8	228.6	-0.9	101.7	-3.4	-1.9	-0.9	0.2	1.6
13	230.8	230.3	0.5	104.5	-2.1	-0.6	0.5	1.6	3.2
14	228.0	225.9	2.1	106.4	-0.5	1.0	2.1	3.1	4.7
15	219.7	213.9	5.8	109.5	3.4	4.8	5.8	6.8	8.2
16	209.7	194.1	15.5	108.4	13.0	14.5	15.5	16.5	18.0
17	202.5	178.0	24.5	106.7	21.8	23.4	24.5	25.7	27.3
18	201.8	123.9	77.9	102.7	75.1	76.8	77.9	79.1	80.8
19	202.5	54.1	148.4	91.1	145.7	147.3	148.4	149.4	151.0
20	203.4	53.9	149.5	84.8	146.6	148.3	149.5	150.7	152.4
21	205.4	55.6	149.8	81.7	147.5	148.8	149.8	150.8	152.2
22	215.7	109.4	106.3	87.1	103.2	105.0	106.3	107.6	109.4
23	219.5	152.8	66.6	86.2	63.2	65.2	66.6	68.1	70.1
24	219.8	178.9	40.9	84.8	36.9	39.3	40.9	42.5	44.9
By Period:	**Estimated Reference Energy Use (MWh)**	**Observed Event Day Energy Use (MWh)**	**Estimated Change in Energy Use (MWh)**	**Cooling Degree Hours (Base 75° F)**	**Uncertainty Adjusted Impact (MWh/hour) - Percentiles**				
					10th	**30th**	**50th**	**70th**	**90th**
Daily	5,051	4,007	1,044	364.1	976.9	1,016.3	1,043.5	1,070.8	1,110.2
Event Hours	203.0	54.0	148.9	25.9	140.6	145.5	148.9	152.3	157.3

* The highlighting indicates all hours affected by the event. However, hour-ending 21 was a partial event-hour and is not included in the average event-hour calculations in the report.

The full set of tables required by the Protocols, including tables for each local capacity area, are in the Excel file attached as an Appendix to this report. Figure 4.1 illustrates the hourly reference load, observed load, and estimated load impact for the typical event day.

Figure 4.1: BIP Loads for the Typical Event Day, *PG&E*

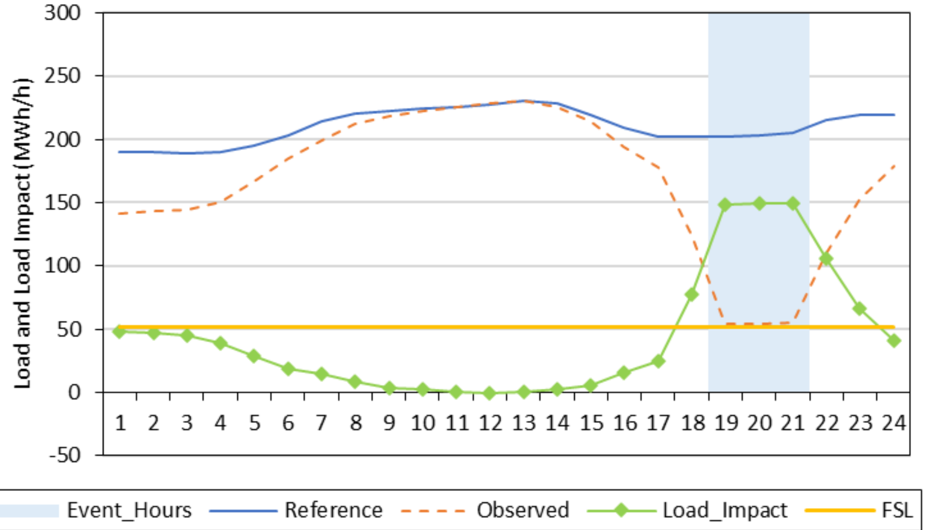


Figure 4.2 illustrates the aggregate hourly load impacts for each of the 2022 events. Non-holiday weekday events are marked with an "x" indicator. The load impact shape and magnitude differ between events as a result of different event hours as well as differing day types. For example, the holiday event, September 5th, has lower load impacts because of lower aggregate reference loads.

Figure 4.2: BIP Aggregate Load Impacts for Each Event Day, *PG&E*

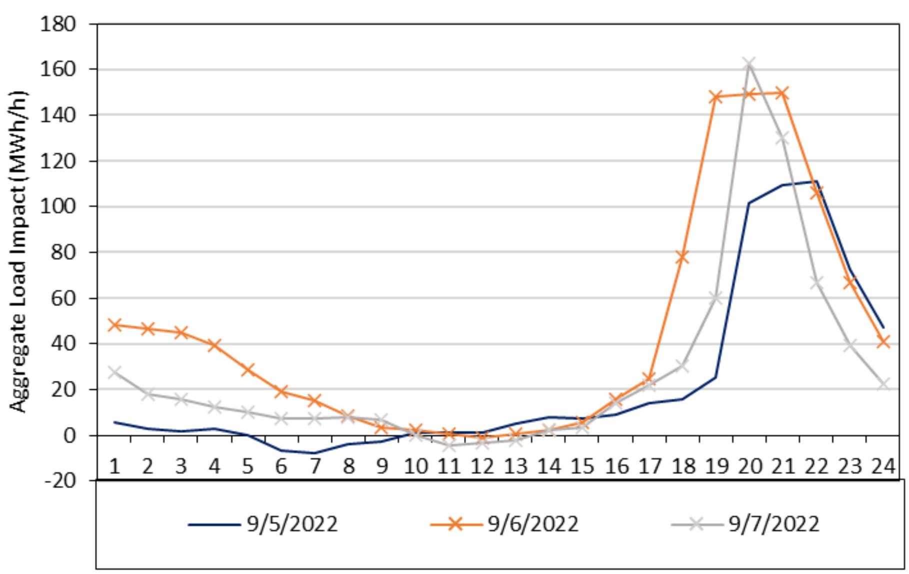
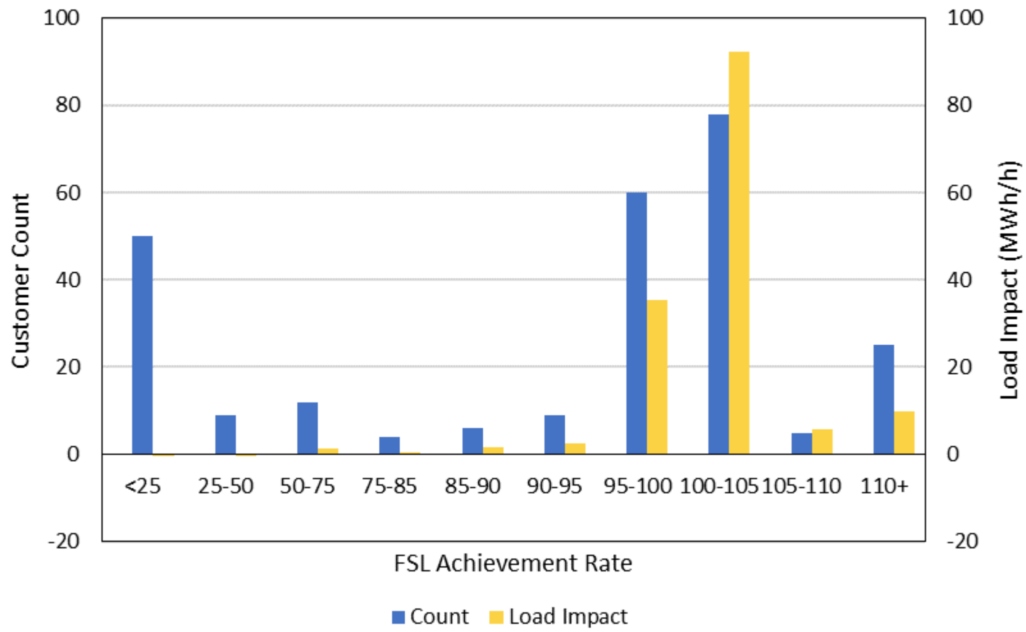


Figure 4.3 shows the range of FSL achievement rates and corresponding load impacts on the typical event day for PG&E customers. Most customers had an FSL achievement rate between 100 and 105%.

Figure 4.3: FSL Achievement Rate and Load Impacts on the Typical Event Day, *PG&E*



4.2 SCE Load Impacts

4.2.1 Average Event-hour Load Impacts by Industry Group and LCA

SCE called three events in 2022. Table 4.6 displays the average full event-hour reference loads and load impacts for the three events.[14] All three events were called in response to a heat wave that occurred in early September. All 343 enrolled BIP customers were called for each event. The September 5th event day was Labor Day and had significantly lower reference loads and total load impacts as it was a holiday. The September 6th and 7th events were both consecutive event days. September 6th is used as the typical event day because it was a weekday event with the longest event window. The typical event day had a 590 MW reference load with a load impact of 463 MW, or 78% of the reference load.

[14] Results are averaged over full event hours only, i.e., partial event hours are omitted.

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

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
1	9/5/2022	Mon.	343	447	106	341	76%
2	9/6/2022	Tue.	343	590	128	463	78%
3	9/7/2022	Wed.	343	600	109	490	82%
Typical Event Day			**343**	**590**	**127**	**463**	**78%**

Table 4.7 provides the SCE BIP event day observed loads compared to the FSL and FSL achievement rate. The program FSL was 122 MW for each of the event days. The typical event day had an FSL achievement rate of 99% during the full event hours.[15] The Labor Day event had the highest FSL achievement rate. This is common for weekend events since customers generally have lower reference loads on weekends with some being under their FSLs and thereby contributing to the overall program FSL achievement rate. September 6th has a slightly lower FSL achievement rate of 99% due to the first full event hour having only an 89% FSL achievement rate. The second and third full event hours have an FSL achievement rate of 103% which is similar to the September 7th event.[16]

Table 4.7: Average Event-hour Observed Loads and FSLs by Event, *SCE*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	9/5/2022	Mon.	106	122	105%
2	9/6/2022	Tue.	128	122	99%
3	9/7/2022	Wed.	109	122	103%
Typical Event Day			**127**	**122**	**99%**

Table 4.8 shows the average event-hour load impact by industry group for the typical event day (September 6th).[17] The total row at the bottom of the table shows the total event-day load impact of 463 MW, or 78 percent of the reference load. Most of the program's load impact came from customers in the Manufacturing industry group.

[15] The FSL achievement rate is capped at 100% for customers who were dually enrolled in ELRP and BIP on dual event days.
[16] The September 6th event started at 5:00 PM sharp. Often customers take time to reduce usage to their FSL. When there is a partial event hour at the beginning of an event, like on September 7th, the reported FSL achievement rate tends to be higher. The September 6th FSL achievement rate is reportedly lower as customers scaling down usage is captured in a full event hour as opposed to a partial event hour at the beginning of the event.
[17] In order to summarize only full-hour load impacts, the tables contain load impacts from 5 to 8 p.m., omitting the partial end hour from 8:00 to 8:43 p.m.

Table 4.8: Typical Event Day Load Impacts – *SCE, by Industry Group*

Industry Group	Enrolled	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	Percent Load Impact
Agriculture, Mining & Construction	30	[redacted]			
Manufacturing	232	350	79	271	77%
Wholesale, Transport, other utilities	60	[redacted]			
Retail stores	2				
Offices, Hotels, Finance, Services	5				
Schools	1				
Institutional/Government	1				
Other (or unknown)	12				
Total	**343**	**590**	**128**	**463**	**78%**

Table 4.9 summarizes average hourly load impacts by LCA. The majority of the load impact comes from customers in the LA Basin.

