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CHRISTENSEN ASSOCIATES ENERGY CONSULTING

2020 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report

CALMAC Study ID SCE0448

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Table of Contents

Tables

Figures

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 2020. The report provides estimates of *ex-post* load impacts that occurred during events called in 2020 and an *ex-ante* forecast of load impacts for 2021 through 2031 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2020 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").

All three utilities called multiple events in 2020 with varying event hours. PG&E called seven events covering August 14th through 18th and September 5th through 6th. SCE called eight events covering August 14th through 18th and September 5th through 7th. SDG&E called five events covering August 14th and August 17th through August 20th. The PG&E and SCE BIP events included weekends.

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 typical event day, an average of the August 17th and 18th events, event averaged 202 MW, or 69 percent of enrolled load. This was 93 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 514 MW during the August 17th event, representing a 77 percent decrease of the reference load. This was 91 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its typical 2020 event day averaged 0.42 MW, or 68 percent of enrolled load, representing 139 percent of the reduction required to meet the aggregate FSL.

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 2020. The report provides estimates of *ex-post* load impacts that occurred during events called in 2020 and an *ex-ante* forecast of load impacts for 2021 through 2031 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2020 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2020?
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 2021 through 2031?

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.

All three utilities called multiple events in 2020. PG&E called seven events covering August 14th through 18th and September 5th through 6th. Each was called as an emergency events with different event hours. Four of the seven PG&E events were on a weekend (August 15th & 16th, and September 5th & 6th).

SCE called eight events covering August 14th through 18th and September 5th through 7th. Two of the SCE events were called as CAISO Stage 2 emergencies, five were called as CIASO warnings, and one was called for local reliability. Event hours varied between events. Four of the eight SCE events were on a weekend (August 15th & 16th, and September 5th & 6th).

SDG&E called five events covering August 14th and August 17th through August 20th. All the SDG&E BIP events were triggered by temperature and system load conditions. The event hours varied between events.

Enrollment

Enrollment in PG&E's BIP decreased relative to PY2019, from 512 to 494. The sum of enrolled customers' coincident maximum demands was 330 MW, or 0.67 MW for the average service agreement.[1] The Manufacturing industry group contains 52 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 469 service accounts during the typical 2020 event day, which is a slight decrease relative to the 484 enrolled service accounts during PY2019. These accounted for a total of 687.7 MW of maximum demand, or 1.47 MW per service account during the August 14th 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.

[1] A customer's coincident maximum demand ("Enrolled Load" in Figures ES.1-3) 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).

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

[redacted]

SDG&E's enrollment in BIP was four service accounts for the typical 2020 event day, which is a decrease by one customer enrolled during PY2019. These accounted for a total of 3.4 MW of maximum demand, or 0.84 MW per service account. Two customers are categorized as part of the Agriculture, Mining, and Construction industry while the remaining two are part of the Manufacturing industry.

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. For instance, the total program load impact for PG&E's August 17th event averaged 198 MW, or 68 percent of enrolled load, representing 93 percent of the reduction required to meet the aggregate FSL. Total load impact for the typical event day, an average of the August 17th and 18th events, event averaged 202 MW, or 69 percent of enrolled load, representing 93 percent of the reduction required to meet the aggregate FSL.

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	8/14/2020	Fri.	480	184	62%	83%
2	8/15/2020	Sat.	468	176	68%	94%
3	8/16/2020	Sun.	472	155	62%	90%
4	8/17/2020	Mon.	482	198	68%	93%
5	8/18/2020	Tue.	482	206	69%	92%
6	9/5/2020	Sat.	427	149	64%	86%
7	9/6/2020	Sun.	467	153	64%	92%
Typical Event Day			**482**	**202**	**69%**	**93%**

Table ES.2 displays a summary of load impact results for each of the SCE BIP events. The load impact was 514 MW during the August 17th event, representing a 77 percent decrease of the reference load. This was 91 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	8/14/2020	Fri.	469	484	76%	90%
2	8/15/2020	Sat.	469	451	75%	91%
3	8/16/2020	Sun.	469	427	76%	93%
4	8/17/2020	Mon.	469	514	77%	91%
5	8/18/2020	Tue.	469	520	76%	90%
6	9/5/2020	Sat.	467	411	70%	93%
7	9/6/2020	Sun.	467	418	69%	91%
8	9/7/2020	Mon.	7			
Typical Event Day			**469**	**514**	**77%**	**91%**

SDG&E's total load impacts for each event day are presented in Table ES.3. The typical 2020 event day load impacts averaged 0.42 MW, or 68 percent of enrolled load, representing 139 percent of the reduction required to meet the aggregate FSL.

Table ES.3: Summary of Event-hour Load Impact by Event, *SDG&E*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	8/14/2020	Fri.	4	0.47	79%	175%
2	8/17/2020	Mon.	4	0.88	75%	103%
3	8/18/2020	Tue.	4	0.45	125%	125%
4	8/19/2020	Wed.	4	0.37	54%	103%
5	8/20/2020	Thu.	4	0.44	72%	151%
Typical Event Day			**4**	**0.42**	**68%**	**139%**

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 BIP enrollments to remain constant from 2021 through 2031, with 308 enrolled service agreements. SCE projects 351 BIP enrollments in 2021 and to increase by eight customers each year (seven in BIP-30 and one in BIP-15). SDG&E forecasts BIP enrollments to increase by one each year until 2025, at which time enrollment is assumed to remain constant at nine service accounts through 2031.

Table ES.4 shows PG&E's aggregate and per-customer *ex-ante* 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 event day, averaged over the resource adequacy window 4 to 9 p.m. Figures ES.3 through ES.4 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.

Table ES.4: Per-customer *Ex-ante* Load Impacts, 2020-2030, *PG&E*

Weather Year	Enrollment	Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
		Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	308	234.3	182.6	760.6	592.9	78.0%
Utility 1-in-10	308	235.2	183.7	763.5	596.3	78.1%
CAISO 1-in-2	308	233.3	181.3	757.6	588.6	77.7%
CAISO 1-in-10	308	234.8	183.2	762.2	594.8	78.0%

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

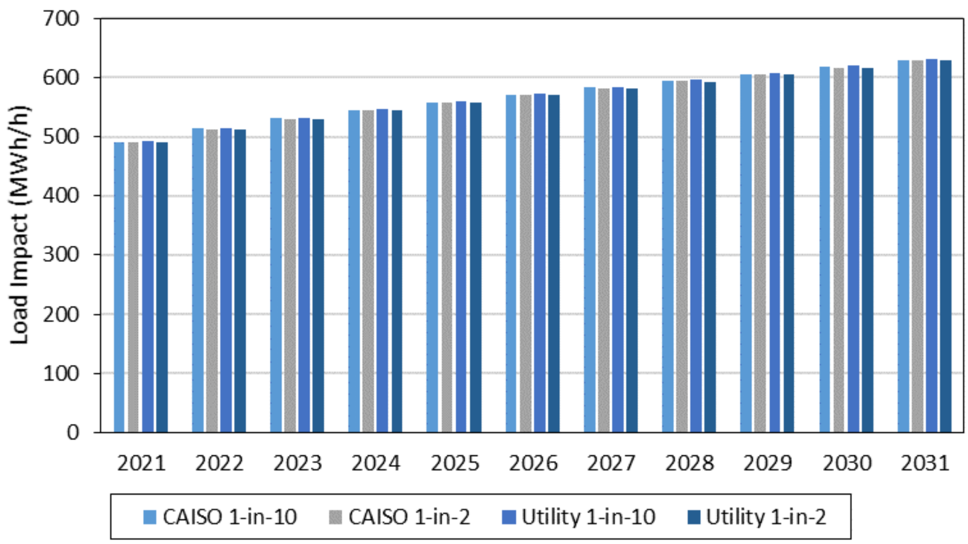
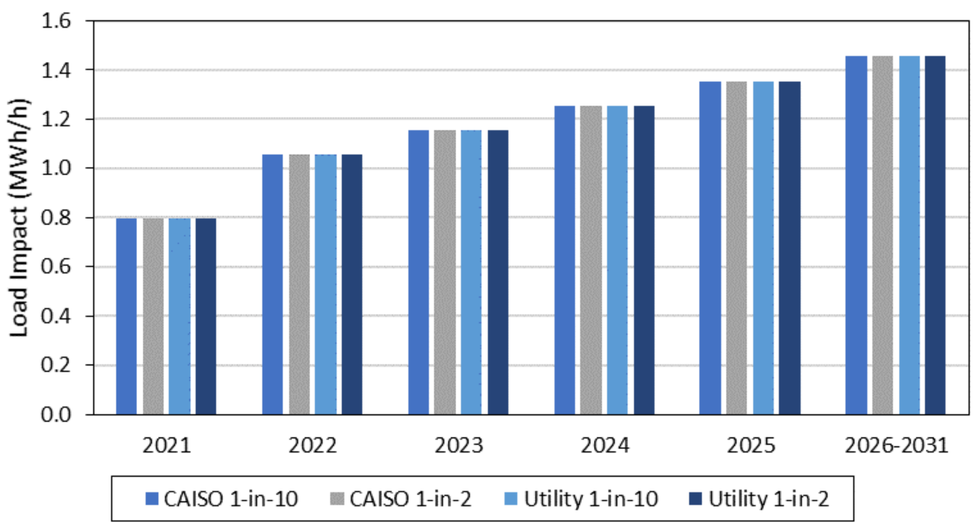


Figure ES.4: Average August *Ex-Ante* Load Impacts by Scenario, 2020-2030, *SDG&E*



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 2020. The report provides estimates of *ex-post* load impacts that occurred during events called in 2020 and an *ex-ante* forecast of load impacts for 2021 through 2031 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2020 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2020?
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 2021 through 2031?

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 2020.

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. Effective January 2013, 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 with a minimum load reduction of 100 kW are eligible for the program. Customers are notified no later than 20 minutes before the event. The monthly incentive payments in 2020 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.

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 four participants in 2020.

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).[2]

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 PY2019, from 512 to 494.[3] The sum of enrolled customers' coincident maximum demands[4] was 330 MW, or 0.67 MW for the average service

[2] 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.

[3] "Enrollment" is defined as the enrollment on the October 6, 2019 event day compared to the 2020 Typical Event Day 2020 (August 17th and 18th) for PG&E.

[4] 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).

agreement. The manufacturing industry group contains over 51 percent of the enrolled load.

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

Industry	Enrolled	Sum of Max MWh/h[5]	Percent of Max MWh/h	Average Max MWh/h[6]
Agriculture, Mining & Construction	272	[redacted]	[redacted]	[redacted]
Manufacturing	99	170.6	51.7%	1.72
Wholesale, Transport, other utilities	104	[redacted]	[redacted]	[redacted]
Retail stores	11	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	6	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]
Other or unknown	1	[redacted]	[redacted]	[redacted]
Total	**494**	**330.3**	**-**	**0.67**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 469 service accounts on the August 14, 2020 event day, which is a decrease relative to the 484 enrolled service accounts during PY2019. These accounted for a total of 687.7 MW of maximum demand, or 1.47 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	38	[redacted]	[redacted]	[redacted]
Manufacturing	289	412.1	59.9%	1.43
Wholesale, Transport, other utilities	57	[redacted]	[redacted]	[redacted]
Retail stores	48	12.2	1.8%	0.25
Offices, Hotels, Finance, Services	14	[redacted]	[redacted]	[redacted]
Schools	2	[redacted]	[redacted]	[redacted]
Institutional/Government	4	[redacted]	[redacted]	[redacted]
Other (or unknown)	17	[redacted]	[redacted]	[redacted]
Total	**469**	**687.7**	**-**	**1.47**

Table 2.3 shows BIP enrollments for SDG&E. SDG&E's enrollment in BIP was four service accounts on for each of the 2020 event days. These accounted for a total of 3.4 MW of maximum demand, or 0.84 MW per service account. Two customers were in the Agriculture, mining, and construction industry group while the remaining two were in the manufacturing industry group.

[5] "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.
[6] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

Table 2.3: BIP Enrollees by Industry Group, *SDG&E*

Industry	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
Agriculture, Mining & Construction	2	2.5	75.7%	1.27
Manufacturing	2	0.8	24.3%	0.41
Total	**4**	**3.4**	**0.0%**	**0.84**

Tables 2.4 and 2.5 show BIP enrollment by local capacity area for PG&E and SCE, respectively. (SDG&E consists of a single LCA.) The majority of PG&E's enrolled load is in the "Other" LCA category. For SCE, 69.4% percent of enrolled load is in the LA Basin.

Table 2.4: 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	47	[redacted]	[redacted]	[redacted]
Greater Fresno Area	170	26.5	8.0%	0.16
Humboldt	1	[redacted]	[redacted]	[redacted]
Kern	45	[redacted]	[redacted]	[redacted]
North Coast / North Bay	13	[redacted]	[redacted]	[redacted]
Other (blank)	176	194.2	58.8%	1.10
Sierra	23	[redacted]	[redacted]	[redacted]
Stockton	19	[redacted]	[redacted]	[redacted]
Total	**494**	**330.3**	**0.0%**	**0.67**

Table 2.5: 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	389	477.6	69.4%	1.23
Outside Basin	24	[redacted]	[redacted]	[redacted]
Ventura	56	[redacted]	[redacted]	[redacted]
Total	**469**	**687.7**	**-**	**1.47**

2.3 Event Days

Table 2.6 lists BIP event days and hours for the three IOUs in 2020. PG&E called seven emergency events, four of which occurred on a weekend. SCE called eight events, two of which were CAISO Stage 2 Emergencies, five of which were CAISO warnings, and one of which was a SCE local reliability event. Four of the events took place on a weekend. SDG&E called five events triggered by temperature and system load conditions. All SDG&E's events took place on a weekday.

