2015 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report

Public Version

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Abstract

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and an *ex-ante* forecast of load impacts for 2016 through 2026 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2015 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 one full event in 2015: PG&E on July 30, SCE on September 24, and SDG&E on August 28. PG&E called four additional re-test events for sub-sets of its program in February, April, September, and November. SCE and SDG&E called no other events. Enrollment in PG&E's BIP was 204 service agreements on July 30. The highest aggregate reference load for any hour on that day was 338 MW. Enrollment in SCE's BIP was 610 service accounts on the September 24 event day. The aggregate reference load reached a high of 904 MW on that day. SDG&E's BIP enrollment was 5 service accounts on the August 28 event day, and the highest aggregate reference load on that day was [redacted].

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 July 30th test event averaged 246 MW, or 84 percent of enrolled load. This was 101 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 average hourly load impact for its September 24th Measurement and Evaluation event was 692 MW, or 80 percent of the total reference load, representing 90 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its August 28th test event averaged [redacted], or 54 percent of enrolled load, representing 99 percent of the reduction required to meet the aggregate FSL.

In the *ex-ante* evaluation, PG&E forecasts BIP enrollment to remain constant from 2016 to 2026 at 208 service agreements. PG&E's average event-hour load impact is forecast to be 255 MW during a utility-specific 1-in-2 August 2016 typical event day. SCE forecasts BIP customer enrollment to decrease somewhat from 2016 through 2019 due to opt outs from the program. During the 2016 program year, SCE's average event-hour load impact is approximately 684 MW. SDG&E enrollment remains constant throughout the forecast period, at 7 service accounts. SDG&E's average event-hour load impact is forecast to be [redacted] during a utility-specific 1-in-2 August 2016 typical event day.

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 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and an *ex-ante* forecast of load impacts for 2016 through 2026 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2015 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2015?
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 2016 through 2026?

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 one full event in 2015: PG&E on July 30, SCE on September 24, and SDG&E on August 28. PG&E also called four re-test events for sub-sets of its program on February 11, April 23, September 22, and November 17.

Enrollment

Enrollment in PG&E's BIP decreased relative to PY2014, from 218 to 204 in 2015. The sum of enrolled customers' coincident maximum demands was 338 MW, or 1.66 MW for the average service agreement. [1] The manufacturing industry group contains almost two thirds 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]

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[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).

SCE's enrollment in BIP was 610 service accounts on the September 24, 2015 event day, which is a slight decrease relative to the 620 enrolled service accounts during PY2014. These accounted for a total of 904 MW of maximum demand, or 1.48 MW per service account. [1] Manufacturers make up about two-thirds of the enrolled load. Figure ES.2 illustrates the distribution of SCE's BIP load across the indicated industry types.

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

[redacted]

SDG&E's enrollment in BIP was 5 service accounts on its August 28th, 2015 event day, which is down from 7 service accounts enrolled during PY2014. These accounted for a total of [redacted] Figure ES.3 illustrates the distribution of SDG&E's BIP load across the indicated industry types.

Figure ES.3 Distribution of BIP Enrolled Load by Industry Type, SDG&E

[redacted]

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

The total program load impact for PG&E's July 30th test event averaged 246 MW, or 84 percent of enrolled load, representing 101 percent of the reduction required to meet the aggregate FSL.

For SCE, the average hourly load impact for its September 24th Measurement and Evaluation event was 692 MW, or 80 percent of the total reference load. This was 90 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its August 28th test event averaged [redacted]

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 2016 through 2026, with 208 enrolled service agreements. SCE projects BIP enrollments to decrease during 2016 through 2019 by a total of 12 percent. SDG&E forecasts constant enrollments for 2016 through 2026 of 7 service accounts.

SDG&E's *ex-ante* load impact for a typical event day under utility-specific 1-in-2 weather conditions is [redacted].

Figures ES.4-6 show the *ex-ante* load impacts for PG&E, SCE, and SDG&E respectively. These figures illustrate the lack of weather sensitivity at the aggregate level.

Figure ES.4: Average August *Ex-ante* Load Impacts by Scenario, 2016-2026, PG&E

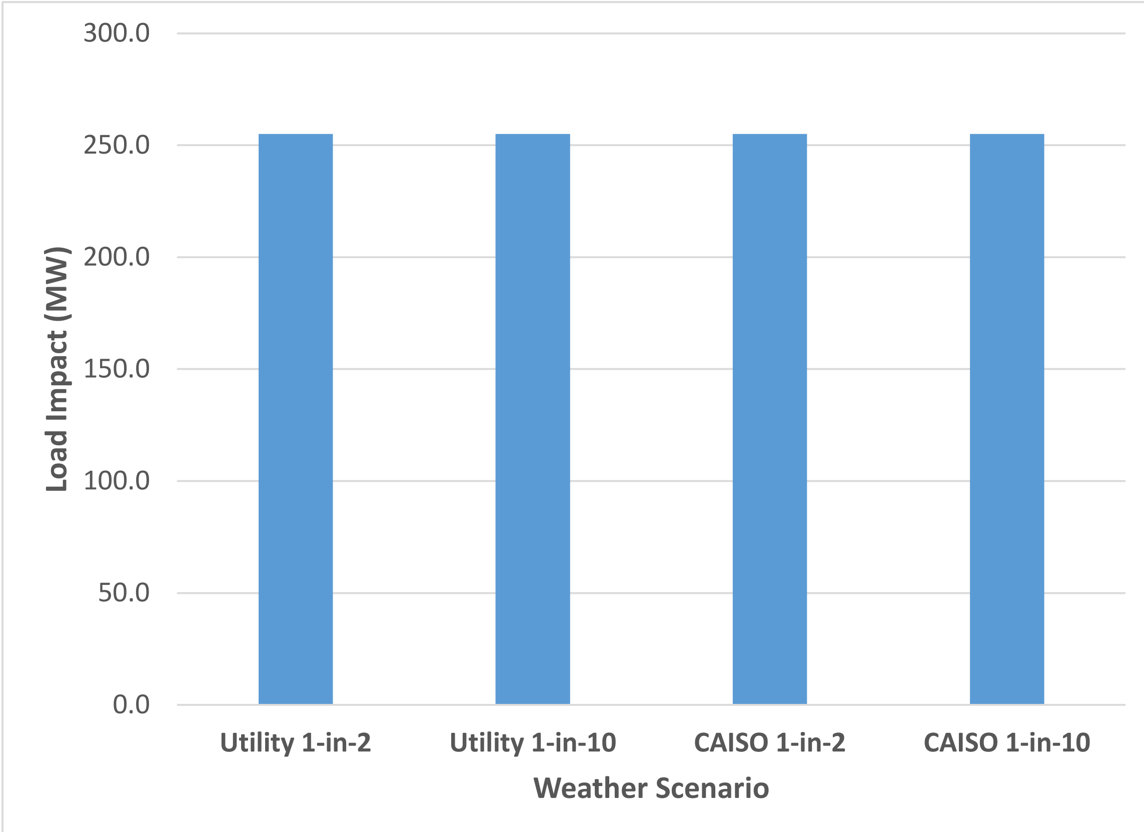


Figure ES.5: Average August *Ex-ante* Load Impacts by Year and Scenario, *SCE*

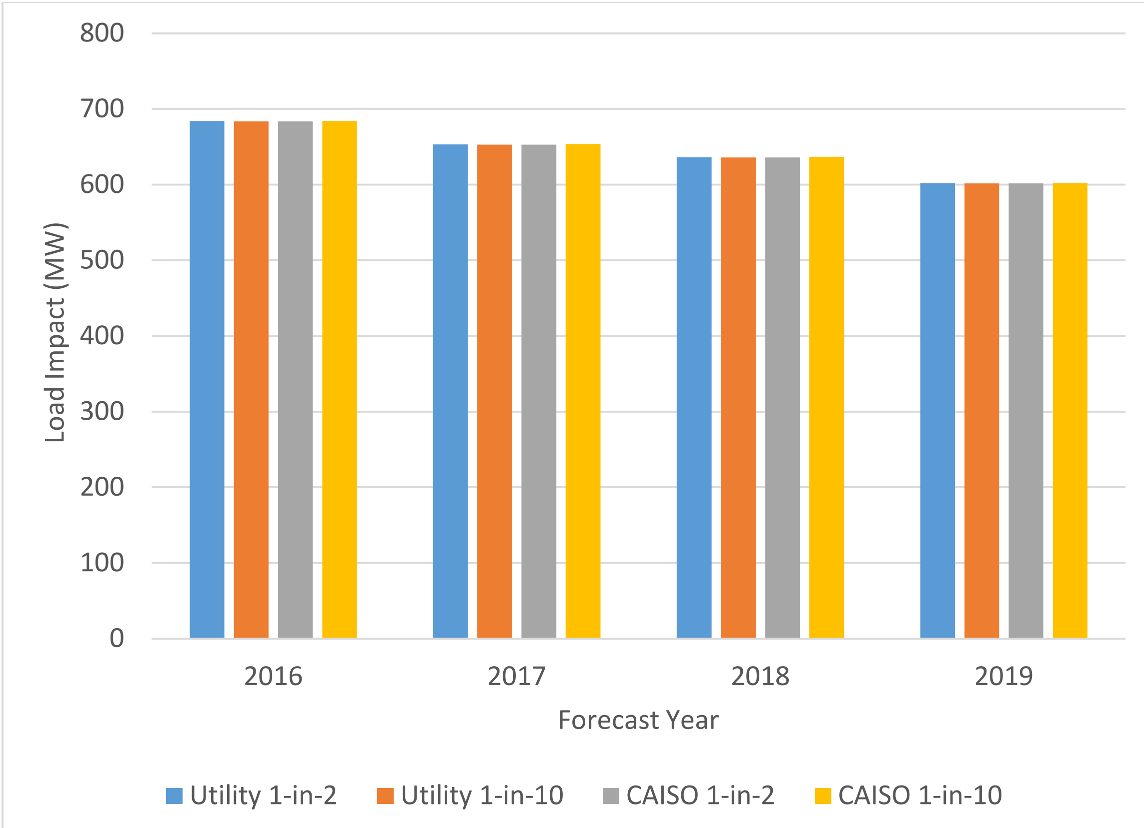


Figure ES.6: Average August *Ex-ante* Load Impacts by Scenario, 2016-2016, SDG&E

[redacted]

1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and an *ex-ante* forecast of load impacts for 2016 through 2026 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2015 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2015?
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 2016 through 2026?

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.

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 2015.

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; and
- 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 four 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 30 minutes before the event. Monthly incentive payments are $12 per kW during May through October and $2 per kW during all other 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 no participants in 2006, three participants in 2007, five participants in 2008, 20 in 2009, 19 customers in 2010, 21 customers in 2011, 11 in 2012,[2] seven participants in 2013 and 2014, and five participants in 2015.

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).[3]

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 on the July 30, 2015 event day. Enrollment in PG&E's BIP decreased relative to PY2014, from 218 to 204.[4] The sum of enrolled customers'

[2] Previously SDG&E offered a BIP option B which required that participating customer be notified at least three hours before the event but SDG&E discontinued this option in 2012.

[3] 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.

[4] "Enrollment" is defined as the enrollment on the July 30, 2015 event day for PG&E; the September 24, 2015 event day for SCE; and the August 28, 2015 event day for SDG&E.

coincident maximum demands[5] was 338 MW, or 1.66 MW for the average service agreement. The manufacturing industry group contains more than half of the enrolled load.

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

Industry Type	# of Service Agreements	Sum of Max MW[6]	% of Max MW	Ave. Max MW[7]
1.Agriculture, Mining, Construction	39	50.8	15.0%	1.30
2.Manufacturing	85	212.5	62.8%	2.50
3.Wholesale, Transportation, Utilities	40	42.0	12.4%	1.05
4.Retail	[redacted]			
5.Offices, Hotels, Health, Services				
6.Schools				
7. Entertainment, Other Services, Government.				
8.Other				
TOTAL	**204**	**338.3**		**1.66**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 610 service accounts on the September 24, 2015 event day, which is a slight decrease relative to the 620 enrolled service accounts during PY2014. These accounted for a total of 904 MW of maximum demand, or 1.48 MW per service account. Manufacturers make up about two-thirds of the enrolled load.

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

Industry Type	# of Service Accounts	Sum of Max MW[6]	% of Max MW	Ave. Max MW
1.Agriculture, Mining, Construction	56	171.6	19.0%	3.06
2.Manufacturing	363	599.0	66.2%	1.65
3.Wholesale, Transportation, Utilities	66	53.3	5.9%	0.81
4.Retail	61	18.5	2.0%	0.30
5.Offices, Hotels, Health, Services	[redacted]			
6.Schools				
7.Entertainment, Other Services, Government.				
TOTAL	**610**	**904.2**		**1.48**

Table 2.3 shows BIP enrollments for SDG&E. SDG&E's enrollment in BIP was 5 service accounts on the August 28, 2015 event day. These accounted for a total of [redacted]

[5] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 4—demand during the hour with the highest aggregate demand that day—including the estimated load impacts (i.e., using the reference loads).

[6] "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.

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

[redacted]

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

Industry Type	# of Service Accounts	Sum of Max MW[6]	% of Max MW	Ave. Max MW
1.Agriculture, Mining, Construction	[redacted]	[redacted]	[redacted]	[redacted]
2.Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]
3.Wholesale, Transportation, Utilities	[redacted]	[redacted]	[redacted]	[redacted]
4.Retail	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]

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 not in an LCA and 75 percent of SCE's enrolled load is in the LA Basin.

