# 2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers:
# Ex Post and Ex Ante Report

**CALMAC Study ID SCE0367**

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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 2014. The report provides estimates of ex post load impacts that occurred during events called in 2014 and an ex ante forecast of load impacts for 2015 through 2025 that is based on the IOU's enrollment forecasts and the ex post load impacts estimated for the 2014 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 a full program event on February 6, 2014. That was SCE's only BIP event of PY2014. PG&E called two partial re-test events (in April and May) and another full test event on September 11, 2014. SDG&E called two additional events on May 14th and 16th. Enrollment in PG&E's BIP was 218 service agreements on September 11. The sum of the enrolled customers' coincident maximum demands on that day was 323 MW. Enrollment in SCE's BIP was 620 service accounts on the February 6 event day. The sum of the enrolled customers' coincident maximum demands on that day was 777 MW. SDG&E's BIP enrollment was 7 service accounts on each event day and the sum of enrolled customer coincident maximum demands on the May 16 event day was 4.2 MW.

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

The total program load impact for PG&E's September 11th test event averaged 228 MW, or 79.8 percent of enrolled load, representing 102% of the reduction required to meet the aggregate FSL.

For SCE, the average hourly load impact for its February 6th event was 624 MW, or 83 percent of the total reference load. This was 93 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its May 16th test event averaged 2 MW, or 50 percent of enrolled load, representing 81% of the reduction required to meet the aggregate FSL.

In the ex ante evaluation, SCE forecasts BIP customer enrollment to decrease slightly from 2015 through 2017 due to a combination of opt outs and disqualifications from the program. During the 2015 program year, SCE's average event-hour load impact is approximately 668 MW. PG&E forecasts BIP enrollment to remain constant from 2015 to 2025 at 203 service agreements. PG&E's average event-hour load impact is forecast to be 246 MW during a utility-specific 1-in-2 August 2015 peak day. 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 1.4 MW during a utility-specific 1-in-2 August 2015 peak 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 2014. The report provides estimates of ex post load impacts that occurred during events called in 2014 and an ex ante forecast of load impacts for 2015 through 2025 that is based on the IOU's enrollment forecasts and the ex post load impacts estimated for the 2014 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2014?
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 2015 through 2025?

## *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").

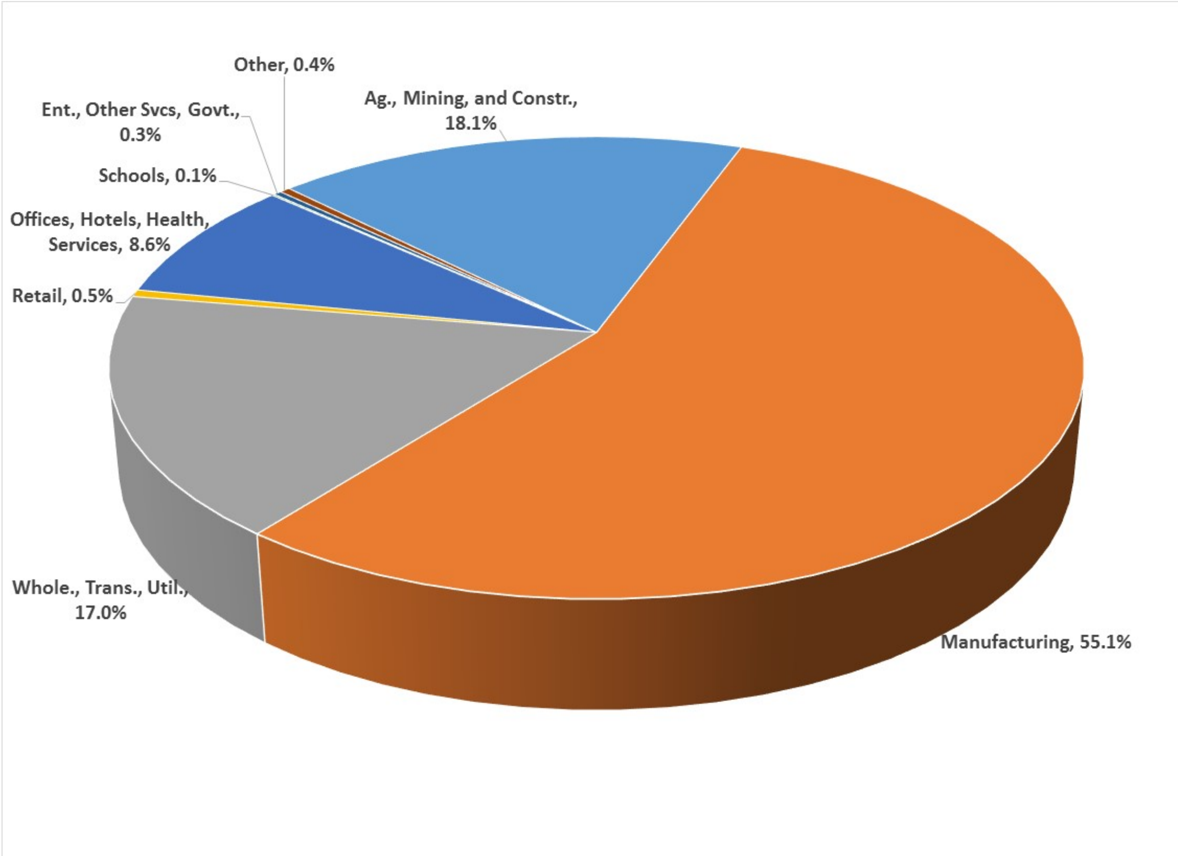
There are a number of similarities and differences in the BIPs offered by the California investor-owned utilities ("IOUs"). The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand.

All three utilities called an event on February 6, 2014. PG&E called two re-test events on April 17$^{th}$ and May 15$^{th}$ and an additional test event on September 11$^{th}$. SDG&E called two additional program events on May 14$^{th}$ and 16$^{th}$.

### Enrollment

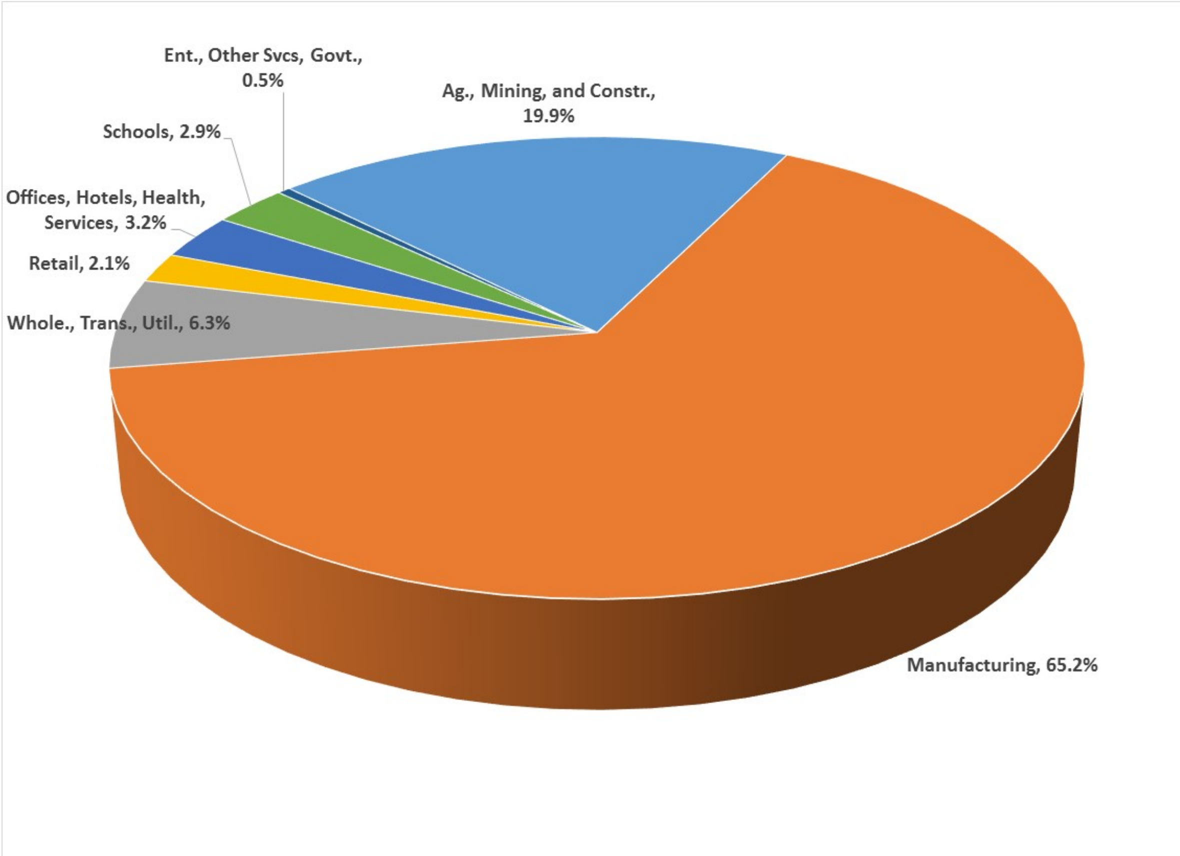
Enrollment in PG&E's BIP decreased relative to PY2013, from 280 to 218 in 2014. The sum of enrolled customers' coincident maximum demands was 323 MW, or 1.48 MW for the average service agreement. The manufacturing industry group contains more than half of the enrolled load. Figure ES.1 illustrates the distribution of BIP load across the indicated industry types.

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



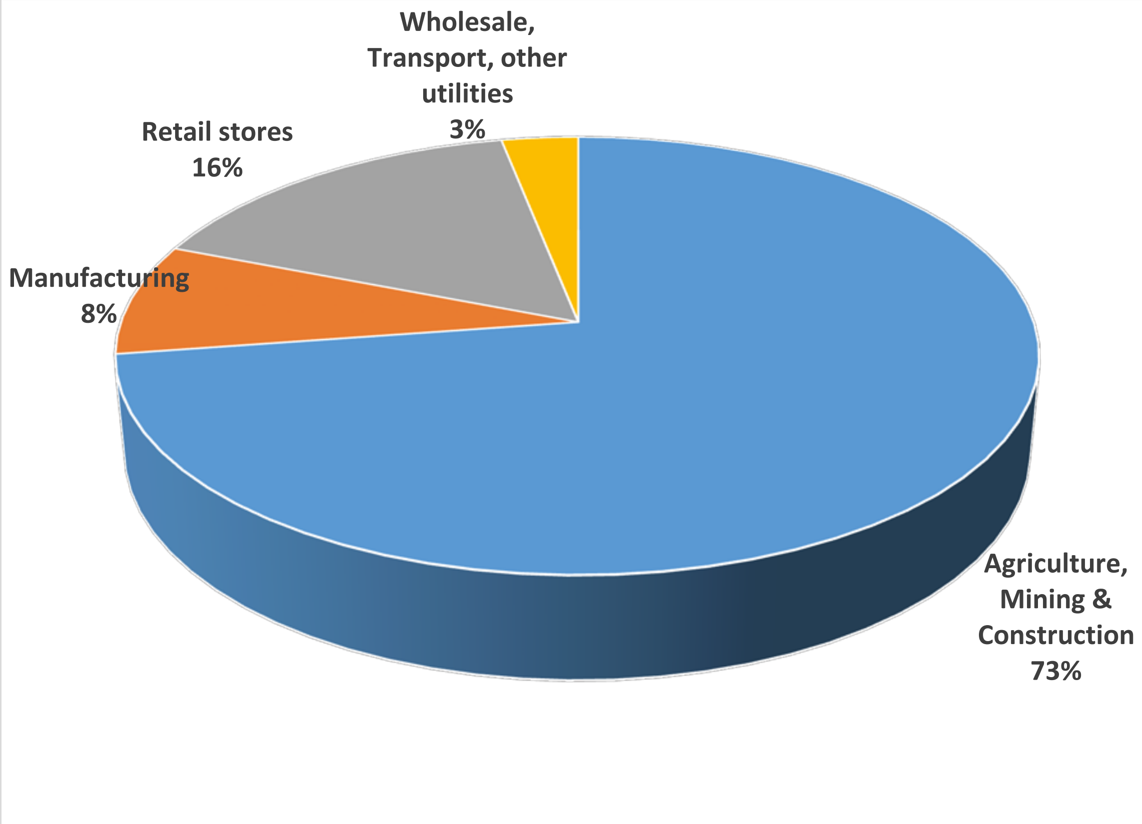

SCE's enrollment in BIP was 620 service accounts on the February 6, 2014 event day, which is a slight decrease relative to the 646 enrolled service accounts during PY2013. These accounted for a total of 777 MW of maximum demand, or 1.25 MW per service account. Manufacturers make up about two-thirds of 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**




SDG&E's enrollment in BIP was 7 service accounts on the May 16, 2014 event day, which is the same number of service accounts enrolled during PY2013. These accounted for a total of 4.2 MW of maximum demand, or 0.60 MW per service account. Two agriculture, mining, and construction customers make up 73% of the enrolled load. 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**




## *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 September 11th test event averaged 228 MW, or 79.8 percent of enrolled load, representing 102% of the reduction required to meet the aggregate FSL. This is quite close to the 216 MW average load impact from the previous program year. The total load impact for the February 6th test event was similar, averaging 200 MW, or 78.2 percent of the enrolled load, 103% of the reduction required to meet the aggregate FSL.