Table 2.6: BIP Event Days

Date	Day of Week	PG&E	SCE	SDG&E
8/14/2020	Friday	Emergency Event 5:02 – 10:47 p.m.	CAISO Stage 2 Emergency 5:10 – 8:35 p.m.	Temp. & Sys. Load 6:00 – 8:00 p.m.
8/15/2020	Saturday	Emergency Event 3:45 – 8:45 p.m.	CAISO Warning 3:00 – 7:45 p.m.	
8/16/2020	Sunday	Emergency Event 7:15 – 7:59 p.m.	CAISO Warning 5:40 – 7:25 p.m.	
8/17/2020	Monday	Emergency Event 3:47 – 7:47 p.m.	CAISO Stage 2 Emergency 3:10 – 7:40 p.m.	Temp. & Sys. Load 3:00 – 7:00 p.m.
8/18/2020	Tuesday	Emergency Event 2:17 – 7:32 p.m.	CAISO Warning 1:40 – 7:25 p.m.	Temp. & Sys. Load 7:00 – 8:00 p.m.
8/19/2020	Wednesday			Temp. & Sys. Load 6:00 – 8:00 p.m.
8/20/2020	Thursday			Temp. & Sys. Load 6:00 – 8:00 p.m.
9/5/2020	Saturday	Emergency Event 6:30 – 8:34 p.m.	CAISO Warning 5:30 – 8:25 p.m.	
9/6/2020	Sunday	Emergency Event 5:17 – 9:00 p.m.	CAISO Warning 4:40 – 8:22 p.m.	
9/7/2020	Monday		SCE: Local Reliability 4:05 – 7:33 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. Weekends and holidays were excluded from the estimation database for SDG&E.[7] Separate weekday and weekend models (without holidays) were estimated for PG&E and SCE to provide load impact estimates for both weekday and weekend 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 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:

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

[7] Including weekends and holidays would require the addition of variables to capture the fact that load levels and patterns on weekends and holidays can differ greatly from those of non-holiday weekdays. Because event days did not occur on weekends or holidays for SDG&E, the exclusion of these data does not affect the model's ability to estimate *ex-post* load impacts.

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[8]
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 an event) for factors that affect pre-event usage but are not accounted for by the other included variables.[9]

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

[8] The summer pricing season is June through September for SCE, May through October for SDG&E, and May through October for PG&E.

[9] 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 PY2020, CA Energy investigated if the morning load variable attributed to lower event hour reference loads. The morning load variable was not used for SCE and a few PG&E customers to estimate reference loads on any consecutive event days.

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 PY2020, PG&E and SCE called weekend events. Separate weekend models were also estimated to account for different usage behavior on weekends. The weekend regression specification only differs by including the appropriate day type indicator variables (*i.e.,* Sunday).

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), and notification type (applicable for SCE).

A parallel set of winter models was estimated for each customer, which were used to simulate *ex-ante* reference loads for those months.[10] 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, or by LCA, 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 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.

[10] 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 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.

Each utility called multiple events in 2020. On a summary level for the typical event day, the average event-hour load impact per enrolled customer was 419 kWh/h for PG&E, 1,095 kWh/h for SCE, and 105 kWh/h for SDG&E.

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 BIP events.[11] Each of the events was called as an emergency event. The highest load impact occurred during the August 18th event with an average 206 MW load impact across the full event hours. There were multiple consecutive BIP events called in 2020. The load impacts increased over the consecutive weekday events. The reference loads and, consequently, load impacts were lower for the weekend events. The typical event day is defined as the average of the August 17th and 18th event days when most customers on the program were called.

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

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[12]
1	8/14/2020	Fri.	480	299	114	184	62%
2	8/15/2020	Sat.	468	260	84	176	68%
3	8/16/2020	Sun.	472	248	94	155	62%
4	8/17/2020	Mon.	482	290	92	198	68%
5	8/18/2020	Tue.	482	299	93	206	69%
6	9/5/2020	Sat.	427	233	84	149	64%
7	9/6/2020	Sun.	467	239	86	153	64%
Typical Event Day			**482**	**294**	**92**	**202**	**69%**

Table 4.2 compares the observed loads and FSLs by event day. 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 (an observed load above the FSL). The FSL achievement rate ranges from 90% to 94% for consecutive event days and is lowest for the initial event days called, August 14th and September 5th.

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	8/14/2020	Fri.	114	76	83%
2	8/15/2020	Sat.	84	73	94%
3	8/16/2020	Sun.	94	76	90%
4	8/17/2020	Mon.	92	76	93%
5	8/18/2020	Tue.	93	76	92%
6	9/5/2020	Sat.	84	61	86%
7	9/6/2020	Sun.	86	72	92%
Typical Event Day			**92**	**76**	**93%**

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 103 MW average event-hour load reduction.

[12] 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	268	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	98	150	48	103	68%
Wholesale, Transport., & Other Utilities	100	[redacted]	[redacted]	[redacted]	[redacted]
Retail Stores	9	[redacted]	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]	[redacted]
Offices, Hotels, Health, Services	5	[redacted]	[redacted]	[redacted]	[redacted]
Other or Unknown	1	[redacted]	[redacted]	[redacted]	[redacted]
Total	**482**	**294**	**92**	**202**	**69%**

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 from service agreements not currently categorized under any LCA (121 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	42	[redacted]	[redacted]	[redacted]	[redacted]
Greater Fresno	169	24.4	11.3	13.1	54%
Humboldt	1	[redacted]	[redacted]	[redacted]	[redacted]
Kern	45	[redacted]	[redacted]	[redacted]	[redacted]
Northern Coast	8	[redacted]	[redacted]	[redacted]	[redacted]
Other	175	171.4	50.3	121.1	71%
Sierra	23	[redacted]	[redacted]	[redacted]	[redacted]
Stockton	19	[redacted]	[redacted]	[redacted]	[redacted]
Total	**482**	**294**	**92**	**202**	**69%**

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 typical event day, which is an average of the August 17th and 18th events when most customers on the program 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	280.2	242.8	37.4	83.0	34.9	36.4	37.4	38.4	39.8
2	278.7	245.0	33.7	81.3	31.5	32.8	33.7	34.6	36.0
3	277.0	255.8	21.2	80.2	19.3	20.4	21.2	22.0	23.2
4	279.2	265.7	13.5	79.1	11.7	12.7	13.5	14.2	15.3
5	287.0	274.1	12.9	78.4	11.3	12.2	12.9	13.6	14.5
6	301.6	290.8	10.8	77.5	9.2	10.1	10.8	11.5	12.4
7	317.0	305.2	11.8	76.7	10.1	11.1	11.8	12.5	13.5
8	327.3	314.7	12.7	79.2	10.9	11.9	12.7	13.4	14.4
9	329.2	317.4	11.8	82.5	10.2	11.2	11.8	12.5	13.4
10	329.3	320.4	8.9	87.0	7.1	8.2	8.9	9.7	10.7
11	330.3	324.9	5.5	90.8	3.4	4.6	5.5	6.3	7.5
12	326.8	323.1	3.7	94.0	1.8	2.9	3.7	4.6	5.7
13	324.7	320.2	4.5	96.2	2.3	3.6	4.5	5.4	6.7
14	320.0	304.3	15.7	97.6	13.4	14.7	15.7	16.7	18.1
15	312.9	201.6	111.3	98.5	108.6	110.2	111.3	112.4	114.0
16	299.3	138.7	160.7	98.5	158.3	159.7	160.7	161.6	163.0
17	293.6	93.7	199.9	99.8	197.3	198.8	199.9	201.0	202.5
18	292.4	91.0	201.4	97.6	198.8	200.3	201.4	202.5	204.1
19	295.8	92.2	203.6	95.6	200.1	202.2	203.6	205.1	207.2
20	301.9	100.1	201.8	92.3	196.6	199.7	201.8	203.9	207.0
21	302.6	176.6	126.0	88.9	121.2	124.0	126.0	127.9	130.8
22	305.9	231.1	74.8	87.9	70.4	73.0	74.8	76.5	79.1
23	307.4	259.4	48.0	86.5	44.1	46.4	48.0	49.6	51.9
24	306.0	274.7	31.3	84.8	27.5	29.7	31.3	32.8	35.1
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	7,326	5,763	1,563	313.8	1,489.1	1,532.6	1,562.8	1,592.9	1,636.4
Event Hours	293.9	92.3	201.7	67.9	198.7	200.5	201.7	202.9	204.6

* The highlighting indicates all hours affected by the event. However, hour-ending 15, 16, and 20 were partial event-hours and are 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. The figure represents the consecutive event days August 17th and 18th event days. As a consecutive event, there exists some load impact in the early morning hours as a carryover from the previous event day's load impacts.

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

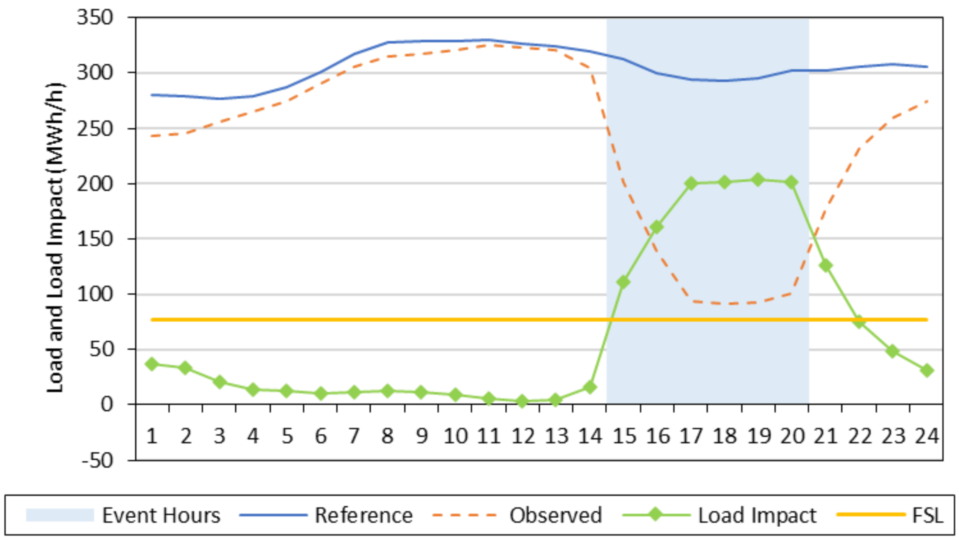
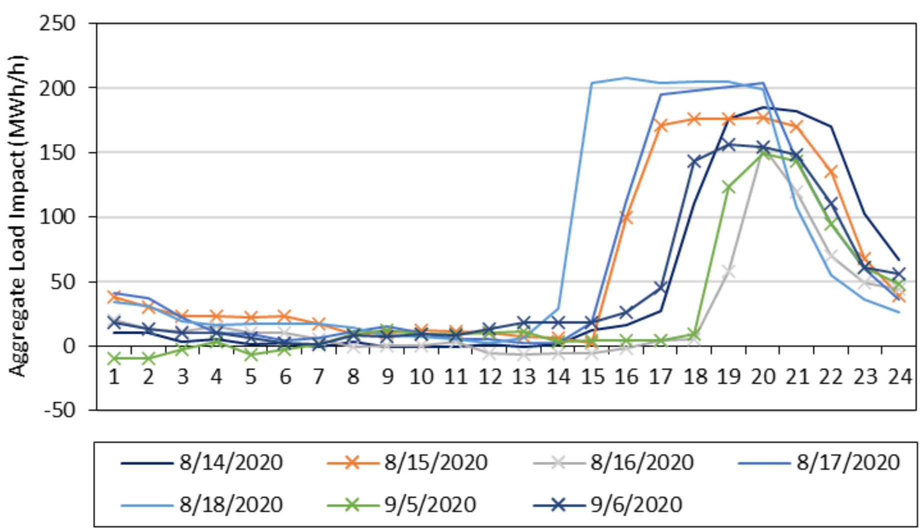


Figure 4.2 illustrates the aggregate hourly load impacts for each of the PG&E 2020 events. Weekend event days are marked with and "x" indicator. The load impact shape and magnitude differ between events as a result of different event hours and numbers of customers called for each event. Nevertheless, the August 18th event exhibits the largest load impacts with the longest event window. The load impacts are lower during the weekend events because of lower aggregate reference loads.

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



4.2 SCE Load Impacts

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

SCE's had multiple BIP event days in 2020, Table 4.6 displays the average full event-hour reference loads and load impacts for each event. All but the last event, September 7th, 2020, was called at the program level. Event hours differ between events. The weekend events have lower reference loads and loads impacts. The load impact and load impact percentage are lower for the September events called at the program level due to an increase in the aggregate FSL. The September the event was called for local reliability and exhibited the lowest load impact percentage. The typical event day is represented by the August 17th event day.

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[13]
1	8/14/2020	Fri.	469	640	156	484	76%
2	8/15/2020	Sat.	469	603	152	451	75%
3	8/16/2020	Sun.	469	563	135	427	76%
4	8/17/2020	Mon.	469	670	155	514	77%
5	8/18/2020	Tue.	469	683	163	520	76%
6	9/5/2020	Sat.	467	587	176	411	70%
7	9/6/2020	Sun.	467	606	188	418	69%
8	9/7/2020	Mon.	7	[redacted]	[redacted]	[redacted]	[redacted]
Typical Event Day			**469**	**670**	**155**	**514**	**77%**

Table 4.7 provides the SCE BIP event day observed loads compared to the FSLs and FSL achievement rate. The FSL achievement rate was consistent between each of the events (except for the September 7th local reliability event) and does not seem to be affected by consecutive event days or weekend events. The FSL increases for the September events which leads to a reduction in load impacts for those events.

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

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	8/14/2020	Fri.	156	105	90%
2	8/15/2020	Sat.	152	105	91%
3	8/16/2020	Sun.	135	105	93%
4	8/17/2020	Mon.	155	105	91%
5	8/18/2020	Tue.	163	105	90%
6	9/5/2020	Sat.	176	145	93%
7	9/6/2020	Sun.	188	145	91%
8	9/7/2020	Mon.	[redacted]	[redacted]	[redacted]
Typical Event Day			**155**	**105**	**91%**

Table 4.8 shows the average event-hour load impact by industry group for the typical event day (which represents the August 17th event).[14] The total row at the bottom of the table shows the total event-day load impact of 514.4 MW, or 76.8 percent of the reference load. Most of the program's load impact came from customers in the Manufacturing industry group.

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	38	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	289	405.9	104.2	301.7	74.3%
Wholesale, Transport, other utilities	57	[redacted]	[redacted]	[redacted]	[redacted]
Retail stores	48	12.9	11.8	1.1	8.4%
Offices, Hotels, Finance, Services	14	[redacted]	[redacted]	[redacted]	[redacted]
Schools	2	[redacted]	[redacted]	[redacted]	[redacted]
Institutional/Government	4	[redacted]	[redacted]	[redacted]	[redacted]
Other (or unknown)	17	[redacted]	[redacted]	[redacted]	[redacted]
Total	**469**	**669.6**	**155.2**	**514.4**	**76.8%**

Table 4.9 summarizes average hourly load impacts by LCA. The majority of the load impact comes from customers in the LA Basin, which is consistent between each of the BIP event days.

[14] In order to summarize only full-hour load impacts, the tables contain load impacts from 4:00 to 7:00 p.m., omitting the partial hour from 3:20 to 4:00 p.m. and 7:00 to 7:40 p.m.