Table 2.4: BIP Enrollees by Local Capacity Area, *PG&E*

Local Capacity Area	# of Service Agreements	Sum of Max MW[6]	% of Max MW	Ave. Max MW
Greater Bay Area	[redacted]	[redacted]	[redacted]	[redacted]
Greater Fresno	[redacted]	[redacted]	[redacted]	[redacted]
Humboldt	[redacted]	[redacted]	[redacted]	[redacted]
Kern	[redacted]	[redacted]	[redacted]	[redacted]
Northern Coast	[redacted]	[redacted]	[redacted]	[redacted]
Not in any LCA	88	241.1	71.3%	2.74
Sierra	[redacted]	[redacted]	[redacted]	[redacted]
Stockton	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL	**204**	**338.3**		**1.66**

Table 2.5: BIP Enrollees by Local Capacity Area, *SCE*

Local Capacity Area	# of Service Accounts	Sum of Max MW[6]	% of Max MW	Ave. Max MW
LA Basin	527	673.6	74.5%	1.28
Outside LA Basin	[redacted]	[redacted]	[redacted]	[redacted]
Ventura	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL	**610**	**904.2**		**1.48**

2.3 Event Days

Table 2.6 lists BIP event days and hours for the three IOUs in 2015. Each utility called one full test event.[8] PG&E called four additional re-test events for sub-sets of its program.

[8] SCE refers to their events of this type as Measurement and Evaluation events.

Table 2.6: BIP Event Days

Date	Day of Week	PG&E	SCE	SDG&E
2/11/2015	Wednesday	Re-test, 2:00-4:00 p.m.		
4/23/2015	Thursday	Re-test, 2:00-4:00 p.m.		
7/30/2015	Thursday	Test, 3:00-7:00 p.m.		
8/28/2015	Friday			Test, 1:00-5:00 p.m.
9/22/2015	Tuesday	Re-test, 2:00-4:00 p.m.		
9/24/2015	Thursday		M&E, 1:00-3:30 p.m.	
11/17/2015	Tuesday	Test, 12:00-2:00 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.[9]

[9] 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, the exclusion of these data does not affect the model's ability to estimate *ex-post* load impacts.

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. This process and its results are explained in Appendix A.

3.2 Description of methods

3.2.1 Regression Model

The following model was separately estimated for each enrolled PG&E and SCE customer. Table 3.1 below describes the terms included in this equation for the observed demand in a given hour h and date d:

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

A modified model was used for SDG&E customers. To better capture the greatly shifting load profiles across months of a few relatively large customers, an interaction term between month and hour was added. To address the potential for overfitting with this near doubling of the total number of estimated coefficients, the interaction terms between specific days of the week (Monday and Friday) and hour were removed.

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

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

Variable Name	Variable Description
Q_t	the demand in hour t for a BIP customer
The various b's	the estimated parameters
$h_{i,t}$	an indicator variable for hour i, equal to one when t corresponds to hour i of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day DR of other demand response programs in which the customer is enrolled (e.g. DR = DBP Event 1, DBP 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
$MornLoadAlt_t$	a variable equal to the average of the day's load in hours 9 through 12
$DTYPE_{j,t}$	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
$SUMMER_t$	an indicator variable for the summer pricing season[10]
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 condition 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 (*e.g.*, Demand Bidding Program, or DBP). 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.

The model allows for the hourly load profile to differ by: day of week, with separate profiles for Monday, Tuesday through Thursday, and Friday; and by pricing season (*i.e.*, summer versus winter), in order to account for potential customer load changes in response to seasonal changes in rates.

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 and local capacity area (LCA).

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

A parallel set of winter models was estimated for each customer. The structure matches the model described above, with the appropriate month indicators substituted in.

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. 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.

On a summary level, the average event-hour load impact per enrolled customer was 1,207 kW for PG&E's program, 1,135 kW for SCE's program, and 309 kW for SDG&E’s program.

4.1 PG&E Load Impacts

4.1.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.1 summarizes average hourly reference loads and load impacts at the program level for each of PG&E's BIP events. Because the first, second, fourth, and fifth events were re-tests,[11] fewer service agreements were called. The highest load impact therefore occurred during the July 30th test event, with an average 246 MW load impact across the two event hours.

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

Event	Date	Day of Week	# Service Agreements	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1	2/11/2015	Wed.	[redacted]				
2	4/23/2015	Thurs.					
3	7/30/2015	Thurs.	204	292.4	46.2	246.2	84.2%
4	9/22/2015	Thurs.	[redacted]				

Table 4.2 compares the observed loads and FSLs by event day. During the July 30th test event in which all service agreements were called, the program load was below the aggregate FSL. This was not the case during the three smaller re-test events. 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 is shown in the rightmost column. That is, 100% indicates that observed loads exactly match the FSL (in aggregate, when averaged across event hours).

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

Event	Date	Day of Week	Observed Load (MW)	Firm Service Level (MW)	Estimated LI / LI at FSL
1	2/11/2015	Wed.	[redacted]		
2	4/23/2015	Thurs.			
3	7/30/2015	Thurs.	46.2	48.1	101%
4	9/22/2015	Thurs.	[redacted]		

Table 4.3 summarizes average hourly BIP load impacts by industry group for the July 30th event day. The Manufacturing industry group accounted for the largest share of the load impacts, with a 164 MW average event-hour load reduction.

[11] The November event was not analyzed for this report because it occurred outside of the study period, which generally ends in September to allow for sufficient time to process and analyze the relevant data.

Table 4.3: July 30, 2015 Load Impacts – PG&E BIP, *by Industry Group*

Industry Group	# of Service Agreements	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	39	38.3	4.4	33.9	88.4%
Manufacturing	85	186.8	23.1	163.7	87.6%
Wholesale, Transportation, & Other Utilities	40	33.5	7.4	26.1	78.0%
Retail Stores	[redacted]				
Offices, Hotels, Health, Services					
Schools					
Entertainment, Other Services, Government					
Other or Unknown					
Total	**204**	**292.4**	**46.2**	**246.2**	**84.2%**

Table 4.4 summarizes July 30th load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from service agreements not associated with any LCA.

Table 4.4: July 30, 2015 Load Impacts – PG&E BIP, *by LCA*

Local Capacity Area	# of Service Agreements	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	[redacted]				
Greater Fresno					
Humboldt					
Kern					
Northern Coast					
Not in any LCA	88	206.9	31.9	175.0	84.6%
Sierra	[redacted]				
Stockton					
Total	**204**	**292.4**	**46.2**	**246.2**	**84.2%**

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 July 30, 2015 event day, which was the only full test event of the program year.

Table 4.5: BIP Hourly Load Impacts for the July 30, 2015 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	289.0	293.0	-4.0	75.0	-5.7	-4.7	-4.0	-3.3	-2.3
2	285.7	287.0	-1.3	74.1	-2.6	-1.8	-1.3	-0.7	0.1
3	283.7	284.0	-0.3	72.9	-1.4	-0.7	-0.3	0.2	0.9
4	289.4	293.7	-4.3	71.1	-5.5	-4.8	-4.3	-3.8	-3.1
5	297.9	300.7	-2.8	70.1	-4.1	-3.3	-2.8	-2.3	-1.6
6	313.0	319.3	-6.2	69.2	-7.5	-6.7	-6.2	-5.7	-4.9
7	332.5	336.8	-4.2	68.9	-5.5	-4.7	-4.2	-3.7	-3.0
8	335.6	337.2	-1.6	70.4	-2.9	-2.1	-1.6	-1.1	-0.3
9	338.3	333.1	5.2	73.4	3.5	4.5	5.2	5.8	6.8
10	338.1	334.5	3.5	76.6	1.7	2.8	3.5	4.3	5.4
11	335.3	331.7	3.6	79.9	1.5	2.7	3.6	4.4	5.7
12	327.0	329.5	-2.5	83.3	-4.5	-3.3	-2.5	-1.7	-0.5
13	317.4	320.7	-3.2	86.7	-5.1	-4.0	-3.2	-2.5	-1.4
14	314.7	318.0	-3.2	89.2	-5.2	-4.0	-3.2	-2.5	-1.3
15	304.8	226.4	78.3	90.3	76.3	77.5	78.3	79.2	80.4
16	295.4	45.4	249.9	90.4	247.9	249.1	249.9	250.7	251.9
17	291.5	46.1	245.4	90.6	243.3	244.5	245.4	246.3	247.6
18	287.6	46.5	241.1	89.8	239.0	240.2	241.1	242.0	243.3
19	295.3	46.9	248.4	88.1	246.2	247.5	248.4	249.3	250.6
20	301.1	159.6	141.5	84.2	139.4	140.6	141.5	142.4	143.7
21	302.4	231.3	71.1	80.7	69.0	70.2	71.1	72.0	73.2
22	304.6	247.4	57.2	78.6	54.9	56.3	57.2	58.2	59.5
23	299.1	256.2	42.8	77.0	40.7	42.0	42.8	43.7	45.0
24	294.3	261.0	33.3	75.3	31.1	32.4	33.3	34.2	35.5
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	7,374	5,986	1,388	135.6	n/a	n/a	n/a	n/a	n/a
Event Hours	292.4	46.2	246.2	58.8	244.3	245.4	246.2	247.0	248.2

Figure 4.1 illustrates the hourly reference load, observed load, and estimated load impact for the July 30th event day. The scale for the hourly load impacts is shown on the right-hand side of the figure. Figure 4.2 shows the estimated load impacts for each of the three re-test days.

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: BIP Loads for the July 30, 2015 Event Day, *PG&E*

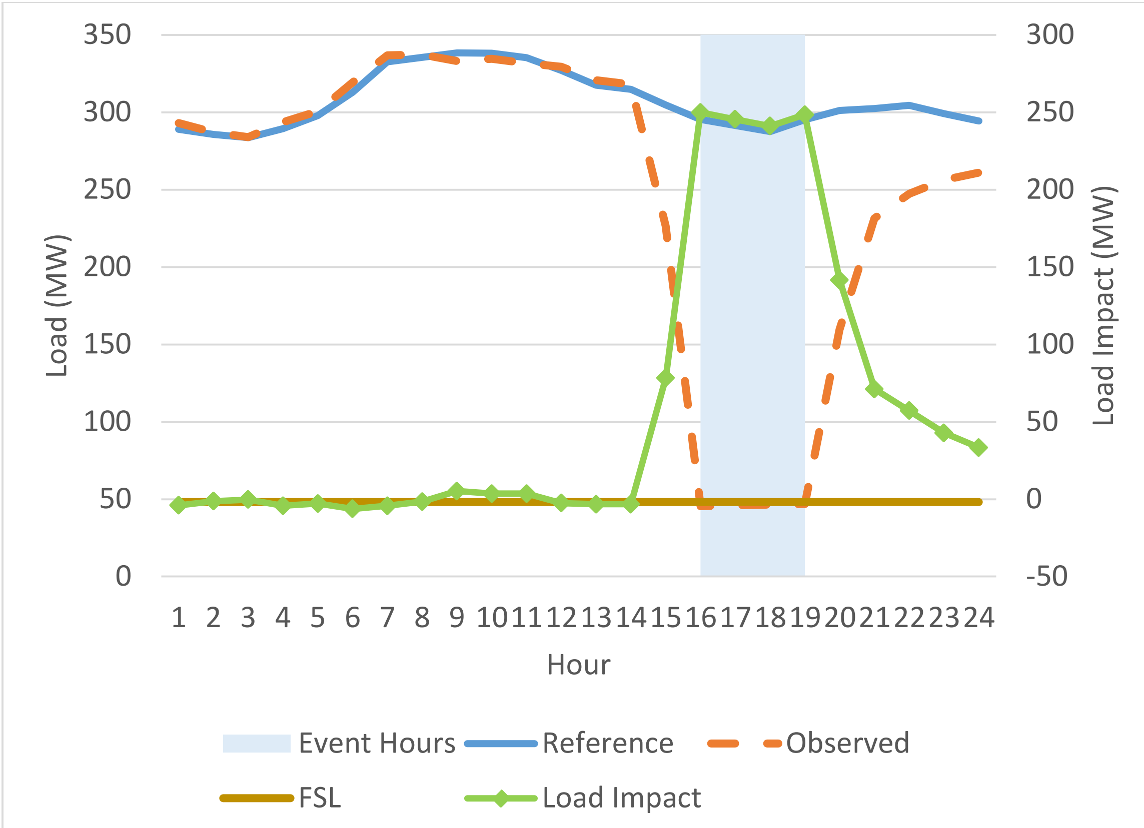
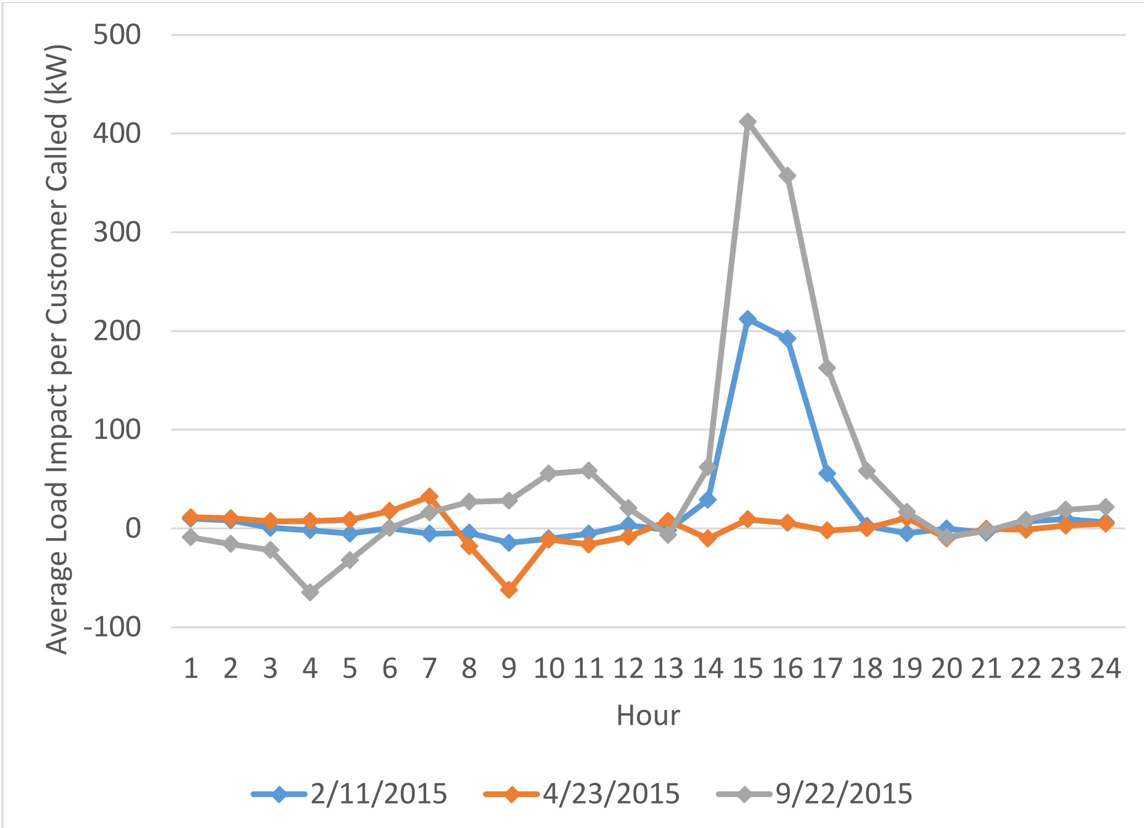