Table 4.9: Typical Event Day Load Impacts – *SCE, by LCA*

Local Capacity Area	Enrolled	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	Percent Load Impact
LA Basin	280	414	104	310	75%
Outside Basin	15	[redacted]			
Ventura	48				
Total	**343**	**590**	**128**	**463**	**78%**

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts for the typical event day (September 6^{th}) in the manner required by the Protocols.

Table 4.10: BIP Hourly Load Impacts for the Typical Event Day, *SCE*

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	522.0	384.2	137.8	26%	80.6	129.1	134.3	137.8	141.4	146.5
2	524.2	399.9	124.2	24%	79.6	115.8	120.8	124.2	127.7	132.7
3	525.2	399.7	125.5	24%	78.7	117.0	122.0	125.5	129.0	134.0
4	533.1	411.2	121.9	23%	77.6	113.9	118.7	121.9	125.2	130.0
5	554.8	438.7	116.1	21%	77.0	107.8	112.7	116.1	119.5	124.5
6	579.9	475.7	104.1	18%	76.1	95.8	100.7	104.1	107.6	112.5
7	604.6	486.8	117.8	19%	75.2	109.3	114.3	117.8	121.3	126.3
8	615.4	511.2	104.2	17%	75.2	95.5	100.7	104.2	107.8	112.9
9	618.9	524.1	94.8	15%	77.0	85.8	91.1	94.8	98.5	103.8
10	622.5	527.5	94.9	15%	79.9	86.3	91.4	94.9	98.5	103.5
11	623.7	536.8	86.9	14%	83.8	78.3	83.4	86.9	90.4	95.5
12	621.9	535.4	86.5	14%	87.8	78.2	83.1	86.5	89.9	94.8
13	617.4	535.1	82.3	13%	91.4	74.1	79.0	82.3	85.7	90.6
14	613.5	528.2	85.4	14%	93.4	77.1	82.0	85.4	88.8	93.6
15	608.6	504.3	104.3	17%	93.9	95.3	100.6	104.3	108.0	113.3
16	602.8	487.0	115.8	19%	94.4	106.8	112.1	115.8	119.4	124.7
17	587.6	481.0	106.6	18%	94.5	97.2	102.7	106.6	110.4	115.9
18	586.6	172.2	414.5	71%	93.5	405.6	410.9	414.5	418.1	423.3
19	591.2	105.9	485.3	82%	87.8	476.4	481.7	485.3	489.0	494.3
20	593.5	105.2	488.3	82%	84.7	479.4	484.7	488.3	492.0	497.3
21	595.3	124.8	470.5	79%	82.0	461.2	466.7	470.5	474.3	479.8
22	605.7	285.2	320.5	53%	83.3	311.9	317.0	320.5	324.0	329.1
23	613.9	399.2	214.7	35%	82.2	205.8	211.1	214.7	218.3	223.6
24	612.5	458.6	153.9	25%	81.5	144.9	150.3	153.9	157.6	162.9
Daily	**14,175**	**9,818**	**4,357**	**31%**	**83.8**	**4,205.6**	**4,295.0**	**4,357.0**	**4,419.0**	**4,508.4**

* The highlighting indicates all hours affected by the event. However, hour-ending 21 was a partial event-hour and is not included in the average event-hour calculations in the report.

Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the September 6th typical event day. The event hours are represented with blue shading with the last event hour (HE21) being a partial event hour. September 6th was a consecutive event day which is why there is some load impact in the early morning hours that carryover from the previous event day's load impacts. Additionally, there are some customers that provide voluntary load reductions outside of the BIP event window, which we discuss below.

Figure 4.4: BIP Loads for the Typical Event Day, *SCE*

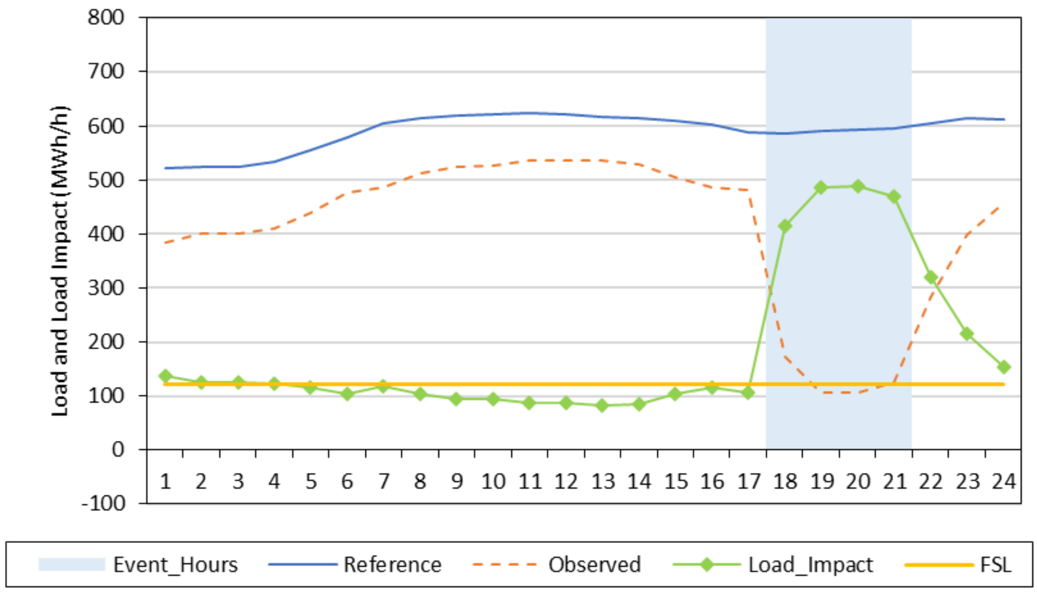
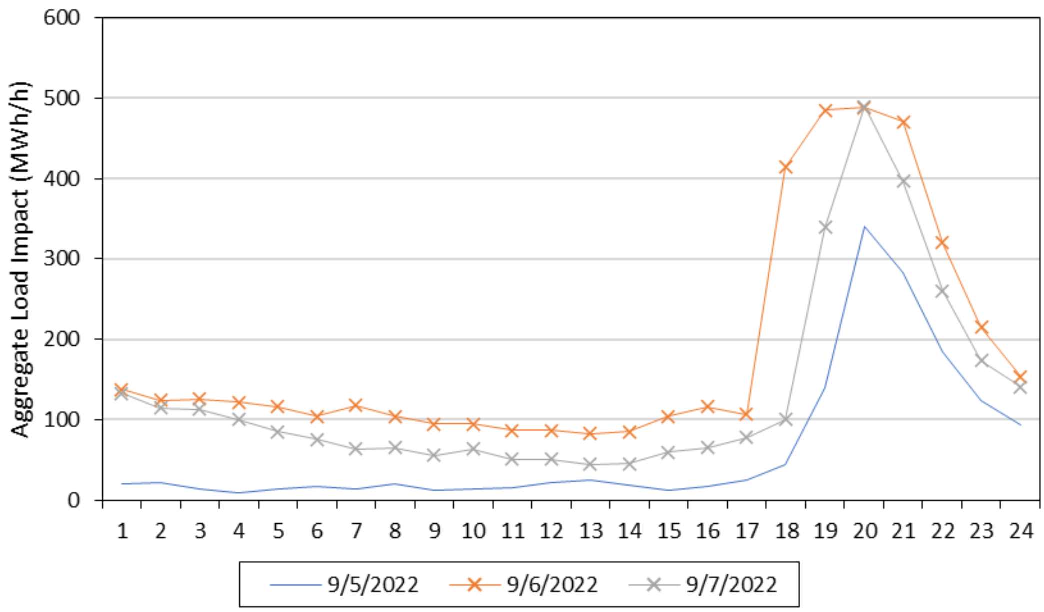


Figure 4.5 illustrates the aggregate hourly load impacts for each of the 2022 events. Non-holiday weekday events are marked with an "x" indicator. The load impact shape and magnitude differ between events as a result of different event hours as well as differing day types. For example, the holiday event, September 5th, has lower load impacts because of lower aggregate reference loads.

Figure 4.5: BIP Aggregate Load Impacts for Each Event Day, *SCE*



In early September of 2022 there was a substantial heat wave in California. In response to this heat wave, certain customers enrolled in BIP were asked to provide additional voluntary load reductions to help ensure grid reliability. Customers were asked to reduce usage in between September 3rd and September 9th.[18] To properly account for load changes that occur from voluntary reductions outside of the BIP event window, we 1) remove non-event days where voluntary reduction was provided for such customers and 2) do not include a morning load variable in our model specification for any of the event days.[19] Figures 4.6 and 4.7 illustrate the aggregate load impacts of customers that provided voluntary reductions outside of BIP event hours and normal customers, respectively during the September 5th event. The gap between the reference load and the observed event day load in Figure 4.4 in the pre-event hours illustrates the effects of the voluntary reduction on customer loads.

[18] 19 customers provided load reduction at some point during the window from the 3rd-9th. Not all customers were asked to provide reductions on all days in the window. 17 customers were listed as providing voluntary reductions on the 5th. Only 9 customers were listed as providing voluntary reductions on the typical event day.

[19] The morning load variable is not used for customers that provided voluntary reductions whereas it is used for the first event day, but not consecutive event days, for other customers. Removing the morning load in the regression specification for customers that provided voluntary reductions outside of the BIP event window allows us to model reference loads as if no voluntary reduction was requested. Otherwise, including a morning load variable would reduce the estimated reference load of these customers and ultimately reduce their estimated load impacts.

Figure 4.6: BIP Impacts on the Typical Event Day for Voluntary Reduction Customers, *SCE*

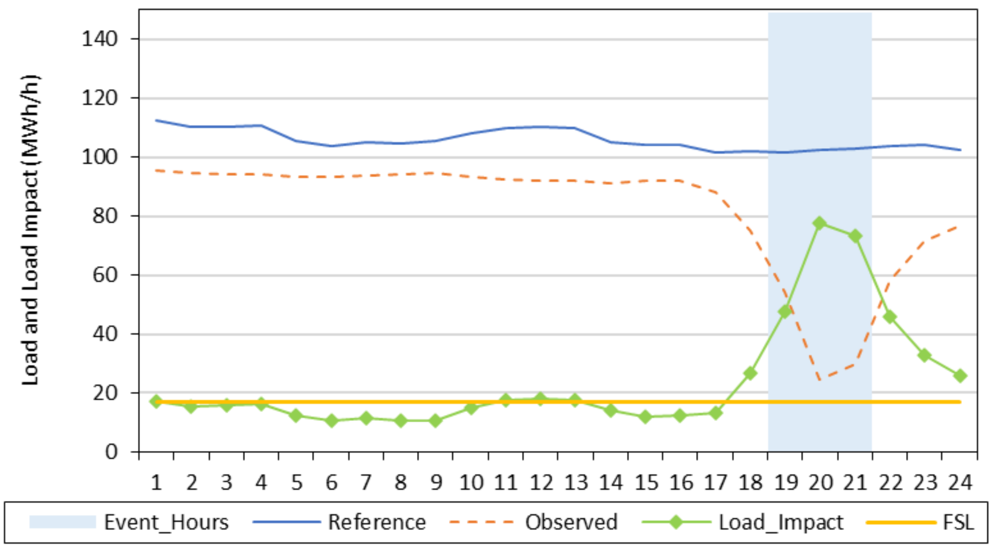


Figure 4.7: BIP Load Impacts on the Typical Event Day for Normal Customers, *SCE*