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	389	457.9	128.6	329.3	71.9%
Outside Basin	24	[redacted]			
Ventura	56				
Total	**469**	**669.6**	**155.2**	**514.4**	**76.8%**

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts for the typical event day (which represents the August 17th BIP event) 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	578.3	484.1	94.2	16%	76.6	88.7	92.0	94.2	96.5	99.8
2	579.3	494.4	84.8	15%	76.1	79.2	82.5	84.8	87.1	90.5
3	583.1	498.3	84.7	15%	75.7	79.0	82.4	84.7	87.1	90.5
4	594.9	515.9	79.0	13%	75.5	72.8	76.4	79.0	81.5	85.2
5	615.0	544.7	70.3	11%	75.2	64.3	67.8	70.3	72.7	76.3
6	644.7	575.8	68.9	11%	74.9	62.9	66.4	68.9	71.3	74.8
7	667.8	601.9	65.8	10%	75.4	60.0	63.4	65.8	68.2	71.7
8	681.8	623.7	58.1	9%	76.9	52.1	55.6	58.1	60.6	64.1
9	691.3	646.5	44.8	6%	81.1	38.7	42.3	44.8	47.3	50.9
10	696.5	642.3	54.2	8%	85.0	47.9	51.6	54.2	56.8	60.5
11	702.7	649.8	52.9	8%	88.3	46.6	50.3	52.9	55.5	59.3
12	705.9	658.4	47.5	7%	90.1	41.4	45.0	47.5	50.0	53.6
13	703.8	654.5	49.3	7%	91.3	43.2	46.8	49.3	51.8	55.4
14	697.0	654.0	43.0	6%	92.8	37.1	40.6	43.0	45.4	48.9
15	689.0	634.8	54.3	8%	93.9	48.2	51.8	54.3	56.7	60.4
16	679.4	303.4	376.1	55%	95.6	370.0	373.6	376.1	378.6	382.2
17	673.4	158.1	515.3	77%	95.8	509.3	512.8	515.3	517.8	521.3
18	669.6	157.2	512.4	77%	94.1	506.3	509.9	512.4	514.9	518.5
19	665.9	150.4	515.5	77%	91.2	509.3	513.0	515.5	518.0	521.6
20	668.6	176.9	491.7	74%	88.0	485.3	489.1	491.7	494.3	498.1
21	668.9	344.0	324.9	49%	83.6	318.6	322.3	324.9	327.4	331.2
22	670.2	460.5	209.6	31%	81.5	203.8	207.3	209.6	212.0	215.5
23	668.6	522.2	146.4	22%	79.7	140.3	143.9	146.4	148.9	152.4
24	661.5	548.9	112.6	17%	78.7	106.8	110.2	112.6	114.9	118.4
Daily	**15,857**	**11,701**	**4,156**	**26%**	**84.0**	**3,995.3**	**4,090.4**	**4,156.2**	**4,222.1**	**4,317.2**

* The highlighting indicates all hours affected by the event. However, hour-ending 16 and 20 were partial event-hours and are not included in the average event-hour calculations in the report.

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the typical event day. The event hours are represented with blue shading with the edge hours as partial event hours.

Figure 4.3: BIP Loads for the Typical Event Day, *SCE*

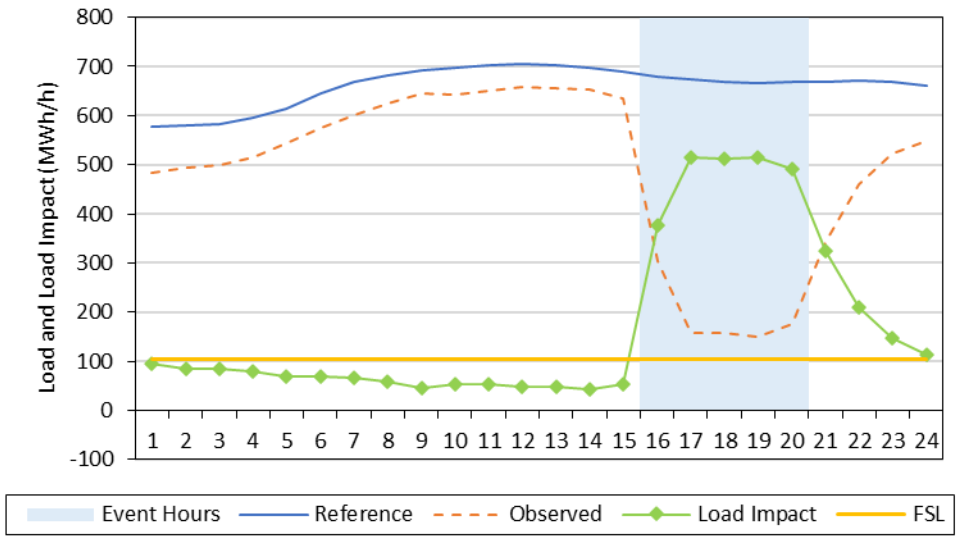


Figure 4.4 illustrates the reference loads and load impacts for the August 14th (Friday) and 15th (Saturday) event days. Figure 4.4 demonstrates how BIP events can influence subsequent event day loads. The pre-event hour reference load on August 14th tracks closely to the observed loads; however, after the load reduction during event hours, the observed load does not fully come back to the level of the reference load during the next day, August 15th.

Figure 4.4: BIP Loads for the August 14th and 15th, 2020 Event Days, *SCE*

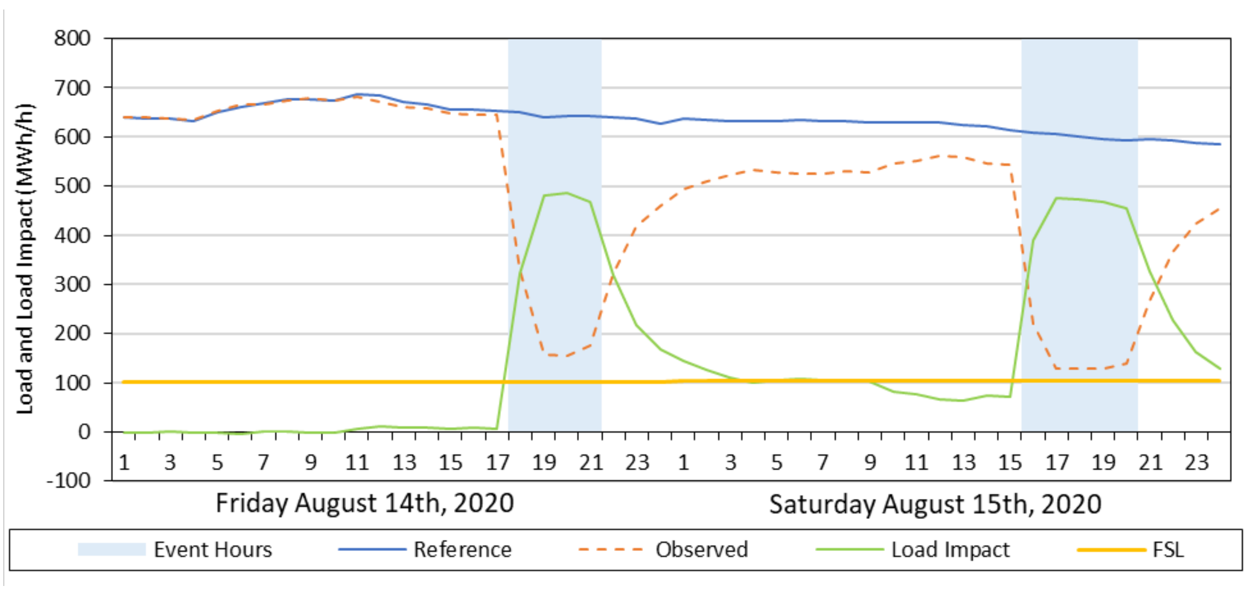
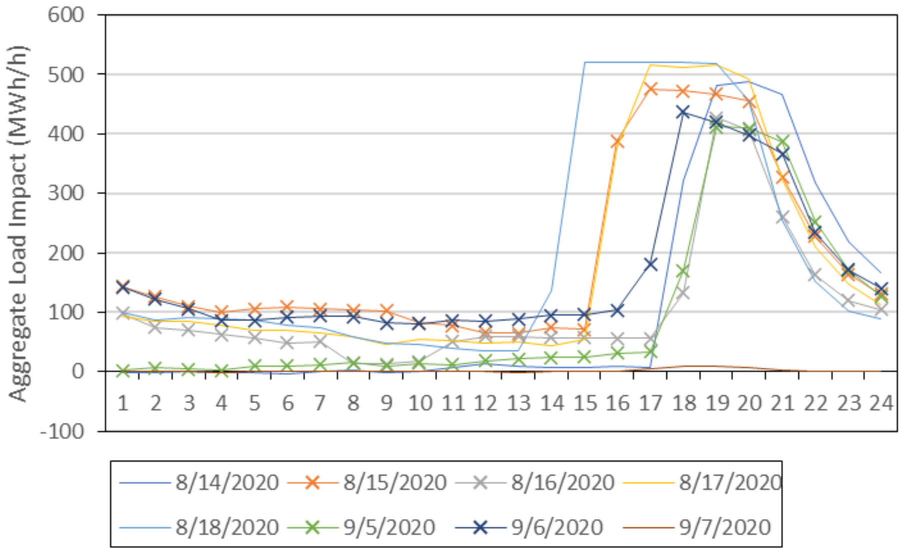


Figure 4.5 provides the hourly aggregate SCE BIP load impacts for each event day. The weekend events are depicted with a "x" indicator, each of which has lower load impacts.

The August 18th event had the largest load impact and duration of event hours. It was also the last consecutive event in its series of events. The September 7th event loads are relatively minor because only a subset of customers was called for local reliability.

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



4.3 SDG&E Load Impacts

4.3.1 Average Event-hour Load Impacts

Average event-hour reference loads and load impacts for SDG&E's BIP events are summarized in Table 4.11. The hourly load profile is similar for each event day, so differences in load impacts are partially driven by which event hours are called. For instance, the largest reference load and load impact occurred on the August 17th event, which had the earliest event hours from 3 to 7 p.m. The typical event day represents averages between the August 14th, 19th, and 20th event days because they had equivalent event hours (6 – 8 p.m.).

Table 4.11: Average Event-hour Load Impacts by Event, *SDG&E*

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI[15]
1	8/14/2020	Fri.	4	0.59	0.12	0.47	79%
2	8/17/2020	Mon.	4	1.17	0.30	0.88	75%
3	8/18/2020	Tue.	4	0.68	0.23	0.45	125%
4	8/19/2020	Wed.	4	0.68	0.31	0.37	54%
5	8/20/2020	Thu.	4	0.61	0.17	0.44	72%
Typical Event Day			**4**	**0.63**	**0.20**	**0.42**	**68%**

Table 4.12 compares the average observed load to the FSL on each event day. The observed load was below the FSL for each of the events, resulting in FSL achievement rates greater than one hundred percent.

Table 4.12: Average Event-hour Observed Loads and FSLs by Event*, SDG&E*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	8/14/2020	Fri.	0.12	0.32	175%
2	8/17/2020	Mon.	0.30	0.32	103%
3	8/18/2020	Tue.	0.23	0.32	125%
4	8/19/2020	Wed.	0.31	0.32	103%
5	8/20/2020	Thu.	0.17	0.32	151%
Typical Event Day			**0.20**	**0.32**	**139%**

Table 4.13 provides SDG&E BIP reference loads and load impacts by industry group for the typical event day. The average load impact over the two-hour event was 0.42 MW, or 68 percent of the reference load. Most of the program's load impact came from customers in the Manufacturing industry group.

Table 4.13: Typical Event Day Load Impacts – *SDG&E, 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	2	0.12	0.10	0.02	16%
Manufacturing	2	0.51	0.10	0.41	80%
Total	**4**	**0.63**	**0.20**	**0.42**	**68%**

4.3.2 Hourly Load Impacts

Table 4.14 presents hourly load impacts for the typical event day in the manner required by the Protocols.

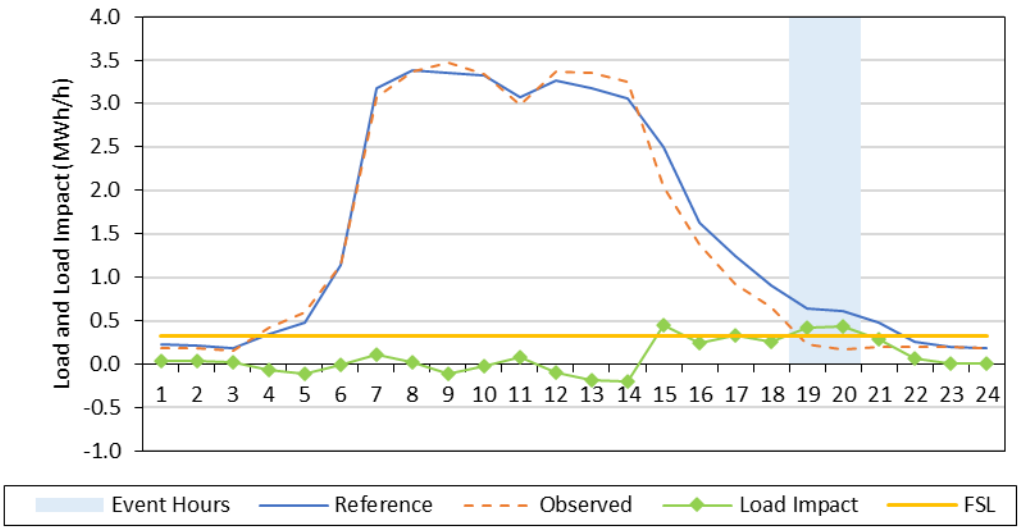
[15] The percentage load impact is calculated as the load impact divided by the reference load.