Figure 4.2: Hourly Load Impacts per Customer by Re-test Event, *PG&E BIP*



4.2 SCE Load Impacts

4.2.1 Average Hourly Load Impacts by Industry Group and LCA

SCE's only BIP event day was September 24, 2015. Table 4.6 shows the average event-hour load impact for that event day by industry group.[12] The total row at the bottom of the table shows the total event-day load impact of 692 MW, or 80 percent of the reference load. The majority of the program's load impact came from customers in the manufacturing industry group.

Table 4.6: Average Event-day Hourly Load Impacts – SCE BIP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	56	159.2	13.5	145.7	91.5%
Manufacturing	363	568.9	111.4	457.5	80.4%
Wholesale, Transportation, & Other Utilities	66	51.7	9.4	42.3	81.8%
Retail Stores	61	19.7	17.0	2.7	13.8%
Offices, Hotels, Health, Services	[redacted]				
Schools					
Entertainment, Other Services, Government					
Total	**610**	**864.1**	**172.0**	**692.1**	**80.1%**

Table 4.7 compares the observed loads and FSLs for the September 24th event day. In aggregate, SCE's BIP program achieved 90 percent of the reduction required to meet its FSL.

Table 4.7: Average Hourly Observed Loads and FSLs*, SCE*

Event	Date	Day of Week	Observed Load (MW)	Firm Service Level (MW)	Estimated LI / LI at FSL
1	9/24/2015	Thursday	172.0	93.3	90%

Table 4.8 summarizes average hourly load impacts by LCA and location (South Orange County, South of Lugo, and elsewhere). The majority of the load impact comes from customers in the LA Basin.

[12] Note that customers were notified at 1:00 p.m. but not required to meet their FSLs until 1:30 or 1:45 p.m., and the event ended at 3:30 p.m. So hour-ending 15 is the only hour for which customers were required to meet their FSLs during the entire hour. For this reason, hour-ending 15 alone is used to calculate all event-hour summary measures for SCE's one event.

Table 4.8: Average Event-day Hourly Load Impacts – SCE BIP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin	527	649.8	126.2	523.6	80.6%
Outside LA Basin	[redacted]				
Ventura					
Total	**610**	**864.1**	**172.0**	**692.1**	**80.1%**
South Orange County	[redacted]				
South of Lugo	206	269.4	48.5	221.0	82.0%
Rest of System	348	493.0	101.0	391.9	79.5%

4.2.2 Hourly Load Impacts

Table 4.9 presents hourly load impacts for the September 24th BIP event in the manner required by the Protocols.

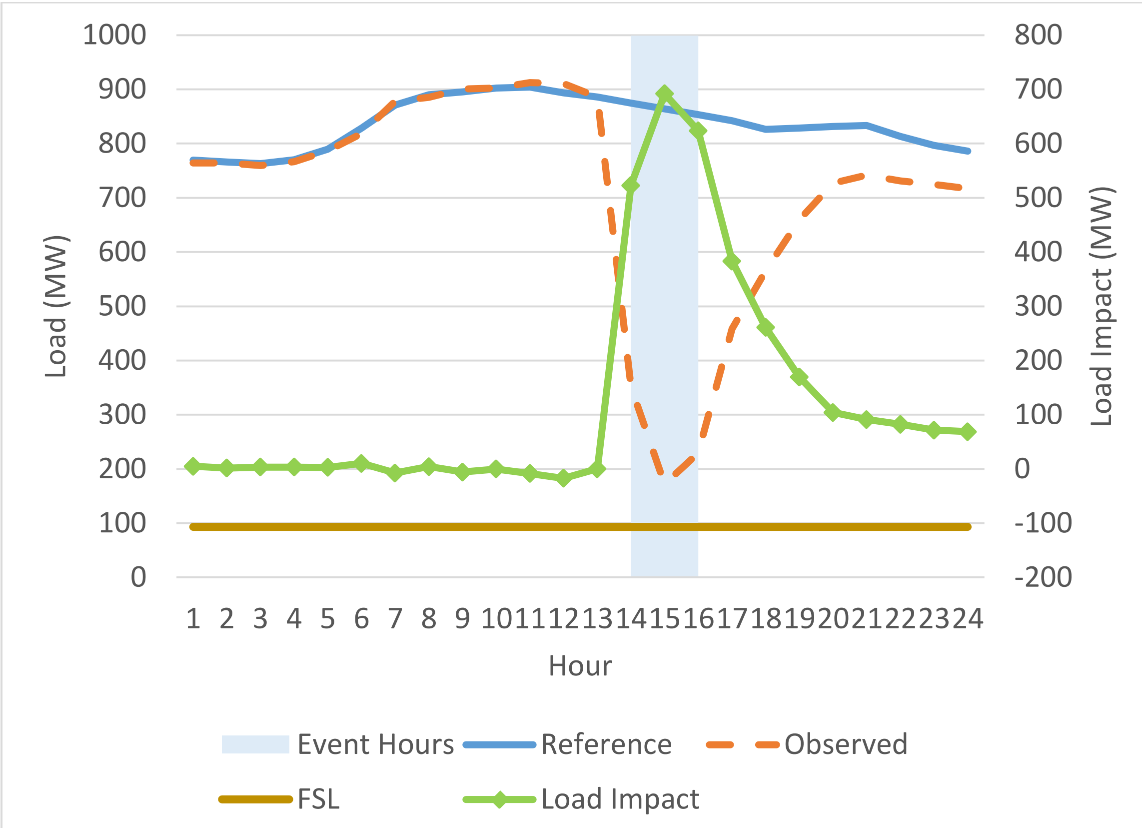
Table 4.9: BIP Hourly Load Impacts for the September 24, 2015 Event Day, *SCE*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (^oF)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	769.6	764.5	5.1	73.4	2.1	3.9	5.1	6.3	8.1
2	765.9	764.1	1.8	71.8	-1.1	0.6	1.8	3.0	4.7
3	763.2	759.6	3.6	70.7	0.8	2.5	3.6	4.7	6.3
4	770.1	766.7	3.4	70.1	0.6	2.3	3.4	4.5	6.2
5	789.8	786.7	3.1	69.3	0.0	1.8	3.1	4.3	6.1
6	828.6	818.4	10.2	68.7	6.6	8.7	10.2	11.7	13.8
7	871.2	878.5	-7.3	68.2	-10.9	-8.8	-7.3	-5.8	-3.6
8	889.7	885.3	4.5	67.7	1.1	3.1	4.5	5.8	7.8
9	895.3	900.8	-5.5	70.0	-9.1	-7.0	-5.5	-4.0	-1.9
10	902.4	902.4	0.0	74.2	-4.0	-1.6	0.0	1.7	4.0
11	904.2	912.5	-8.2	79.0	-12.6	-10.0	-8.2	-6.5	-3.9
12	893.8	910.8	-17.1	83.9	-21.9	-19.0	-17.1	-15.1	-12.2
13	886.0	885.9	0.2	87.8	-5.1	-2.0	0.2	2.3	5.4
14	874.5	351.8	522.8	89.6	517.6	520.6	522.8	524.9	528.0
15	864.1	172.0	692.1	91.0	686.5	689.8	692.1	694.3	697.6
16	853.2	229.5	623.7	92.1	618.0	621.4	623.7	626.1	629.4
17	842.2	458.6	383.6	92.5	378.1	381.3	383.6	385.8	389.1
18	826.2	565.2	261.0	91.7	255.7	258.9	261.0	263.2	266.3
19	828.7	658.9	169.8	88.7	163.8	167.4	169.8	172.2	175.8
20	831.6	727.4	104.2	84.9	98.3	101.8	104.2	106.6	110.1
21	833.2	742.1	91.2	81.2	84.9	88.6	91.2	93.7	97.4
22	813.5	731.0	82.5	78.6	76.3	79.9	82.5	85.0	88.6
23	796.7	724.8	71.8	77.1	66.5	69.6	71.8	74.0	77.1
24	785.8	716.9	68.9	76.0	63.8	66.8	68.9	71.0	74.0
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75^{o}F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	20,080	17,014	3,065	144.2	n/a	n/a	n/a	n/a	n/a
Event Hours*	864.1	172.0	692.1	91.0	686.5	689.8	692.1	694.3	697.6

* The highlighting indicates all hours affected by the event. However, hour-ending 15 was the only hour during which customers were required to respond for the full hour.

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the September 24th BIP event. The scale for the hourly load impacts is shown on the right-hand side of the figure.

Figure 4.3: BIP Load Impacts for the September 24, 2015 Event Day, *SCE*



4.3 SDG&E Load Impacts

4.3.1 Average Hourly Load Impacts

Average hourly reference loads and load impacts for SDG&E single event (August 28, 2015) are summarized in Table 4.10. The average load impact over the four hour event was [redacted].

Table 4.10: Average Hourly Load Impacts, *SDG&E*

Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1	8/28/2015	Friday	[redacted]			

Table 4.11 compares the average observed load to the FSL on the event day. On average the observed load was just slightly above the FSL during the event.

Table 4.11: Average Hourly Observed Loads and FSLs, *SDG&E*

Event	Date	Day of Week	Observed Load (MW)	Firm Service Level (MW)	Estimated LI / LI at FSL
1	8/28/2015	Friday	[redacted]		

Table 4.12 shows the load impacts for the August 28th event day by industry group. [redacted]

Table 4.12: August 28, 2015 Load Impacts – SDG&E BIP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	[redacted]				
Manufacturing					
Retail Stores					
Total					

4.3.2 Hourly Load Impacts

Table 4.13 presents hourly load impacts for the August 28th event day in the manner required by the Protocols.

Table 4.13: BIP Hourly Load Impacts for the August 28, 2015 Event Day, *SDG&E*

[redacted]

Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the August 28th event day. The scale for the hourly load impacts is shown on the right-hand side of the figure.

Figure 4.4: BIP August 28, 2015 Load Impacts, *SDG&E*

[redacted]

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 grouped in three ways separately. They are assigned to one of three LCAs and, separately, one of three locations (South Orange County, South of Lugo, and elsewhere). They are also categorized by participation option (15 minutes notice or 30 minutes notice).

For SDG&E, we assume that the specific customers anticipated to be enrolled in 2016 continue to participate in BIP, 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 start of the 2016 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the start of the 2016 program year, based on their estimated *ex-post* load impacts during program year 2015.

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.[13] 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.[14]

[13] 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.

[14] A modified regression model is used for SDG&E to better control for large differences in load profiles across months for the few relevant customers, as in the *ex-post* analysis. See Section 3.2.1 above for details.

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

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 = DBP Event 1, DBP 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

For PG&E, we removed the weather variables from the reference load regressions and simulation models.[15] A large fraction of PG&E's BIP load consists of large non-weather-sensitive customers for which the models can sometimes estimate wrong-signed weather effects (*e.g.*, loads go down slightly as temperatures go up). Our investigations of the program-level loads from 2015 found no statistically significant relationship between loads and weather conditions. Therefore, while some of the (typically smaller) customers in BIP do display weather sensitivity, this effect is overwhelmed by the noise from the usage fluctuations of non-weather-sensitive customers. With the weather effects included in the *ex-ante* analysis, we were often forecasting slightly higher load impacts for 1-in-2 scenarios versus equivalent 1-in-10 scenarios. Removing the weather effects makes the reference loads and load impacts identical across weather scenarios.