For SCE, the average hourly load impact for its February 6th event was 624 MW, or 83 percent of the total reference load. This was 93 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its May 16th test event averaged 2 MW, or 50 percent of enrolled load, representing 81% of the reduction required to meet the aggregate FSL.

## 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 data and results of the ex post load impact evaluation.

PG&E forecasts BIP enrollments to remain constant from 2015 through 2025, with 203 enrolled service agreements. SCE projects BIP enrollments to decrease during 2015 through 2017 by 15 customers each year. SDG&E forecasts enrollments to remain at the historical level 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 1.4 MW.

Figures ES.4 and ES.5 show the ex ante load impacts for PG&E and SCE, respectively. Both figures illustrate the lack of weather sensitivity at the aggregate level.

**Figure ES.4: Average August Ex Ante Load Impacts by Scenario, PG&E**

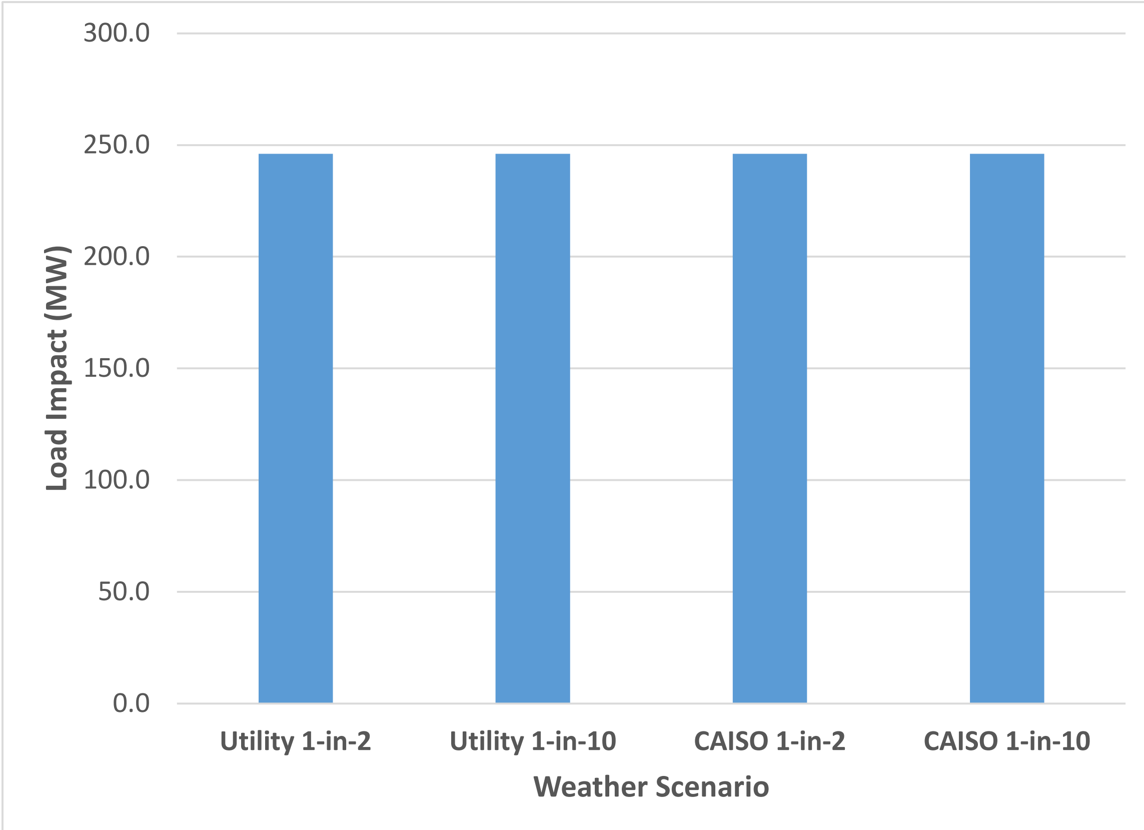
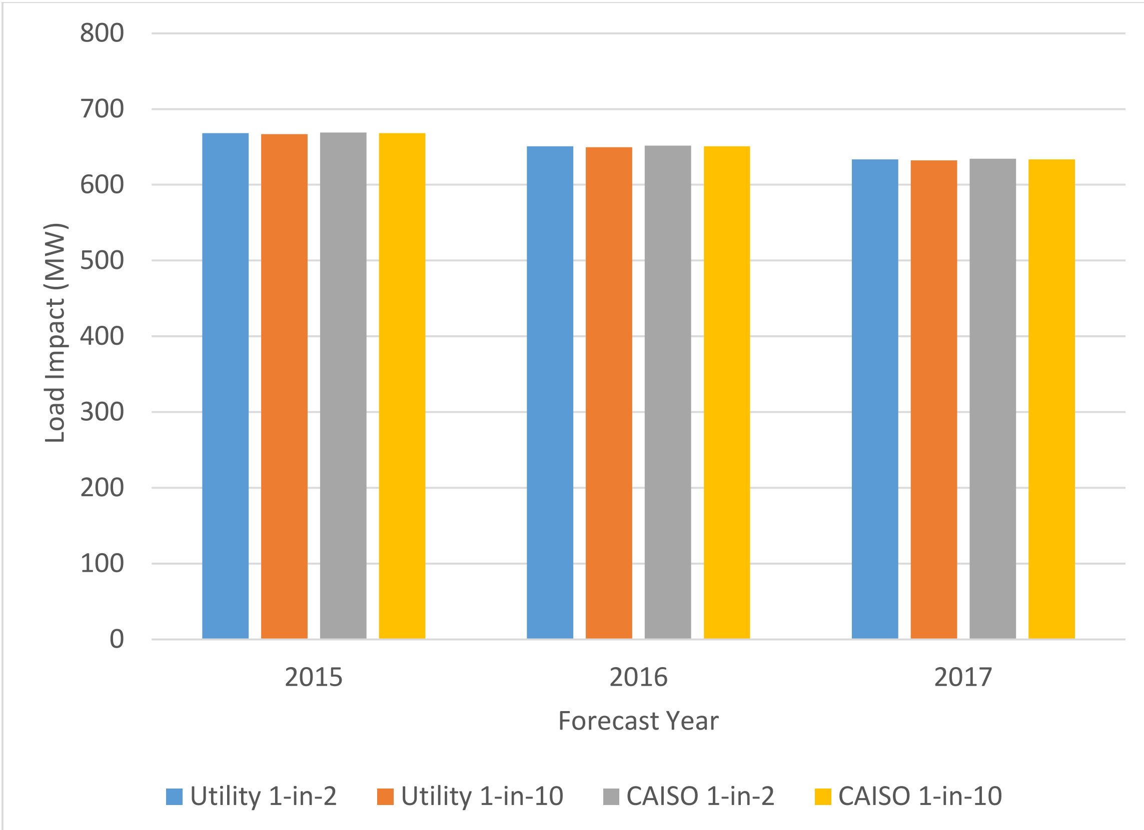


**Figure ES.5: Average August Ex Ante Load Impacts by Year and Scenario, *SCE***



## 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 2014. The report provides estimates of ex post load impacts that occurred during events called in 2014 and an ex ante forecast of load impacts for 2015 through 2025 that is based on the IOU's enrollment forecasts and the ex post load impacts estimated for the 2014 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2014?
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 2015 through 2025?

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 2014.

## *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. Customers must be notified at least 30 minutes prior to the event and monthly incentive payments are $12.00 per kW for the months of May through October and $2.00 per kW in all other months. Previously SDG&E offered a BIP option B which required that participating customer be notified at least 3 hours before the event but SDG&E discontinued this option in 2012.

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, and seven participants in 2013.

## *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).[1]

### 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 September 11, 2014 event day. Enrollment in PG&E's BIP decreased relative to PY2013, from 280 to 218 in 2014.[2] The sum of enrolled customers' coincident maximum demands[3] was 323 MW, or 1.48 MW for the average

[1] 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.

[2] "Enrollment" is defined as the enrollment on the September 11, 2014 event day for PG&E; the February 6, 2014 event day for SCE; and the May 16, 2014 event day for SDG&E.

[3] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 2, including the estimated load impacts (i.e., using the reference loads).

service agreement. The manufacturing industry group contains more than half of the enrolled load. Note that portions of the table have been removed due to confidentiality concerns.

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

| Industry Type | # of Service Agreements | Sum of Max MW[4] | % of Max MW | Ave. Max MW[5] |
|---|---|---|---|---|
| 1.Agriculture, Mining, Construction | 41 | 58.4 | 18.1% | 1.42 |
| 2.Manufacturing | 85 | 177.8 | 55.1% | 2.09 |
| 3.Wholesale, Transportation, Utilities | 52 | 54.7 | 17.0% | 1.05 |
| 4.Retail | | | | |
| 5.Offices, Hotels, Health, Services | | | | |
| 6.Schools | | | | |
| 7. Entertainment, Other Services, Government. | | | | |
| 8.Other | | | | |
| **TOTAL** | **218** | **322.6** | | **1.48** |

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 620 service accounts on the February 6, 2014 event day, which is a slight decrease relative to the 646 enrolled service accounts during PY2013. These accounted for a total of 777 MW of maximum demand, or 1.25 MW per service account. Manufacturers make up about two-thirds of the enrolled load. Note that portions of the table have been removed due to confidentiality concerns.

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

| Industry Type | # of Service Accounts | Sum of Max MW | % of Max MW | Ave. Max MW |
|---|---|---|---|---|
| 1.Agriculture, Mining, Construction | 53 | 154.7 | 19.9% | 2.92 |
| 2.Manufacturing | 353 | 506.5 | 65.2% | 1.43 |
| 3.Wholesale, Transportation, Utilities | 68 | 48.6 | 6.3% | 0.71 |
| 4.Retail | 40 | 16.0 | 2.1% | 0.40 |
| 5.Offices, Hotels, Health, Services | | | | |
| 6.Schools | 68 | 22.8 | 2.9% | 0.34 |
| 7.Entertainment, Other Services, Government. | | | | |
| **TOTAL** | **620** | **777.3** | | **1.25** |

Table 2.3 shows BIP enrollments for SDG&E. SDG&E's enrollment in BIP was 7 service accounts on the May 16, 2014 event day, which is the same number of service accounts enrolled during PY2013. These accounted for a total of 4.2 MW of maximum demand, or

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

0.60 MW per service account. Agriculture, mining, and construction customers comprise the majority of the enrolled load. Note that the contents of the table have been removed due to confidentiality concerns.

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

| Industry Type | # of Service Accounts | Sum of Max MW | % of Max MW | Ave. Max MW |
|---|---|---|---|---|
| 1.Agriculture, Mining, Construction | | | | |
| 2.Manufacturing | | | | |
| 3.Wholesale, Transportation, Utilities | | | | |
| 4.Retail | | | | |
| **TOTAL** | **7** | **4.2** | | **0.60** |

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 76 percent of SCE's enrolled load is in the LA Basin. Note that portions of the tables have been removed due to confidentiality concerns.