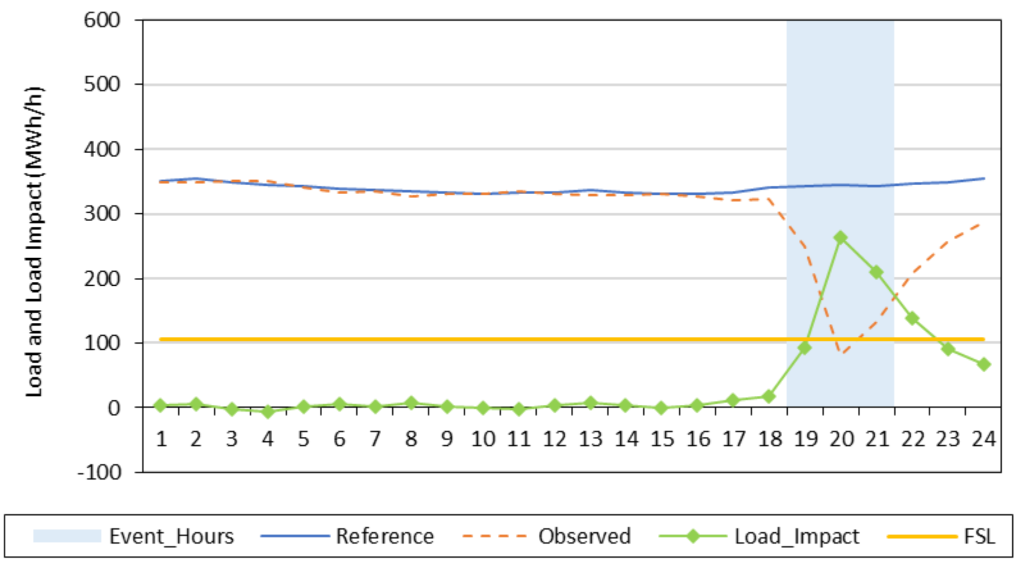
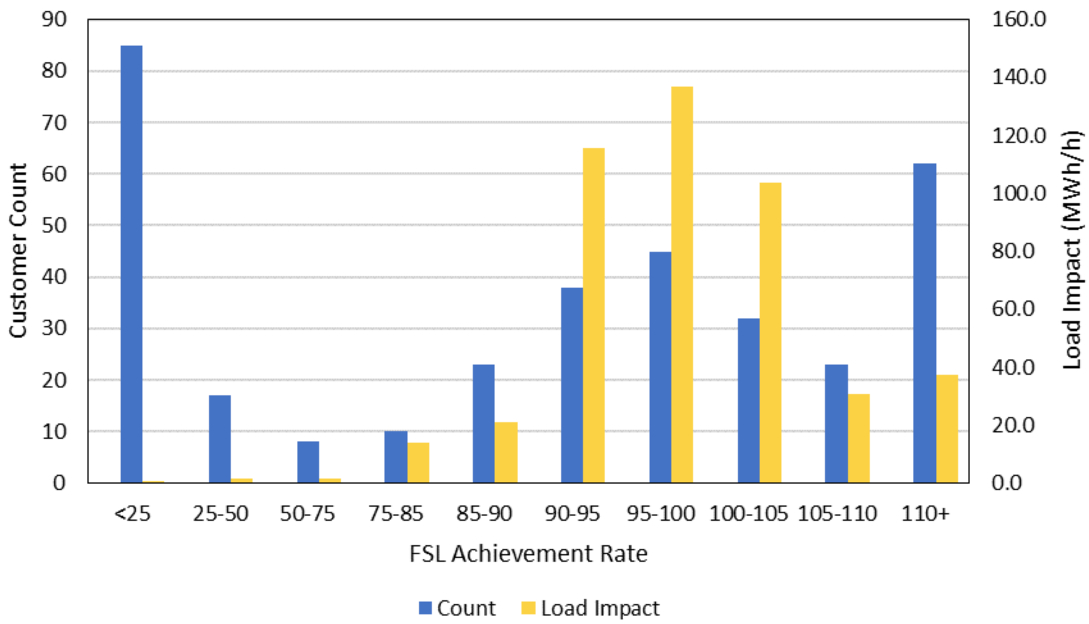


Figure 4.8 illustrates the FSL achievement rate distribution and the load impacts by group for all SCE customers on the typical event day in 2022. The largest portion of load impacts were provided by the customers who had between 95% and 100% FSL achievement rates.

Figure 4.8: FSL Achievement Rates and Load Impacts on the Typical Event Day, *SCE*



4.3 SDG&E Load Impacts

SDG&E had no customers enrolled in BIP and did not call any events during the 2022 program year.

5. EX-ANTE LOAD IMPACT FORECAST

5.1 Ex-ante Load Impact Requirements

The DR Load Impact Evaluation Protocols require that hourly load impact forecasts for event-based DR resources must be reported at the program level and by LCA for the following scenarios:

- For a typical event day in each year; and
- For the monthly system peak load day in each month for which the resource is available;

under both:

- 1-in-2 weather conditions for both utility-specific and CAISO-coincident load conditions, and
- 1-in-10 weather conditions for both utility-specific and CAISO-coincident load conditions;

at both:

- the program level (i.e., in which only the program in question is called), and
- the portfolio level (i.e., in which all demand response programs are called).

5.2 Description of Methods

This section describes the methods used to develop the relevant groups of customers, to develop reference loads for the relevant customer types and event-day types, and to develop load impacts for a typical event day.

5.2.1 Development of Customer Groups

For PG&E's program, customer accounts were assigned to one of three size groups, the relevant LCA, and SubLAP. The three size groups were the following:

- Small – maximum demand less than 20 kW;
- Medium – maximum demand between 20 and 200 kW;
- Large – maximum demand greater than 200 kW.

For SCE, customers are assigned to one of three LCAs, the relevant SubLAP, and by participation option (15 minutes notice or 30 minutes notice).

For SDG&E, we do not distinguish the forecast by size or location.

5.2.2 Development of Reference Loads and Load Impacts

Reference loads and load impacts for all of the above factors were developed in the following series of steps:

1. Define data sources;
2. Estimate ex-ante regressions and simulate reference loads by service account and scenario;
3. Calculate historical FSL achievement rates from ex-post results;
4. Apply achievement rates to the reference loads; and
5. Scale the reference loads using enrollment forecasts.

Each of these steps is described below.

1. Define data sources

The reference loads are developed using data for customers enrolled in BIP at the end of the 2022 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the end of the 2022 program year, based on their estimated ex-post load impacts during program year 2022.[20]

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[20] Current program year loads are used to simulate references loads and load impacts. We assume that the current year provides the most up-to-date information regarding customers' usage behavior, as opposed to averaging across multiple years.

For each service account, we determine the appropriate size group, LCA, and SubLAP. Although BIP customers may be dually enrolled in some other DR programs, the BIP obligation takes precedence on event days, so *program-specific* scenarios (in which each DR program is assumed to be called in isolation) are identical to *portfolio-level* scenarios (in which all DR programs are assumed to have been called) for this program.

2. Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations for each enrolled customer account using data for the current program year. The resulting estimates were used to simulate reference loads for each service account under the various scenarios required by the Protocols (e.g., the typical event day in a utility-specific 1-in-2 weather year). For SDG&E, no customers were enrolled in PY2022, therefore we estimated regression equations using SDG&E loads we considered as representative of a potential BIP customer.

For the summer months, the re-estimated regression equations were similar in design to the ex-post load impact equations described in Section 3.2, differing in two ways. First, the ex-ante models excluded the morning-usage variables. While these variables are useful for improving the accuracy of ex-post load impact estimates, they complicate the use of the equations in ex-ante simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the ex-post and ex-ante models is that the ex-ante models do not use weather variables that incorporate information from prior days.[21] The primary reason for this is that the ex-ante weather days were not selected based on weather from the prior day, restricting the use of lagged weather variables to construct the ex-ante scenarios.

Because BIP events may be called in any month of the year, we estimated separate regression models to allow us to simulate winter reference loads. The winter model is shown below. This model is estimated separately from the summer ex-ante model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table 5.1 describes the terms included in the equation.

$$
\begin{aligned}
Q_t \; = \; & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) \\
& + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{j=2-4,11-12}(b_j^{MONTH} \times MONTH_{j,t}) + e_t
\end{aligned}
$$

[21] In particular, where CDH60 and CDH60_MA24, the 24-hour moving average of CDH60, are used together for summer ex-post regressions, only CDH60 is used for the ex-ante models. Similarly, where CDH60_MA3, the three-hour moving average, is used for ex-post regressions, CDH60 is used for the ex-ante analysis. See Appendix A for weather variable details.

Table 5.1: Descriptions of Terms included in the Ex-ante Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a customer enrolled in BIP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday
$MONTH_{j,t}$	a series of indicator variables for each month
e_t	the error term

Similar to the ex-post analysis, we tested a variety of weather variables included in the above regression equation to determine the best specification for explaining usage on event-like non-event days. Each specification is tested separately by customer group, defined by industry group and weather sensitivity.[22] This process and its results are explained in Appendix A.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. In 2014, two sets of 1-in-2 and 1-in-10 weather years were introduced in the load impact analyses. The sets are differentiated according to whether they correspond to utility-specific conditions or CAISO-coincident conditions. The weather conditions used in prior evaluations corresponded to the utility-specific scenarios.

3. Calculate forecast load impacts

Each service account's FSL achievement rate is defined as the estimated load impact divided by the difference between the reference load and the FSL. A result of 100 percent implies that the customer dropped its load exactly to its FSL. Values greater than 100 percent imply event-day loads lower than the FSL, and values less than 100 percent imply event-day loads higher than the FSL.[23]

The achievement rates are based on the estimates for the most recent observed event day where the customers' reference load was above their FSL.[24] In consultation with the

[22] Customer-specific specifications are tested at an individual level for SDG&E customers.
[23] It is not possible to calculate an achievement rate for customers with reference loads below their FSLs throughout an event period—the event effectively has no effect on them.
[24] Customers with reference loads below their FSL do not provide any information regarding how they would respond to an event in which their reference loads are above their FSL. Therefore, if a customer's reference load is not above their FSL for the latest event that they were called, then we evaluate whether their reference load was higher than their FSL during their previous event, if applicable, and so forth. If a customer does not have their reference load above their FSL for any event, then the average program FSL achievement rate is assumed.

utilities, we determined that using a longer time period (e.g., three years of ex-post load impacts) was not appropriate for this program. Specifically, as customers experience events, they are re-tested if they fail to meet their obligation (i.e., reduce load to the FSL). If they continue to fail, their FSL is increased to the point at which the customer is expected to be able to comply. Therefore, the most recent load impact estimates should provide a good indication of customer performance going forward. In addition, some program design changes make older load impacts less relevant as predictors of future performance. For example, an increased excess energy charge for non-compliance (and a higher excess energy charge for failing to comply during re-test events) may make more recent performance rates higher than performance rates in the more distant past.

[redacted] The forecasted "observed" loads is thus calculated as the difference between the simulated ex-ante reference load and the assumed load impact.

From these customer-level forecasts of reference loads and load impacts, we form results for any given sub-group of customers (e.g., customers over 200 kW in size in the Greater Bay Area), by summing the reference loads and load impacts across the relevant customers.