[15] For SDG&E, we removed the weather variables for one customer only for non-summer months, the customer estimated to contribute the greatest load impact in non-summer. For summer months, weather variables were retained for that customer but removed for a different customer with implausible weather estimates.

Note that the overall level of *ex-ante* load impacts was not overly sensitive to the inclusion of weather effects.

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 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.[16]

The achievement rates are based on the estimates for the most recent observed event day. In consultation with the utilities, we determined that using a longer time period (*e.g.*, three years of *ex-post* load impacts, as we do for the DBP study) 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. So 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 (1:00 to 6:00 p.m. in April through October; and 4:00 to 9:00 p.m. in all other months) differs from the historical event window (which can vary across 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 historical load impacts to the forecast window to best represent the pattern of customer response given the limitations of the

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[16] 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 impact on them.

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.

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

In this step, the customer-specific 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, either because they were not enrolled in 2015 or because their reference loads were below their FSLs, the average achievement rate among all customers is used. The FSL achievement rates for each utility are presented 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 2026, 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 2016 through 2026. We assume that the *ex-post* shares of customers (LCA and location) hold throughout the forecast period. SDG&E indicated that we assume enrollments remain constant throughout the forecast period.

5.3 Enrollment Forecasts

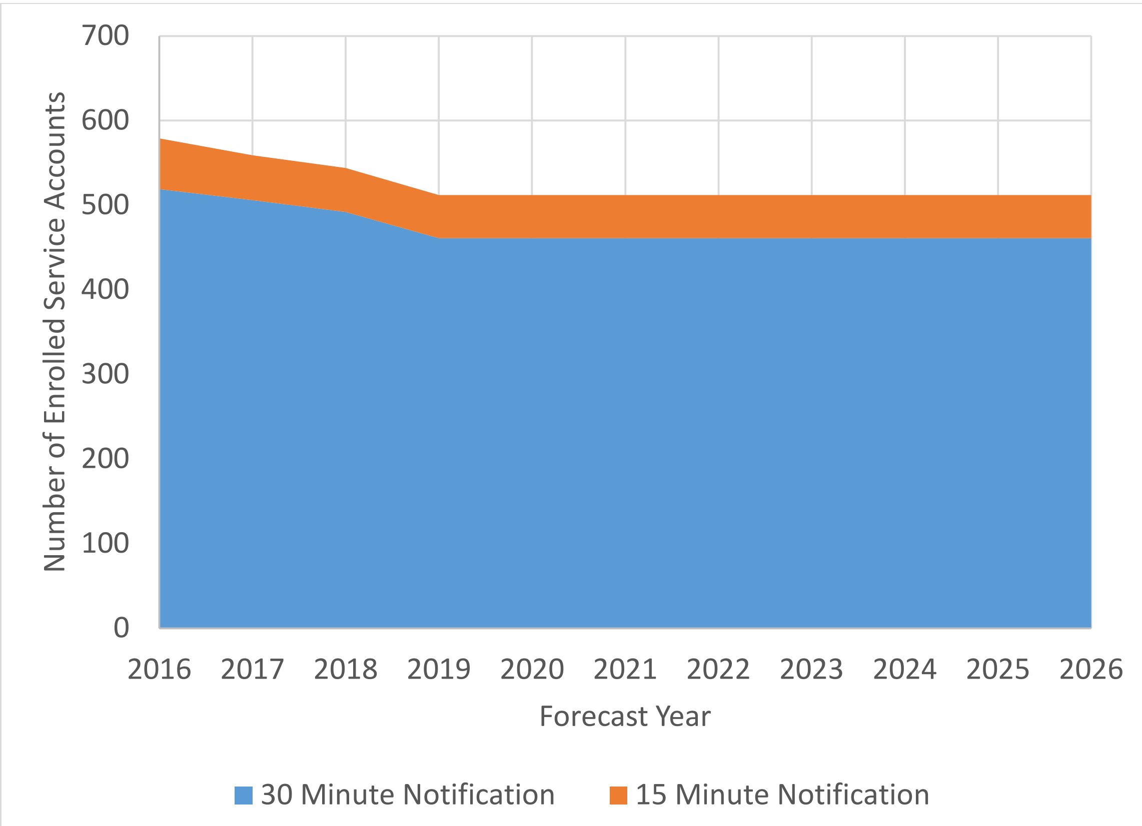
PG&E

PG&E forecasts BIP enrollments to remain constant from 2016 through 2026, with 208 enrolled service agreements. The vast majority of these agreements (198) are in the large customer group (over 200 kW). The total enrollment forecast of 208 is a slight increase over the 204 service agreements enrolled for the PY2015 test day (on July 30, 2015).

SCE

Figure 5.1 shows SCE's forecast of enrollments by year, broken down by notification time. SCE projects BIP enrollments to decrease during 2016 through 2018 and remain constant thereafter. Much of the expected decrease over the first few years is connected to expectations that specific groups of customers will opt out. [redacted] In addition, customers can opt-out of BIP at any time during calendar year 2016 to participate in the Demand Response Auction Mechanism (DRAM) Phase One pilot.

Figure 5.1: Number of Enrolled Customers in Each Forecast Year, *SCE*



SDG&E

SDG&E forecasts BIP enrollments to remain constant from 2016 through 2026, with 7 enrolled service agreements. Enrollments for the PY2015 test day (on August 28, 2015) were lower, at 5 service agreements, but the forecast is merely for a return to the PY2013 and PY2014 enrollment levels of 7 service agreements.

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 typical event days; 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 of the tables required by the Protocols are provided in an Appendix.

5.4.1 PG&E

Figure 5.2 shows the August 2016 forecast load impacts for a typical event day in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 255 MW, which represents 84.1 percent of the enrolled reference load. The program-level FSL is 49.8 MW, compared to the average event-hour program load of 48.3 MW. This slight over-performance at the program level is consistent with our estimates for the July 30, 2015 event day that serves as the basis for the *ex-ante* load impacts.

Figure 5.2: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August 2016

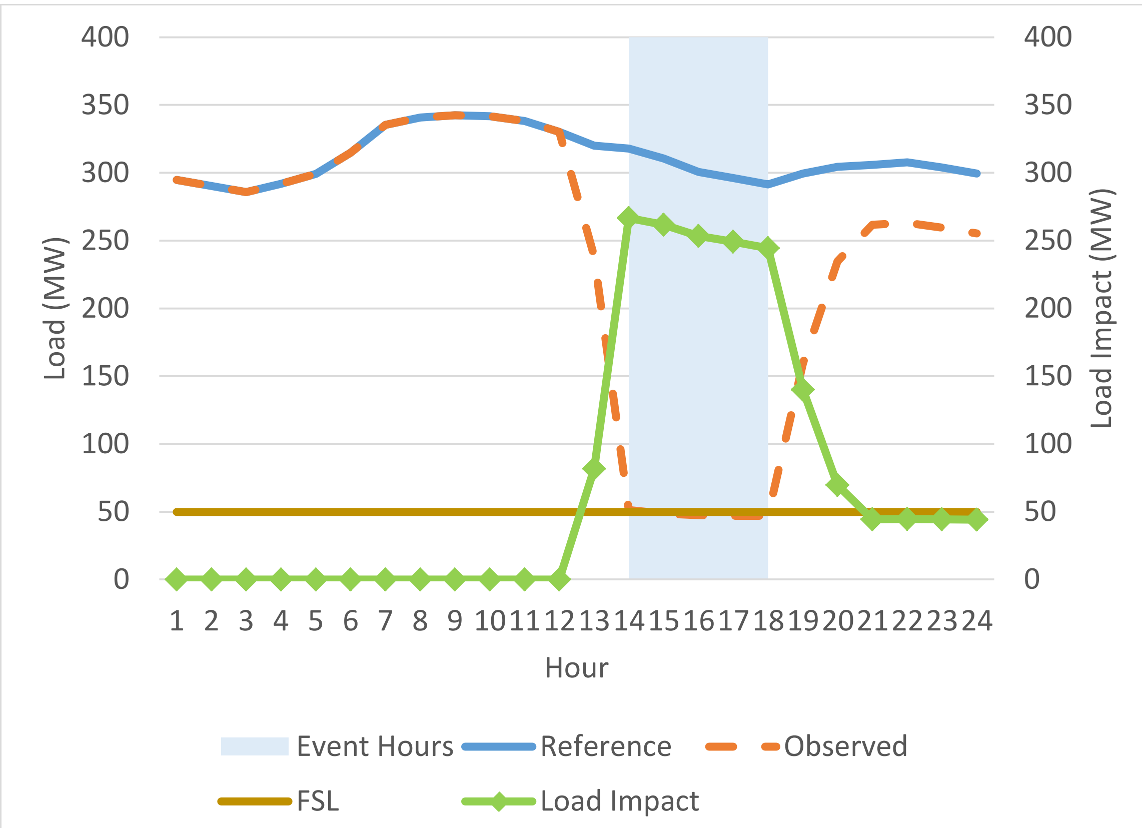


Figure 5.3 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2016 utility-specific 1-in-2 weather year. Customers not in any LCA account for the largest share, with 71 percent of the load impacts.

Figure 5.3: Share of PG&E Load Impacts by LCA for the August 2016 Typical Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.4 illustrates 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 does not change across the 2016-2026 window, so these load impacts stay constant for August across the forecast years. Recall that weather effects were removed from PG&E's *ex-ante* forecast, so each of these scenarios contains a load impact forecast of 255 MW.

Figure 5.4: Average August *Ex-ante* Load Impacts by Scenario, 2016-2026, *PG&E*

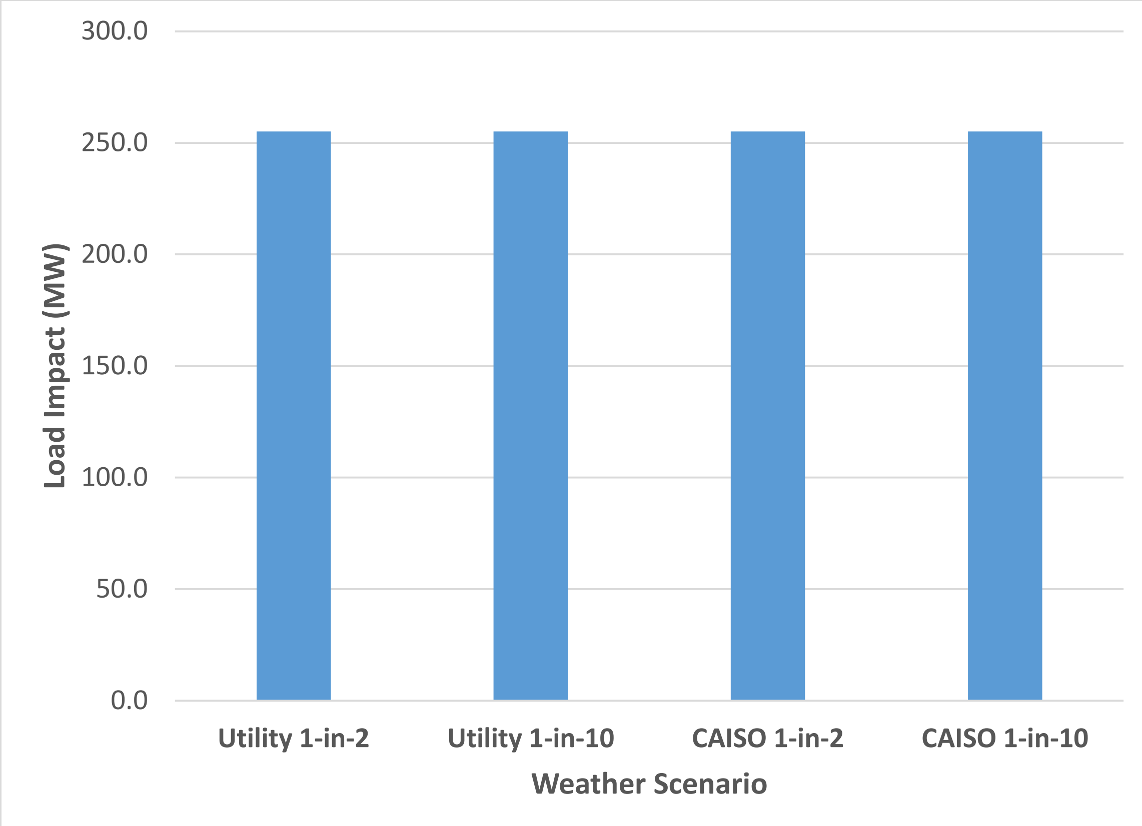


Table 5.2 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August typical event day.

Table 5.2: Per-customer *Ex-ante* Load Impacts, *PG&E*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Utility-specific	1-in-2	1,438	1,226	84.1%
	1-in-10	1,438	1,226	84.1%
CAISO-coincident	1-in-2	1,438	1,226	84.1%
	1-in-10	1,438	1,226	84.1%

5.4.2 SCE

Figure 5.5 shows the August 2016 forecast load impacts for a typical event day in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 684 MW, which represents 81.8 percent of the enrolled reference load. The program-level FSL is 87.2 MW, compared to the average event-hour program load of 152.6 MW. This under-performance at the program level is consistent with our estimates for the September 24, 2015 event day that serves as the basis for the *ex-ante* load impacts.