Table 4.14: BIP Hourly Load Impacts for the Typical Event Day, *SDG&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	0.2	0.2	0.0	72.3	0.0	0.0	0.0	0.1	0.1
2	0.2	0.2	0.0	71.9	0.0	0.0	0.0	0.0	0.1
3	0.2	0.2	0.0	70.0	0.0	0.0	0.0	0.0	0.0
4	0.3	0.4	-0.1	69.8	-0.3	-0.2	-0.1	0.0	0.1
5	0.5	0.6	-0.1	70.4	-0.5	-0.3	-0.1	0.0	0.2
6	1.1	1.1	0.0	70.6	-0.2	-0.1	0.0	0.1	0.2
7	3.2	3.1	0.1	70.1	-0.2	0.0	0.1	0.2	0.4
8	3.4	3.4	0.0	71.4	-0.3	-0.1	0.0	0.1	0.3
9	3.4	3.5	-0.1	75.8	-0.4	-0.2	-0.1	0.0	0.2
10	3.3	3.3	0.0	80.9	-0.3	-0.1	0.0	0.1	0.3
11	3.1	3.0	0.1	85.4	-0.3	-0.1	0.1	0.2	0.5
12	3.3	3.4	-0.1	89.3	-0.4	-0.2	-0.1	0.0	0.2
13	3.2	3.4	-0.2	90.1	-0.5	-0.3	-0.2	0.0	0.1
14	3.1	3.2	-0.2	91.0	-0.6	-0.4	-0.2	0.0	0.2
15	2.5	2.0	0.5	92.8	-0.3	0.2	0.5	0.7	1.2
16	1.6	1.4	0.2	93.3	-0.2	0.1	0.2	0.4	0.7
17	1.3	0.9	0.3	92.5	0.0	0.2	0.3	0.5	0.7
18	0.9	0.7	0.3	92.1	0.1	0.2	0.3	0.3	0.5
19	0.6	0.2	0.4	86.4	0.3	0.4	0.4	0.5	0.5
20	0.6	0.2	0.4	80.0	0.3	0.4	0.4	0.5	0.5
21	0.5	0.2	0.3	77.6	0.2	0.3	0.3	0.3	0.4
22	0.3	0.2	0.1	76.3	0.0	0.0	0.1	0.1	0.1
23	0.2	0.2	0.0	75.5	0.0	0.0	0.0	0.0	0.0
24	0.2	0.2	0.0	74.2	0.0	0.0	0.0	0.0	0.0
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	37	35	2.0	154.1	0.4	1.4	2.0	2.6	3.6
Event Hours	0.6	0.2	0.4	16.5	0.4	0.4	0.4	0.5	0.5

Figure 4.6 illustrates the hourly reference load, observed load, and load impact for the typical event day. During the event hours, the observed load is below the FSL. The majority of curtailable load occurs during the middle of the day, as the aggregate reference approaches the FSL during later hours

Figure 4.6: BIP Loads for the Typical Event Day, *SDG&E*



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 and the relevant LCA. 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.

The total number of customer "cells" developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

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

For SDG&E, we do not distinguish the forecast by size or location, so we do not need to develop customer groups.

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 2020 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the end of the 2020 program year, based on their estimated *ex-post* load impacts during program year 2020.[16]

[16] 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 and LCA. 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 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 accuracy in estimating *ex-post* load impacts for particular events, 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 using information from prior days.[17] 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.

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

[17] 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.[18] 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.[19]

[18] Customer-specific specifications are tested separately for the four SDG&E customers.

[19] 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.

The achievement rates are based on the estimates for the most recent observed event day where the customers' reference load was above their FSL.[20] In consultation with the 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.

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 (4:00 to 9:00 p.m. for all months) differs from the historical event window (which can vary across utilities and event days), we needed 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. 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.

[20] 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.

4. Apply achievement rates to reference loads for each event scenario.
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 2020. 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 2031, with separate enrollments provided at the program and portfolio level (which are identical for BIP), by LCA and size group. SCE provided annual enrollments by notice level (15 versus 30 minute) for 2021 through 2031. We assume that the *ex-post* shares of customers by LCA hold throughout the forecast period. The SDG&E enrollment forecast is five in 2021 and is set to increase by one in each year until 2025, at which time enrollment is forecast to remain constant at nine service accounts through 2031. The SDG&E load impact is assumed to increase by 0.1 MW for each newly enrolled customer. SDG&E reference load and FSL is scaled based on recent participants.

5.2.3 Methodology for COVID-19 Adjustments to the *Ex-Ante* Forecast

BIP customers, on average, exhibited a reduction in load as a response to the COVID-19 pandemic which began in March 2020. As a result, the methodology described above for estimating *ex-ante* reference loads and load impacts requires an adjustment to account for how COVID will affect customer usage over the forecast period. First, we estimate the effect COVID had on each customer's hourly reference loads. Second, we adjust the magnitude of the COVID effect over time based on utility-provided assumptions regarding the expected evolution of the COVID effect during the forecast period. Consequently, the load impacts are also adjusted because they are calculated based upon the FSL achievement rate relative to the reference load. Further details are provided below.

The following regression specification is estimated for each customer and hour separately to capture the effect COVID had on consumption:

$$Q_d = \beta_0 + \beta_1 \times COVID_d + \beta_2 \times CDD65_d + \beta_3 \times HDD65_d + \Sigma_m (\beta_{4,m} \times MONTH_{d,m}) \\ + \beta_5 \times MON_d + \beta_5 \times FRI_d + e_d$$

Table 5.2: Descriptions of Terms included in the COVID Regression Equation

Variable Name	Variable Description
Q_d	the hourly demand on day *d* for a customer enrolled in BIP
The various *b*'s	the estimated parameters
$COVID_d$	an indicator variable for if day *d* is during the COVID-19 pandemic (*i.e,* post March 2020)
$CDD65_d$	average cooling degree days[21]
$HDD65_d$	average heating degree days[22]
$MONTH_d$	a series of indicator variables for each month
MON_d, FRI_d,	indicator variables for Monday and Friday
e_d	the error term

Table 5.2 provides a description of the variables in the model. Customer non-holiday weekday load data covering the period October 2018 through September 2020 is used to provide sufficient pre-COVID information.[23] The variable of importance, *COVID*, provides an estimate of each customer's load change in response to the pandemic. The estimated coefficient for *COVID*, β_1, is used to adjust *ex-ante* reference loads for the various levels of COVID specified in the utility's forecasts.

Figures 5.1 through 5.3 illustrate the June *ex-ante* program reference loads with and without COVID for PG&E, SCE, and SDG&E, respectively.[24] The aggregate COVID effect on program load is -12 MW for PG&E during the RA window (*i.e.,* hour-ending 17 through 21), representing a five percent decrease. The COVID related reduction for SCE is 43 MW, or seven percent, during the RA window. For SDG&E, the average program load reduction was 0.3 MW during the RA window as a response to the pandemic.

[21] 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.

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

[23] A greater period of data is required to not confound the COVID effect with usage that occurs during summer months. Therefore, it is important to have at least of full year of data before the pandemic began in March 2020. The maximum amount of data available is used for customers that had less than the full two-year period. Specific days that have an effect on customer usage are removed from the analysis (*e.g.,* program events, public safety power shutoffs, FLEX alert).

[24] Only customers that remain enrolled in BIP and are used as the basis for the *ex-ante* analysis are included.

Figure 5.1: ***Ex-Ante*** **Aggregate June Load with Covid-19 Adjustment,** ***PG&E***

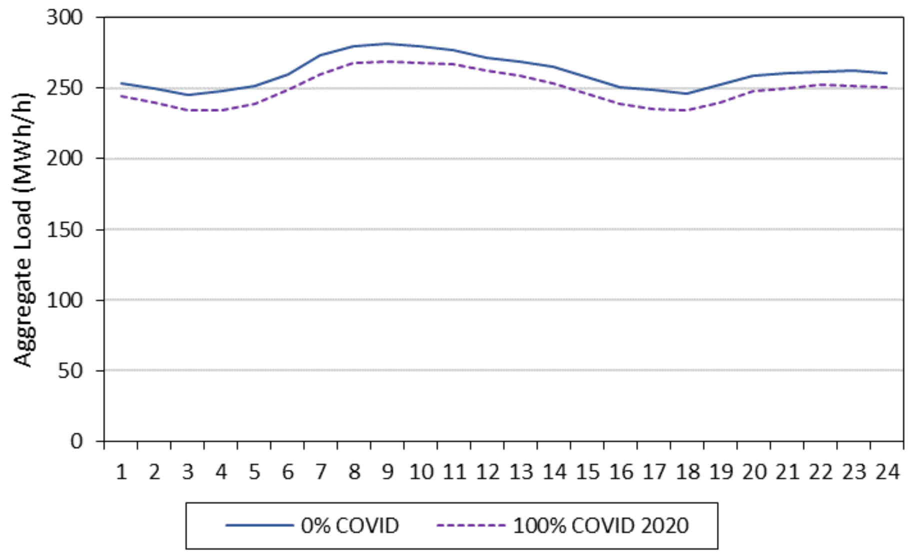


Figure 5.2: ***Ex-Ante*** **Aggregate June Load with Covid-19 Adjustment,** ***SCE***

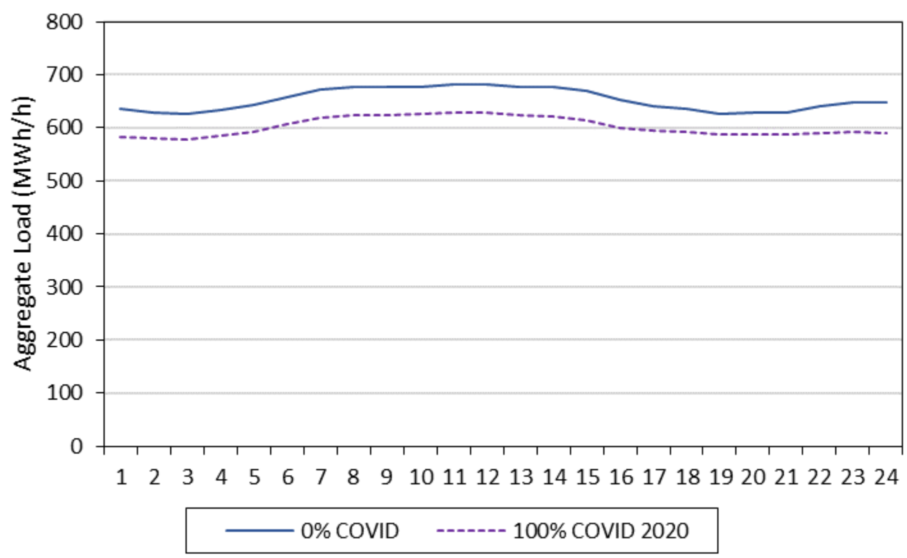
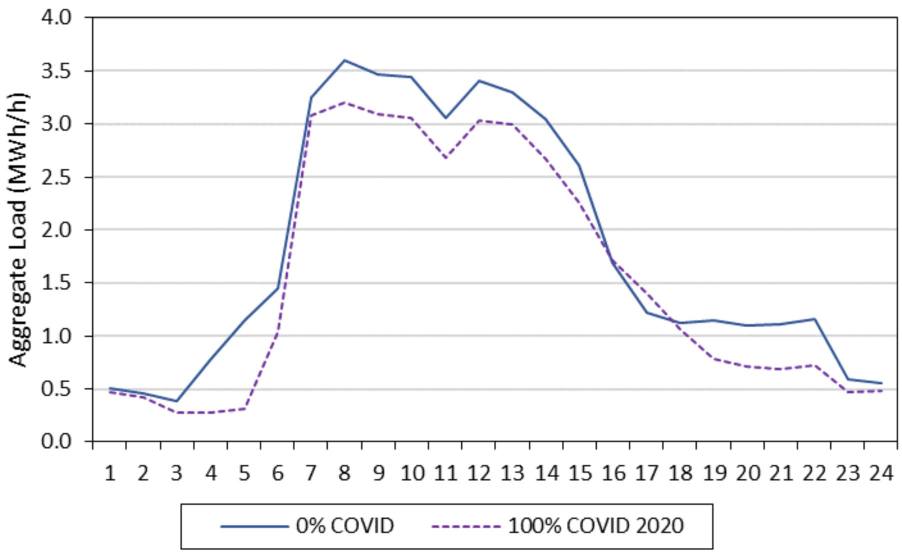


Figure 5.3: *Ex-Ante* Aggregate June Load with Covid-19 Adjustment, *SDG&E*



Each utility provided assumptions regarding how to adjust the magnitude of the COVID effect over time. The magnitude of the pandemic effect on customer usage lessens over time. Therefore, COVID-affected reference loads will approach the non-COVID reference load according to each utilities COVID transition assumptions. Figure 5.4 illustrates the monthly COVID transition assumption for SDG&E, with the effect assumed to be zero percent starting in 2022. Similarly, Table 5.3 provides the annual COVID transition assumption for SCE, which decreases by half each year until it reaches zero percent in 2031. The percentage assumptions are applied to the magnitude of the COVID effect in its respective period. For example, a 1 MW COVID related usage decrease is reduced to 0.5 MW when 50 percent of the COVID effect is assumed. PG&E provided us with a COVID forecast but has chosen to withhold the details from the load impact evaluations. For each utility, the COVID effects are estimated and applied at a customer level.

Figure 5.4: COVID-19 Transition Path Assumption, *SDG&E*

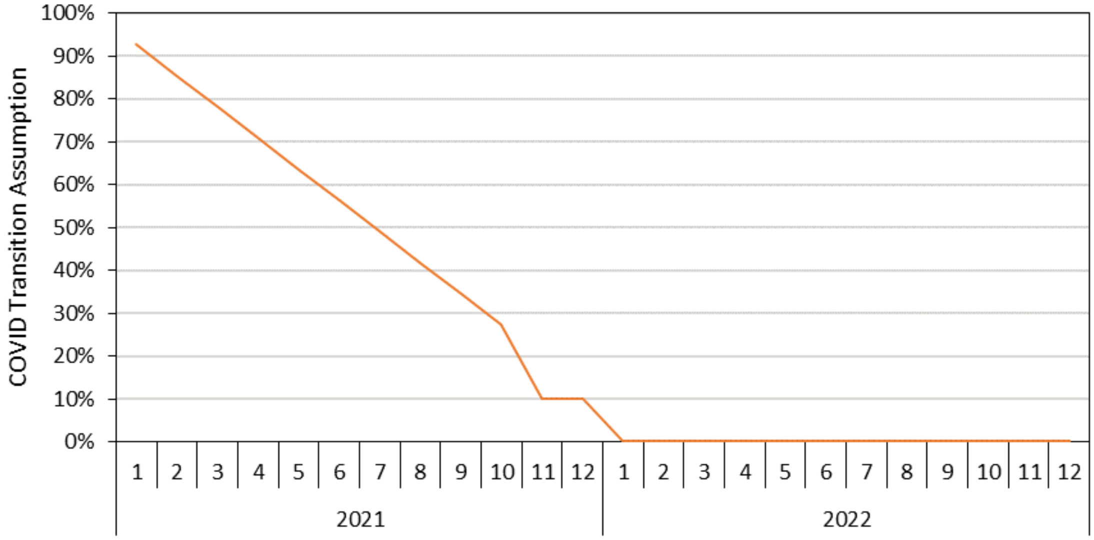


Table 5.3: COVID-19 Transition Path Assumption, *SCE*

Year	Commercial & Industrial
2020	100.0%
2021	50.0%
2022	25.0%
2023	12.5%
2024	6.2%
2025	3.1%
2026	1.6%
2027	0.8%
2028	0.4%
2029	0.2%
2030	0.1%
2031	0.0%

5.3 Enrollment Forecasts

PG&E

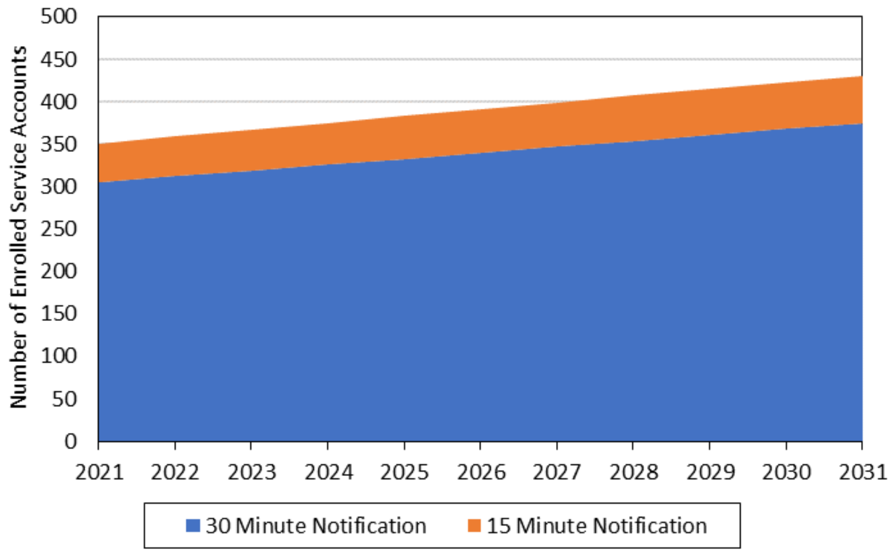
PG&E forecasts BIP enrollments to remain constant from 2021 through 2031, with 308 enrolled service agreements. Of these, 203 are in the large customer group (over 200 kW) while the majority of the remaining agreements are in the medium customer group (20 to 200 kW).[25] The total enrollment forecast is a decrease from the 494 enrolled customers during the 2020 BIP event days.