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

| Local Capacity Area | # of Service Agreements | Sum of Max MW | % of Max MW | Ave. Max MW |
|---|---|---|---|---|
| Greater Bay Area | | | | |
| Greater Fresno | | | | |
| Humboldt | | | | |
| Kern | | | | |
| Northern Coast | | | | |
| Not in any LCA | 95 | 229.6 | 71.2% | 2.42 |
| Sierra | | | | |
| Stockton | | | | |
| **TOTAL** | **218** | **322.6** | | **1.48** |

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

| Local Capacity Area | # of Service Accounts | Sum of Max MW | % of Max MW | Ave. Max MW |
|---|---|---|---|---|
| LA Basin | 533 | 594.5 | 76.5% | 1.12 |
| Outside LA Basin | | | | |
| Ventura | | | | |
| **TOTAL** | **620** | **777.3** | | **1.25** |

## *2.3 Event Days*

Table 2.6 lists BIP event days for the three IOUs in 2014. All of the utilities called an event on February 6, 2014. SDG&E called two additional program events on May 14th and 16th. PG&E called two re-test events on April 17th and May 15th and an additional test event on September 11th.

**Table 2.6: BIP Event Days**

| Date | Day of Week | SCE | PG&E | SDG&E |
|---|---|---|---|---|
| 2/6/2014 | Thursday | 1 | 1 | 1 |
| 4/17/2014 | Thursday | | 2 (re-test) | |
| 5/14/2014 | Wednesday | | | 2 |
| 5/15/2014 | Thursday | | 3 (re-test) | |
| 5/16/2014 | Friday | | | 3 |
| 9/11/2014 | Thursday | | 4 (test) | |

# 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.[6]

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.

[6] 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.

## 3.2 Description of methods

### 3.2.1 Regression Model

The model shown below was separately estimated for each enrolled customer. Table 3.1 describes the terms included in the equation.

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

**Table 3.1: Descriptions of Terms included in the Ex Post Regression Equation**

| Variable Name / Term | Variable / Term 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 |
| $h_{i,t}$ | a dummy variable for hour *i* |
| $BIP_t$ | an indicator variable for program event days |
| $Weather_t$ | the weather variables selected using our model screening process |
| $E$ | the number of event days that occurred during the program year |
| $MornLoad_t$ | a variable equal to the average of the day's load in hours 1 through 10 |
| $OtherEvt^{DR}{}_t$ | equals one on the event days of other demand response programs in which the customer is enrolled |
| $MON_t$ | a dummy variable for Monday |
| $FRI_t$ | a dummy variable for Friday |
| $SUMMER_t$ | a dummy variable for the summer pricing season[7] |
| $DTYPE_{i,t}$ | a series of dummy variables for each day of the week |
| $MONTH_{i,t}$ | a series of dummy variables for each month |
| $e_t$ | 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

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

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 non-summer), 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).

A parallel set of non-summer models was estimated for each customer. The structure matches the model described above, with appropriate modifications made to the month indicators, summer variables, and weather variables.

### 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 $10^{th}$, $30^{th}$, $70^{th}$, and $90^{th}$ 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 1,046.7 kW for PG&E's program, 1,464.8 kW for SCE's program, and 298.4 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 second and third events were re-tests following the February 6th event, fewer service agreements were called. The highest load impact occurred during the September 11th test event, with an average 228 MW load impact across the two event hours. Note that portions of the table have been removed due to confidentiality concerns.

**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 | 2/6/2014 | Thurs. | 220 | 255.7 | 55.7 | 200.1 | 78.2% |
| 2 | 4/17/2014 | Thurs. | | | | | |
| 3 | 5/15/2014 | Thurs. | | | | | |
| 4 | 9/11/2014 | Thurs. | 218 | 285.8 | 57.6 | 228.2 | 79.8% |

Table 4.2 compares the observed loads and FSLs by event day. During the two events in which all service agreements were called (February 6th and September 11th), the program load was below the aggregate FSL. This was not the case during the two 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). Note that portions of the table have been removed due to confidentiality concerns.

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

| Event | Date | Day of Week | Average Observed Load (MW) | Average Firm Service Level (MW) | Estimated LI / LI at FSL |
|---|---|---|---|---|---|
| 1 | 2/6/2014 | Thurs. | 55.7 | 61.1 | 103% |
| 2 | 4/17/2014 | Thurs. | | | |
| 3 | 5/15/2014 | Thurs. | | | |
| 4 | 9/11/2014 | Thurs. | 57.6 | 61.8 | 102% |

Table 4.3 summarizes average hourly BIP load impacts by industry group for the September 11th event day. This date was selected because it is a full-program event (in contrast to the April and May events) that occurred in the summer season, which is more typical of when one would expect BIP events to occur. The Manufacturing industry group accounted for the largest share of the load impacts, with a 144 MW average event-hour load reduction. Note that portions of the table have been removed due to confidentiality concerns.

**Table 4.3: September 11, 2014 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 | 41 | 45.9 | 15.4 | 30.6 | 66.5% |
| Manufacturing | 85 | 161.7 | 17.3 | 144.3 | 89.3% |
| Wholesale, Transportation, & Other Utilities | 52 | 40.2 | 11.3 | 28.9 | 71.9% |
| Retail Stores | | | | | |
| Offices, Hotels, Health, Services | | | | | |
| Schools | | | | | |
| Entertainment, Other Services, Government | | | | | |
| Other or Unknown | | | | | |
| **Total** | **218** | **285.8** | **57.6** | **228.2** | **79.8%** |

Table 4.4 summarizes September 11th 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. Note that portions of the table have been removed due to confidentiality concerns.

**Table 4.4: September 11, 2014 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 | | | | | |
| Greater Fresno | | | | | |
| Humboldt | | | | | |
| Kern | | | | | |
| Northern Coast | | | | | |
| Not in any LCA | 95 | 198.9 | 33.6 | 165.3 | 83.1% |
| Sierra | | | | | |
| Stockton | | | | | |
| **Total** | **218** | **285.8** | **57.6** | **228.2** | **79.8%** |

### 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. Because of variation across event days (in terms of service agreements and hours called), the table only reflects the September 11, 2014 event day.[8]

[8] A comparison of load impacts using 15-minute and 60-minute data is provided in Appendix A.

### Table 4.5: BIP Hourly Load Impacts for the September 11, 2014 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 ($^oF$) | Uncertainty Adjusted Impact (MWh/hr)- Percentiles 10th%ile | 30th%ile | 50th%ile | 70th%ile | 90th%ile |
|---|---|---|---|---|---|---|---|---|---|
| **1** | 274.0 | 271.5 | 2.5 | 69.5 | 0.9 | 1.9 | 2.5 | 3.2 | 4.1 |
| **2** | 267.9 | 272.2 | -4.2 | 68.7 | -5.7 | -4.8 | -4.2 | -3.6 | -2.7 |
| **3** | 266.3 | 273.0 | -6.6 | 67.7 | -8.0 | -7.2 | -6.6 | -6.1 | -5.3 |
| **4** | 273.2 | 274.4 | -1.2 | 66.6 | -2.2 | -1.6 | -1.2 | -0.8 | -0.2 |
| **5** | 281.8 | 283.5 | -1.7 | 65.2 | -2.6 | -2.1 | -1.7 | -1.3 | -0.8 |
| **6** | 297.0 | 302.2 | -5.2 | 64.1 | -6.2 | -5.6 | -5.2 | -4.8 | -4.2 |
| **7** | 318.0 | 315.8 | 2.2 | 62.9 | 1.1 | 1.7 | 2.2 | 2.6 | 3.2 |
| **8** | 322.6 | 318.7 | 3.9 | 64.2 | 2.7 | 3.4 | 3.9 | 4.4 | 5.0 |
| **9** | 322.1 | 321.4 | 0.7 | 68.0 | -0.7 | 0.1 | 0.7 | 1.3 | 2.1 |
| **10** | 322.3 | 321.2 | 1.1 | 72.6 | -0.3 | 0.5 | 1.1 | 1.7 | 2.5 |
| **11** | 319.8 | 317.5 | 2.3 | 77.5 | 0.7 | 1.6 | 2.3 | 2.9 | 3.9 |
| **12** | 316.0 | 321.0 | -5.1 | 82.2 | -6.8 | -5.8 | -5.1 | -4.4 | -3.3 |
| **13** | 303.0 | 305.9 | -2.9 | 86.4 | -4.7 | -3.6 | -2.9 | -2.2 | -1.2 |
| **14** | 297.9 | 239.3 | 58.6 | 89.9 | 56.7 | 57.8 | 58.6 | 59.4 | 60.6 |
| **15** | 291.0 | 59.1 | 231.9 | 92.6 | 229.9 | 231.0 | 231.9 | 232.7 | 233.8 |
| **16** | 280.6 | 56.1 | 224.5 | 93.3 | 222.5 | 223.7 | 224.5 | 225.3 | 226.5 |
| **17** | 277.9 | 166.6 | 111.3 | 92.4 | 109.3 | 110.5 | 111.3 | 112.1 | 113.2 |
| **18** | 274.2 | 217.8 | 56.4 | 91.9 | 54.4 | 55.6 | 56.4 | 57.3 | 58.5 |
| **19** | 281.9 | 237.8 | 44.1 | 88.9 | 42.0 | 43.2 | 44.1 | 45.0 | 46.3 |
| **20** | 286.7 | 248.1 | 38.6 | 83.6 | 36.3 | 37.7 | 38.6 | 39.6 | 41.0 |
| **21** | 286.1 | 251.0 | 35.2 | 79.4 | 32.6 | 34.1 | 35.2 | 36.2 | 37.7 |
| **22** | 288.0 | 249.3 | 38.7 | 76.7 | 36.3 | 37.7 | 38.7 | 39.7 | 41.2 |
| **23** | 285.3 | 251.5 | 33.8 | 73.9 | 31.4 | 32.8 | 33.8 | 34.8 | 36.2 |
| **24** | 280.7 | 256.3 | 24.3 | 71.9 | 22.0 | 23.4 | 24.3 | 25.3 | 26.7 |
| 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** | 7,014 | 6,131 | 883 | 135.0 | n/a | n/a | n/a | n/a | n/a |
| **Event Hours** | 285.8 | 57.6 | 228.2 | 35.9 | 226.4 | 227.5 | 228.2 | 228.9 | 229.9 |

Figure 4.1 illustrates the hourly reference load, observed load, and load impacts for the September 11th event day. The scale for the hourly load impacts is shown on the right-hand side of the figure. Figure 4.2 shows the variability of estimated load impacts across the four event 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 Load Impacts for the September 11, 2014 Event Day, *PG&E***