Figure 5.5: SCE Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August 2016

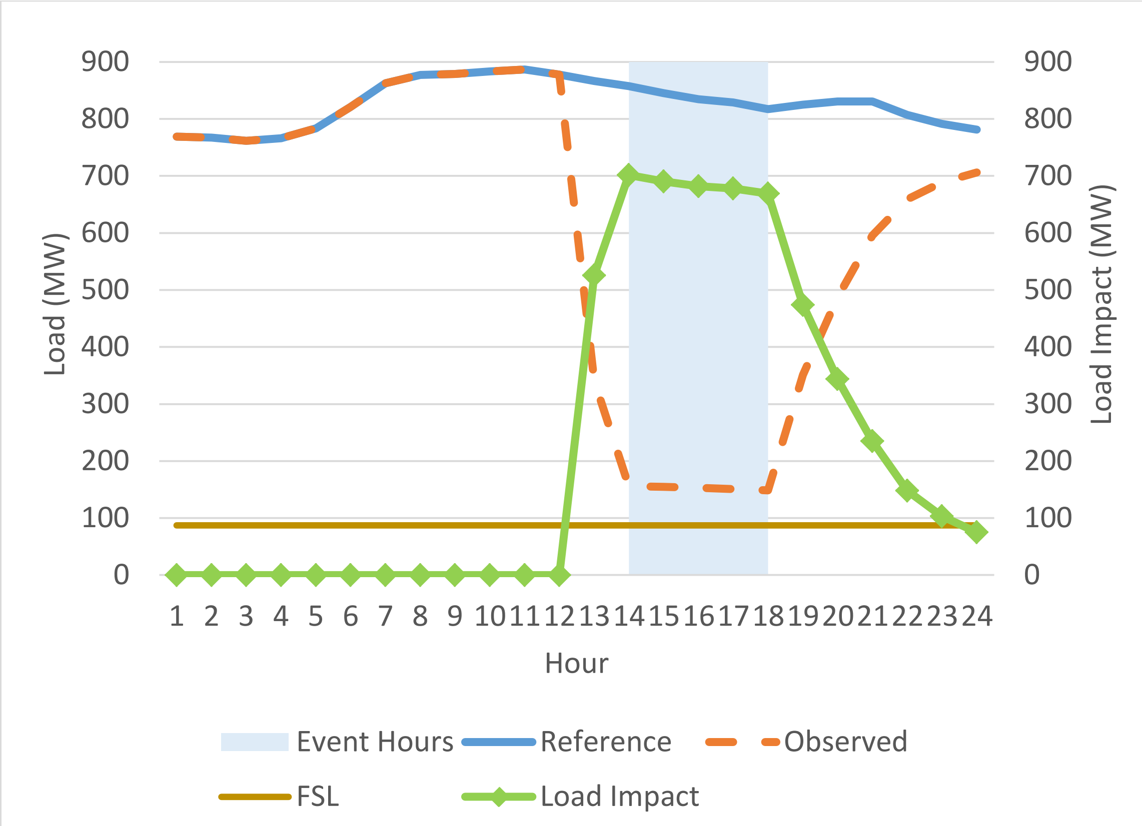


Figure 5.6 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2016 utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 77 percent of the load impacts.

Figure 5.6: Share of SCE Load Impacts by LCA for the August 2016 Typical Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.7 shows the share of load impacts by notification time, assuming a typical event day in an August 2016 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 just 10 percent of customers but account for 22 percent of the load impacts.

Figure 5.7: Share of SCE Load Impacts by Notification Time for the August 2016 Typical Event Day in a Utility-specific 1-in-2 Weather Year

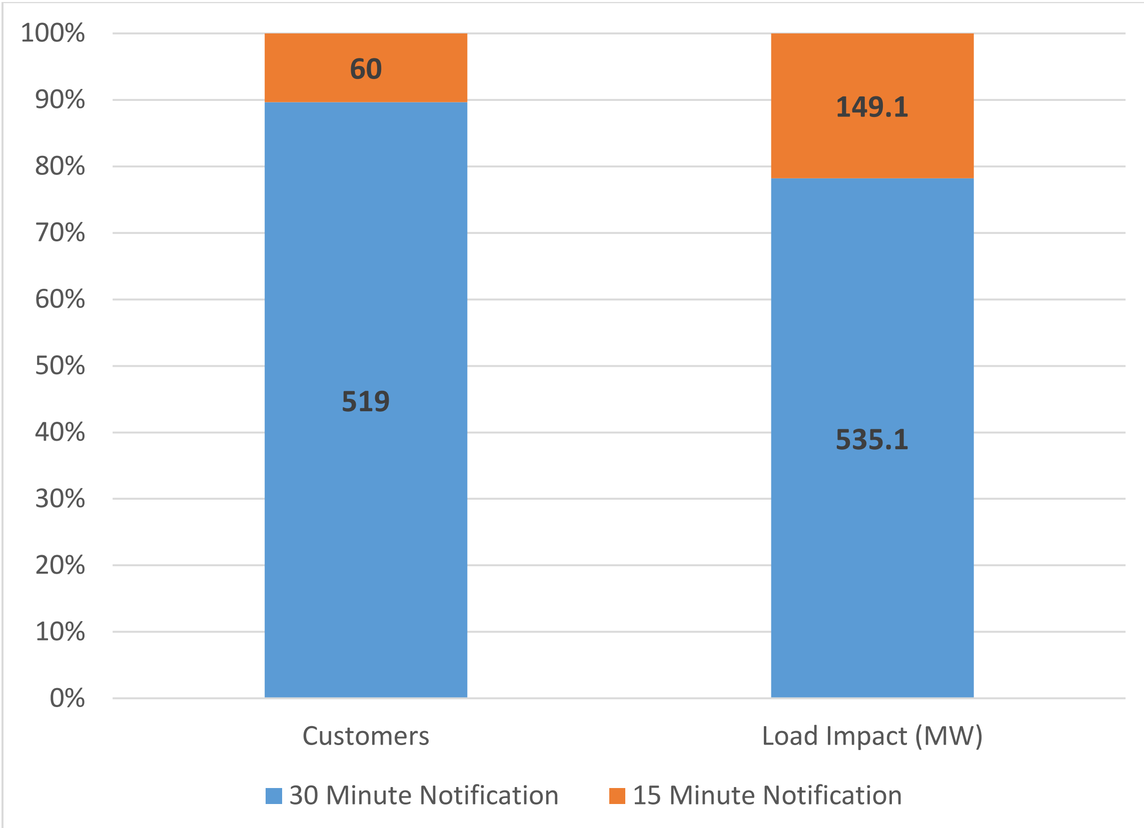


Figure 5.8 illustrates August typical event day load impacts for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. These load impacts are shown for forecast years 2016 through 2019. The load impact is not sensitive to weather conditions, but it decreases over time due to forecast reductions in enrollment.

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

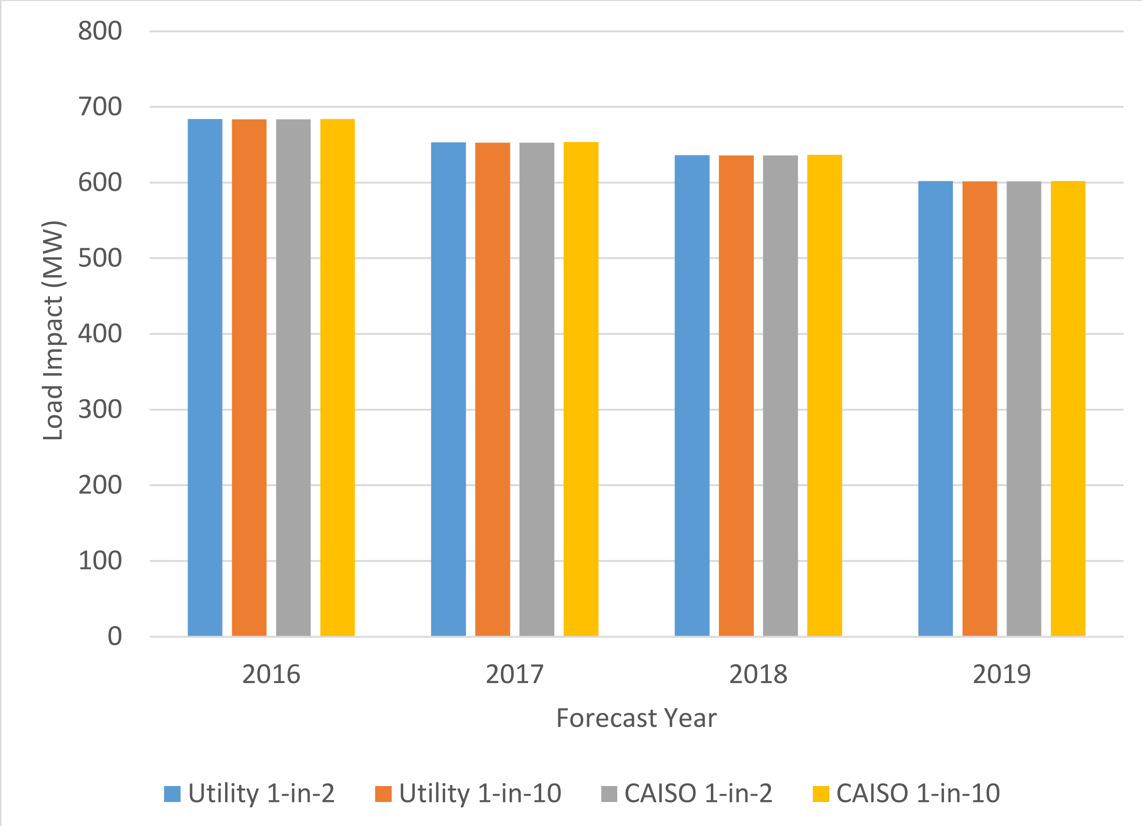


Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2016 typical event day.

Table 5.3: Per-customer *Ex-ante* August 2016 Load Impacts by Scenario, *SCE*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Utility-specific	1-in-2	1,445	1,182	81.8%
	1-in-10	1,447	1,181	81.6%
CAISO-coincident	1-in-2	1,445	1,181	81.7%
	1-in-10	1,448	1,182	81.6%

5.4.3 SDG&E

Figure 5.9 shows the load impact forecast for 2016-2026 for a typical event day (which is assumed to be in August) in a utility-specific 1-in-2 weather year. [redacted]

[redacted]

Figure 5.9: SDG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August

[redacted]

Figure 5.10 illustrates 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 does not change across the 2016-2026 window, so these load impacts stay constant for August across the forecast years.

Figure 5.10: Average August *Ex-ante* Load Impacts by Scenario, 2016-2026, *SDG&E*

[redacted]

Table 5.4 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 2016 typical event day. The lack of variation across scenarios indicates that the reference loads (and therefore the load impacts) are not very sensitive to weather conditions.

Table 5.4: Per-customer *Ex-ante* August 2016 Load Impacts by Scenario, *SDG&E*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Utility-specific	1-in-2	[redacted]		
	1-in-10			
CAISO-coincident	1-in-2			
	1-in-10			

6. Comparisons of Results

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

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

- Current *ex-post* and *ex-ante* load impacts.

In the above “current study” refers to this report, which is based on findings from the 2015 program year; and “previous study” refers to the report that was developed following the 2014 program year.

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 PY2014 and PY2015. The PY2014 load impacts are based on the two event hours on September 11, 2014. The PY2015 load impacts are based on the four event hours on July 30, 2015.

Table 6.1: Comparison of *Ex-post* Impacts in PY 2014 and PY 2015, *PG&E*

Level	Outcome	*Ex-post* PY2014	*Ex-post* PY2015
Total	# SAIDs	218	204
	Reference (MW)	286	292
	Load Impact (MW)	228	246
Per SAID	Reference (kW)	1,311	1,434
	Load Impact (kW)	1,047	1,207
	% Load Impact	79.8%	84.2%

There are fewer service agreements in PY2015, but the total reference load and load impact increase somewhat. As a result, the per-customer reference loads and load impacts are higher in PY2015.

6.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY 2014 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 6.2 contains this comparison for the August 2016 utility-specific 1-in-2 typical event day forecast.

Table 6.2: Comparison of *Ex-ante* Impacts from PY 2014 and PY 2015 Studies, *PG&E*

Level	Outcome	*Ex-ante* 2016 Typical Event Day, *Previous Study*	*Ex-ante* 2016 Typical Event Day, *Current Study*
Total	# SAIDs	203	208
	Reference (MW)	288	303
	Load Impact (MW)	246	255
	FSL (MW)	47.5	49.8
Per SAID	Reference (kW)	1,418	1,458
	Load Impact (kW)	1,212	1,226
	% Load Impact	85.5%	84.1%

The current study includes 5 additional service agreements, and the reference load and load impacts are higher, accordingly. The per-customer load impact is relatively unchanged. What differences there are in the per-customer measures are attributable to changes in the observed average reference loads of existing customers between program years 2014 and 2015.

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

Table 6.3 provides a comparison of the *ex-ante* forecast of 2015 load impacts prepared following PY2014 and the PY2015 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 July 30, 2015 event day.