Because the forecast event window (5:00 to 10:00 p.m. for March and April and 4:00 to 9:00 p.m. for all other months) differs from the historical event window (which can vary across utilities and event days), we need to adjust the historical load impacts for use in the ex-ante study. Load impacts are assumed to be zero until the hour prior to the beginning of the event, at which time we apply the customer's historical FSL performance rate to the forecast window to best represent the pattern of customer response given the limitations of the observed events.[25] We develop forecast load impacts through the end of the event day because customers load reductions often persist well after the end of the event hours.

The uncertainty-adjusted load impacts (i.e., the 10th, 30th, 50th, 70th, and 90th percentile scenarios of load impacts) are based on the standard errors associated with the estimated load impacts from the event day used to determine the customer's event-day achievement rate, scaled to account for the difference between observed and forecast enrollments. The square of these standard errors (i.e., the variance) is added across customers within each required subgroup. Each uncertainty-adjusted scenario is then calculated under the assumption that the load impacts are normally distributed with a mean equal to the total estimated load impact and a variance based on the standard errors in the estimated load impacts. The uncertainty-adjusted load impacts for the average event hour are based on the same event-hour standard errors used in the ex-post study.

4. Apply achievement rates to reference loads for each event scenario.

[25] For PG&E, FSL achievement rates are capped at 100% for dually enrolled ELRP customers if the last historical event was also an ELRP event day. For SCE, when producing Portfolio-level load impacts, FSL achievement rates are capped at 100% for dually enrolled ELRP customers if the last history was also an ELRP event day. For Program-level load impacts, SCE FSL achievement rates are not capped for dually enrolled customers because FSL achievement rates greater than 100% is not uncommon.

In this step, the customer-specific FSL achievement rates are applied to the reference loads for each scenario to produce all of the required estimated event-day loads and load impacts. For customers for which an achievement rate cannot be calculated because either their reference loads were below their FSLs or they are newly enrolled customers, the average achievement rate across all customers is used. The FSL achievement rate is assumed to be 100% for customers that change their FSL in the beginning of 2022. The ex-post FSL achievement rates for each utility are summarized in Appendix B, with the results differentiated by industry group (and hour relative to the called event window).

5. *Apply forecast enrollments to produce program-level load impacts*.

The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2033, with separate enrollments provided at the program and portfolio level (which are identical for BIP), by LCA, SubLAP, and size group. SCE provided annual enrollments for 2023 through 2033. We assume that the ex-post shares of customers by notice level (15 versus 30 minute), LCA, and SubLAP hold throughout the forecast period. SDG&E forecasts an enrollment of one BIP customer until 2033.

5.3 Enrollment Forecasts

PG&E

PG&E forecasts BIP enrollments to decrease from 258 in ex-post to 240 at the beginning of 2023, and then remain constant through 2033. Of these, 171 are in the large customer group (over 200 kW) while the majority of the remaining accounts are in the medium customer group (20 to 200 kW).[26]

SCE

SCE projects 332 BIP enrollments by April 2023, remaining constant through 2033. Of these, 289 customers are forecasted to be enrolled in the BIP-30 program and the remaining 43 customers are enrolled in the BIP-15 program.

SDG&E

SDG&E had no customers enrolled in 2022. [redacted]

5.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information: the hourly profile of reference loads and load impacts for an August event day; the level of load impacts across years; and the distribution of load impacts by local capacity area.

Together, these figures provide a useful indication of the anticipated changes in the forecast load impacts across the various scenarios represented in the Protocol tables.

All tables required by the Protocols are provided in an Appendix.

[26] Only three customers are forecasted to be enrolled in the small customer group (below 20 kW).

5.4.1 PG&E

Figure 5.1 shows the August 2023 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 169 MW, which represents 73 percent of the enrolled reference load. The program-level FSL is 57 MW, compared to the average event-hour program load of 62 MW. The FSL achievement rate of 97% is slightly lower than the achievement rate during the 2022 event.

Figure 5.1: PG&E Hourly Event Day Load Impacts for the August 2023 Event Day in a Utility-Specific 1-in-2 Weather Year

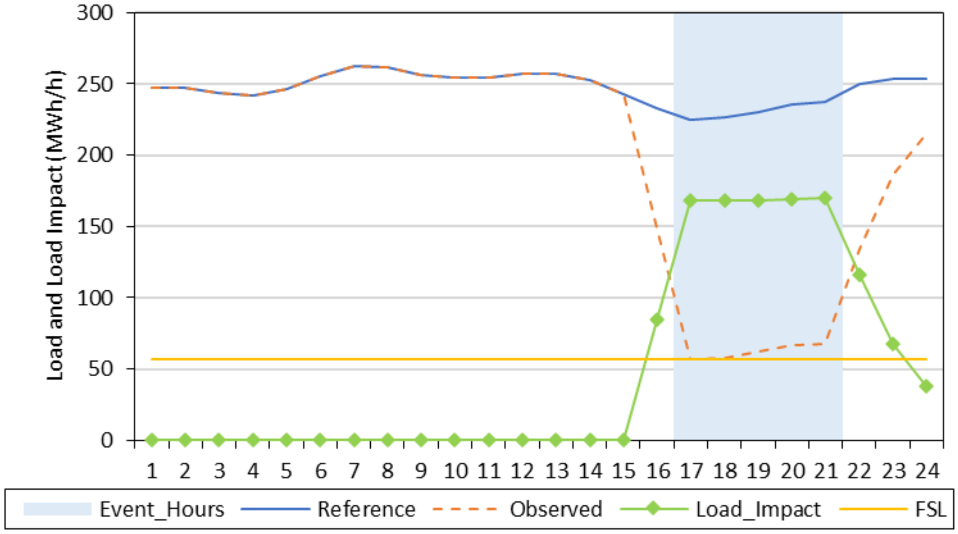


Figure 5.2 shows the share of load impacts by local capacity area, assuming a 2023 August event day in a utility-specific 1-in-2 weather year. [redacted]

Figure 5.2: Share of PG&E Load Impacts by LCA for the August 2023 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.3 illustrates August average event-hour load impact for each forecast scenario and year, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The differences in load impacts between weather scenarios is minimal because the largest customers are not weather sensitive. (Recall that customers are first sorted according to their weather sensitivity.) Impacts increase by 2 MW in 2026 due to the end of ELRP and then remain constant through 2033 as there is no forecasted change in enrollments.[27] No COVID-19 related adjustments were made to the forecast.

[27] The BIP ex-post ad ex-ante load impact is capped at a 100% FSL achievement rate for customers that are dually enrolled in BIP and ELRP. Any load impact above the 100% FSL achievement rate is credited towards ELRP. After the end of ELRP in November 2025, BIP load impacts are allowed to exceed the 100% FSL achievement rate for customers who have demonstrated the ability to surpass this threshold prior to enrollment in ELRP.

Figure 5.3: Average August Ex-ante Load Impacts by Scenario and Year, *PG&E*

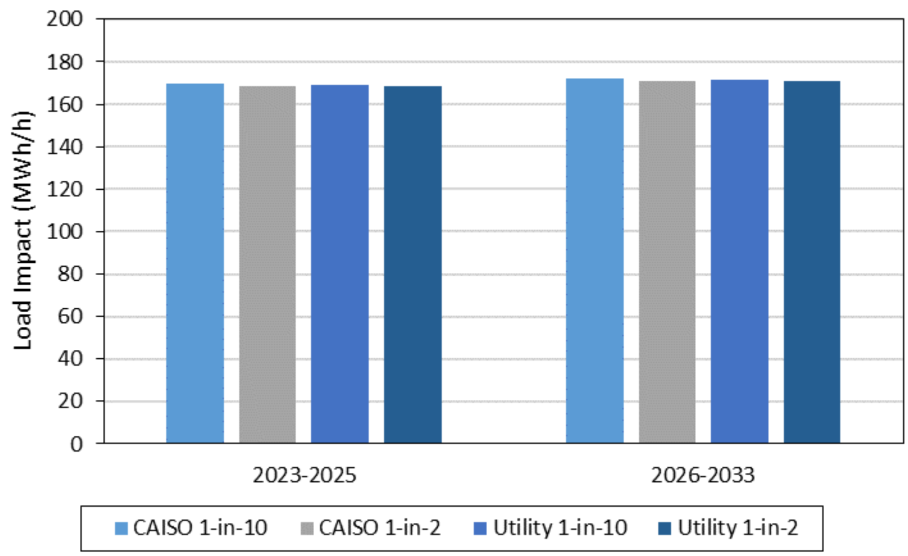


Table 5.2 shows the aggregate and per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2023 event day.

Table 5.2: Ex-ante August 2023 Load Impacts by Scenario, *PG&E*

Weather Year	Enrollment	Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
		Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	240	230.9	168.7	962.3	702.9	73.0%
Utility 1-in-10	240	231.5	169.2	964.8	705.1	73.1%
CAISO 1-in-2	240	230.8	168.6	961.5	702.6	73.1%
CAISO 1-in-10	240	231.9	169.6	966.3	706.6	73.1%

5.4.2 SCE

Figure 5.4 shows the August 2023 forecast load impacts in a utility-specific 1-in-2 weather year.[28] Event-hour (4:00 to 9:00 p.m.)[29] load impacts average 500 MW, which represents 82 percent of the 611 MW reference load. The program-level FSL of 118 MW, compared to the average event-hour program load of 111 MW, results in an FSL achievement rate of 101%. The FSL achievement rate is higher than shown in our ex-post summary because the customers that remained enrolled in BIP for the ex-ante

[28] The following section presents the program level BIP ex-ante forecast. A portfolio level forecast is provided in the ex-ante table generators. Portfolio impacts represent the load impacts attributed to BIP on days in which both a BIP event and an ELRP event are called. To calculate portfolio impacts we cap FSL achievement rates at 100% for dually enrolled customers when both programs are called. All impacts above 100% are attributed to ELRP for those customers and not represented in BIP portfolio forecasts.

[29] Starting in 2023, the event window shifts from 5:00 PM to 10:00 PM in March and April.

forecast had higher performance than those that were de-enrolled. Additionally, the ex-post event had an FSL achievement rate of 103% during the second and third full event hours. A longer ex-ante event window results in more event hours when customers achieve the higher FSL achievement rate.

Figure 5.4: SCE Hourly Event Day Load Impacts for the August 2023 Event Day in a Utility-Specific 1-in-2 Weather Year

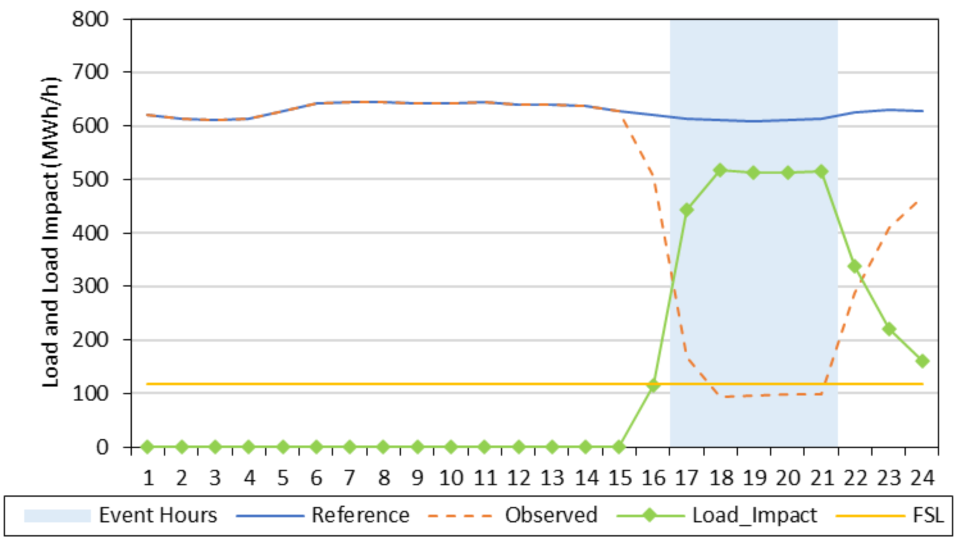


Figure 5.5 shows the share of load impacts by local capacity area for an August 2023 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 68 percent of the load impacts.