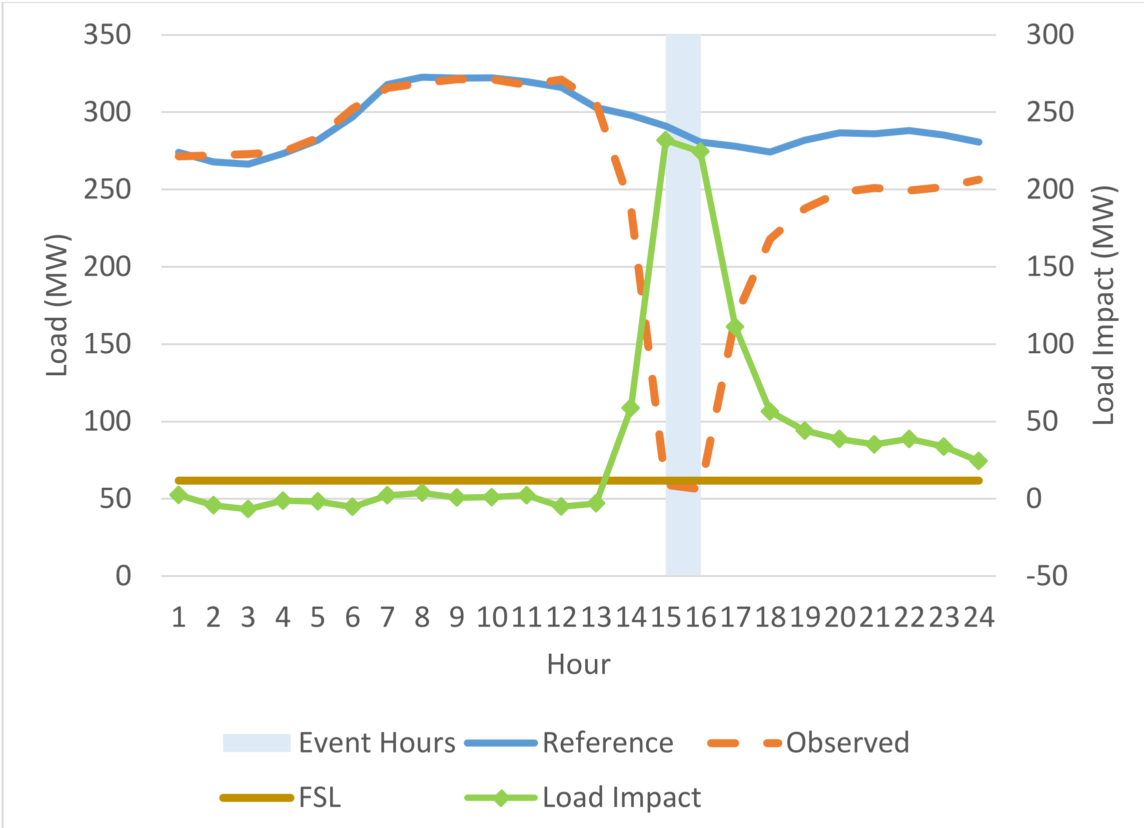
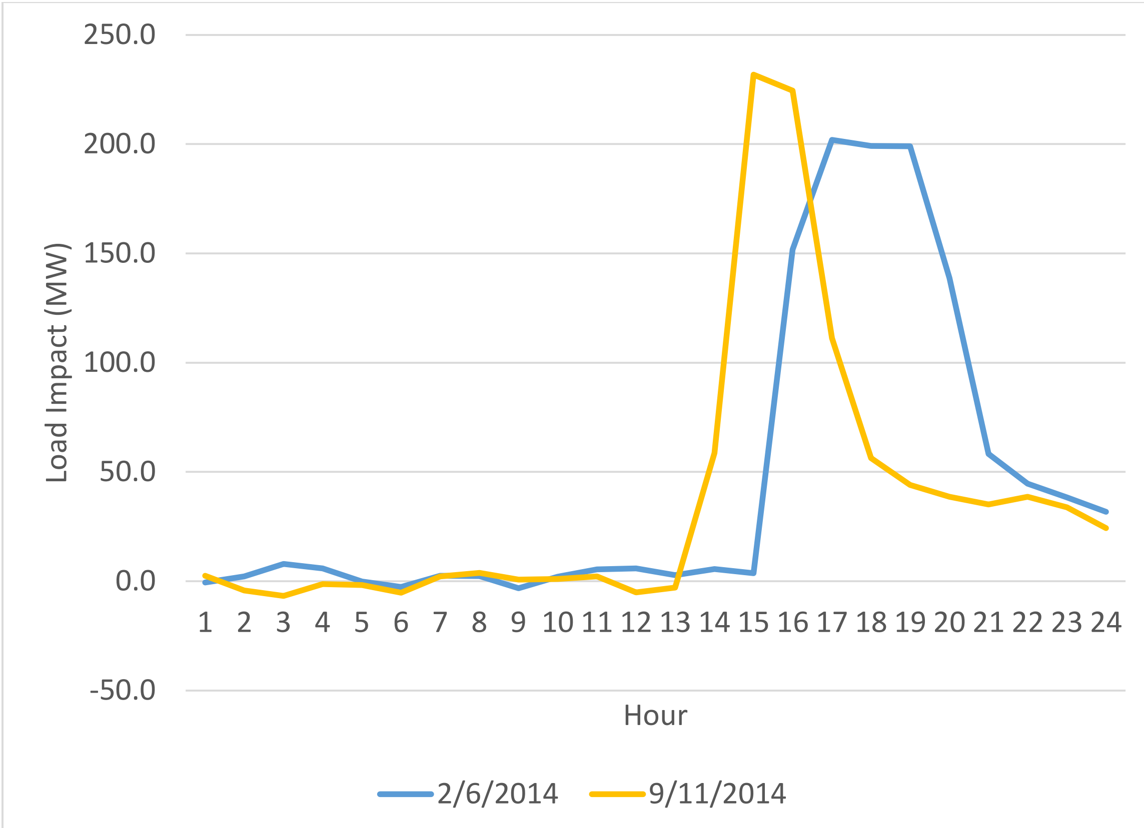


**Figure 4.2: Hourly Load Impacts by Event, *PG&E BIP***



## 4.2 SCE Load Impacts

### 4.2.1 Average Hourly Load Impacts by Industry Group and LCA

SCE's only BIP event day was February 6, 2014. Table 4.6 shows the average event-hour load impact for that event day by industry group. The total row at the bottom of the table shows the total event-day load impact of 624 MW, or 83 percent of the reference load. The majority of the program's load impact came from customers in the manufacturing industry group. Note that portions of the table have been removed due to confidentiality concerns.

**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 | 53 | 150.7 | 7.3 | 143.3 | 95.1% |
| Manufacturing | 353 | 493.2 | 90.2 | 403.0 | 81.7% |
| Wholesale, Transportation, & Other Utilities | 68 | 49.9 | 9.1 | 40.8 | 81.8% |
| Retail Stores | 40 | 15.6 | 8.8 | 6.8 | 43.7% |
| Offices, Hotels, Health, Services | | | | | |
| Schools | 68 | 17.8 | 8.3 | 9.4 | 53.0% |
| Entertainment, Other Services, Government | | | | | |
| **Total** | **620** | **755.1** | **131.2** | **623.9** | **82.6%** |

Table 4.7 compares the observed loads and FSLs for the February 6th event day. In aggregate, SCE's BIP program achieved 93 percent of the reduction required to meet its FSL.

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

| Event | Date | Day of Week | Average Observed Load (MW) | Average Firm Service Level (MW) | Estimated LI / LI at FSL |
|---|---|---|---|---|---|
| 1 | 2/6/2014 | Thursday | 131.2 | 82.7 | 93% |

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. Note that portions of the table have been removed due to confidentiality concerns.

**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 | 533 | 570.9 | 108.0 | 462.9 | 81.1% |
| Outside LA Basin | | | | | |
| Ventura | | | | | |
| **Total** | **620** | **755.1** | **131.2** | **623.9** | **82.6%** |
| South Orange County | 55 | 82.9 | 14.3 | 68.6 | 82.7% |
| South of Lugo | 227 | 248.2 | 51.0 | 197.3 | 79.5% |
| Rest of System | 338 | 423.9 | 65.9 | 358.0 | 84.4% |

### 4.2.2 Hourly Load Impacts

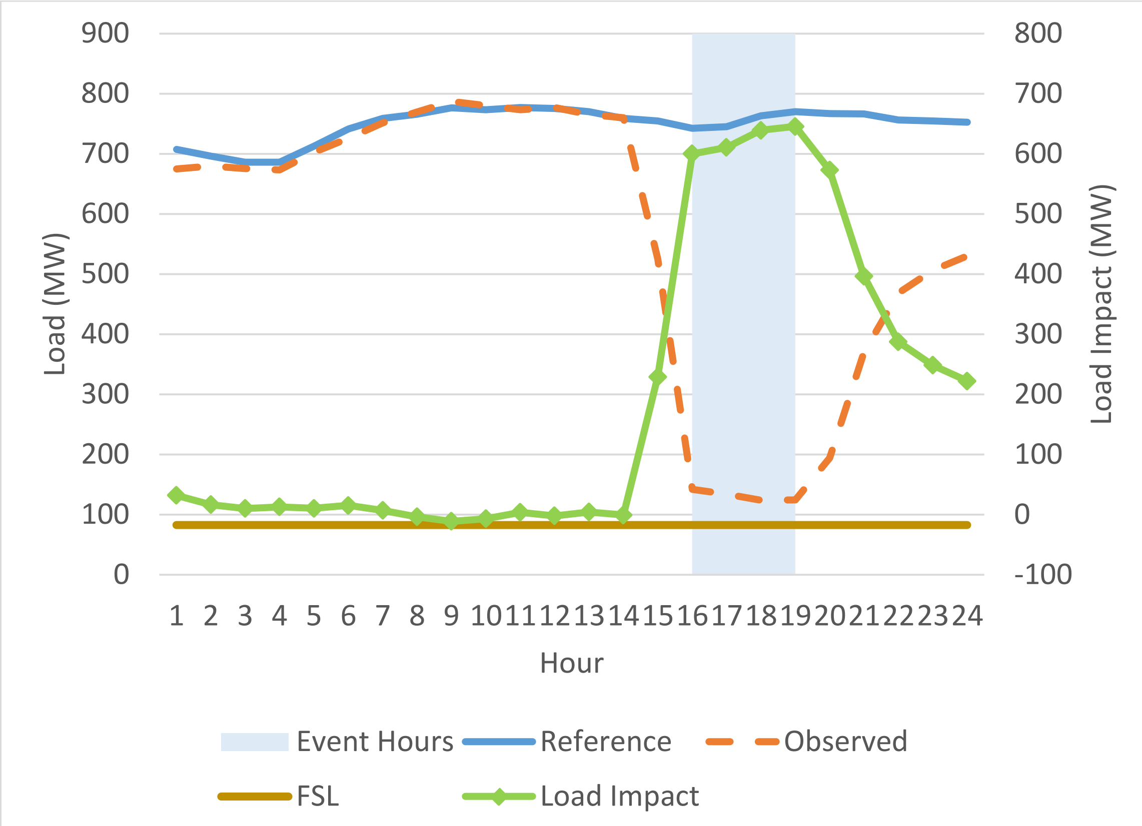
Table 4.9 presents hourly load impacts for the February 6th BIP event in the manner required by the Protocols. The hourly load impact ranges from 600 MW to 646 MW.

**Table 4.9: BIP Hourly Load Impacts for the February 6, 2014 Event Day, *SCE***

| 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** | 707.2 | 675.0 | 32.2 | 49.1 | 26.4 | 29.9 | 32.2 | 34.6 | 38.0 |
| **2** | 696.2 | 679.5 | 16.6 | 49.0 | 12.0 | 14.7 | 16.6 | 18.5 | 21.2 |
| **3** | 685.9 | 675.6 | 10.3 | 48.8 | 5.0 | 8.1 | 10.3 | 12.4 | 15.6 |
| **4** | 686.1 | 673.2 | 13.0 | 48.7 | 7.8 | 10.8 | 13.0 | 15.1 | 18.2 |
| **5** | 712.9 | 702.4 | 10.5 | 48.6 | 6.7 | 9.0 | 10.5 | 12.1 | 14.4 |
| **6** | 741.4 | 726.1 | 15.3 | 48.8 | 11.4 | 13.7 | 15.3 | 16.9 | 19.2 |
| **7** | 758.7 | 751.5 | 7.2 | 48.8 | 1.6 | 4.9 | 7.2 | 9.5 | 12.8 |
| **8** | 765.9 | 769.5 | -3.6 | 49.3 | -9.4 | -6.0 | -3.6 | -1.2 | 2.2 |
| **9** | 776.4 | 787.3 | -10.9 | 51.1 | -17.7 | -13.7 | -10.9 | -8.1 | -4.0 |
| **10** | 773.5 | 780.2 | -6.7 | 53.1 | -12.3 | -9.0 | -6.7 | -4.4 | -1.1 |
| **11** | 777.3 | 773.2 | 4.0 | 54.5 | -2.8 | 1.2 | 4.0 | 6.8 | 10.8 |
| **12** | 775.3 | 777.3 | -1.9 | 55.3 | -9.2 | -4.9 | -1.9 | 1.1 | 5.4 |
| **13** | 770.0 | 765.5 | 4.5 | 55.2 | -4.3 | 0.9 | 4.5 | 8.1 | 13.3 |
| **14** | 759.1 | 759.8 | -0.7 | 54.4 | -11.5 | -5.1 | -0.7 | 3.8 | 10.1 |
| **15** | 754.7 | 525.5 | 229.3 | 53.3 | 212.9 | 222.6 | 229.3 | 236.0 | 245.6 |
| **16** | 742.2 | 142.2 | 600.0 | 52.7 | 585.8 | 594.2 | 600.0 | 605.8 | 614.2 |
| **17** | 744.9 | 134.3 | 610.6 | 51.7 | 596.6 | 604.9 | 610.6 | 616.4 | 624.7 |
| **18** | 763.1 | 123.9 | 639.2 | 51.0 | 625.8 | 633.7 | 639.2 | 644.7 | 652.6 |
| **19** | 770.0 | 124.4 | 645.6 | 50.2 | 629.6 | 639.0 | 645.6 | 652.2 | 661.6 |
| **20** | 767.1 | 194.2 | 572.9 | 49.6 | 560.2 | 567.7 | 572.9 | 578.1 | 585.6 |
| **21** | 766.6 | 369.8 | 396.7 | 48.1 | 384.6 | 391.8 | 396.7 | 401.7 | 408.9 |
| **22** | 756.1 | 468.7 | 287.5 | 48.0 | 277.0 | 283.2 | 287.5 | 291.7 | 297.9 |
| **23** | 754.8 | 506.1 | 248.6 | 48.6 | 238.6 | 244.6 | 248.6 | 252.7 | 258.7 |
| **24** | 752.5 | 530.2 | 222.2 | 48.4 | 212.2 | 218.1 | 222.2 | 226.3 | 232.2 |
| 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** | 17,958 | 13,415 | 4,543 | 0.0 | n/a | n/a | n/a | n/a | n/a |
| **Event Hours** | 755.1 | 131.2 | 623.9 | 0.0 | 613.8 | 619.8 | 623.9 | 628.0 | 633.9 |

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the February 6th 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 February 6, 2014 Event Day, *SCE***




## *4.3 SDG&E Load Impacts*

### 4.3.1 Average Hourly Load Impacts

Table 4.10 summarizes average hourly reference loads and load impacts for each of SDG&E's three BIP events. Load impacts were relatively low for the first event day, which appears to be due to the fact that customer loads would have been below the FSL even in the absence of the event day. Load impacts are considerably higher for the two May events, with 28 percent and 50 percent load impacts on the two days.[9] Note that the contents of the table have been removed due to confidentiality concerns.