The aggregate forecast and *ex-post* load impacts are the same, due to slightly lower forecast reference loads being offset by slightly higher forecast impacts as a percentage of reference loads.

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

Level	Outcome	*Ex-ante* 2015 Typical Event Day, Previous Study	*Ex-post* PY2015
Total	# SAIDs	203	204
	Reference (MW)	288	292
	Load Impact (MW)	246	246
Per SAID	Reference (kW)	1,418	1,434
	Load Impact (kW)	1,212	1,207
	% Load Impact	85.5%	84.2%

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 2016 typical event day with utility-specific 1-in-2 weather conditions. Load impacts as a percentage of reference load are nearly identical, so that the higher *ex-ante* reference load means proportionally higher *ex-ante* load impacts.

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

Level	Outcome	*Ex-post* PY2015	*Ex-ante* 2016 Typical Event Day, Current Study
Total	# SAIDs	204	208
	Reference (MW)	292	303
	Load Impact (MW)	246	255
	FSL (MW)	48.1	49.8
Per SAID	Reference (kW)	1,434	1,458
	Load Impact (kW)	1,207	1,226
	% Load Impact	84.2%	84.1%

Table 6.5 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. The earlier *ex-ante* event window is the primary cause of the higher *ex-ante* reference loads and load impacts. The net addition of four customers also accounts for around a third of the increases in aggregate *ex-ante* measures, with relatively little impact on per-customer measures.

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

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	89.7 degrees Fahrenheit during event hours.	94.8 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day.	None. The program reference load and load impact are not weather sensitive.
Event window	HE 16-19.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Slightly higher average reference loads for *ex-ante*.
% of resource dispatched	All.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	204 SAIDs during the 7/30/2015 event day.	208 SAIDs.	7 medium-sized (on average) SAIDs joined, while 3 similarly sized SAIDs dropped, increasing aggregate reference loads and load impacts somewhat with little effect on per-customer measures.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on SAID-level performance on the most recent event day (7/30/2015).	Possible differences between simulated *ex-ante* and estimated *ex-post* reference loads. In this case, however, the aggregate differences are minimal.

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 PY2014 and PY2015. Only one BIP event was called in each year: February 6, 2014 (4 hours in duration); and September 24, 2015 (1 hour in duration). The reference loads and load impacts are higher in PY2015 despite the slight decrease in the number of participating service accounts, as might be expected given that the only PY2014 event was called during the winter. Indeed, as discussed below, the *ex-ante* forecast based on performance during that PY2014 event—but with August reference loads—closely matches the current *ex-post* per-customer load impacts. The difference in per-customer load impacts here can therefore be attributed to the difference in season between the two events.

Table 6.6 Comparison of *Ex-post* Impacts in PY 2014 and PY 2015, *SCE*

Level	Outcome	*Ex-post* PY2014	*Ex-post* PY2015
Total	# SAIDs	620	610
	Reference (MW)	755	864
	Load Impact (MW)	624	692
Per SAID	Reference (kW)	1,218	1,417
	Load Impact (kW)	1,006	1,135
	% Load Impact	82.6%	80.1%

6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY 2014 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2016 utility-specific 1-in-2 typical event day.

Table 6.7: Comparison of *Ex-ante* Impacts from PY 2014 and PY 2015 Studies, *SCE*

Level	Outcome	*Ex-ante* 2016 Typical Event Day, Previous Study	*Ex-ante* 2016 Typical Event Day, Current Study
Total	# SAIDs	565	579
	Reference (MW)	795	837
	Load Impact (MW)	645	684
Per SAID	Reference (kW)	1,407	1,445
	Load Impact (kW)	1,142	1,182
	% Load Impact	81.2%	81.8%

The forecasts for per-customer reference loads and load impacts have increased. That is partly accounted for by the increase in forecast enrollment, but it is mostly due to a change in the composition of customers used to forecast reference loads, as discussed in more detail in the comparison of current *ex-post* and *ex-ante* load impacts below.

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

Table 6.8 provides a comparison of the *ex-ante* forecast of 2015 load impacts prepared following PY2014 and the PY2015 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the September 24, 2015 event day.

Per-customer reference loads and load impacts estimated *ex-post* are very close to what we forecast in the previous study. However, the enrollment forecast has 30 fewer service accounts, so the forecasts for total program reference load and load impacts were proportionately lower.

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

Level	Outcome	*Ex-ante* 2015 Typical Event Day, Previous Study	*Ex-post* PY2015
Total	# SAIDs	580	610
	Reference (MW)	816	864
	Load Impact (MW)	663	692
Per SAID	Reference (kW)	1,408	1,417
	Load Impact (kW)	1,143	1,135
	% Load Impact	81.2%	80.1%

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 sole event day (September 24, 2015) and the *ex-ante* load impact represents the 2016 typical event day in a utility-specific 1-in-2 weather year.

The lower forecast enrollment level is the primary reason for the lower forecasts of total reference load and load impact. The reason the load impacts (and reference loads) fall less than proportionately with enrollments is that the 5 percent of customers leaving BIP average only a third of the size of the remaining customers.

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

Level	Outcome	*Ex-post* PY2015	*Ex-ante* 2016 Typical Event Day, Current Study
Total	# SAIDs	610	579
	Reference (MW)	864	837
	Load Impact (MW)	692	684
	FSL (MW)	93.3	87.2
Per SAID	Reference (kW)	1,417	1,445
	Load Impact (kW)	1,135	1,182
	% Load Impact	80.1%	81.8%

Table 6.10 lays out all the potential sources of differences between the *ex-post* and *ex-ante* load impacts, but it is the reduction in enrollment that primarily accounts for the differences, as explained above.

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

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	91.0 degrees Fahrenheit during event window.	89.9 degrees Fahrenheit during event hours on utility-specific 1-in-2 Aug typical event day.	None. The load is not weather sensitive and the temperatures are close.
Event window	HE 15 only is used, as the event was effectively 1:30-3:30pm.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	The slightly earlier *ex-post* event window tends toward slightly higher reference loads and load impacts relative to the *ex-ante* window.
% of resource dispatched	All customers were called.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	610 SAIDs during the *ex-post* event day.	579 SAIDs in August 2016.	The 31 dropped customers decrease aggregate loads but increase per-customer reference loads because the average size of their reference loads is just a third of the overall reference load per customer.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on the SAID-specific load impacts from the PY2015 event day.	Little effect because the 2015 *ex-post* event day is the basis of the *ex-ante* forecast.

6.3 SDG&E

6.3.1 Previous versus current *ex-post*

Table 6.11 compares *ex-post* load impacts between PY2014 and PY2015. The PY2014 load impacts are based on the May 16, 2014 event, while the PY2015 load impacts are based on the single August 28, 2015 event. Enrollment has dropped from seven to five, and loads with it. Per-customer reference loads and load impacts, however, have changed relatively little.

Table 6.11: Comparison of *Ex-post* Impacts in PY 2014 and PY 2015, *SDG&E*

Level	Outcome	*Ex-post* PY2014	*Ex-post* PY2015
Total	# SAIDs	[redacted]	
	Reference (MW)		
	Load Impact (MW)		
Per SAID	Reference (kW)		
	Load Impact (kW)		
	% Load Impact		

6.3.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY 2014 (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. Reference loads and load impacts are very similar across the two studies.

Table 6.12: Comparison of *Ex-ante* Impacts from PY 2014 and PY 2015 Studies, *SDG&E*

Level	Outcome	*Ex-ante* 2016 Typical Event Day, Previous Study	*Ex-ante* 2016 Typical Event Day, Current Study
Total	# SAIDs	[redacted]	
	Reference (MW)		
	Load Impact (MW)		
Per SAID	Reference (kW)		
	Load Impact (kW)		
	% Load Impact		

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

Table 6.13 compares the *ex-ante* forecast prepared following PY2014 to the PY2015 *ex-post* load impact estimates contained in this report for the August 28, 2015 event day. The *ex-ante* load impacts are based on the typical event day in a utility-specific 1-in-2 weather year. Three customers dropped and one new customer enrolled in between the forecast and event, but the aggregate *ex-post* reference loads and load impacts are similar to the *ex-ante* forecast. The higher per-customer measures can be partly explained by a slightly earlier event window, as discussed further in the following section. However, other unpredictable factors also have a large effect when there are so few customers. [redacted]

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

Level	Outcome	***Ex-ante*** **2015 Typical Event Day, Previous Study**	***Ex-post*** **PY2015**
Total	# SAIDs	[redacted]	[redacted]
	Reference (MW)	[redacted]	[redacted]
	Load Impact (MW)	[redacted]	[redacted]
Per SAID	Reference (kW)	[redacted]	[redacted]
	Load Impact (kW)	[redacted]	[redacted]
	% Load Impact	[redacted]	[redacted]

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

Table 6.14 shows a comparison of *ex-post* and *ex-ante* load impacts. Enrollment increases, but the aggregate load impact is nonetheless forecast to be slightly lower in the forecast period.

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

Level	Outcome	***Ex-post*** **PY2015**	***Ex-ante*** **2016 Typical Event Day, Current Study**
Total	# SAIDs	[redacted]	[redacted]
	Reference (MW)	[redacted]	[redacted]
	Load Impact (MW)	[redacted]	[redacted]
	FSL (MW)	[redacted]	[redacted]
Per SAID	Reference (kW)	[redacted]	[redacted]
	Load Impact (kW)	[redacted]	[redacted]
	% Load Impact	[redacted]	[redacted]

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

The *ex-ante* forecast is based on the *ex-post* achievement (*i.e.*, observed loads) relative to the FSL during event hours. So in terms of achievement relative to the FSL, the *ex-post* and *ex-ante* load impacts for the five continuing customers match by design. However, the forecast reference loads may differ from the ex-post event-hour reference loads for various reasons. For instance, forecast reference loads are lower partly due to a difference in event windows, as the historical event occurred from 1:00 to 5:00 p.m., ending one hour earlier than *ex-ante* event window, which also includes the relatively low loads of hour 18.

More importantly, ex-post reference loads for the five original customers are higher due to the unusually high reference load of the largest customer, the result of higher-thanusual loads early on the event day as picked up by the "morning load" control variables. [redacted]

However, the addition of two new customers to the 2016 forecast almost completely cancels out the effect of the above factors on aggregate ex-ante load impact. These new customers increase the aggregate reference load even more, resulting in a higher ex-ante aggregate reference load overall despite the above factors working in the opposite direction. [redacted], these new customers slightly decrease the per-customer load impact despite increasing the per-customer reference load.

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

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	88.5 degrees Fahrenheit during HE 14-17 on the August 28th event day	79.6 degrees Fahrenheit during HE 14-18 on utility-specific 1-in-2 typical event day	Program load is not very weather sensitive, so a small effect.
Event window	HE 14-17	HE 14-18 in Apr-Oct.	Reference loads are substantially lower by 5 p.m. relative to earlier in the day, so the inclusion of hour-ending 18 tends to drag down the average *ex-ante* reference loads and load impacts relative to *ex-post*.
% of resource dispatched	All	All	None
Enrollment	5 service accounts	7 service accounts	[redacted]
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions.	[redacted]

7. Recommendations

BIP continues to perform well, with its customers providing substantial load impacts with short notice. We encourage utilities to dually enroll these customers in programs like DBP and PDP, which provide additional opportunities for these customers to provide demand response.

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.

BIP Study Appendix C	PG&E *Ex-post* Load Impact Tables
BIP Study Appendix D	SCE *Ex-post* Load Impact Tables
BIP Study Appendix E	SDG&E *Ex-post* Load Impact Tables
BIP Study Appendix F	PG&E *Ex-ante* Load Impact Tables
BIP Study Appendix G	SCE *Ex-ante* Load Impact Tables
BIP Study Appendix H	SDG&E *Ex-ante* Load Impact Tables

Appendix A. Validity Assessment

A.1 Model Specification Tests

A range of model specifications were tested before arriving at the models used in the *ex-post* load impact analysis. The basic structure of the model is shown in Section 3.2.1. The tests are conducted using average-customer data (by utility) rather than at the individual customer level. Model variations include 21 different combinations of weather variables for summer models and 11 different combinations for winter models. The weather variables include: temperature-humidity index (THI)[17]; the 24-hour moving average of THI; heat index (HI)[18]; the 24-hour moving average of HI; cooling degree hours (CDH)[19]; the 3-hour moving average of CDH; the 24-hour moving average of CDH; heating degree hours (HDH)[20]; the 24-hour moving average of HDH; the one-day lag of cooling degree days (CDD)[21]; the one-day lag of heating degree days (HDD)[22]; and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). For CDH, HDH, CDD, and HDD, both 60 and 65 degree Fahrenheit thresholds are used. A list of all combinations of these variables that we tested is provided in Table A.1.

[17] 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").

[18] 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.

[19] Cooling degree hours (CDH) are 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.

[20] Heating degree hours (HDH) are defined analogously to CDH as MAX[0, Threshold – Temperature].

[21] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – Threshold], 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 analogously to CDD as MAX[0, Threshold – (Max Temp + Min Temp) / 2].