Figure 5.5: Share of SCE Load Impacts by LCA for the August 2023 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.6 shows the share of load impacts by notification time, assuming an August 2023 event day in a utility-specific 1-in-2 weather year. Customers required to reduce demand to their FSL within 15 minutes of a Notice of Interruption make up 13 percent of customers but account for 36 percent of the load impacts.

Figure 5.6: Share of SCE Load Impacts by Notification Time for the August 2023 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.7 illustrates August event day load impacts for each forecast scenario by year, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The load impacts are constant over the forecast period 2023-2033 due to the steady enrollment forecast. The load impact is not sensitive to weather conditions. For example, the minimum and maximum load impacts are 500 MW and 501 MW, respectively.

Figure 5.7: Average August Ex-ante Load Impacts by Scenario and Year, *SCE*

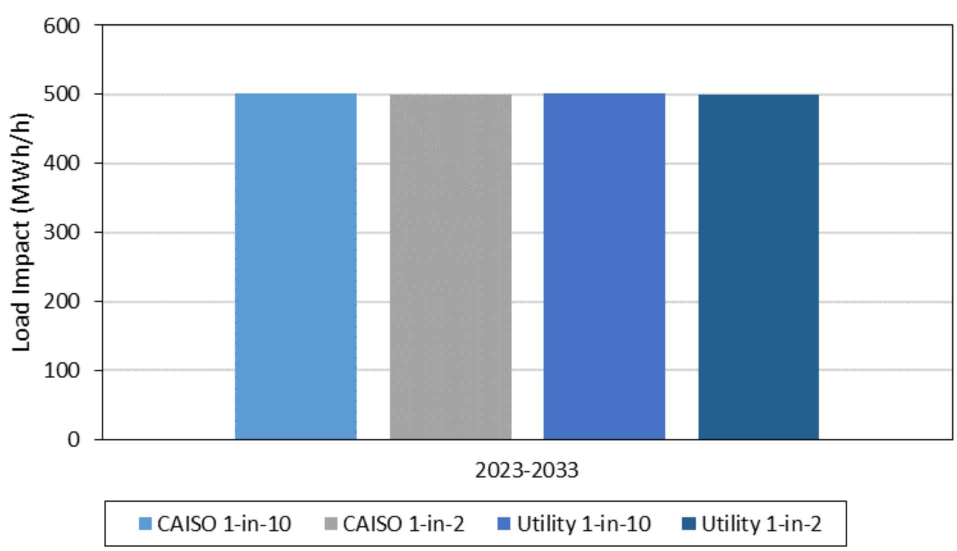


Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2023 event day.

Table 5.3: Per-customer Ex-ante August 2023 Load Impacts by Scenario, *SCE*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	1,841	1,507	82%
Utility 1-in-10	1,843	1,509	82%
CAISO 1-in-2	1,838	1,505	82%
CAISO 1-in-10	1,842	1,508	82%

5.4.3 SDG&E

SDG&E proposed to sunset the BIP program in the 2024-2027 demand response application, however they are still waiting for an official decision. In 2022 there were no customers enrolled in BIP. We build ex-ante forecasts using what we believe a representative load shape would be if a customer were to enroll in BIP.

Figure 5.8 shows the load impact forecast for an August 2023 event day in a utility-specific 1-in-2 weather year. [redacted]

Figure 5.8: SDG&E Hourly Event Day Load Impacts for the August 2023 Event Day in a Utility-Specific 1-in-2 Weather Year

[redacted]

Figure 5.9 illustrates 2023 to 2033 August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The enrollment forecasts one customer from 2023 through 2033, resulting in load impacts that are identical between years. [redacted]

Figure 5.9: Average August Ex-Ante Load Impacts by Scenario and Year, *SDG&E*

[redacted]

Table 5.4 shows the per-customer reference loads and load impacts by weather condition (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak) for the August 2023 event day. The reference load does not vary between weather scenarios because the load profile used for simulation was not weather sensitive. [redacted]

Table 5.4: Per-customer Ex-ante August 2023 Load Impacts by Scenario, *SDG&E*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	[redacted]		
Utility 1-in-10			
CAISO 1-in-2			
CAISO 1-in-10			

6. COMPARISONS OF RESULTS

In this section, we present several comparisons of load impacts for each utility:

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

In the above "current study" refers to this report, which is based on findings from the 2022 program year; and "previous study" refers to the report that was developed following the 2021 program year. Ex-post reference loads and load impacts are averaged over the associated event window (excluding partial event hours). Ex-ante reference loads and load impacts are averaged over the Resource Adequacy (RA) window (i.e., HE 17-21).

6.1 PG&E

6.1.1 Previous versus current ex-post

Table 6.1 shows the average event-hour reference loads and load impacts for PY2021 and PY2022. The PY2021 load impacts are based on the one full event hour (HE 20) during the typical event day (July 9th, 2021). The PY2022 load impacts are based on the two full event hours (HE 19-20) on the September 6th typical event day.

Table 6.1: Comparison of Ex-post Impacts in PY2021 and PY2022, *PG&E*

Level	Outcome	Ex-post PY2021	Ex-post PY2022
Total	# Customers	293	258
	Reference (MWh/h)	238	203
	Load Impact (MWh/h)	155	149
Per SAID	Reference (kWh/h)	813	787
	Load Impact (kWh/h)	531	577
	% Load Impact	65.3%	73.4%

There are fewer service accounts in PY2022, resulting in a lower aggregate reference load and load impact. Per customer reference load is also lower in PY2022. The per customer load impacts, percentage load impact and FSL achievement rate are all higher in PY2022 in part due to lower reported load impacts in 2021 because 68 customers were called late to the PY2021 event. The FSL achievement rate was 97% in PY2022 and 93% in PY2021 (after adjusting for late notifications). Customers that remained on the program in both years exhibited an increase in FSL achievement rate (83% vs 100%). Their total load impact increased from 143 to 146 MW. [redacted] The aggregate reference loads for these customers decreased from 217 MW to 191 MW, but their FSL remained similar at just over 45 MW. Customers who joined the program added 2 MW of load impact in 2022 while customers who left the program after 2021 had provided 12 MW during the 2021 event.

6.1.2 Previous versus 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 6.2 contains this comparison for the August 2023 utility-specific 1-in-2 typical event day forecast.

Table 6.2: Comparison of Ex-ante Impacts from PY2022 and PY2023 Studies, *PG&E*

Level	Outcome	Ex-ante 2023 Typical Event Day, *Previous Study*	Ex-ante 2023 Typical Event Day, *Current Study*
Total	# Customers	278	240
	Reference (MWh/h)	245	231
	Load Impact (MWh/h)	175	169
	FSL (MW)	56	57
Per SAID	Reference (kWh/h)	880	961
	Load Impact (kWh/h)	628	702
	% Load Impact	71.4%	73.1%

PG&E BIP enrollment decreased by 38 customers, from 278 to 240 customers. The aggregate reference load decreased by 14 MW. The per customer reference loads and load impacts increase in part because customers who leave the program tend to be smaller customers. [redacted] Forecast reference loads were similar for customers that remain on the program for both years of the ex-ante analysis. The FSL achievement rate was forecast to be 93% in the PY2021 ex-ante analysis. In the PY2022 ex-ante analysis, the FSL achievement rate was forecast to be 97% due to higher performance from customers during PY2022 ex-post events.

6.1.3 Previous ex-ante versus current ex-post

Table 6.3 provides a comparison of the ex-ante forecast of 2022 load impacts prepared following PY2021 and the ex-post PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the typical event day in 2022, September 6th.

Table 6.3: Comparison of Previous Ex-ante and Current Ex-post Impacts, *PG&E*

Level	Outcome	Ex-ante 2022 Typical Event Day, Previous Study	Ex-post PY2022
Total	# Customers	268	258
	Reference (MWh/h)	236	203
	Load Impact (MWh/h)	170	149
Per SAID	Reference (kWh/h)	881	787
	Load Impact (kWh/h)	633	577
	% Load Impact	71.8%	73.4%

The total number of customers enrolled in the ex-post event in PY2022 is 10 lower than the number of forecast customers. The aggregate reference load and load impact are lower in the current ex-post event than in the previous ex-ante forecast. The FSL achievement rate is 4% higher in the current ex-post study than in the previous ex-ante forecast. Reference loads are significantly lower, due in part to September 6th following Labor Day and thus having lower loads (similar to Mondays which were about 10 MW lower than other midweek days during the summer of PY2022). Additionally, the September 6th event day happened to be about 15 MW lower than other Mondays during the PY2022 program year. These contributed to a lower aggregate program reference load and load impacts despite an increase in percent load impact and FSL achievement rate.

6.1.4 Current ex-post versus current ex-ante

Table 6.4 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent the 2022 typical event day with utility-specific 1-in-2 weather conditions. The enrollments decreased from 258 to 240. The aggregate FSL achievement rate decreases from roughly 98% in the ex-post analysis to 97% in the ex-ante forecast. The average per-customer reference load and load impact is significantly larger in the ex-ante forecast because customers that remain on the program are larger, on average, than customers that left [redacted]

Table 6.4: Comparison of Current Ex-post and Current Ex-ante Impacts, *PG&E*

Level	Outcome	Ex-post PY2022	Ex-ante 2023 Typical Event Day, Current Study
Total	# Customers	258	240
	Reference (MWh/h)	203	231
	Load Impact (MWh/h)	149	169
	FSL (MWh/h)	51	57
Per SAID	Reference (kWh/h)	787	961
	Load Impact (kWh/h)	577	702
	% Load Impact	73.4%	73.1%

Table 6.5 documents the various potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.5: PG&E Ex-post versus Ex-ante Factors

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperature of 96 degrees Fahrenheit.	93 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day.	Little to no impact because most customers are categorized as not weather sensitive.
Event window	HE 19-20 on 9/6/2022.	HE 17-21.	Periods corresponding to larger reference loads result in larger load impacts. Reference loads are similar between these periods.
Event Day of the Week	Monday Event.	Average Weekday.	This can have an impact on reference loads. Mondays tend to have lower reference loads than average weekday loads. Higher ex-ante average weekday loads results in higher load impacts. Weekend events would have lower reference loads with lower load impacts albeit likely higher FSL achievement rates.
% of resource dispatched	All customers dispatched.	Assume all customers are called.	Similar load impacts. The ex-ante method assumes that all enrolled customers are dispatched.
Enrollment	258 customers during 2022 event days.	240 customers.	Lower enrollment reduces the aggregate reference load and load impact; however, the per-customer reference load and FSL achievement rate are higher due to size and performance of remaining customers.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day that a customer has reference loads above their FSL.	Possible difference between simulated ex-ante and estimated ex-post reference loads. In this case, however, the aggregate differences are minimal for the average weekday.