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

SCE

Figure 5.5 shows SCE's forecast of enrollments by year, broken down by notification time. SCE projects 351 BIP enrollments by April 2021 and to increase by eight customers in each year in April (seven in BIP-30 and one in BIP-15).

Figure 5.5: Number of Enrolled Customers in Each Forecast Year, *SCE*



SDG&E

SDG&E had four customers enrolled during 2020. SDG&E forecasts BIP enrollments to increase by one each year until 2025, at which time enrollment is assumed to remain constant at nine service accounts through 2031.

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.

5.4.1 PG&E

Figure 5.6 shows the August 2021 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 183 MW, which represents 78 percent of the enrolled reference load. The program-level FSL is 56 MW, compared to the average event-hour program load of 51.7 MW. The FSL achievement rate of 102% is higher than the achievement rates during the 2020 events. This occurs because the customers that remain enrolled in BIP for the *ex-ante* forecast had larger FSL achievement rates than those customers that were de-enrolled.

Figure 5.6: PG&E Hourly Event Day Load Impacts for the August 2021 Event Day in a Utility-Specific 1-in-2 Weather

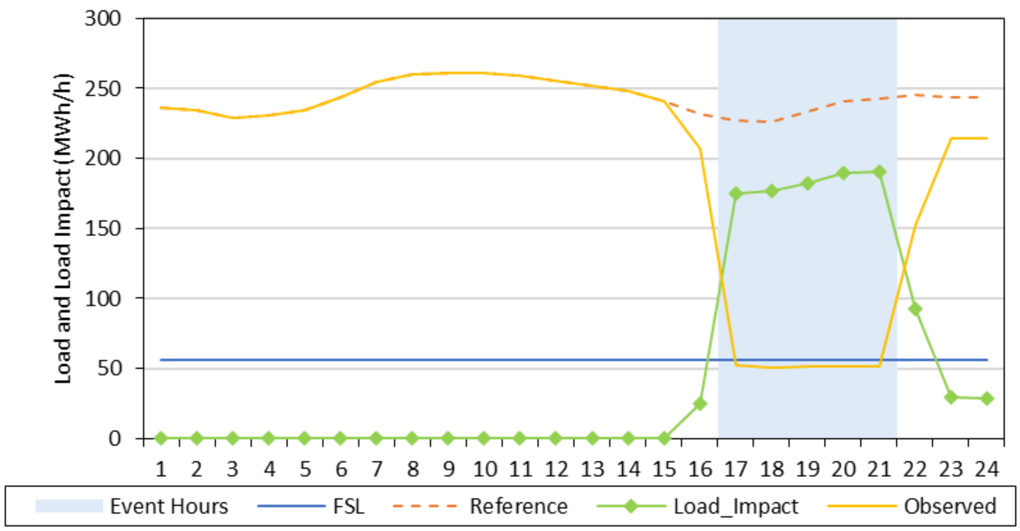


Figure 5.7 shows the share of load impacts by local capacity area, assuming a 2021 August event day in a utility-specific 1-in-2 weather year. Customers in the Other LCA account for the largest share, 62%, of load impacts. Followed by 22% of load impacts being contributed from the Kern LCA.

Figure 5.7: Share of PG&E Load Impacts by LCA for the August 2021 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.8 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 enrollment forecast does not change across the 2024 to 2031 window, so these load impacts stay constant for August across the forecast years. The differences between the scenarios is minimal because the largest customers are not weather sensitive. (Recall that customers are first sorted according to their weather sensitivity.) The enrollment forecast remains constant throughout, thus the increase in load impact over the years is due to a reduction in the COVID effect. For instance, the smallest load impact is 181 MW for the CAISO 1-in-2 weather scenario in 2021 and grows to 194 MW in 2024.

Figure 5.8: Average August *Ex-ante* Load Impacts by Scenario and Year, *PG&E*

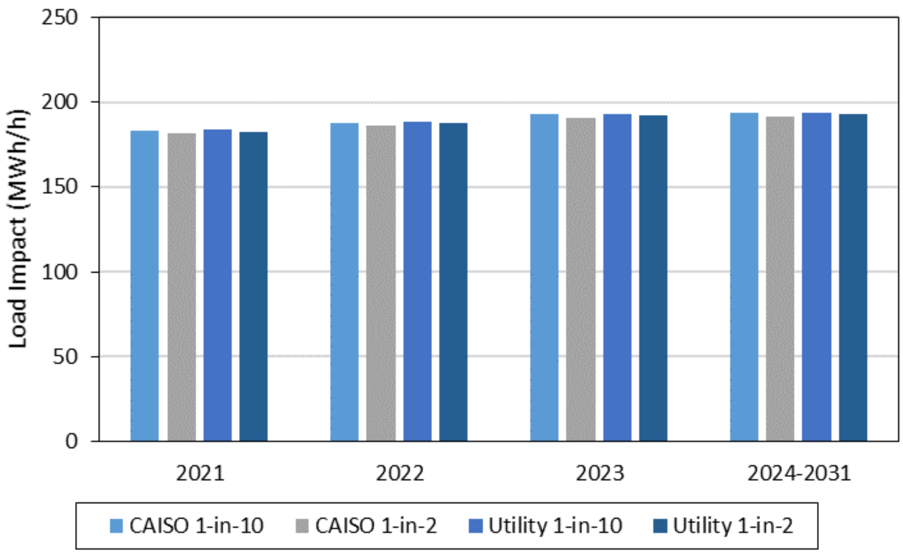


Table 5.4 shows the aggregate and per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2021 event day.

Table 5.4: Per-customer *Ex-ante* August 2021 Load Impacts by Scenario, *PG&E*

		Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
Weather Year	Enrollment	Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	308	234.3	182.6	760.6	592.9	78.0%
Utility 1-in-10	308	235.2	183.7	763.5	596.3	78.1%
CAISO 1-in-2	308	233.3	181.3	757.6	588.6	77.7%
CAISO 1-in-10	308	234.8	183.2	762.2	594.8	78.0%

5.4.2 SCE

Figure 5.9 shows the August 2021 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 490 MW, which represents 78 percent of the enrolled reference load. The program-level FSL is 109 MW, compared to the average event-hour program load of 490 MW. The FSL achievement rate is 94%, which is higher than the 2020 event days because the customers that remained enrolled in BIP for the *ex-ante* forecast had higher performance than those that were de-enrolled.

Figure 5.9: SCE Hourly Event Day Load Impacts for the August 2021 Event Day in a Utility-Specific 1-in-2 Weather Year

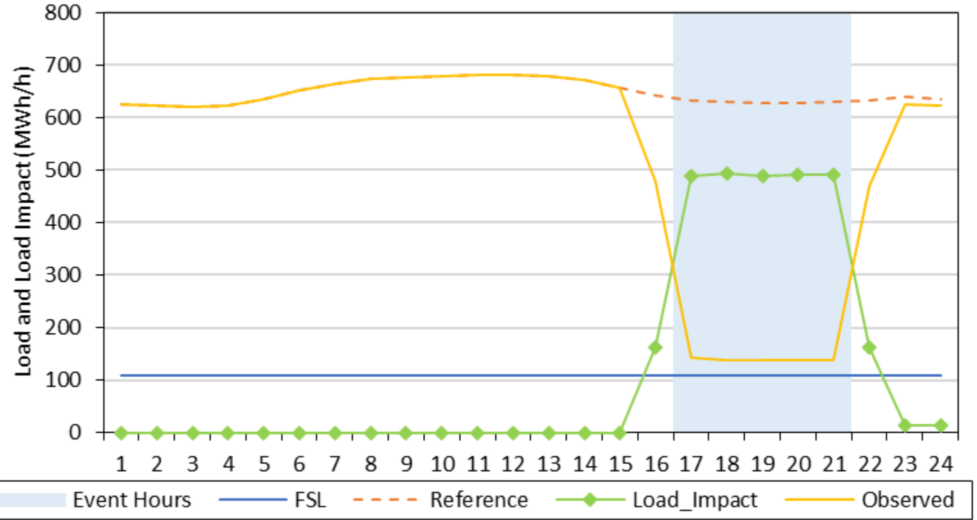


Figure 5.10 shows the share of load impacts by local capacity area for an August 2021 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 69 percent of the load impacts.

Figure 5.10: Share of SCE Load Impacts by LCA for the August 2021 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.11 shows the share of load impacts by notification time, assuming an August 2021 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 [redacted]

Figure 5.11: Share of SCE Load Impacts by Notification Time for the August 2021 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.12 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. These load impacts are shown for forecast years 2021 through 2031. The load impact is not sensitive to weather conditions, for example, the minimum and maximum in 2021 is 490 MW and 493 MW, respectively. The load impact increases over time to a maximum of 631 MW because of an increase in enrollment numbers as well as a decrease in the assumed COVID affect.

Figure 5.12: Average August *Ex-ante* Load Impacts by Scenario and Year, *SCE*

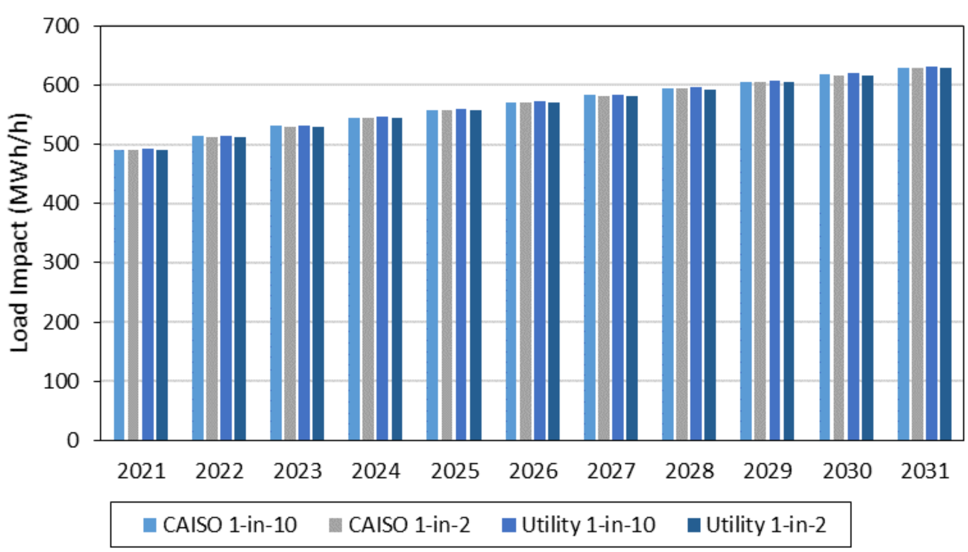


Table 5.5 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2021 event day.

Table 5.5: Per-customer *Ex-ante* August 2021 Load Impacts by Scenario, *SCE*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	1,793	1,397	78%
Utility 1-in-10	1,801	1,404	78%
CAISO 1-in-2	1,794	1,399	78%
CAISO 1-in-10	1,795	1,400	78%

5.4.3 SDG&E

Figure 5.13 shows the load impact forecast for an August 2021 event day in a utility-specific 1-in-2 weather year. The average hourly load impact from 4:00 to 9:00 p.m. is forecast to be 0.80 MW, which represents 65 percent of the enrolled reference load. The average event-hour program load of 0.42 MW is slightly above the program-level FSL of 0.40 MW, thus representing a 97% FSL achievement rate.

Figure 5.13: SDG&E Hourly Event Day Load Impacts for the August 2021 Event Day in a Utility-Specific 1-in-2 Weather Year

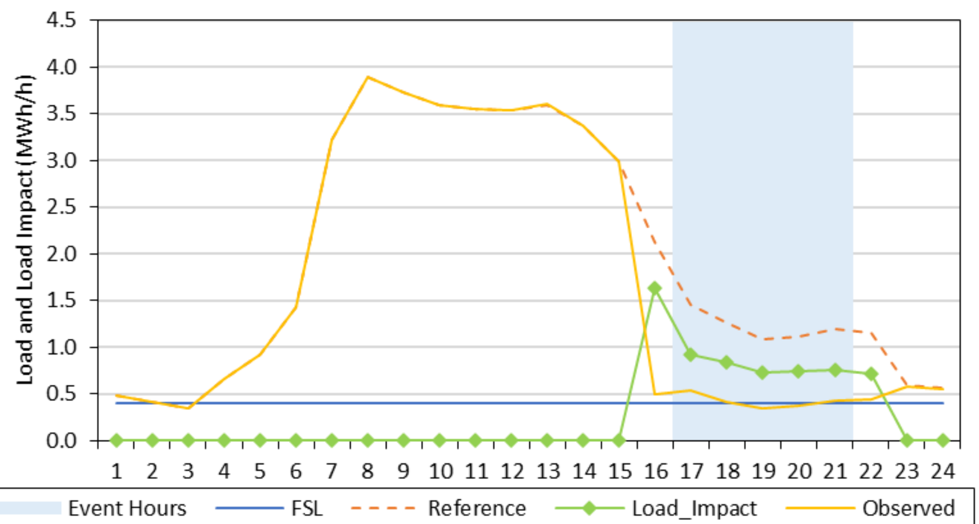


Figure 5.14 illustrates 2021 to 2031 August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The enrollment forecast increases by one customer until 2025 and remains constant thereafter. The load impact is assumed to increases by 0.1 MW for each newly enrolled customer. The load impacts are equivalent for each weather scenario because each customer was classified as not weather sensitive.