Table A.1: Weather Variables Included in the Tested Specifications

Model Number	Included Weather Variables	
	Summer	Winter
1	THI	CDH60 HDH60
2	HI	CDH65 HDH65
3	CDH60	CDH60 CDH60_MA24 HDH60 HDH60_MA24
4	CDH65	CDH65 CDH65_MA24 HDH65 HDH65_MA24
5	CDH60_MA3	CDH60 CDD60 HDH60 HDD60
6	CDH65_MA3	CDH65 CDD65 HDH65 HDD65
7	THI THI_MA24	CDH60 Lag_CDD60 HDH60 Lag_HDD60
8	HI HI_MA24	CDH65 Lag_CDD65 HDH65 Lag_HDD65
9	CDH60 CDH60_MA24	Mean17
10	CDH65 CDH65_MA24	CDH60 HDH60 Mean17
11	CDH60_MA3 CDH60_MA24	CDH65 HDH65 Mean17
12	CDH65_MA3 CDH65_MA24	
13	THI Lag_CDD60	
14	HI Lag_CDD60	
15	CDH60 Lag_CDD60	
16	CDH65 Lag_CDD60	
17	CDH60_MA3 Lag_CDD60	
18	CDH65_MA3 Lag_CDD60	
19	Mean17	
20	CDH60 Mean17	
21	CDH65 Mean17	

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.1.1 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 event-window temperature (hours-ending 15 through 19 for PGE summer, 15 and 16 for PGE winter, 14 through 16 for SCE , and 14 through 17 for SDG&E), omitting holidays, weekends, and event days for programs in which BIP customers are dually enrolled (*e.g.*, DBP). Table A.2 lists the event-like non-event days selected for each program.

Table A.2: List of Event-Like Non-Event Days by Program

PG&E		SCE	SDG&E
Summer	Winter	Summer	Summer
6/17/2015	11/12/2014	8/12/2015	7/23/2015
7/02/2015	1/29/2015	8/13/2015	7/31/2015
7/16/2015	2/03/2015	8/14/2015	8/04/2015
7/17/2015	2/10/2015	8/24/2015	8/25/2015
7/20/2015	3/11/2015	9/25/2015	8/26/2015
7/22/2015	3/12/2015	9/28/2015	8/27/2015
7/23/2015	4/22/2015	9/30/2015	9/11/2015
7/27/2015			
9/25/2015			

A.1.2 Results from Tests of Alternative Weather Specifications

For each utility, we tested 21 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each utility.

For each utility/season (5) and specification (21 for summer and 11 for winter), the tests are conducted by estimating one model for every event-like day (9 for PG&E summer and 7 for the others). 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-window hours of the withheld days.

Table A.3 summarizes the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) of the winning specification for each program. The bias is generally low with the exception of the SDG&E winter model. That high bias and the high error rate are likely due to the fact that SDG&E's program contains only five customers, only two of which ever have loads substantially above their FSLs around the time of the event, with somewhat large variations in load across days. Model performance tends to improve as the sample size increases, since customer-specific idiosyncrasies get averaged out. This helps explain the superior performance of the PG&E and SCE models, which are much larger programs than the SDG&E program.

Table A.3: Specification Test Results

Utility	Season	Selected Specification Number	Adjusted R^2	MPE	MAPE
PG&E	Summer	10	0.93	0.5%	1.5%
PG&E	Winter	6	0.97	2.9%	4.8%
SCE	Summer	15	0.84	-0.7%	1.5%
SDG&E	Summer	5	0.90	-3.7%	7.2%

For each specification, we estimated a single model that included all of the days (*i.e.*, not withholding any event-like days), but using a single set of actual event variables (*i.e.*, a 24-hour profile of the average event-day load impacts). Figures A.1 through A.4 show the estimated hourly load impacts for each of the models by utility/season. The load impacts for the selected specification are highlighted in bold in each of the figures. With the possible exceptions of SDG&E (Figure A.4) and a single specification for PG&E Winter (Figure A.2), the results of these tests indicated that very little is at stake when selecting from the specifications, as the load impact profile was quite stable across them.

Figure A.1: Average Event-Hour Load Impacts by Specification, PG&E Summer Models

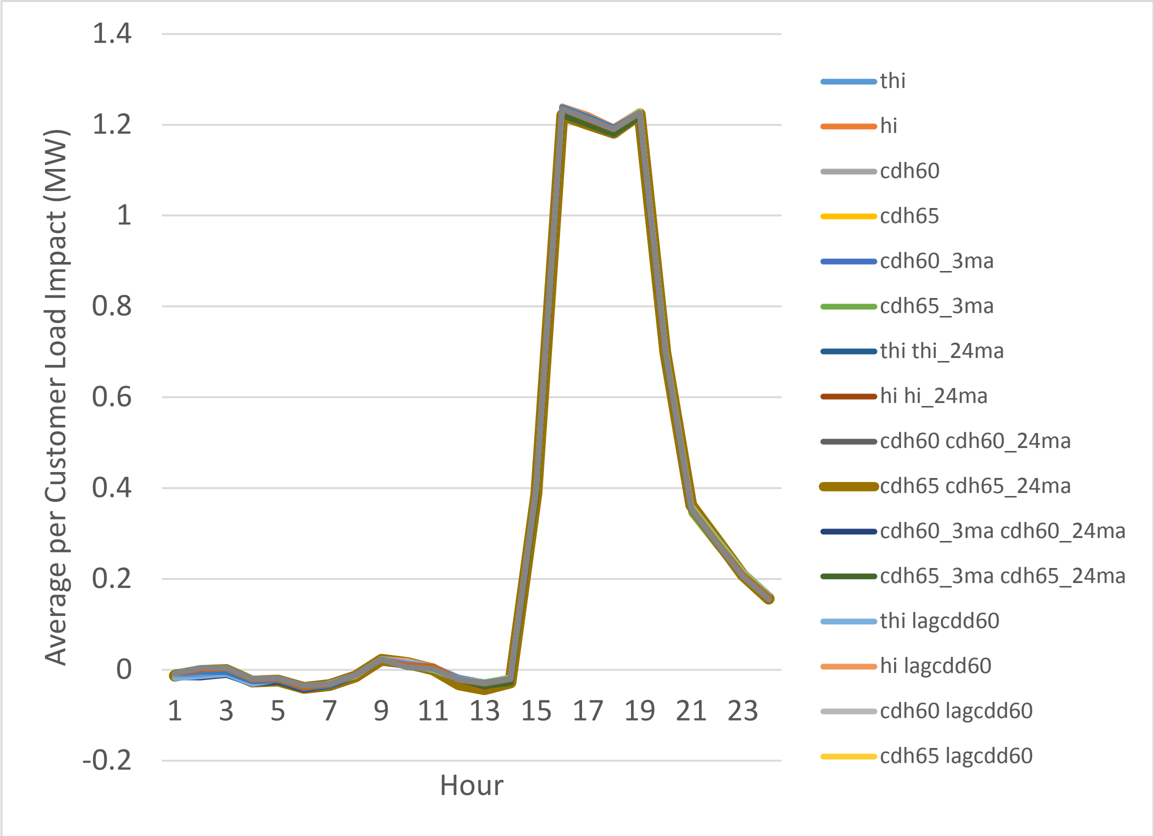


Figure A.2: Average Event-Hour Load Impacts by Specification, PG&E Winter Models

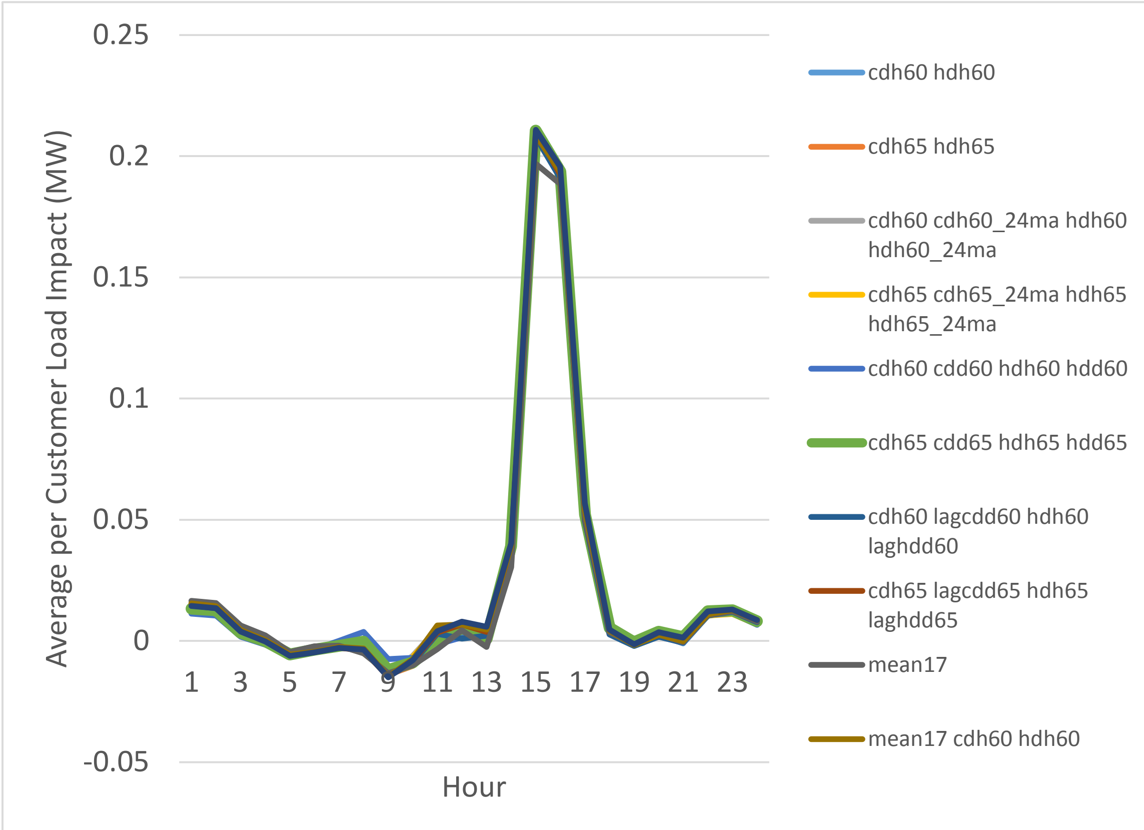


Figure A.3: Average Event-Hour Load Impacts by Specification, SCE Summer Models

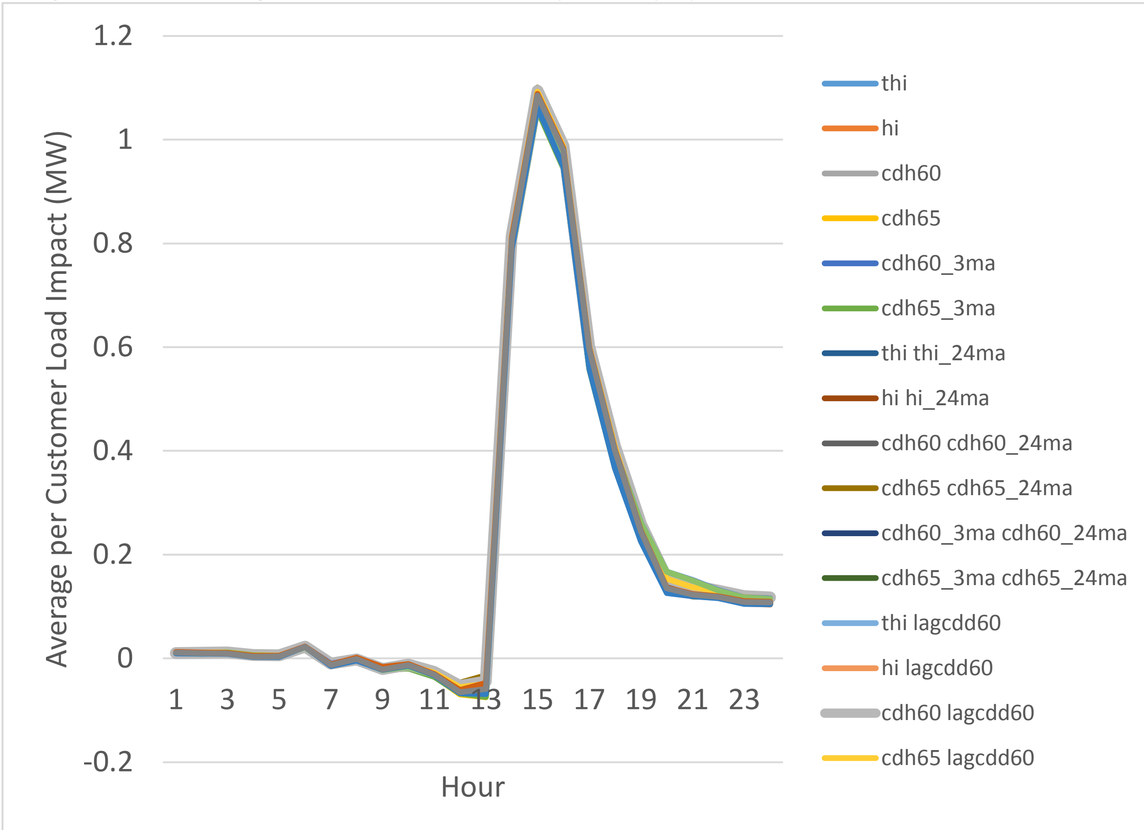


Figure A.4: Average Event-Hour Load Impacts by Specification, SDG&E Summer Models

[redacted]

A.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section A.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data (averaged across all customers who submitted a bid on at least one event day), including a set of 24 hourly "synthetic" event-day variables. These variables equaled one of the days listed in Table A.2, 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.4 presents the results of this test for each utility, showing only the coefficients during the hours-ending 14 through 19, which time period includes all actual BIP event hours. The values in parentheses are p-values, or measures of statistical significance. A p-value less than 0.05 indicates that the estimated coefficient is statistically significantly different from zero with 90 percent confidence. The models perform well overall, with no statistically significant event-like load impacts.