6.2 SCE

6.2.1 Previous versus current ex-post

Table 6.6 compares ex-post load impacts between the July 9th event day in PY2021 and the September 6th event day in PY2022. One BIP event was called in PY2021 compared to three events called in PY2022. The September 6th event day is used as a comparison because it was the non-holiday weekday event with the longest event window. The PY2021 event was called during the hours 5:50 to 8:53 p.m. while the PY2022 event was called from 5:00 to 8:43 p.m.

Table 6.6: Comparison of Ex-post Impacts in PY2021 and PY2022, *SCE*

Level	Outcome	Ex-post *Previous Study*	Ex-post *Current Study*
Total	# SAIDs	344	343
	Reference (MWh)	551	590
	Load Impact (MWh/h)	409	463
	FSL (MW)	115	122
Per SAID	Reference (kWh/h)	1,603	1,721
	Load Impact (kWh/h)	1,188	1,349
	% Load Impact	74.1%	78.4%

Enrollment decreased from 344 accounts to 343, however aggregate reference load and load impacts increased during the PY2022 typical event. The per-customer reference load is larger in PY2022 because customers that remained enrolled on BIP were larger, on average. 23 customers left the program who had an aggregate load impact of 9 MW in the PY2021 event. 24 new customers joined the program who had an aggregate 13 MW of additional load impact during the PY 2022 typical event day. Customers who stayed on the program in 2022 had a Load Impact of 449 MW, which was 49 MW higher than the 399 MW impact during the PY2021 event. [redacted] This substantive increase from customers remaining on the program could in part be because the PY2021 event had unusually low reference loads on the event day. Additionally, this increase in reference loads could be due to customers returning to pre COVID consumption levels when compared to PY2020 and PY2021.

6.2.2 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante program level forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2023 utility-specific 1-in-2 typical event day. The results are averaged over the RA window, 4 to 9 p.m.

Table 6.7: Comparison of Ex-ante Impacts from PY2021 and PY2022 Studies, *SCE*

Level	Outcome	Ex-ante 2023 Typical Event Day, *Previous Study*	Ex-ante 2023 Typical Event Day, *Current Study*
Total	# Customers	341	332
	Reference (MWh/h)	624	611
	Load Impact (MWh/h)	511	500
	FSL (MWh/h)	112	118
Per SAID	Reference (kWh/h)	1,828	1840
	Load Impact (kWh/h)	1,499	1507
	% Load Impact	82.0%	81.9%

The enrollment numbers decreased by 9 customers between the previous and current studies. The total reference load is lower in the current study because of customers that left the program, whereas per-customer reference load remains similar albeit slightly larger in the current study. Customers that were on the program in both years have similarly forecasted reference loads. In year PY2021 we adjusted reference loads for COVID based on a utility provided glidepath. We do not make a COVID adjustment to reference loads in the PY2022 ex-ante forecast. Because the reference load increased significantly from PY2021 ex-post to PY2022 ex-post, our ex-ante forecast reference loads are similar for customers who remain on the program across years, indicating that customers did return to pre-COVID levels. The aggregate load impact is 11 MW lower in the current study, in part due to smaller customer counts. The load impact percentage is the same between the previous and current study.

6.2.3 Previous ex-ante versus current ex-post

Table 6.8 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 the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the September 6th, 2022, event day and are averaged over full event hours only (HE 18-20).

Table 6.8: Comparison of Previous Ex-ante and Current Ex-post Impacts, *SCE*

Level	Outcome	Ex-ante 2022 Typical Event Day, *Previous Study*	Ex-post *PY2022*
Total	# Customers Reference (MWh/h) Load Impact (MWh/h) FSL (MW)	341 614 502 112	343 590 463 122
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact	1,800 1,471 81.7%	1,721 1,349 78.4%

The FSL achievement rate was 100% in the previous forecast and 99% during the PY2022 ex-post event. Thus, the differences in load impacts are a result of enrollments and reference loads. Reference loads were lower during the PY2022 ex-post event because it was a Tuesday directly following a holiday and therefore had a lower load profile (similar to a Monday). Monday and Friday load profiles are generally less than other weekday loads that serve as the basis for simulating ex-ante reference loads. The Wednesday, September 7th, 2022, event had a reference load and load impact of 600 MW and a 490 MW, respectively, which resembles more closely the ex-ante forecast from PY2021. Lastly, the FSL increased from 112 MW to 122 MW resulting in a lower load impact and percentage load impact.

6.2.4 Current ex-post versus current ex-ante

Table 6.9 compares the ex-post and ex-ante load impacts from this study, where the ex-post impacts are based on the September 6th, 2022, event day and the ex-ante load impact represents the 2023 typical event day in a utility-specific 1-in-2 weather year.

Table 6.9: Comparison of Current Ex-post and Current Ex-ante Impacts, *SCE*

Level	Outcome	Ex-post *PY2022*	Ex-ante 2023 Typical Event Day, *Current Study*
Total	# Customers Reference (MWh/h) Load Impact (MWh/h) FSL (MWh/h)	343 590 463 122	332 611 500 118
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact	1,721 1,349 78.4%	1840 1507 81.9%

The forecast calls for a reduction in enrollment of eleven customers. Loads are scaled to enrollments based on customers remaining on the program that have load data. The per-customer reference load increases because customers who remained on BIP were larger than those that left. Additional impact comes from longer event hours during the ex-ante RA window where the FSL achievement rate is higher, as described below. Lastly, the September 6th event day was similar to a Monday in terms of its load shape which typically has lower usage than other days that are used to build the ex-ante forecast. This difference provides for roughly 25 MW in additional reference load and load impact.

The FSL achievement rate is 99% in ex-post and 101% in ex-ante. The increased FSL achievement rate is reflective of a longer RA window than the ex-post event. The FSL achievement rate was 103% in ex-post by the second hour of the event, while the average over all event hours is 99% due to the first full event hour FSL achievement rate being 89%. The ex-ante achievement rate has more hours following the second event hour (i.e., HE 18-21) that are assumed to remain at 104%, thus increasing the entire event average.

Table 6.10 lays out all the potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.10: SCE Ex-post versus Ex-ante Factors

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperatures ranging from 85 to 94 degrees Fahrenheit.	Temperatures ranging from 84 to 93 degrees Fahrenheit.	Higher temperatures result in higher references loads for weather sensitive customers. There is some impact on total reference load although it does not affect the majority of the program due to the lack of weather sensitivity for most customers.
Event window	HE 18-20 on 9/6/2022.	HE 17-21.	The slightly earlier ex-ante event window tends toward slightly higher reference loads and load impacts relative to the ex-post window.
Event Day of the Week	Tuesday event following holiday.	Average Weekday.	Tuesday ex-post event following Labor Day had lower reference loads than the average weekday that serves as the basis for ex-ante. Ex-ante reference loads will thus be larger and have larger load impacts than ex-post.
% of resource dispatched	All customers were called.	Assume all customers are called.	None.
Enrollment	343 customers enrolled during the 9/6/2022 event.	332 customers in August 2023.	Lower enrollment reduces the aggregate reference load and load impact; however, the per-customer reference load and FSL achievement rate are higher due to size and performance of remaining customers.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day that a customer has reference loads above their FSL.	Possible difference between simulated ex-ante and estimated ex-post reference loads. In this case, however, the aggregate differences are minimal for the average weekday.

6.3 SDG&E

SDG&E did not call any ex-post events during the PY2022 program year. Therefore, the only relevant reconciliation is the comparison of ex-ante impacts from PY2021 and PY2022.

6.3.1 Previous versus 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 6.11 presents this comparison for the ex-ante forecasts of the utility-specific 1-in-2 August 2023 typical event day.

Table 6.11: Comparison of Ex-ante Impacts from PY2021 and PY2022 Studies, *SDG&E*

Level	Outcome	Ex-ante 2023 Typical Event Day, *Previous Study*	Ex-ante 2023 Typical Event Day, *Current Study*
Total	# Customers	[redacted]	[redacted]
	Reference (MWh/h)		
	Load Impact (MWh/h)		
	FSL (MWh/h)		
Per SAID	Reference (kWh/h)		
	Load Impact (kWh/h)		
	% Load Impact		

[redacted]

7. RECOMMENDATIONS

BIP continues to perform well, with its customers providing substantial load impacts with short notice when events are called. SDG&E did not call any events in PY2022. PG&E and SCE each called one weekend/holiday event and two weekday events. The weekend/holiday events had higher FSL achievement rates but lower total impacts because of lower weekend reference loads. Consecutive event days resulted in lower observed loads compared to normal usage as some customers kept loads low. PG&E saw a decrease in enrollment which led to decreased load impacts. SCE had increased impacts due to increased reference loads when compared to PY2021.

APPENDICES

The following Appendices accompany this report. Appendix A is the validity assessment associated with our ex-post load impact evaluation. Appendix B contains the FSL achievement rates for each utility, by industry group. The additional appendices are Excel files that can produce the tables required by the Protocols. The Excel file names are listed below.

BIP Study Appendix C	6.a PG&E_2022_BIP_Ex_Post
BIP Study Appendix D	PY2022_SCE_BIP_Ex_Post_Load_Impacts
BIP Study Appendix E	6.b PGE_2022_BIP_Ex_Ante
BIP Study Appendix F	PY2022_SCE_BIP_Ex_Ante_Load_Impacts
BIP Study Appendix G	SDG&E 2022 BIP Ex-Ante

APPENDIX A. VALIDITY ASSESSMENT

A.1 Customer Weather Sensitivity

Customer-specific regressions are implemented to categorize customers as weather sensitive or not. Weather sensitive customers change usage in response to changes in the weather, while non-weather sensitive customers do not. Determining which customers are non-weather sensitive allows for a more parsimonious regression model by not including weather variables as explanatory variables for these customers. The following regression specification is used to determine whether a customer is weather sensitive:

$$Q_t = b^{Weather} \times Weather_t + \sum_{i=2}^{5}\left(b_i^{DTYPE} \times DTYPE_{i,t}\right) + \sum_{i=7}^{9}\left(b_i^{MONTH} \times MONTH_{i,t}\right) + \sum_{i=1}^{EVT}\left(b_i^{EVT} \times EVT_{i,t}\right) + e_t$$

where Q_t represents the average customer usage during hours-ending 13 through 20 on day t in the summer months of June through September. $DTYPE_{i,t}$ represents the day of week, while $MONTH_{i,t}$ represents each month. The $EVT_{i,t}$ variables control for any event days a customer faces (BIP, CPP, etc.). The variable of importance is $Weather_t$, which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant for any of the three separate weather specifications. Tables A.1 through A.5 provide the number of customers that are categorized as weather sensitive by industry group and utility. We separately categorize customers as weather sensitive by weekday and weekend/holiday. Additionally, we separately classify customers who provided voluntary reductions for SCE on weekends as we exclude morning load variables from their customer specific regressions in order to not capture the effects of their voluntary reduction on reference loads. The proportion of PG&E customers classified as non-weather sensitive was 78% on weekdays. The proportion of SCE customers classified as non-weather sensitive was 75% (although non-voluntary reducers were 89% non-weather sensitive on the weekend event).