Figure 5.14: Average August *Ex-ante* Load Impacts by Scenario and Year, *SDG&E*

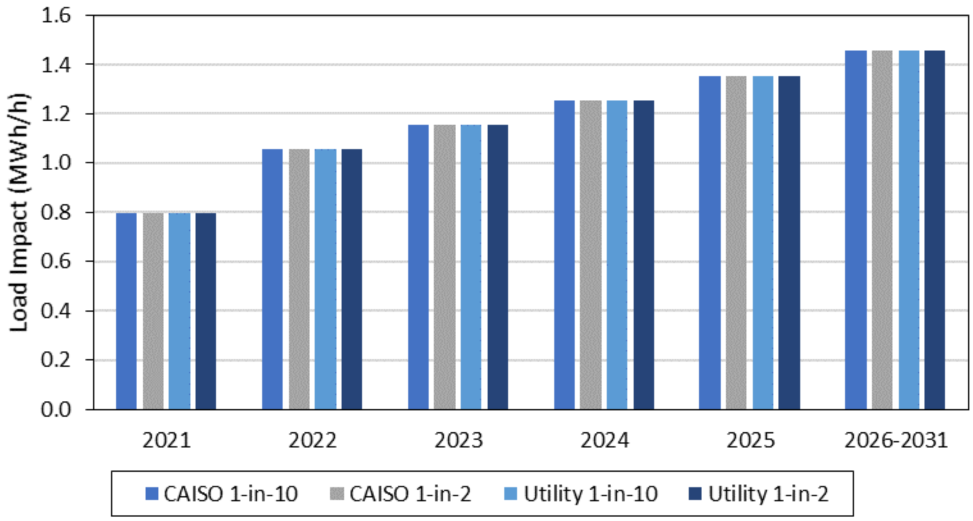


Table 5.6 shows the per-customer reference loads and load impacts by weather condition (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak) for the 2021 August event day. As mentioned above, the complete lack of variation across scenarios is a direct result of none of the customers being classified as sensitive to weather conditions.

Table 5.6: Per-customer *Ex-ante* August 2021 Load Impacts by Scenario, *SDG&E*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	244	160	65%
Utility 1-in-10	244	160	65%
CAISO 1-in-2	244	160	65%
CAISO 1-in-10	244	160	65%

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 2020 program year; and "previous study" refers to the report that was developed following the 2019 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 PY2019 and PY2020. The PY2019 load impacts are based on the two event hours (HE 18-19) on October 6, 2019. The PY2020 load impacts are based on the three event hours (HE 17-19) on the Typical Event Day (an average of August 17th and 18th 2020 events).

Table 6.1: Comparison of *Ex-post* Impacts in PY2019 and PY2020, *PG&E*

Level	Outcome	*Ex-post* PY2019	*Ex-post* PY2020
Total	# Customers	512	494
	Reference (MWh/h)	252	294
	Load Impact (MWh/h)	173	202
Per SAID	Reference (kWh/h)	492	595
	Load Impact (kWh/h)	337	408
	% Load Impact	68.6%	68.6%

There are fewer service accounts in PY2020; however, reference loads are higher because the October 6th, 2019 event was called on a Sunday, when the average customer's usage is less than it is on weekdays. The PY2020 reference load is higher than PY2019 even considering the lower than regular load as a result of COVID. The percentage load impact is similar between program years. The FSL achievement rate was 99% in PY2019 and 93% in PY2020. The higher PY2019 FSL achievement rate is a function of a greater proportion of customers in PY2019 having reference loads below their FSLs during the event hours.[26]

6.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2019 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.2 contains this comparison for the August 2021 utility-specific 1-in-2 typical event day forecast.

[26] Customers' with reference loads below their FSLs do not contribute a load impact but still contribute to the aggregate FSL, resulting in a larger FSL achievement rate. Consider, for example, two groups of customers that both achieve a 100% FSL achievement rate. Group 1 has a 100 MW reference load, 20 MW FSL, and therefore 80 MW of load impact. Group 2 has a 15 MW reference load, 10 MW FSL, and resulting 5 MW of load impact. The aggregate results would thus be a 115 MW reference load, 30 MW FSL, and 85 MW load impact, resulting in a 100% aggregate FSL achievement rate. Now consider the scenario where Group 2 has a 5 MW reference load, which is below their 10 MW FSL. The aggregate results would then be a 105 MW reference load, the same 30 MW FSL, and 80 MW of load impact (since zero load impact is contributed from Group 2). The FSL achievement rate is larger in this scenario at 107%.

Table 6.2: Comparison of *Ex-ante* Impacts from PY2019 and PY2020 Studies, *PG&E*

Level	Outcome	Ex-ante 2021 Typical Event Day, *Previous Study*	Ex-ante 2021 Typical Event Day, *Current Study*
Total	# Customers	512	308
	Reference (MWh/h)	334	234
	Load Impact (MWh/h)	236	183
	FSL (MW)	82	56
Per SAID	Reference (kWh/h)	652	761
	Load Impact (kWh/h)	461	593
	% Load Impact	70.8%	78.0%

PG&E BIP enrollment decreased by 201 customers, from 512 to 308 customers. The aggregate reference load decreased by 99 MW. The reduction in reference load comes from customers that left the program as well as lower reference loads for remaining customers because of COVID-19. Specifically, customers that de-enrolled from BIP represented 87 MW of the difference in reference loads. The remaining 12 MW is due to lower reference loads because COVID. The FSL achievement rate forecast is higher in the current study, 102%, than the previous study, 94%, because underperforming customers left the program. As well, customers that remain enrolled are larger, on average. Specifically, the per-customer reference load is 0.76 MW while assuming a COVID effect. Their non-COVID reference load would be 0.80 MW. In comparison, the average per-customer reference load in PY2019 was 0.65 MW.

6.1.3 Previous *ex-ante* versus current *ex-post*

Table 6.3 provides a comparison of the *ex-ante* forecast of 2020 load impacts prepared following PY2019 and the *ex-post* PY2020 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 2020.

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

Level	Outcome	*Ex-ante* 2020 Typical Event Day, Previous Study	*Ex-post* PY2020
Total	# Customers	512	494
	Reference (MWh/h)	334	294
	Load Impact (MWh/h)	236	202
Per SAID	Reference (kWh/h)	652	595
	Load Impact (kWh/h)	461	408
	% Load Impact	70.8%	68.6%

The aggregate load impact forecast from the previous study is larger than the current *ex-post* load impacts. The decrease is driven by two major factors. First, the enrollment forecast was slightly larger than the current *ex-post* study, 512 versus 494. Second, the average per-customer reference load was less in PY2020 because of COVID. The FSL achievement rate forecast of 94% was similar to the 93% which occurred *ex-post.* Per-customer FSLs were also similar.

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 2021 typical event day with utility-specific 1-in-2 weather conditions. The enrollments decreased from 494 to 308 from customer de-enrollment. The aggregate FSL achievement rate is larger for customers that remained on the program at 102% compared to the 93% rate which occurred during *ex-post*. The average per-customer reference load is larger in the *ex-ante* forecast because as the COVID assumption is relaxed over time, the reference load increases. In addition, customers that remain on the program are larger on average. Specifically, without COVID, the per-customer reference load of customers remaining on the program is 0.8 MW while the reference load of customers that left is 0.5 MW.

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

Level	Outcome	*Ex-post* PY2020	*Ex-ante* 2021 Typical Event Day, Current Study
Total	# Customers	494	308
	Reference (MWh/h)	294	234
	Load Impact (MWh/h)	202	183
	FSL (MWh/h)	76	56
Per SAID	Reference (kWh/h)	595	761
	Load Impact (kWh/h)	408	593
	% Load Impact	68.6%	78.0%

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 temperatures ranging from 94 to 102 degrees Fahrenheit. 98 degrees Fahrenheit on the typical event day.	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 18-23 on 8/14/2020, HE 16-21 on 8/15/2020, HE 20-20 on 8/16/2020, HE 16-20 on 8/17/2020, HE 15-20 on 8/18/2020, HE 18-23 on 9/5/2020, HE 18-21 on 9/6/2020.	HE 17-21.	Periods corresponding to larger reference loads result in larger load impacts.
Event Day of the Week	Weekend events: 8/15/2020, 8/16/2020, 9/5/2020, and 9/6/2020.	Average Weekday.	Weekday event performance is used for *ex-ante.* Weekend events correspond with lower customer reference loads which can result in lower load impacts; however, FSL achievement rates are higher because a greater proportion of customers are below their FSL.
% of resource dispatched	Events ranged from 467 to 482 customers called out of 494.	Assume all customers are called.	Larger load impacts. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	494 customers during 2020 event days.	308 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.
COVID-19	Lower reference loads because of COVID-19.	Reference loads increase over time to a non-COVID level as the effect of COVID is reduced.	Load impacts increase over time as reference loads approach a non-COVID usage level.

6.2 SCE

6.2.1 Previous versus current *ex-post*

Table 6.6 compares *ex-post* load impacts for the typical event day between PY2019 and PY2020. Only one BIP event was called in PY2019, on September 4, 2019, while eight events were called in PY2020. (The PY2020 typical event day represents the August 17th event day.) The PY2019 event was called during the hours 3:20 to 7 p.m. while the PY2020 event was called 3:10 to 7:40 p.m. Results are provided over the same hours since partial event hours are excluded from the calculations.

Table 6.6: Comparison of *Ex-post* Impacts in PY2019 and PY2020, *SCE*

Level	Outcome	*Ex-post* PY2019	*Ex-post* PY2020
Total	# Customers	479	469
	Reference (MWh/h)	685	670
	Load Impact (MWh/h)	537	514
Per SAID	Reference (kWh/h)	1,430	1,428
	Load Impact (kWh/h)	1,122	1,097
	% Load Impact	78.5%	76.8%

Enrollment decreased from 479 account so 469. There were 32 customers that de-enrolled and provided 44 MW load impact in PY2019, while there were 17 newly enrolled customer that provided 5MW load impact in PY2020. There were 484 enrolled and 479 called customers during the PY2019 event day (five customers were exempt). [redacted] The load impact of the 447 customers that were called in both program years was 47 MW lower in 2020 because of a 52 MW reduction in the reference load as a response to COVID-19. These customers' FSL achievement rate was similar in both years; however, their aggregate FSL slightly increased from 83 MW to 89 MW.

6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2019 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2021 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 PY2019 and PY2020 Studies, *SCE*

Level	Outcome	Ex-ante 2021 Typical Event Day, *Previous Study*	Ex-ante 2021 Typical Event Day, *Current Study*
Total	# Customers	452	351
	Reference (MWh/h)	690	627
	Load Impact (MWh/h)	541	488
	FSL (MWh/h)	95	109
Per SAID	Reference (kWh/h)	1,526	1,786
	Load Impact (kWh/h)	1,197	1,391
	% Load Impact	78.4%	77.9%

The enrollment numbers decreased by 101 customers between the previous and current studies. The aggregate load impact decreased by 53 MW and is caused by a mixture of effects. First, the reference load is lower in the current study as a result of customers that left the program with 83 MW of load. Second, the reference load for customers that were on the program both years have a 22 MW reduction in the current study forecast as a result of COVID. The reference load will increase over time as the COVID assumption is lessened. Third, the aggregate FSL increased from 95 MW to 109 MW. Fourth, the FSL achievement rate increase from 91% to 94% (contributing to a larger load impact). The customer that remain on the program in the current study are, on average, larger and have a larger FSL achievement rate. Without COVID, the per-customer reference load is 1.85 MW compared to the average 1.5 MW reference load in the previous study forecast.

6.2.3 Previous *ex-ante* versus current *ex-post*

Table 6.8 provides a comparison of the *ex-ante* forecast of 2020 load impacts prepared following PY2019 and the PY2020 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 August 17th, 2020 event day, averaged over only full event hours (HE 17-19).

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

Level	Outcome	*Ex-ante* 2020 Typical Event Day, Previous Study	*Ex-post PY2020*
Total	# Customers	464	469
	Reference (MWh/h)	716	670
	Load Impact (MWh/h)	562	514
	FSL (MW)	98	105
Per SAID	Reference (kWh/h)	1,542	1,428
	Load Impact (kWh/h)	1,211	1,097
	% Load Impact	78.5%	76.8%

The FSL achievement rate was 91% in the both previous forecast and during the *ex-post* event. While the enrollment number increased slightly, the lower load impact for the PY2020 event is caused by an increase to the FSL and a reduction in reference loads as a result of COVID.

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 August 17th, 2020, event day and the *ex-ante* load impact represents the 2021 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 PY2020	Ex-ante 2021 Typical Event Day, Current Study
Total	# Customers	469	351
	Reference (MWh/h)	670	627
	Load Impact (MWh/h)	514	488
	FSL (MWh/h)	105	109
Per SAID	Reference (kWh/h)	1,428	1,786
	Load Impact (kWh/h)	1,097	1,391
	% Load Impact	76.8%	77.9%

The forecast calls for a reduction in enrollment of 118 customers. The reduction in customer enrollment is from either voluntary or low performance de-enrollment. As a result, the FSL achievement rate is larger for the *ex-ante* forecast because of the customers that remain enrolled on BIP. The per-customer reference load is also larger in *ex-ante* because a) the remaining customers are larger, and b) the COVID assumption is reduced over time.