Table A.4: Synthetic Event-Day Tests by Program

Hour	PG&E		SCE	SDG&E
	Summer	Winter	Summer	Summer
14	0.001 (0.93)	0.009 (0.25)	0.028 (0.11)	0.007 (0.92)
15	0.00008 (1.00)	0.001 (0.87)	0.013 (0.48)	0.052 (0.45)
16	-0.0003 (0.98)	-0.007 (0.39)	-0.004 (0.83)	0.060 (0.39)
17	-0.011 (0.38)	-0.003 (0.70)	-0.014 (0.43)	0.104 (0.14)
18	-0.014 (0.26)	0.002 (0.84)	-0.014 (0.45)	0.126 (0.07)
19	-0.009 (0.48)	0.001 (0.84)	0.001 (0.96)	0.056 (0.42)

A.2 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.5 through A.8 illustrate the average predicted and observed loads across the event-like days. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model.[23]

Figures A.5 through A.7 show that the PG&E and SCE predicted loads are quite close to the observed loads for the event-like non-event days. Figure A.8 shows that the SDG&E predicted loads are somewhat different from the observed loads during the afternoon. This reflects the increased difficulty of predicting loads precisely when the aggregate load is dominated by a single customer with irregular load profiles.

[23] The reason that PG&E's winter per-customer average loads shown in Figure A.6 differ markedly from the summer load profile shown in Figure A.5 because only the small subset of customers participating in PG&E's non-summer re-test events are included.

Figure A.5: Average Predicted and Observed Loads on Event-like Days, PG&E Summer

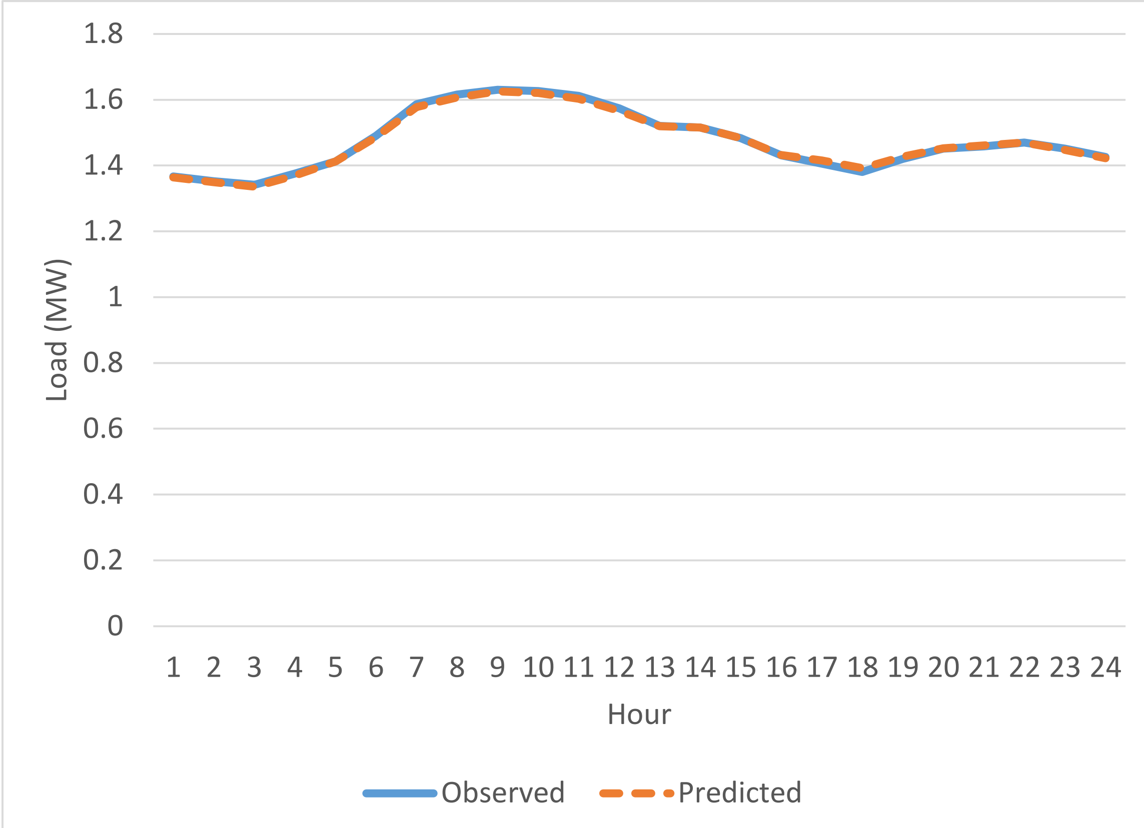


Figure A.6: Average Predicted and Observed Loads on Event-like Days, PG&E Winter

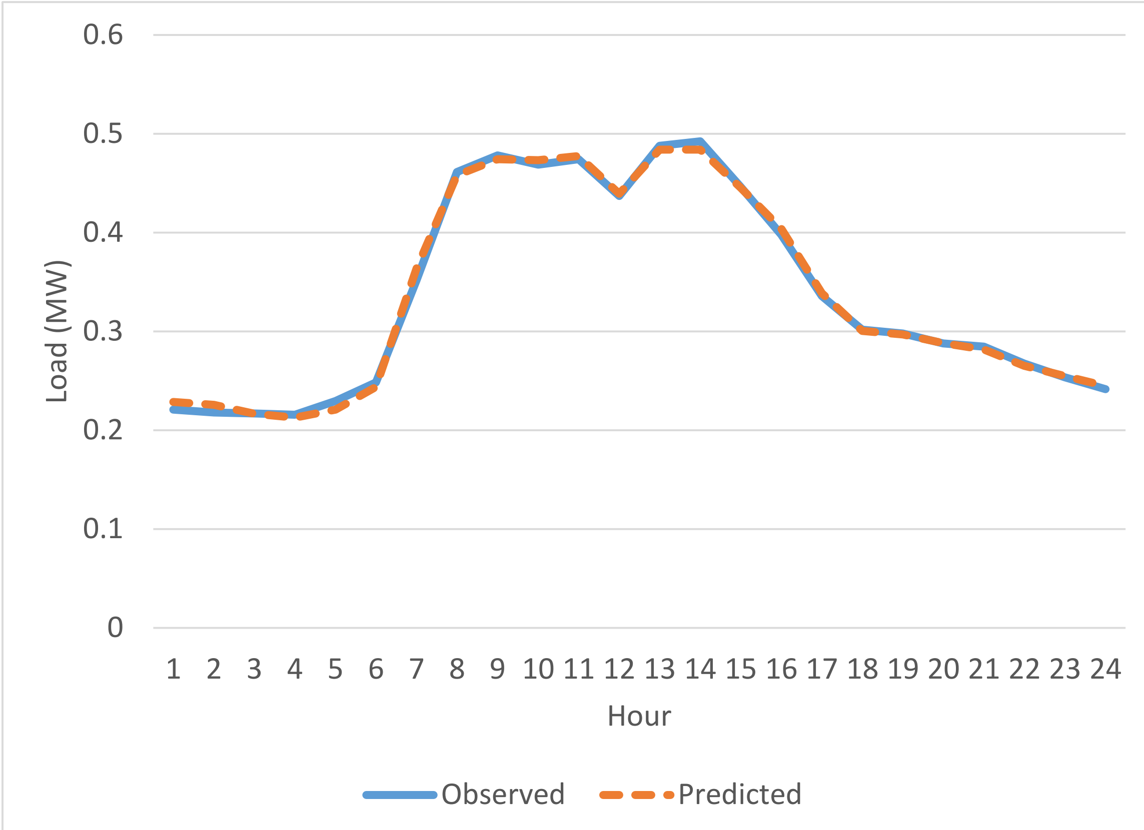


Figure A.7: Average Predicted and Observed Loads on Event-like Days, SCE Summer

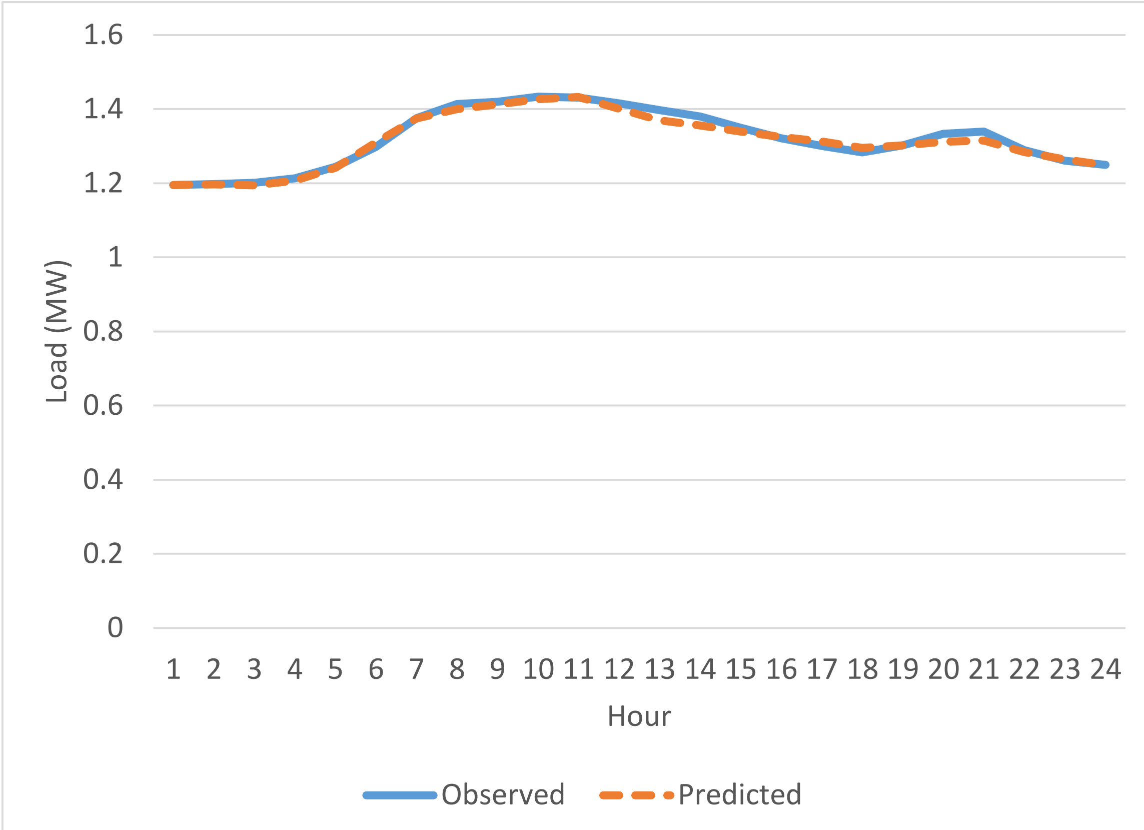


Figure A.8: Average Predicted and Observed Loads on Event-like Days, SDG&E Summer

[redacted]

A.3 Potential Refinement of Customer-Level Models

While the specification tests described in Section A.1 were conducted on aggregated load profiles for each utility, the *ex-post* load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a "day matching" load impact that may be compared to the estimated load impacts. After this evaluation, we have not modified the estimated load impacts for any customers.

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. 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. The notes following each table indicate the included hours.

Table B.1: July 30, 2015 Over/Under Performance – PG&E BIP, *by Industry Group and Event Hour*

Industry Group	Percent Over/Under Performance			
	Hour Before Event	**First Hour of Event**	**Last Hour of Event**	**Hour After Event**
Agriculture, Mining, & Construction	36%	108%	105%	71%
Manufacturing	30%	103%	102%	59%
Wholesale, Transportation, & Other Utilities	33%	98%	99%	49%
Retail Stores	[redacted]			
Offices, Hotels, Health, Services				
Entertainment, Other Services, Government				
Other or Unknown				
All Customers	**31%**	**103%**	**102%**	**57%**

(HE15, HE16, HE19, and HE20 shown.)

Table B.2: September 24, 2015 Over/Under Performance – SCE BIP, *by Industry Group and Event Hour*

Industry Group	Percent Over/Under Performance			
	Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining, & Construction	72%	99%	97%	79%
Manufacturing	69%	90%	82%	51%
Wholesale, Transportation, & Other Utilities	72%	93%	77%	21%
Retail Stores	12%	16%	12%	2%
Offices, Hotels, Health, Services	[redacted]			
Schools				
Entertainment, Other Services, Government				
All Customers	**67%**	**90%**	**82%**	**51%**

(HE14, HE15, HE16, and HE17 are shown. Note that HE14 and HE16 are partial event hours because the event ended at 3:30 p.m. and went into effect at 1:30 for the 15-minute notification program and 1:45 p.m. for the 30-minute notification program.)

Table B.3: August 28, 2015 Over/Under Performance – SDG&E BIP, *by Industry Group and Event Hour*

Industry Group	Percent Over/Under Performance			
	Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining, & Construction	[redacted]			
Manufacturing				
Retail Stores				
All Customers				

(HE15, HE16, HE19, HE20 shown. "n/a" indicates total reference load is below the FSL.)