Table A.1: Weather Sensitive Customer Count by Industry Type, PG&E Weekday

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	18	83	101	18%
2. Manufacturing	9	61	70	13%
3. Wholesale, Transportation, Utilities	23	54	77	30%
4. Retail	4	0	4	100%
5. Offices, Hotels, Health, Services	1	2	3	33%
6. Schools	1	0	1	100%
8. Other	1	1	2	50%
Total	**57**	**201**	**258**	**22%**

Table A.2: Weather Sensitive Customer Count by Industry Type, PG&E Weekend/Holiday

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	17	84	101	17%
2. Manufacturing	15	55	70	21%
3. Wholesale, Transportation, Utilities	12	65	77	16%
4. Retail	4	0	4	100%
5. Offices, Hotels, Health, Services	1	2	3	33%
6. Schools	1	0	1	100%
8. Other	0	2	2	0%
Total	**50**	**208**	**258**	**19%**

Table A.3: Weather Sensitive Customer Count by Industry Type, SCE Weekday

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	3	27	30	10%
2. Manufacturing	57	175	232	25%
3. Wholesale, Transportation, Utilities	17	43	60	28%
4. Retail	1	1	2	50%
5. Offices, Hotels, Health, Services	4	1	5	80%
6. Schools	1	0	1	100%
7. Entertainment, Other Services, Government	0	1	1	0%
8. Other	4	8	12	33%
Total	**87**	**256**	**343**	**25%**

Table A.4: Weather Sensitive Customer Count by Industry Type, SCE Weekend/Holiday (Normal Customers)

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	3	23	26	12%
2. Manufacturing	59	163	222	27%
3. Wholesale, Transportation, Utilities	13	45	58	22%
4. Retail	2	0	2	100%
5. Offices, Hotels, Health, Services	1	4	5	20%
6. Schools	0	0	0	0%
7. Entertainment, Other Services, Government	0	1	1	0%
8. Other or unknown	3	7	10	30%
Total	**81**	**243**	**324**	**25%**

Table A.5: Weather Sensitive Customer Count by Industry Type, SCE Weekend/Holiday (Voluntary Reductions Customers)

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	0	4	4	0%
2. Manufacturing	1	9	10	10%
3. Wholesale, Transportation, Utilities	0	2	2	0%
4. Retail	0	0	0	0%
5. Offices, Hotels, Health, Services	0	0	0	0%
6. Schools	1	0	1	100%
7. Entertainment, Other Services, Government	0	0	0	0%
8. Other or unknown	0	2	2	0%
Total	**2**	**17**	**19**	**11%**

A.2 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the ex-post load impact analysis. A separate set of specifications was also tested to be used in the ex-ante load impact analysis.[30] The tests are conducted using average-customer data by industry group and weather-sensitivity. Separate model specifications were tested for weather sensitive and non-weather sensitive customers. Model variations for weather sensitive customers include 17 combinations of weather-related variables for ex-post and 7 combinations for ex-ante*;* 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 3.2.1 for ex-post and Section 5.2.2 for ex-ante. The weather variables include: temperature-humidity index (THI)[31]; heat index (HI)[32]; cooling degree hours (CDH)[33], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of

[30] Recall that the ex-ante set of specifications eliminate the use of morning load variables as well as weather variables using information from prior days.

[31] THI = $T - 0.55 \times (1 - HUM) \times (T - 58)$ 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").

[32] 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.

[33] 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.

CDH; cooling degree days (CDD)[34], 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 tested for weather sensitive customers is provided in Table A.6, including 17 specifications for the ex-post analysis and 7 for ex-ante analysis.

Table A.6: Weather Variables Included in the Tested Specifications for Weather Sensitive Customers

Model Number	Ex-post Analysis	Ex-ante Analysis
1	THI	CDH60
2	HI	CDH65
3	CDH60	CDD60
4	CDH65	CDD65
5	CDD60	Mean17
6	CDD65	CDH60, Mean17
7	Mean 17	CDH65, Mean17
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 tested 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 and interactions of month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is shown in Table A.7, 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. The morning load variable is also excluded when estimating ex-post event that are consecutive event days or if customers were requested to provide voluntary reductions before an event.

[34] 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.

Table A.7: Variables Included in the Tested Specifications for Non-Weather Sensitive Customers

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

The model variations are evaluated according to two primary validation tests:

1. Ability to predict usage on event-like *non-event days*. Specifically, we identified a set of days that were 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 all of the test days. 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.

2. Performance on *synthetic* event days (e.g., event-like non-event days that are treated as event days in estimation), to test for "event" coefficients that demonstrate statistically significant bias, as opposed to expected non-significance, since customers have no reason to modify usage on days that are not actual events. This is an extension of the previous test. The same test days are used, with a set of hourly "synthetic" event variables included in addition to the rest of the specification to test whether non-zero load impacts are estimated for these days. A successful test involves synthetic event load impact coefficients that are not statistically significantly different from zero.

A.2.1 Selection of Event-Like Non-Event Days

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

We selected days according to the average typical event-hours, omitting holidays, weekends, event days for programs in which BIP customers are dually enrolled (e.g., CPP), Flex Alert days, and Public Safety Power Shutoff days. For the most part, the selection involved selecting the hottest qualifying days. Table A.8 lists the event-like non-event days selected.

Table A.8: List of Event-Like Non-Event Days by IOU

PG&E	PG&E (Weekend)	SCE	SCE (Weekend)
6/10/2022	7/10/2022	6/27/2022	5/30/2022
6/21/2022	7/16/2022	7/15/2022	6/26/2022
6/23/2022	7/17/2022	7/22/2022	7/4/2022
6/24/2022	8/20/2022	8/11/2022	7/16/2022
7/11/2022	9/11/2022	8/12/2022	8/7/2022
7/18/2022		8/15/2022	8/13/2022
8/3/2022		8/19/2022	8/14/2022
8/16/2022		8/23/2022	
		8/30/2022	

A.2.2 Results from Tests of Alternative Weather Specifications

For each industry group, we tested 17 different sets of weather variables for weather sensitive customers and five different specifications for non-weather sensitive customers. The aggregate load used in conducting these tests was constructed separately for each industry group and weather sensitivity categorization. Only customers who were called on at least one event day are included.

The tests are conducted by estimating one model for every industry, weather sensitivity, specification (17 for weather sensitive customers, 5 for non-weather sensitive 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.

Tables A.9 through A.13 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for each industry by weather sensitivity type (specified in Tables A.4 and A.5) for specifications in the ex-post analysis.

Table A.9: Specification Test Results for the Ex-Post analysis, PG&E Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	17	0%	3%	18
	2. Manufacturing	4	-1%	3%	9
	3. Wholesale, Transportation, Utilities	5	-1%	6%	23
	4. Retail	6	1%	1%	4
	5. Offices, Hotels, Health, Services	7	1%	4%	1
	6. Schools	7	2%	4%	1
	8. Other	16	0%	13%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	-1%	3%	83
	2. Manufacturing	2	0%	3%	61
	3. Wholesale, Transportation, Utilities	1	1%	5%	54
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	0	3%	58%	2
	6. Schools	n/a	n/a	n/a	0
	8. Other	1	13%	19%	1

Table A.10: Specification Test Results for the Ex-Post analysis, PG&E Weekend

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	1%	2%	17
	2. Manufacturing	4	0%	2%	15
	3. Wholesale, Transportation, Utilities	7	1%	5%	12
	4. Retail	4	0%	2%	4
	5. Offices, Hotels, Health, Services	3	1%	4%	1
	6. Schools	3	1%	4%	1
	8. Other	n/a	n/a	n/a	0
Non-Weather Sensitive	1. Agriculture, Mining, Construction	4	1%	2%	84
	2. Manufacturing	4	-1%	3%	55
	3. Wholesale, Transportation, Utilities	5	2%	3%	65
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	5	0%	5%	2
	6. Schools	n/a	n/a	n/a	0
	8. Other	4	55%	66%	2

Table A.11: Specification Test Results for the Ex-Post analysis, SCE Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	17	-2%	9%	3
	2. Manufacturing	6	-1%	6%	57
	3. Wholesale, Transportation, Utilities	16	0%	2%	17
	4. Retail	7	1%	2%	1
	5. Offices, Hotels, Health, Services	16	1%	3%	4
	6. Schools	3	0%	6%	1
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	0
	8. Other or unknown	16	0%	6%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	4%	15%	27
	2. Manufacturing	2	2%	5%	175
	3. Wholesale, Transportation, Utilities	2	2%	4%	43
	4. Retail	2	0%	2%	1
	5. Offices, Hotels, Health, Services	0	1%	2%	1
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	0	16%	33%	1
	8. Other or unknown	0	2%	8%	8

Table A.12: Specification Test Results for the Ex-Post analysis, SCE Weekend/Holiday (Non-Voluntary Reducers)

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	6	2%	6%	3
	2. Manufacturing	6	0%	5%	59
	3. Wholesale, Transportation, Utilities	5	-1%	3%	13
	4. Retail	7	1%	3%	2
	5. Offices, Hotels, Health, Services	2	5%	30%	1
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	0
	8. Other or unknown	6	0%	3%	3
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	0%	2%	23
	2. Manufacturing	4	0%	4%	163
	3. Wholesale, Transportation, Utilities	4	0%	3%	45
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	3	0%	1%	4
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	4	4%	25%	1
	8. Other or unknown	4	-1%	3%	7

Table A.13: Specification Test Results for the Ex-Post analysis, SCE Weekend/Holiday (Voluntary Reducers)

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	2. Manufacturing	16	0%	5%	1
	6. Schools	4	1%	3%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	9%	28%	4
	2. Manufacturing	0	4%	7%	9
	3. Wholesale, Transportation, Utilities	2	-1%	63%	2
	8. Other or unknown	2	8%	12%	2

Tables A.14 through A.15 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and customer count of the winning specification (as shown in Tables A.4 and A.5) for each industry by weather sensitivity type for specifications included in the ex-ante analysis.

Table A.14: Specification Test Results for the Ex-Ante analysis, PG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	3%	3%	36
	2. Manufacturing	5	11%	12%	13
	3. Wholesale, Transportation, Utilities	5	-11%	12%	24
	4. Retail	4	1%	1%	4
	5. Offices, Hotels, Health, Services	5	1%	4%	1
	6. Schools	5	2%	4%	1
	8. Other	2	-1%	11%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	0%	4%	73
	2. Manufacturing	1	0%	3%	61
	3. Wholesale, Transportation, Utilities	1	1%	5%	56
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	0	3%	57%	2
	6. Schools	n/a	n/a	n/a	0
	8. Other	0	12%	19%	1

Table A.15: Specification Test Results for the Ex-Ante analysis, SCE

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	2	-3%	6%	3
	2. Manufacturing	2	0%	3%	65
	3. Wholesale, Transportation, Utilities	5	0%	2%	21
	4. Retail	5	1%	2%	2
	5. Offices, Hotels, Health, Services	6	1%	3%	4
	6. Schools	1	0%	7%	1
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	0
	8. Other or unknown	6	0%	6%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	5%	14%	27
	2. Manufacturing	2	2%	5%	171
	3. Wholesale, Transportation, Utilities	0	3%	4%	45
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	0	1%	2%	1
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	0	16%	33%	1
	8. Other or unknown	2	2%	8%	8

A.2.3 Synthetic Event Day Tests

For the specification selected using the testing described in Section A.2.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data by industry and weather sensitivity (averaged across all applicable customers), including a set of 24 hourly "synthetic" event-day variables. These variables equaled one on the days listed in Table A.8, with a separate estimate for each hour of the day.

If the model produces synthetic event-day coefficients that are not statistically significantly different from zero, the test provides some added confidence that our actual event-day coefficients are not biased. That is, the absence of statistically significant results for the synthetic event days indicates that the remainder of the model is capable of explaining the loads on those days.