[9] Some partial event hours are excluded from the estimates and calculations shown in SDG&E's summary tables. Specifically, the results for the February 6th event include hours ending 18 through 20; May 14th includes hours ending 17 through 20; and the results for the May 16th event include hours ending 12 through 14.

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

| Event | Date | Day of Week | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|---|
| 1 | 2/6/2014 | Thursday | | | | |
| 2 | 5/14/2014 | Wednesday | | | | |
| 3 | 5/16/2014 | Friday | | | | |

Table 4.11 compares the observed loads to the FSLs for each event day. Notice that the FSL for the February 6th event (1.57 MW) is below the reference load for that event (1.37 MW, shown in Table 4.10), which indicates that, in aggregate, BIP customers did not need to reduce their use to meet their FSL. Both the May 14th and May 16th results show underachievement at the program level. Note that the contents of the table have been removed due to confidentiality concerns.

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

| Event | Date | Day of Week | Average Observed Load (MW) | Average Firm Service Level (MW) | Estimated LI / LI at FSL |
|---|---|---|---|---|---|
| 1 | 2/6/2014 | Thursday | | | |
| 2 | 5/14/2014 | Wednesday | | | |
| 3 | 5/16/2014 | Friday | | | |

Table 4.12 shows the load impacts for the May 16th event day by industry group. The two service accounts in the agriculture, mining, and construction group accounted for nearly the entire BIP load impact on that event day. Note that the contents of the table have been removed due to confidentiality concerns.

**Table 4.12: May 16, 2014 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 | | | | | |
| Manufacturing | | | | | |
| Wholesale, Transportation, & Other Utilities | | | | | |
| Retail Stores | | | | | |
| **Total** | | | | | |

### 4.3.2 Hourly Load Impacts

Table 4.13 presents hourly load impacts for the May 16th event day. We do not present an "average event day" because of the dissimilarities across the three events. That is, one event is in winter while the other two are in May, and the two May events have different event windows.

**Table 4.13: BIP Hourly Load Impacts for the May 16, 2014 Event Day, *SDG&E***

These results have been removed due to confidentiality concerns.

Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the May 16$^{th}$ event day. The scale for the hourly load impacts is shown on the right-hand side of the figure. Figure 4.5 shows the hourly load impacts for each of the three event days.

**Figure 4.4: BIP May 16, 2014 Load Impacts, *SDG&E***

These results have been removed due to confidentiality concerns.

**Figure 4.5: Hourly Load Impacts by Event, *SDG&E***

These results have been removed due to confidentiality concerns.

# 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 currently enrolled customers 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 during the 2014 program year. The load impacts are developed using the historical FSL achievement rates based on the estimated ex post load impacts for the same customers.

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.[10] 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 non-summer reference loads. The non-summer model is shown below. This model is estimated separately from the summer ex ante model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table 5.1 describes the terms included in the equation.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR} \sum_{i=1}^{24} (b_i^{DR} \times h_{i,t} \times OtherEvt^{DR}{}_{i,t}) \\
&+ \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times Weather_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) \\
&+ \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) \\
&+ \sum_{i=2-5,10-12} (b_i^{MONTH} \times MONTH_{i,t}) + e_t
\end{aligned}
$$

[10] In particular, whereas CDH60 and CDH60_MA24 are used for summer ex post regressions, only CDH60 is used for the ex ante models. See Appendix A for weather variable details.

**Table 5.1: Descriptions of Terms included in the Ex Ante Regression Equation**

| Variable Name | Variable Description |
|---|---|
| $Q_t$ | the demand in hour *t* for a customer enrolled in BIP prior to the last event date |
| The various *b*'s | the estimated parameters |
| $h_{i,t}$ | a dummy variable for hour *i* |
| $BIP_t$ | an indicator variable for program event days |
| $OtherEvt^{DR}_t$ | equals one on the event days of other demand response programs in which the customer is enrolled |
| $Weather_t$ | the weather variables selected using our model screening process |
| $MON_t$ | a dummy variable for Monday |
| $FRI_t$ | a dummy variable for Friday |
| $DTYPE_{i,t}$ | a series of dummy variables for each day of the week |
| $MONTH_{i,t}$ | a series of dummy 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.[11] 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 as temperatures go up). Our investigations of the program-level loads from 2014 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 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. Note that the overall level of ex ante load impacts was not overly sensitive to the inclusion of weather effects, and in fact the exclusion of weather factors results in a conservative program-level load impact compared to other scenarios.

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. Much of the differences across scenarios can be attributed to varying weather conditions. This is the first program year in which the evaluation includes two sets of 1-in-2 and 1-in-10 weather years. 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. All of the weather scenarios (including the utility-specific scenarios) were newly generated in a separate project as part of this year's evaluation process.

*3. Calculate forecast load impacts*

[11] For SCE, we removed the weather variables for SCE's largest customer only.

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.

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, combined with the most recent FSLs, 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 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 $10^{th}$, $30^{th}$, $50^{th}$, $70^{th}$, and $90^{th}$ 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 reference loads, estimated event-day loads, and scenarios of load impacts. 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).

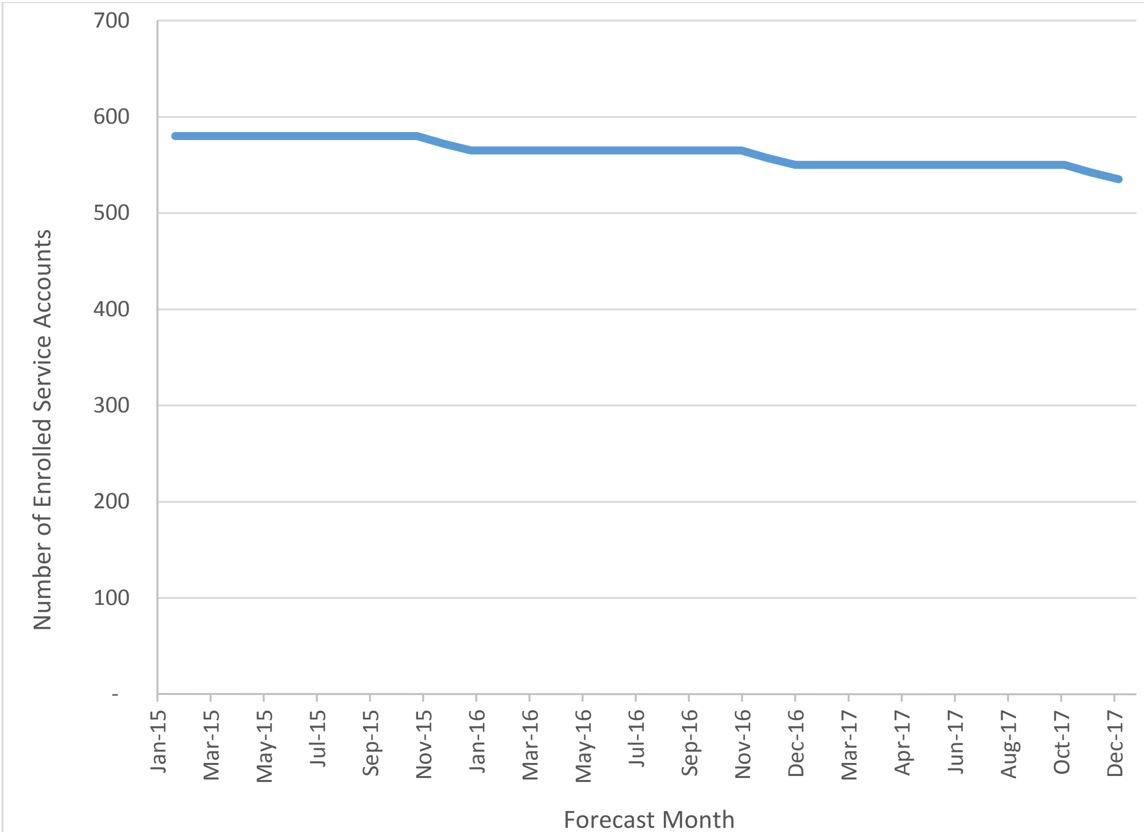
*5. Apply forecast enrollments to produce program-level load impacts*.
The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2025, with separate enrollments provided at the program and portfolio level (which are identical for BIP) by LCA and size group. SCE provided monthly enrollments for 2015, 2016, and 2017. We assume that the December 2017 enrollments apply through 2025. We assume that the ex post shares of customers by notification (15 and 30 minute, LCA, and location (e.g., South of Lugo) 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 2015 through 2025, with 203 enrolled service agreements. The vast majority of these agreements (195) are in the large customer group (over 200 kW). There were 218 service agreements enrolled for the last PY2014 event day (on September 11, 2014) and forecast enrollment falls to 203 service agreements because of voluntary departure and de-enrollment due to non-compliance.

*SCE*
Figure 5.1 shows SCE's forecast of enrollments by month. SCE projects BIP enrollments to decrease during 2015 through 2017 by 15 customers each year, with the reductions occurring in November and December of each year.

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




*SDG&E*

We assumed that the seven currently enrolled customers continue to be enrolled in BIP.

## 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 2015 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 246 MW, which represents 85.5 percent of the enrolled reference load. The program-level FSL is 47.5 MW, compared to the average event-hour program load of 41.9 MW. This slight over-performance at the program level is consistent with our estimates for the September 11, 2014 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 2015**

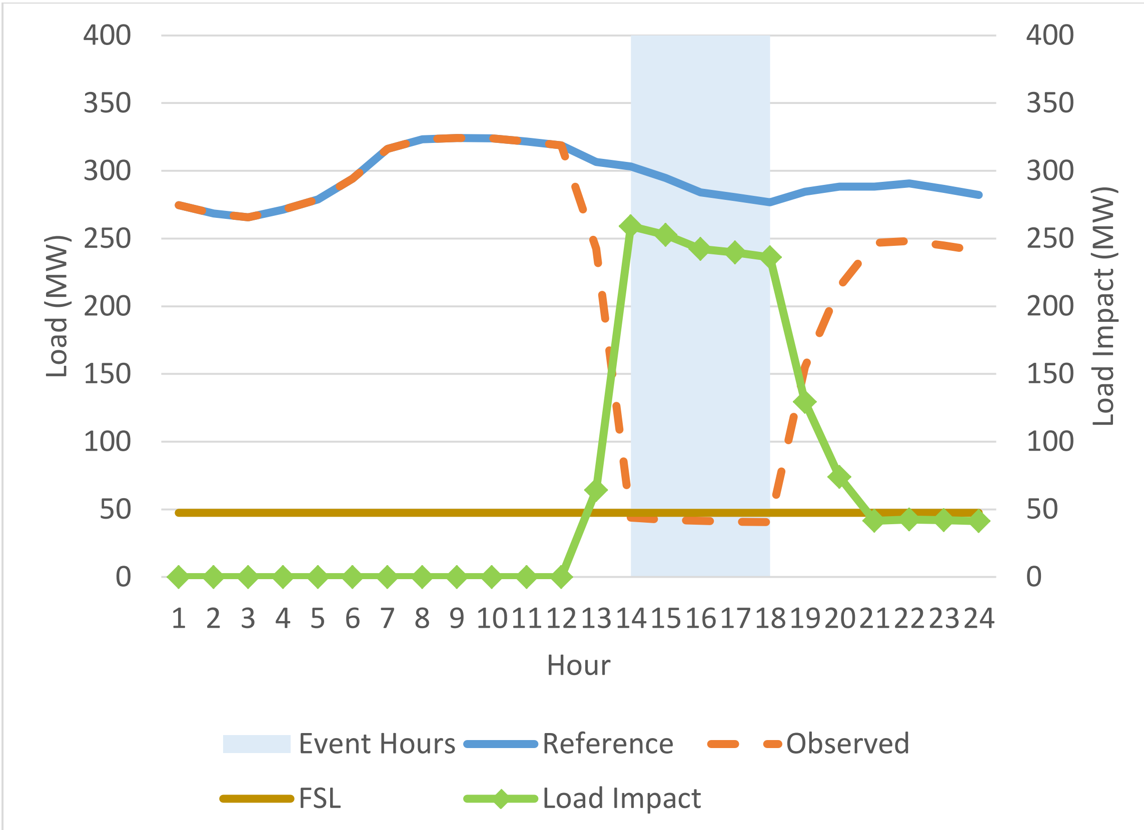



Figure 5.3 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2015 utility-specific 1-in-2 weather year. Customers not in any LCA account for the largest share, with 74 percent of the load impacts.