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 87 to 102 degrees Fahrenheit.	87 degrees Fahrenheit during event hours on utility-specific 1-in-2 Aug typical event day.	Higher temperatures result in higher references loads for weather sensitive customers. There is little effect on the load impact because most responsive customers are categorized as not weather sensitive.
Event window	HE 18-21 on 8/14/2020, HE 16-20 on 8/15/2020, HE 18-20 on 8/16/2020, HE 16-20 on 8/17/2020, HE 14-20 on 8/18/2020, HE 18-21 on 9/5/2020, HE 17-21 on 9/6/2020, HE 17-20 on 9/7/2020.	HE 17-21.	The slightly later *ex-ante* event window tends toward slightly lower reference loads and load impacts relative to the *ex-post* window.
Event Day of the Week	Weekend events: 8/15/2020, 8/16/2020, 9/5/2020, and 9/6/2020.	Average Weekday.	Weekday event performance is used for *ex-ante.* Weekend events correspond with lower customer reference loads which can result in lower load impacts; however, FSL achievement rates are higher because a greater proportion of customers are below their FSL.
% of resource dispatched	All customers were called except 9/7/2020 event day.	Assume all customers are called.	None.
Enrollment	469 customers during the typical *ex-post* event day.	351 customers in August 2021.	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.
COVID-19	Lower reference loads because of COVID-19.	Reference loads increase over time to a non-COVID level as the effect of COVID is reduced.	Load impacts increase over time as reference loads approach a non-COVID usage level.

6.3 SDG&E

6.3.1 Previous versus current *ex-post*

Table 6.11 compares *ex-post* load impacts between PY2019 and PY2020. The PY2019 load impacts are based on the September 4, 2019 event while the PY2020 load impacts are based on the 2020 typical event day (*i.e.,* August 14th, 19th, and 20th). Calculations for the PY2019 are over the event hours-ending 13 through 16 while the PY2020 event calculations are over the event hours-ending 19 through 20.

Table 6.11: Comparison of *Ex-post* Impacts in PY2019 and PY2020, *SDG&E*

Level	Outcome	*Ex-post* PY2019	*Ex-post* PY2020
Total	# Customers	5	4
	Reference (MWh/h)	3.6	0.6
	Load Impact (MWh/h)	2.9	0.4
Per SAID	Reference (kWh/h)	725.0	156.3
	Load Impact (kWh/h)	573.5	106.1
	% Load Impact	79.1%	67.9%

SDG&E BIP enrollment decreased by one customer to four. The one customer that left the program provided a 0.3 MW load impact in PY2019. The load impact for the customers that were called both years decreased from 2.6 MW in 2019 to 0.4 MW in 2020. The hourly reference load profiles are similar between years and did not exhibit a significant reduction in response to COVID. The difference in load impact is a result of difference in event hours called. The aggregate load decrease to a level below the program FSL around hour-ending 17, thus reducing the amount of curtailable load. The earlier called event hours in 2019 resulted in a larger load impact.

6.3.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2019 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.12 presents this comparison for the *ex-ante* forecasts of the utility-specific 1-in-2 August typical event day.

Table 6.12: Comparison of *Ex-ante* Impacts from PY2019 and PY2020 Studies, *SDG&E*

Level	Outcome	Ex-ante 2021 Typical Event Day, *Previous Study*	Ex-ante 2021 Typical Event Day, *Current Study*
Total	# Customers	6	5
	Reference (MWh/h)	1.6	1.2
	Load Impact (MWh/h)	1.0	0.8
	FSL (MWh/h)	0.5	0.4
Per SAID	Reference (kWh/h)	263.6	244.0
	Load Impact (kWh/h)	165.4	159.8
	% Load Impact	62.8%	65.5%

The enrollment forecast is slightly lower in the current study which also results in lower reference loads and load impacts. Per-customer reference loads are slightly lower in the current study because of one customer that left the program. While COVID had minimal effect on the reference loads of SDG&E's remaining BIP customers, the effect occurs mostly during the evening hours. The percentage load impact is similar between both years.

6.3.3 Previous *ex-ante* versus current *ex-post*

Table 6.13 compares the *ex-ante* forecast prepared following PY2019 to the PY2020 *ex-post* load impact estimates contained in this report for the typical event day. The *ex-ante* load impacts are based on the typical event day in a utility-specific 1-in-2 weather year. The later event hours in the *ex-post* analysis (HE 19-20 vs HE 17-21) contributes to smaller per-customer load impacts because the larger enrolled customers have greater loads during the earlier hours and reduced to their FSL around hour-ending 17, resulting in less curtailable load during evening hours. When comparing similar hours for customers that existed in both analyses, the PY2020 reference loads are slightly lower as a result of COVID.

Table 6.13: Comparison of Previous *Ex-ante* and Current *Ex-post* Impacts, *SDG&E*

Level	Outcome	*Ex-ante* 2020 Typical Event Day, Previous Study	*Ex-post PY2020*
Total	# Customers	5	4
	Reference (MWh/h)	1.3	0.6
	Load Impact (MWh/h)	0.9	0.4
Per SAID	Reference (kWh/h)	263.6	156.3
	Load Impact (kWh/h)	178.5	106.1
	% Load Impact	67.7%	67.9%

6.3.4 Current *ex-post* versus current *ex-ante*

Table 6.14 shows a comparison of *ex-post* and *ex-ante* load impacts. SDG&E assumes enrollment to increase by one each year until 2025. The increased reference loads and load impacts in the *ex-ante* forecast is caused by the RA window of 4 to 9 p.m., which begins earlier than the *ex-post* event hours of 6 to 8 p.m. The earlier event window corresponds to a period when customers have more curtailable load above their FSLs. Nevertheless, over similar hours, the per-customer reference load is slightly larger in the *ex-ante* forecast as the effect of COVID on reference loads diminishes over time. The *ex-post* and *ex-ante* FSL achievement rate match by design for four customers currently enrolled in the program. Additional customer enrollments are assumed to provide a 0.1 MW load impact during the RA window.

Table 6.14: Comparison of Current *Ex-post* and Current *Ex-ante* Impacts, *SDG&E*

Level	Outcome	Ex-post PY2020	Ex-ante 2021 Typical Event Day, Current Study
Total	# Customers	4	5
	Reference (MWh/h)	0.6	1.2
	Load Impact (MWh/h)	0.4	0.8
	FSL (MWh/h)	0.32	0.40
Per SAID	Reference (kWh/h)	156.3	244.0
	Load Impact (kWh/h)	106.1	159.8
	% Load Impact	67.9%	65.5%

Table 6.15 below describes the factors that differ between the *ex-post* and *ex-ante* load impacts for SDG&E.

Table 6.15: SDG&E BIP *Ex-post* versus *Ex-ante* Factors, Typical Event Day

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	Event hour temperatures ranging from 78 to 91 degrees Fahrenheit, 83 degrees Fahrenheit for the typical event day.	90 degrees Fahrenheit during HE 17 to 21 on utility-specific 1-in-2 typical event day	Program load is not very weather sensitive, so little to no effect.
Event window	HE 19-20 on 8/14/2020, HE 16-19 on 8/17/2020, HE 20-20 on 8/18/2020, HE 19-20 on 8/19/2020, HE 19-20 on 8/20/2020.	HE 17 to 21.	Reference loads are substantially lower during evening hours, resulting in higher average *ex-ante* reference loads and load impacts relative to *ex-post* because the RA window begins slightly earlier.
% of resource dispatched	All	All	None.
Enrollment	4 service accounts	5 service accounts in 2021.	The *ex-ante* forecast scales reference loads. The load impact is assumed to increase by 0.1 MW for additionally enrolled customers.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions.	Possible difference between simulated *ex-ante* and estimated *ex-post* reference loads. In this case, however, the aggregate differences are minimal.
COVID-19	Slightly lower reference loads because of COVID-19.	Reference loads slightly increase over time to a non-COVID level as the effect of COVID is reduced.	Load impacts increase over time as reference loads approach a non-COVID usage level.

7. Recommendations

BIP continues to perform well, with its customers providing substantial load impacts with short notice. PG&E and SCE called seven and eight events, respectively, including weekends and multiple consecutive events. Load decreases persisted into the morning hours of consecutive event days.

Load impacts did not appear to diminish as a result of consecutive event days. However, load impacts on consecutive event days look somewhat different than those of the first event in a series (or a stand-alone event day) because a portion of the event-hour impact is due to persistence from the prior day's event, as is shown in Figure 4.4. A key implication is that the within-day load drop on a consecutive event day will be appear lower than the total impact of the program. For example, if 70 MW of load impact persists during the hours in between two events, the load drop (not to be confused with the load impact) during the second event day will be 70 MW lower than it was on the first event day (all else equal) even though the total program load impact is the same on both days.

SDG&E called five events but may want to consider calling earlier events to ensure that its customers are capable of consistently meeting their obligation during hours in which their loads are above their FSL. However, this decision is likely offset by the need to call events during the RA window.

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_2020_BIP_Ex_Post_PUBLIC
BIP Study Appendix D	SCE 2020 BIP *Ex-Post* PUBLIC
BIP Study Appendix E	SDG&E 2020 BIP *Ex-Post*
BIP Study Appendix F	6.b PGE_2020_BIP_Ex_Ante_PUBLIC
BIP Study Appendix G	SCE 2020 BIP *Ex-Ante* PUBLIC
BIP Study Appendix H	SDG&E 2020 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.3 provides the number of customers that are categorized as weather sensitive by industry group and utility. Customer weather sensitivity was evaluated for weekdays and weekends for PG&E and SCE because of the weekend *ex-post* events called.[27] The proportion of PG&E customers classified as non-weather sensitive was 81% for weekdays and 82% for weekends. The proportion of SCE customers classified as non-weather sensitive was 65% for weekdays and 66% for weekends. All SDG&E customers were classified as non-weather sensitive for weekdays (no weekend events were called). The retail industry group had the greatest proportion of weather sensitive customers.

[27] The total number of customers included in the weekday models was less than the weekend models because not all enrolled customers were called for the weekday events.

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	44	223	267	16%
2. Manufacturing	23	75	98	23%
3. Wholesale, Transportation, Utilities	15	85	100	15%
4. Retail	9	0	9	100%
5. Offices, Hotels, Health, Services	1	4	5	20%
6. Schools	1	0	1	100%
8. Other	0	1	1	0%
Total	**93**	**388**	**481**	**19%**

WEEKEND

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	42	223	265	16%
2. Manufacturing	15	76	91	16%
3. Wholesale, Transportation, Utilities	17	83	100	17%
4. Retail	8	1	9	89%
5. Offices, Hotels, Health, Services	1	4	5	20%
6. Schools	1	0	1	100%
Total	**84**	**387**	**471**	**18%**

Table A.2: Weather Sensitive Customer Count by Industry Type, SCE

WEEKDAY

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	7	31	38	18%
2. Manufacturing	72	217	289	25%
3. Wholesale, Transportation, Utilities	23	34	57	40%
4. Retail	44	4	48	92%
5. Offices, Hotels, Health, Services	10	4	14	71%
6. Schools	2	0	2	100%
7. Entertainment, Other Services, Government	2	2	4	50%
8. Other	2	15	17	12%
Total	**162**	**307**	**469**	**35%**

WEEKEND

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	5	33	38	13%
2. Manufacturing	74	215	289	26%
3. Wholesale, Transportation, Utilities	25	32	57	44%
4. Retail	40	8	48	83%
5. Offices, Hotels, Health, Services	12	2	14	86%
6. Schools	1	1	2	50%
7. Entertainment, Other Services, Government	2	2	4	50%
8. Other	2	15	17	12%
Total	**161**	**308**	**469**	**34%**

Table A.3: Weather Sensitive Customer Count by Industry Type, SDG&E

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	0	2	2	0%
2. Manufacturing	0	2	2	0%
Total	**0**	**4**	**4**	**0%**

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.[28] The tests are conducted using average-customer

[28] 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.

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)[29]; heat index (HI)[30]; cooling degree hours (CDH)[31], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[32], including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we tested for weather sensitive customers is provided in Table A.4, including 17 specifications for the *ex-post* analysis and 7 for *ex-ante* analysis.

[29] 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").

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

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

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

Table A.4: 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.5, where an "X" between two variables represents the interaction of these two variables. Each specification includes the following variables in common: hour indicators, day type indicators, and events interacted with hour indicators. For the *ex-ante* analysis, we exclude the specifications with the morning load variable.

Table A.5: 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 (for SDG&E), 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.6 lists the event-like non-event days selected, separated by weekday and weekend for PG&E and SCE.

Table A.6: List of Event-Like Non-Event Days by IOU

PG&E		SCE		SDG&E
Weekday	Weekend	Weekday	Weekend	Weekday
5/26/2020	7/11/2020	6/4/2020	6/20/2020	7/10/2020
5/27/2020	7/12/2020	6/24/2020	7/11/2020	7/31/2020
6/3/2020	8/22/2020	7/6/2020	7/12/2020	8/13/2020
7/10/2020	8/23/2020	7/30/2020	8/1/2020	8/24/2020
8/13/2020	9/27/2020	7/31/2020	8/2/2020	8/25/2020
9/8/2020		8/20/2020	8/22/2020	8/27/2020
9/28/2020		8/21/2020	8/23/2020	9/16/2020
		9/4/2020		9/17/2020
				9/18/2020
				9/29/2020

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.7 through A.9 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.7 for PG&E bifurcates the results by weekday and weekend.