Table A.16 presents the results of this test, showing the percentage of statistically significant synthetic event-day coefficients for each hour during the relevant event windows. The synthetic event-day load impacts are estimated using the chosen model specification shown in Tables A.9 through A.15. The "Average Event Hour" row at the bottom of the table shows the percentage of statistically significant estimates across all event hours. As the table shows, the models perform quite well on this test.

Table A.16: Percentage of Statistically Significant Synthetic Event-Day Estimated Load Impacts

Hour	Percent Statistically Significant				
	PG&E		SCE		
	Weekday	Weekend	Weekday	Weekend	Weekend (Voluntary Reduction)
18			1%		
19	0%		0%		
20	2%	0%	0%	0%	0%
Average Event Hour	1.0%	0.0%	0.3%	0.0%	0.0%

A.3 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.5 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen (by industry and weather sensitivity) for each customer. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days. The predictions are slightly worse for non-voluntary reducers however there were only 19 customers on that day and there were event like days to choose from after days in which their voluntary load reductions were removed from the models to prevent bias.

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

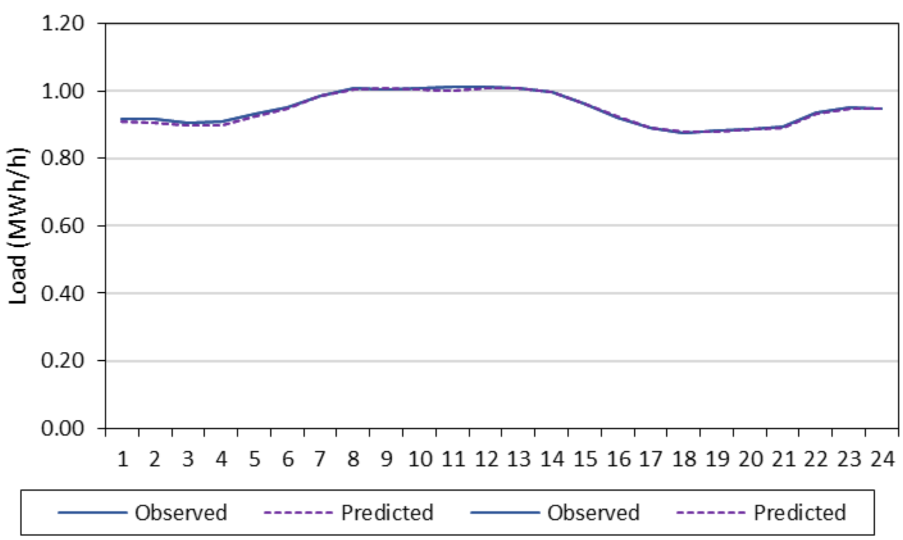


Figure A.2: Average Observed & Predicted Loads on Weekend/Holiday Event-like Days, *PG&E*

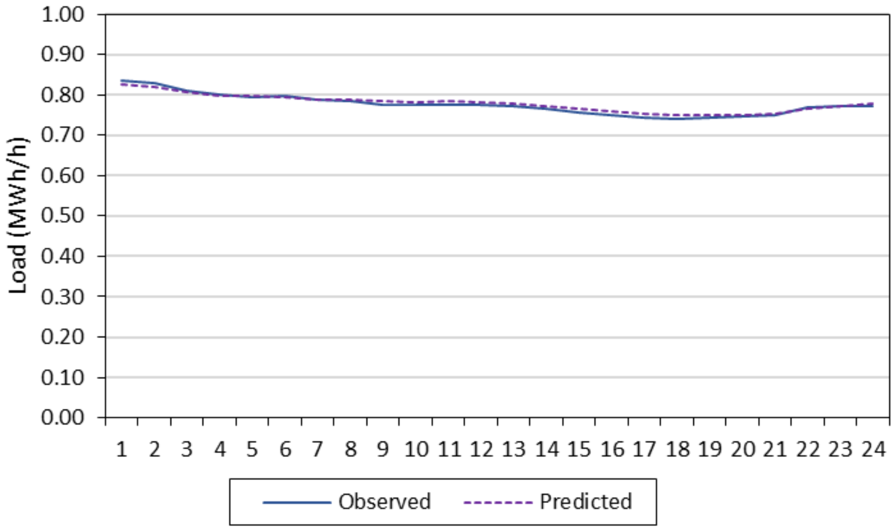


Figure A.3: Average Observed & Predicted Loads on Weekday Event-like Days, *SCE*

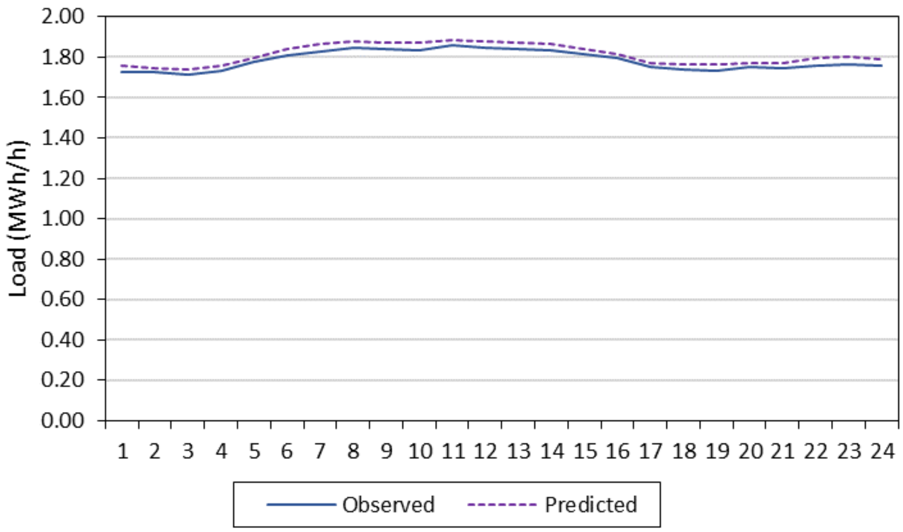


Figure A.4: Average Observed & Predicted Loads on Weekend/Holiday Event-like Days, SCE (Non-Voluntary Reducers)

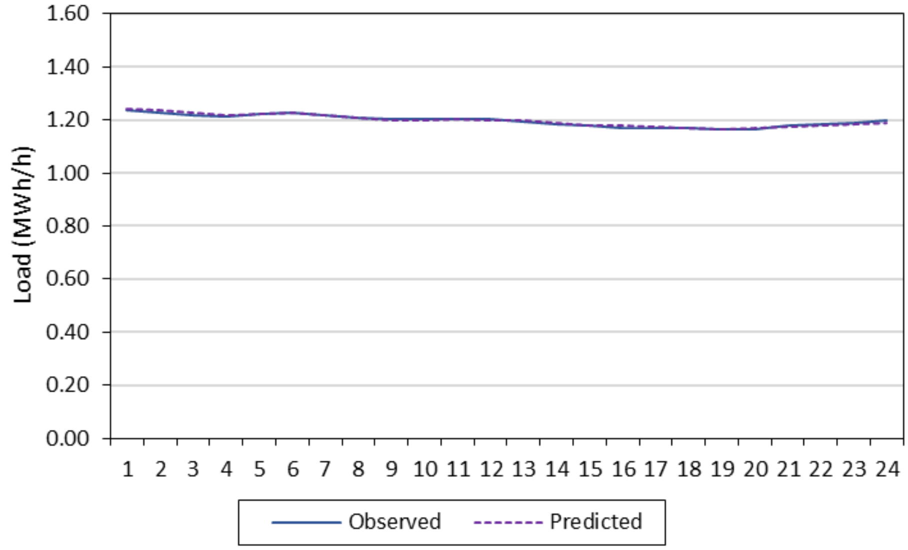
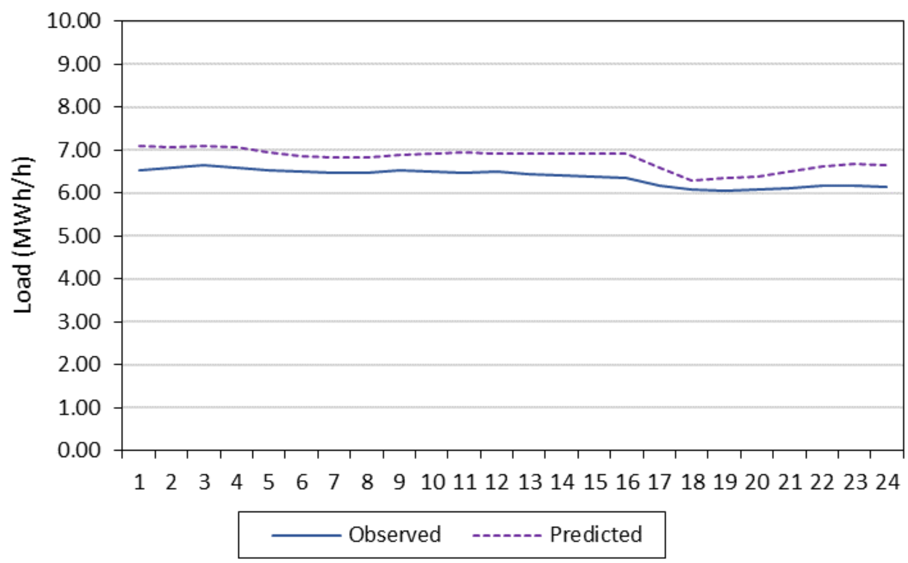


Figure A.5: Average Observed & Predicted Loads on Weekend/Holiday Event-like Days, SCE (Voluntary Reducers)



APPENDIX B. FSL ACHIEVEMENT BY INDUSTRY GROUP

This appendix contains tables showing the FSL achievement by industry group and hour (relative to the called event window) for the events used as the basis for the ex-ante load impacts.[35] FSL achievement is defined as the estimated ex-post load impact divided by

[35] Only customers that remain enrolled in BIP for ex-ante are included.

the difference between the reference load and the FSL. The denominator represents the load impact required to exactly meet the customer's BIP obligation. Because BIP events do not always begin and end on the hour, the hours before and after the event are not always well-defined. Partial event hours are therefore not considered for the first or remainder event hour FSL achievement rate calculations. We use a customer's FSL achievement for the last weekday event day that they were called and had their reference load above their FSL (since no FSL achievement is applicable when a customer's reference load was below their FSL). Tables B.1 and Table B.2 summarize the FSL achievement rate by industry group for each utility. The term "n/a" indicates when a group's reference load is already below the FSL.

Table B.1: Ex-Post Event Day Over/Under Performance – PG&E BIP,
by Industry Group and Event Hour

		Percent Over/Under Performance			
Industry Group	Count	Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	101	[redacted]			
2. Manufacturing	70	48%	99%	99%	50%
3. Wholesale, Transportation, Utilities	77	43%	93%	94%	50%
4. Retail	4	[redacted]			
5. Offices, Hotels, Health, Services	3				
6. Schools	1				
8. Other	2				

Table B.2: Ex-Post Event Day Over/Under Performance – SCE BIP,
by Industry Group and Event Hour

		Percent Over/Under Performance			
Industry Group	Count	Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	30	[redacted]			
2. Manufacturing	232	16%	81%	98%	53%
3. Wholesale, Transportation, Utilities	60	[redacted]			
4. Retail	2				
5. Offices, Hotels, Health, Services	5				
6. Schools	1				
7. Institutional/Government	1				
8. Other	12				