**Figure 5.3: Share of PG&E Load Impacts by LCA for the August 2015 Typical Event Day in a Utility-specific 1-in-2 Weather Year**

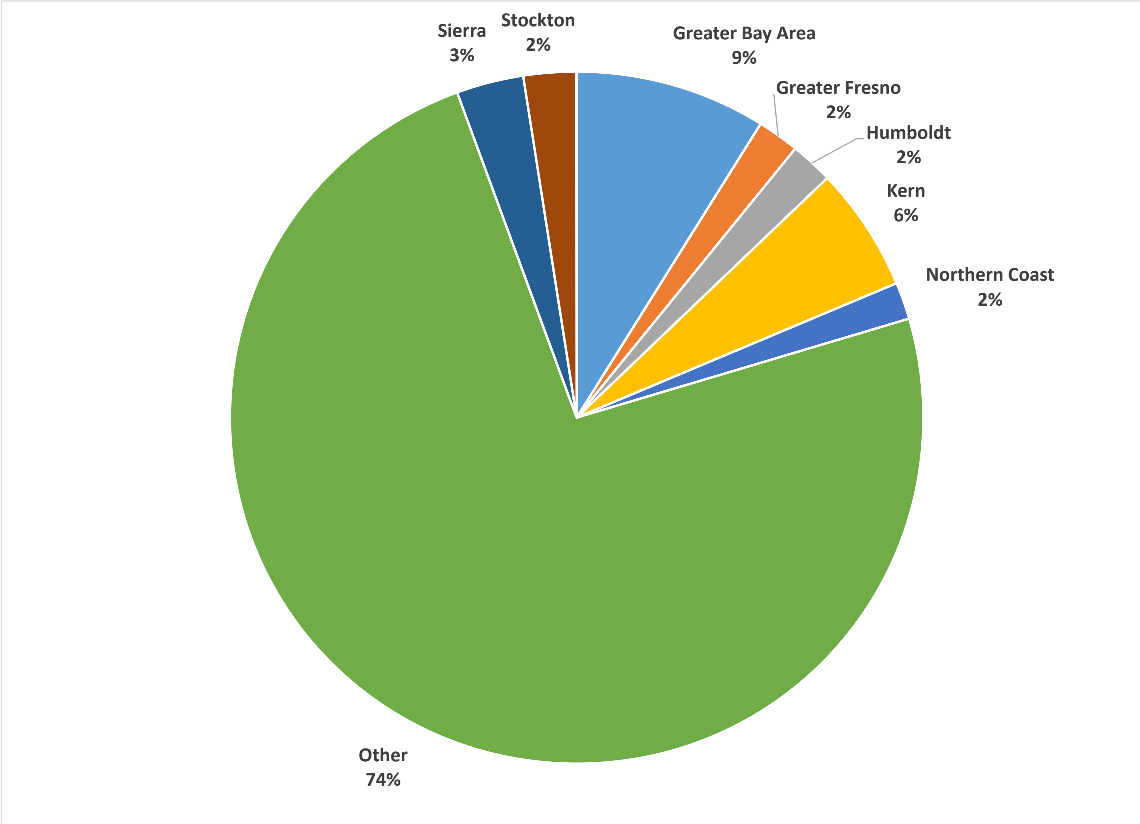



Figure 5.4 illustrates August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The enrollment forecast does not change across the 2015-2025 window, so these load impacts stay constant for 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 246 MW.

**Figure 5.4: Average Hourly Ex Ante Load Impacts by Scenario for August, *PG&E***

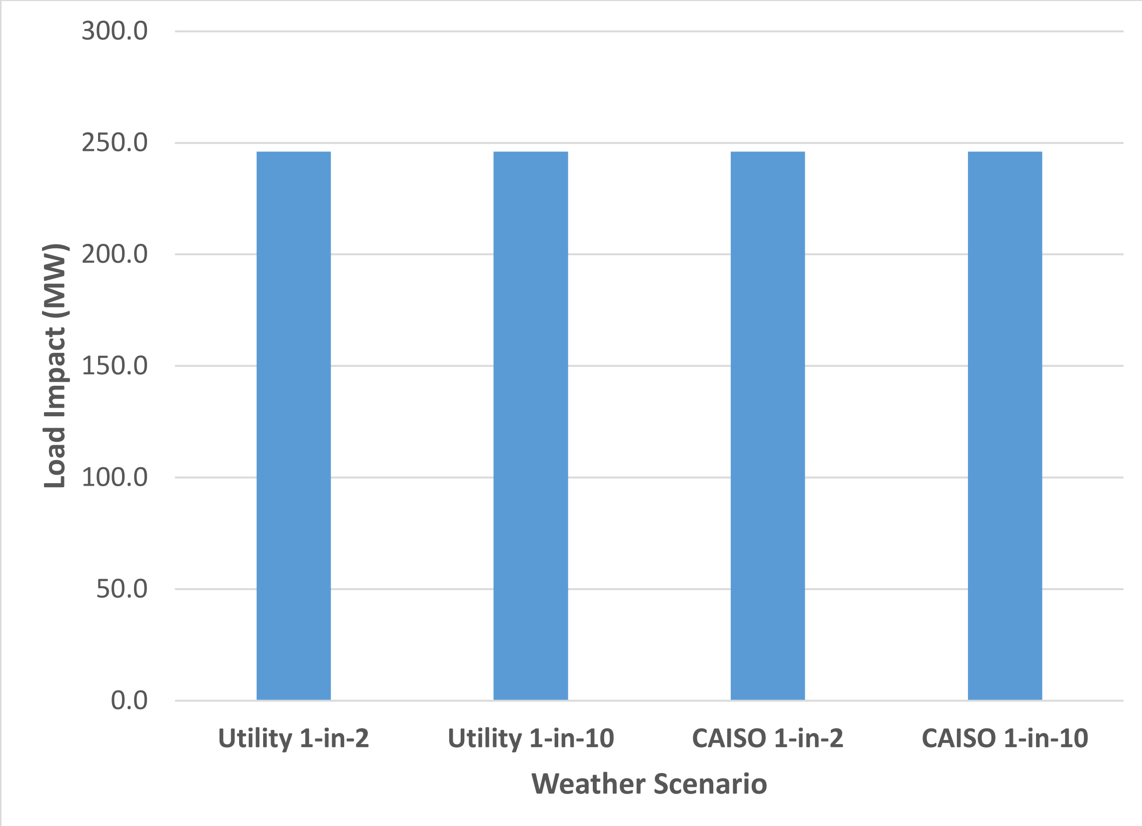



Table 5.2 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August monthly peak day.

**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 | 1,418 | 1,212 | 85.5% |
| | 1-in-10 | 1,418 | 1,212 | 85.5% |
| CAISO-coincident | 1-in-2 | 1,418 | 1,212 | 85.5% |
| | 1-in-10 | 1,418 | 1,212 | 85.5% |

### 5.4.2 SCE

Figure 5.5 shows the August 2015 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 668 MW, which represents 81.2 percent of the enrolled reference load. The program-level FSL is 84.1 MW, compared to the average event-hour program load of 154.8 MW. This under-performance at the program level is consistent with our estimates for the February 6, 2014 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 2015**

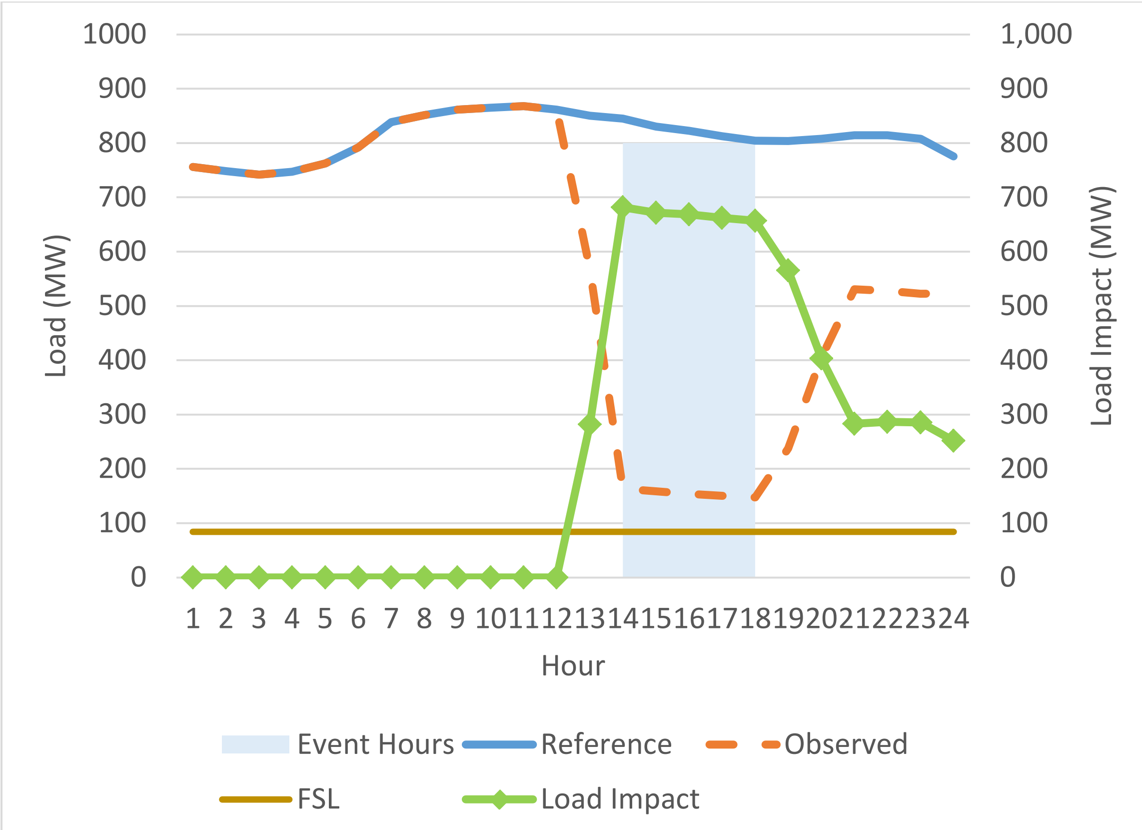



Figure 5.6 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2015 utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 70 percent of the load impacts.