Table A.7: 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	1.2%	3.6%	44
	2. Manufacturing	5	0.0%	10.9%	23
	3. Wholesale, Transportation, Utilities	12	1.6%	5.1%	15
	4. Retail	15	1.6%	2.1%	9
	5. Offices, Hotels, Health, Services	17	1.3%	9.8%	1
	6. Schools	3	0.8%	6.0%	1
	8. Other	n/a	n/a	n/a	n/a
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	-1.5%	3.3%	223
	2. Manufacturing	2	0.1%	1.9%	75
	3. Wholesale, Transportation, Utilities	4	11.7%	16.6%	85
	5. Offices, Hotels, Health, Services	2	83.7%	98.2%	4
	6. Schools	n/a	n/a	n/a	n/a
	8. Other	2	13.1%	20.3%	1

WEEKEND

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	16	-0.1%	5.6%	42
	2. Manufacturing	3	15.5%	29.1%	15
	3. Wholesale, Transportation, Utilities	17	1.7%	9.9%	17
	4. Retail	7	0.3%	1.1%	8
	5. Offices, Hotels, Health, Services	14	-0.2%	3.7%	1
	6. Schools	5	-2.3%	3.2%	1
	8. Other	n/a	n/a	n/a	n/a
Non-Weather Sensitive	1. Agriculture, Mining, Construction	4	-0.1%	3.5%	223
	2. Manufacturing	4	1.5%	2.8%	76
	3. Wholesale, Transportation, Utilities	4	3.2%	4.3%	83
	5. Offices, Hotels, Health, Services	3	93.2%	105.0%	4
	6. Schools	n/a	n/a	n/a	n/a
	8. Other	n/a	n/a	n/a	n/a

Table A.8: 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	16	0.1%	4.6%	7
	2. Manufacturing	16	1.9%	2.3%	72
	3. Wholesale, Transportation, Utilities	16	-0.2%	5.0%	23
	4. Retail	1	0.1%	1.0%	44
	5. Offices, Hotels, Health, Services	14	0.1%	3.3%	10
	6. Schools	4	0.0%	2.3%	2
	7. Entertainment, Other Services, Government	6	-0.7%	4.9%	2
	8. Other	4	0.5%	2.0%	2
Non-Weather Sensitive	1. Agriculture, Mining, Construction	4	0.8%	3.2%	31
	2. Manufacturing	3	3.5%	4.6%	217
	3. Wholesale, Transportation, Utilities	1	-0.4%	3.8%	34
	5. Offices, Hotels, Health, Services	4	-0.6%	2.7%	4
	6. Schools	5	1.7%	5.4%	4
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	n/a
	8. Other	5	-3.7%	18.9%	2

WEEKEND

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	11	-0.7%	3.9%	5
	2. Manufacturing	17	0.0%	2.4%	74
	3. Wholesale, Transportation, Utilities	3	-0.1%	11.1%	25
	4. Retail	7	0.0%	1.6%	40
	5. Offices, Hotels, Health, Services	16	0.5%	2.1%	12
	6. Schools	10	-2.0%	4.1%	1
	7. Entertainment, Other Services, Government	3	-0.3%	7.7%	2
	8. Other	4	6.2%	8.6%	2
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	0.7%	1.9%	33
	2. Manufacturing	3	1.7%	5.2%	215
	3. Wholesale, Transportation, Utilities	3	0.8%	4.4%	32
	5. Offices, Hotels, Health, Services	4	-0.1%	2.6%	8
	6. Schools	3	4.9%	15.9%	2
	7. Entertainment, Other Services, Government	3	-0.2%	4.2%	1
	8. Other	5	0.9%	3.2%	2

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

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1 & 2[33]	207.7%	231.9%	2
	2. Manufacturing	2	112.1%	139.3%	2

Tables A.10 through A.12 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.10: 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	1	0.2%	3.4%	81
	2. Manufacturing	4	3.8%	13.8%	20
	3. Wholesale, Transportation, Utilities	5	1.3%	7.0%	37
	4. Retail	5	0.5%	1.6%	9
	5. Offices, Hotels, Health, Services	1	-0.6%	3.7%	4
	8. Other	4	0.0%	3.6%	10
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	-0.8%	2.3%	187
	2. Manufacturing	2	-1.8%	3.9%	74
	3. Wholesale, Transportation, Utilities	1	3.3%	8.9%	72
	4. Retail	n/a	n/a	n/a	n/a
	5. Offices, Hotels, Health, Services	1	71.8%	98.1%	1
	8. Other	2	-1.8%	12.6%	17

[33] A separate regression specification was chosen for each SDG&E customer, instead of a specification choice by industry group, because of the low number of customers.

Table A.11: 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	6.0%	8.5%	8
	2. Manufacturing	4	-0.3%	2.1%	103
	3. Wholesale, Transportation, Utilities	6	-0.4%	4.2%	29
	4. Retail	4	0.0%	1.5%	46
	5. Offices, Hotels, Health, Services	5	-0.4%	4.2%	15
	6. Schools	1	3.6%	9.1%	5
	7. Entertainment, Other Services, Government	4	-2.5%	5.5%	4
	8. Other or unknown	5	-3.0%	5.7%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1	1.6%	1.7%	38
	2. Manufacturing	2	-0.4%	3.3%	196
	3. Wholesale, Transportation, Utilities	1	-1.7%	5.7%	31
	4. Retail	1	19.4%	27.5%	2
	5. Offices, Hotels, Health, Services	2	-3.1%	15.9%	1
	6. Schools	n/a	n/a	n/a	n/a
	7. Entertainment, Other Services, Government	1	2.8%	16.6%	2
	8. Other or unknown	1	22.6%	32.3%	3

Table A.12: Specification Test Results for the *Ex-Ante* analysis, SDG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1 & 2	112%	137%	2
	2. Manufacturing	1	3.2%	16.9%	2

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.6, 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.13 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.7 through A.9. 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. However, there is a higher proportion of statistically significant load impacts on synthetic event days on weekdays for SCE. This is driven in large part by the manufacturing industry group and the lack of using morning load variables in the regression specifications for SCE (see Section 3.2.1).

Table A.13: Percentage of Statistically Significant Synthetic Event-Day Estimated Load Impacts

Hour	Percent Statistically Significant				
	PG&E		SCE		SDG&E
	Weekday	Weekend	Weekday	Weekend	
14			47%	23%	
15	0%	47%	47%	26%	
16	2%	9%	46%	0%	0%
17	47%	0%	46%	0%	0%
18	2%	0%	53%	0%	0%
19	20%	0%	53%	0%	0%
20	20%	0%	54%	0%	0%
21	18%	0%	49%	16%	
Average Event Hour	**15.5%**	**8.1%**	**49.6%**	**8.1%**	**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.4 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.

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

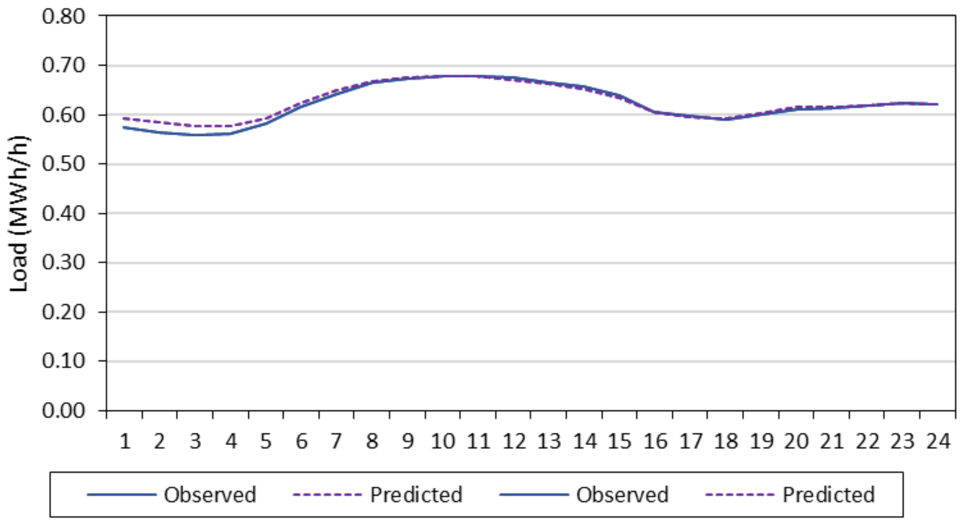


Figure A.2 Average Observed & Predicted Loads on Weekend Event-like Days, *PG&E*

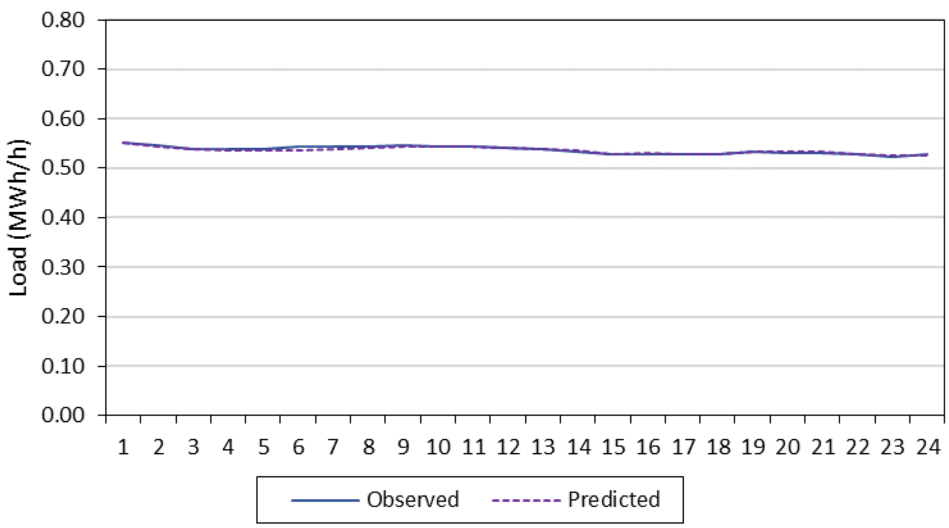


Figure A.3: Average Observed & Predicted Loads on Weekday Event-like Days, *SCE*

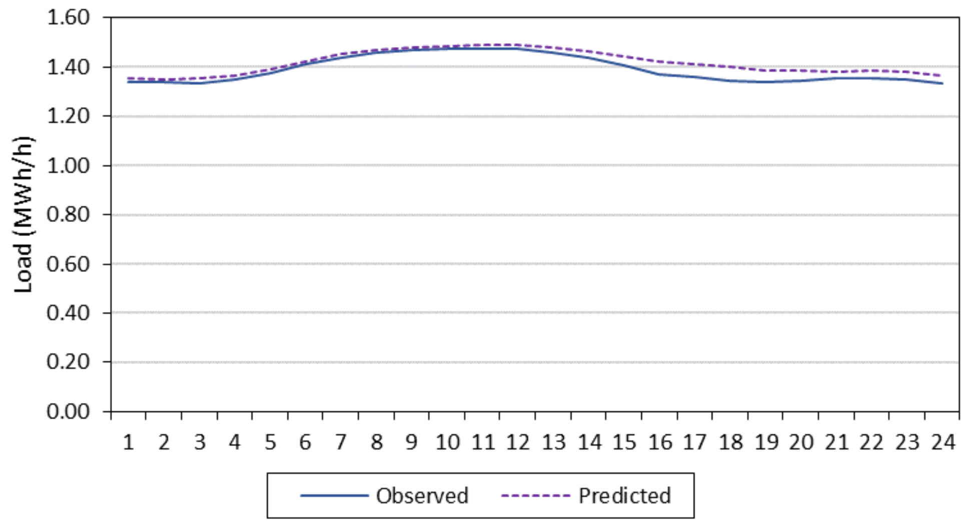


Figure A.4: Average Observed & Predicted Loads on Weekend Event-like Days, *SCE*

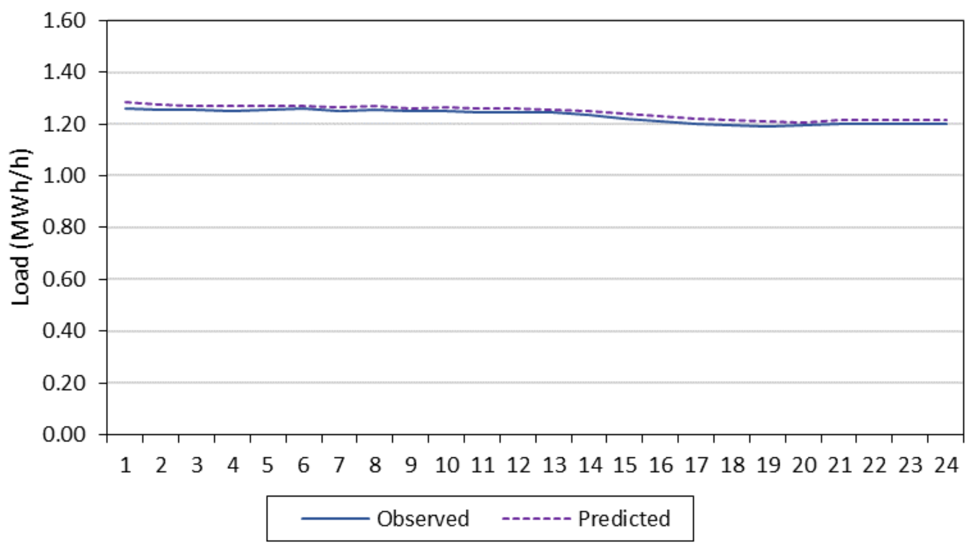
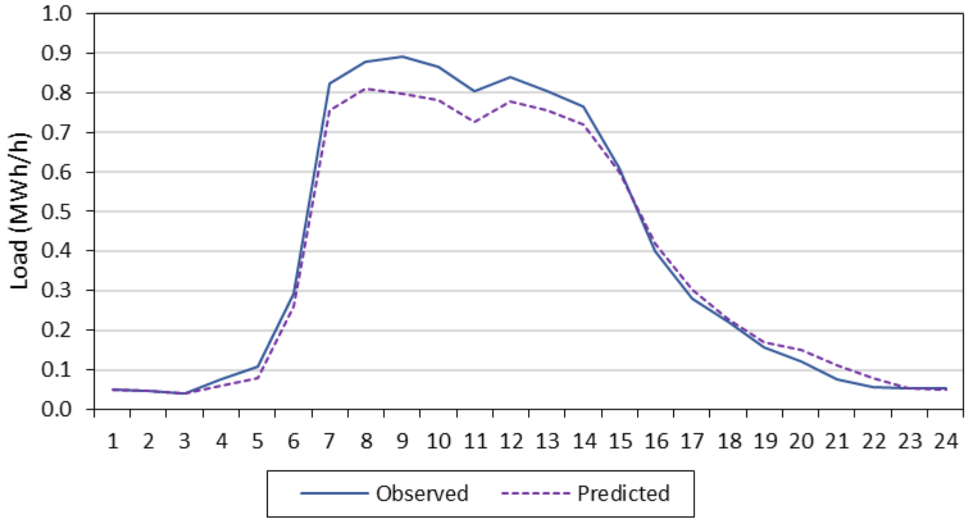


Figure A.4: Average Observed & Predicted Loads on Weekday Event-like Days, *SDG&E*



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.[34] FSL achievement is defined as the estimated *ex-post* load impact divided by 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. Each utility called multiple events in 2020, including weekdays and weekends (for PG&E and SCE). 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).[35] Table B.1 through Table B.2 summarizes the FSL achievement rate by industry group for each utility.

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

[35] FSL achievement rates can vary between event dates; however, they were consistent between the last event dates, even as consecutive events.

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

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	129	[redacted]			
2. Manufacturing	72	5%	102%	102%	51%
3. Wholesale, Transportation, Utilities	98	[redacted]			
4. Retail	4				
5. Offices, Hotels, Health, Services	3				
6. Schools	1				
8. Other	1				

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

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	30	[redacted]			
2. Manufacturing	236	28%	91%	92%	30%
3. Wholesale, Transportation, Utilities	46	[redacted]			
4. Retail	3	30%	100%	100%	31%
5. Offices, Hotels, Health, Services	4	[redacted]			
6. Schools	2				
7. Institutional/Government	3				
8. Other	17				

Table B.3: *Ex-Post* Event Day Over/Under Performance – SDG&E BIP,
by Industry Group and Event Hour

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	2	119%	89%	89%	85%
2. Manufacturing	2	84%	90%	90%	86%