**Figure 5.6: Share of SCE Load Impacts by LCA for the August 2015 Typical Event Day in a Utility-specific 1-in-2 Weather Year**

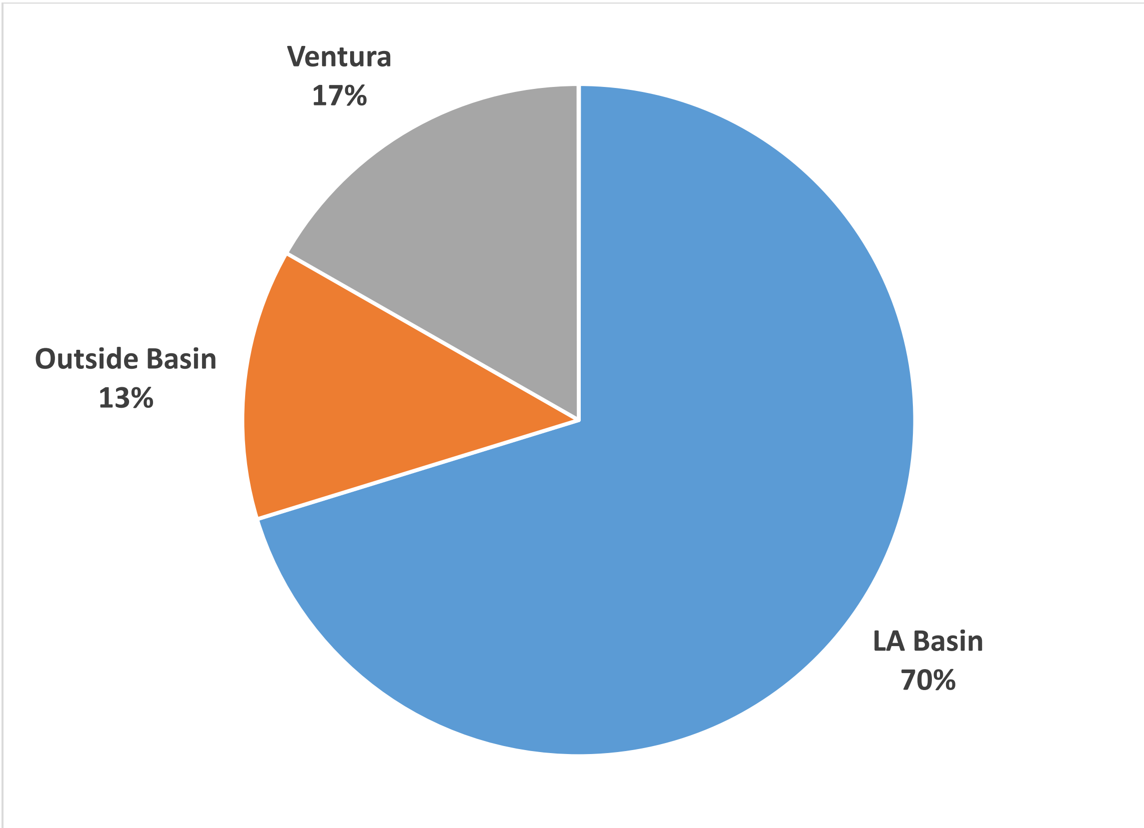



Figure 5.7 shows the share of load impacts by notification time, assuming a typical event day in an August 2015 utility-specific 1-in-2 weather year. Customers required to reduce demand to their FSL within 15 minutes of a Notice of Interruption make up just 11 percent of customers but account for 22 percent of the load impacts.

**Figure 5.7: Share of SCE Load Impacts by Notification Time for the August 2015 Typical Event Day in a Utility-specific 1-in-2 Weather Year**

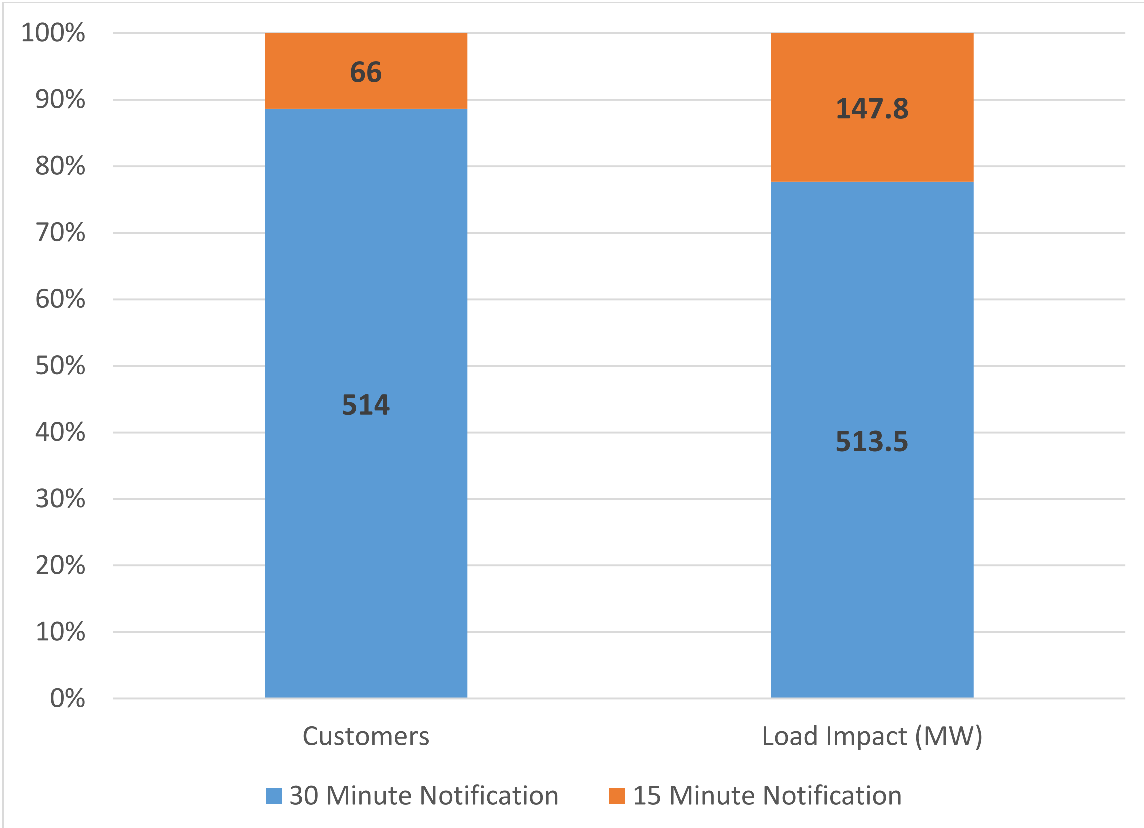



Figure 5.8 illustrates August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. These load impacts are shown for forecast years 2015 through 2017. The load impact is not sensitive to weather conditions, but it decreases over time due to forecast reductions in enrollment.

**Figure 5.8: Average Hourly Ex Ante Load Impacts by Scenario and Year for August, *SCE***

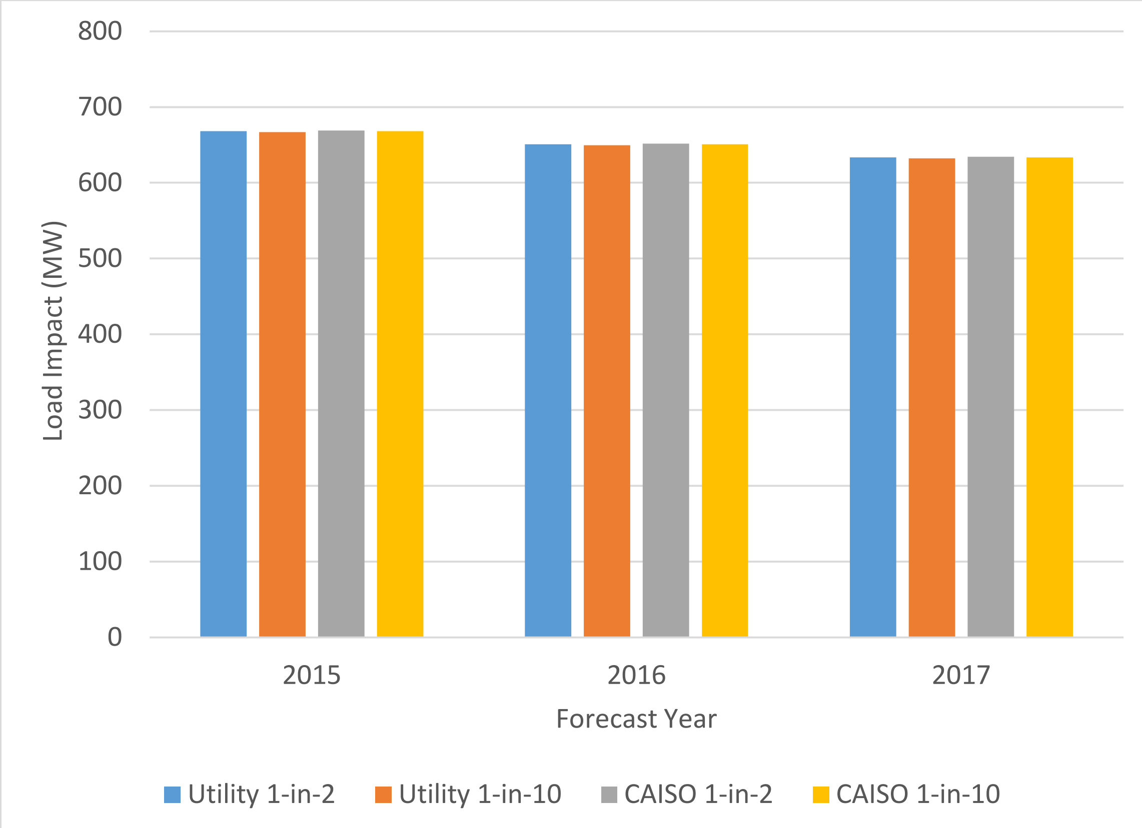



Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2015 monthly peak day.

**Table 5.3: Per-customer Ex Ante Load Impacts, *SCE***

| Scenario | Weather Year | Reference Load (kW) | Load Impact (kW) | % Load Impact |
|---|---|---|---|---|
| Utility-specific | 1-in-2 | 1,419 | 1,152 | 81.2% |
| | 1-in-10 | 1,418 | 1,150 | 81.1% |
| CAISO-coincident | 1-in-2 | 1,420 | 1,153 | 81.2% |
| | 1-in-10 | 1,419 | 1,152 | 81.2% |

### 5.4.3 SDG&E

SDG&E's enrollment forecast assumes that the number of customers remains constant (at PY2014 levels) throughout the forecast period. Therefore, we do not have any variation across years to illustrate. Because our ex post estimates were very different for the non-summer event (on February 6, 2014) than the summer events (we use May 16, 2014 as the basis of the summer ex ante load impacts), we differentiate the ex ante load impacts by season accordingly.

Figure 5.9 shows the forecast load impacts for a typical event day (which is assumed to be in August) in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 1.4 MW, which represents 44.8 percent of the enrolled reference load. The program-level FSL is 1.5 MW, compared to the average event-hour program load of 1.8 MW. This under-performance at the program level is consistent with our estimates for the May 16, 2014 event day that serves as the basis for the ex ante load impacts. Note that in this case, the underperformance is limited to the first event hour, which is consistent with the estimates for the ex post event.

**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**

These results have been removed due to confidentiality concerns.

Figure 5.10 shows the hourly reference loads, observed loads, and load impacts for the February peak day in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 0.2 MW, which represents 9.7 percent of the enrolled reference load. The average event-hour program load of 1.4 MW is less than the aggregate FSL of 1.5 MW. Therefore, the low load impacts may be explained by the fact that the program load was already low relative to the FSL, such that customers did not need to reduce their load to meet their BIP obligations (at least in the later event hours).

**Figure 5.10: SDG&E Hourly Event Day Load Impacts for the February Peak Day in a Utility-Specific 1-in-2 Weather Year**

These results have been removed due to confidentiality concerns.

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 2015 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. Note that the contents of the table have been removed due to confidentiality concerns.

**Table 5.4: Per-customer Ex Ante Load Impacts, *SDG&E***

| Scenario | Weather Year | Reference Load (kW) | Load Impact (kW) | % Load Impact |
|---|---|---|---|---|
| Utility-specific | 1-in-2 | | | |
| | 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 2014 program year; and “previous study” refers to the report that was developed following the 2013 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 PY2013 and PY2014. The PY2013 load impacts are based on the four event hours on July 2, 2013. The PY2014 load impacts are based on the two event hours on September 11, 2014.

**Table 6.1: Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2013 and PY 2014, *PG&E***

| Level | Outcome | PY2013 | PY2014 |
|---|---|---|---|
| **Total** | # SAIDs | 280 | 218 |
| | Reference (MW) | 291 | 286 |
| | Load Impact (MW) | 216 | 228 |
| **Per SAID** | Reference (kW) | 1,038 | 1,311 |
| | Load Impact (kW) | 772 | 1,047 |
| | % Load Impact | 74.3% | 79.8% |

There are substantially fewer service agreements in PY2014 (218 versus 280 in PY2013), but the total reference load and load impact did not change very much. As a result, the per-customer reference loads and load impacts are higher in PY2014.

### 6.1.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2013 (the “previous study”) to the ex ante forecast contained in this study (the “current study”). Table 6.2 contains this comparison for the August 2015 utility-specific 1-in-2 peak month day forecast.

**Table 6.2: Comparison of Ex Ante Impacts from PY 2013 and PY 2014 Studies, *PG&E***

| Level | Outcome | Previous Study 2015 | Current Study 2015 |
|---|---|---|---|
| Total | # SAIDs | 218 | 203 |
| | Reference (MW) | 292 | 288 |
| | Load Impact (MW) | 231 | 246 |
| | FSL (MW) | 61.0 | 47.5 |
| Per SAID | Reference (kW) | 1,340 | 1,418 |
| | Load Impact (kW) | 1,062 | 1,212 |
| | % Load Impact | 79.2% | 85.5% |

The current study includes 15 fewer service agreements, but the reference load is quite similar and the load impacts are higher in the current study. One notable change is that the program-level FSL decreased by 13.5 MW across years. The average customer size and load impact increased somewhat across forecasts.[12]

### 6.1.3 Previous ex ante versus current ex post

Table 6.3 provides a comparison of the ex ante forecast of 2014 load impacts prepared following PY2013 and the PY2014 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 11, 2014 event day.

The forecast and ex post load impacts are remarkably close, with the forecast including the correct number of service agreements and only small differences in reference loads and load impacts.

**Table 6.3 Comparison of Previous Ex Ante and Current Ex Post Impacts, *PG&E***

| Level | Outcome | Ex Ante for Typical Event Day in PY2014, following PY2013 Study | Ex Post Average Event Day, PY2014 |
|---|---|---|---|
| Total | # SAIDs | 218 | 218 |
| | Reference (MW) | 292 | 286 |
| | Load Impact (MW) | 231 | 228 |
| Per SAID | Reference (kW) | 1,340 | 1,311 |
| | Load Impact (kW) | 1,062 | 1,047 |
| | % Load Impact | 79.2% | 79.8% |

[12] Recall that ex ante load impacts are based on ex post FSL achievement ratios. This is the reason that the forecast load impact is greater than the difference between the reference load and the FSL.

### 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 2015 typical event day with utility-specific 1-in-2 weather conditions. Although program enrollment is somewhat lower, the total load impact is higher in the ex ante forecast than we estimated for the September 11, 2014 event.

**Table 6.4 Comparison of Current Ex Post Ante and Current Ex Ante Impacts, *PG&E***

| Level | Outcome | Ex Post Average Event Day, PY2014 | Ex Ante Typical Event Day |
|---|---|---|---|
| **Total** | # SAIDs | 218 | 203 |
| | Reference (MW) | 286 | 288 |
| | Load Impact (MW) | 228 | 246 |
| | FSL (MW) | 61.8 | 47.5 |
| **Per SAID** | Reference (kW) | 1,311 | 1,418 |
| | Load Impact (kW) | 1,047 | 1,212 |
| | % Load Impact | 79.8% | 85.5% |

Table 6.5 documents the various potential sources of differences between the ex post and ex ante load impacts. The final point in the table proved to be the most important.

The single largest difference between the ex post and ex ante load impacts is due to a difference in the load level for a large customer that reduces its load to zero MW during event hours. This customer had, by its standards, a relatively low reference load of 7.6 MW on the September 11, 2014 event day. In contrast, its average weekday load level during those same hours in August 2014 was 22.8 MW. The higher August loads serve as the basis for this customer's typical event day reference load in the ex ante forecast. Because the customer reduces its load to zero during event hours, the higher reference load has the effect of adding approximately 15 MW to the ex ante load impact relative to the ex post load impact.

Our ex ante load impacts account for the service agreements that have left the program as well as the service agreements that have joined BIP since the last PY2014 event day. While the net result is a decrease in enrolled service agreements, the change in enrollment mix leads to a slight increase (~6 MW) in program-level load impacts. This is due to the fact that the service agreements that left the program provided very little load impact, while the new service agreements are assumed to provide the average amount of load impact.

**Table 6.5: PG&E Ex Post versus Ex Ante Factors**

| Factor | Ex Post | Ex Ante | Expected Impact |
|---|---|---|---|
| Weather | 92.9 degrees Fahrenheit during event hours. | 94.3 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 15-16. | HE 14-18 in Apr-Oct;<br>HE 17-21 in Nov-Mar. | Minimal. The load profile is fairly flat across the hours in question. |
| % of resource dispatched | All. | Assume all customers are called. | None. The ex ante method assumes that all enrolled customers are dispatched. |
| Enrollment | 218 SAIDs during the 9/11/2014 event day. | 203 SAIDs. | The SAIDs that left BIP had low load impacts, but relatively high FSLs, causing the program FSL to go down by nearly 16 MW. |
| 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 (9/11/2014). | Differences between simulated ex ante and estimated ex post reference loads. One SAID in particular had low loads on the 9/11 event day relative to its TED load. This SAID is the single largest contributor to the load impact difference. |

## *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 PY2013 and PY2014. Only one BIP event was called in each year: September 19, 2013 (1 hour in duration); and February 6, 2014 (4 hours in duration). The number of service accounts, total reference load, and load impacts are slightly lower in PY2014, but the per-customer reference loads and load impacts are quite similar across the two years. This may be surprising given that the two events were called in different seasons.

**Table 6.6 Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2013 and PY 2014, *SCE***

| Level | Outcome | PY2013 | PY2014 |
|---|---|---|---|
| **Total** | # SAIDs | 646 | 620 |
| | Reference (MW) | 816 | 755 |
| | Load Impact (MW) | 687 | 624 |
| **Per SAID** | Reference (kW) | 1,264 | 1,218 |
| | Load Impact (kW) | 1,063 | 1,006 |
| | % Load Impact | 84.1% | 82.6% |

## 6.2.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2013 (the "previous study") to the ex ante forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2015 utility-specific 1-in-2 peak month day. Both program-level and portfolio-level forecasts are included in the table.

**Table 6.7: Comparison of Ex Ante Impacts from PY 2013 and PY 2014 Studies, *SCE***

| Level | Outcome | Previous Study 2015 | Current Study 2015 |
|---|---|---|---|
| **Total** | # SAIDs | 610 | 580 |
| | Reference (MW) | 780 | 823 |
| | Load Impact (MW) | 650 | 668 |
| **Per SAID** | Reference (kW) | 1,278 | 1,419 |
| | Load Impact (kW) | 1,065 | 1,152 |
| | % Load Impact | 83.3% | 81.2% |

Forecast enrollment is lower in the current forecast, but per-customer reference loads and load impacts have increased. This is likely due to a change in the composition of customers that we will discuss 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 2014 load impacts prepared following PY2013 and the PY2014 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 February 6, 2014 event day.

The ex ante forecast contains 10 fewer service accounts, but the total program reference load and load impacts are slightly higher than we estimated for the one PY2014 event day. Seasonal differences may have contributed to these differences, since the PY2014 event was called in February while the typical event day is assumed to occur in August. The ex ante load impact for the February peak day averaged 585 MW across the 4:00 to 9:00 p.m. resource adequacy window, which is slightly lower than we estimated for the ex post event.

**Table 6.8 Comparison of Previous Ex Ante and Current Ex Post Impacts, *SCE***

| Level | Outcome | Ex Ante for TED in PY2014, following PY2013 Study | Ex Post Average Event Day, PY2014 |
|---|---|---|---|
| Total | # SAIDs | 610 | 620 |
| | Reference (MW) | 780 | 755 |
| | Load Impact (MW) | 650 | 624 |
| Per SAID | Reference (kW) | 1,278 | 1,218 |
| | Load Impact (kW) | 1,065 | 1,006 |
| | % Load Impact | 83.3% | 82.6% |

## 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 (February 6, 2014) and two versions of the ex ante load impacts are shown: the first is based on the 2015 typical event day in a utility-specific 1-in-2 weather year; and the second is based on the 2015 February peak day in a utility-specific 1-in-2 weather year. The latter is included to provide a more direct comparison to the ex post event day.

As the table shows, the per-customer reference loads and load impacts for the ex post event day are quite comparable to those of the February peak day forecast. The lower forecast enrollments is the primary reason for the lower total reference load and load impact. Enrollments are down 6.5 percent while load impacts are down 2.4 percent. The reason the load impacts (and reference loads) fall less than proportionately with enrollments is that smaller-than-average customers left BIP, while some average-sized customers joined the program (for a net reduction of 40 service accounts).

**Table 6.9 Comparison of Current Ex Post Ante and Current Ex Ante Impacts, *SCE***

| Level | Outcome | Ex Post Average Event Day, PY2014 | Ex Ante Typical Event Day | Ex Ante February Peak Day |
|---|---|---|---|---|
| Total | # SAIDs | 620 | 580 | 580 |
| | Reference (MW) | 755 | 824 | 740 |
| | Load Impact (MW) | 624 | 670 | 609 |
| | FSL (MW) | 82.7 | 84.1 | 84.1 |
| Per SAID | Reference (kW) | 1,218 | 1,420 | 1,275 |
| | Load Impact (kW) | 1,006 | 1,155 | 1,050 |
| | % Load Impact | 82.6% | 81.3% | 82.4% |

Table 6.10 describes the sources of differences between the ex post and ex ante load impacts, using the August 2015 1-in-2 scenario as the benchmark for comparison.

**Table 6.10: SCE Ex Post versus Ex Ante Factors**

| Factor | Ex Post | Ex Ante | Expected Impact |
|---|---|---|---|
| Weather | 51.4 degrees Fahrenheit during event hours. | 93.1 degrees Fahrenheit during event hours on utility-specific 1-in-2 Aug peak day. | The load is not very weather sensitive, but the temperature difference is large so it is a factor. As described above, the February 1-in-2 per-customer reference load is very close to ex post levels. |
| Event window | HE 16-19. | HE 14-18 in Apr-Oct;<br>HE 17-21 in Nov-Mar. | The earlier summer ex ante event window contributes to higher reference loads and load impacts relative to the ex post window. In non-summer the difference in event window is inconsequential. |
| % 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 | 620 SAIDs during the ex post event day. | 580 SAIDs in August 2015. | The lower forecast enrollment also leads to a slight increase in average customer size because relatively small customers left the program. |
| 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 PY2014 event day. | No effect because the 2014 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 PY2013 and PY2014. Seven service accounts were enrolled in each year. The PY2013 load impacts are based on the

September 5, 2013 event (four hours in duration), while the PY2014 load impacts are based on the May 16, 2014 event (four hours in duration). The total reference load and load impact was somewhat lower in PY2013, though the percentage load impact was similar in the two years.

**Table 6.11: Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2013 and PY2014, *SDG&E***

| Level | Outcome | PY2013 | PY2014 |
|---|---|---|---|
| **Total** | # SAIDs | 7 | 7 |
| | Reference (MW) | 3.2 | 4.0 |
| | Load Impact (MW) | 1.7 | 2.0 |
| **Per SAID** | Reference (kW) | 450 | 575 |
| | Load Impact (kW) | 236 | 288 |
| | % Load Impact | 52.4% | 50.1% |

## 6.3.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2013 (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 peak day. Reference loads, load impacts, and percentage load impacts are all slightly lower in the current ex ante forecast. These likely reflect differences in customer usage levels across PY2013 and PY2014. The relationship between event-day loads and the FSL is similar across the two years, in that the program load is above the FSL early in the event window but below the FSL for the latter portion of the event.

**Table 6.12: Comparison of Ex Ante Impacts from PY 2013 and PY 2014 Studies, *SDG&E***

| Level | Outcome | Previous Study 2015 | Current Study 2015 |
|---|---|---|---|
| **Total** | # SAIDs | 7 | 7 |
| | Reference (MW) | 3.4 | 3.2 |
| | Load Impact (MW) | 1.8 | 1.4 |
| **Per SAID** | Reference (kW) | 484 | 458 |
| | Load Impact (kW) | 262 | 205 |
| | % Load Impact | 54.1% | 44.8% |

## 6.3.3 Previous ex ante versus current ex post

Table 6.13 compares the ex ante forecast prepared following PY2013 to the PY2014 ex post load impact estimates contained in this report. The ex ante load impacts are based on the typical event day in a utility-specific 1-in-2 weather year. The ex post load impacts are based on the May 16, 2014 event day. The ex post reference loads and load impacts are somewhat higher than the ex ante forecast, though the percentage load impacts are quite similar.

**Table 6.13: Comparison of Previous Ex Ante and Current Ex Post Impacts, *SDG&E***

| Level | Outcome | Ex Ante for TED in PY2014, following PY2013 Study | Ex Post Average Event Day, PY2014 |
|---|---|---|---|
| **Total** | # SAIDs | 7 | 7 |
| | Reference (MW) | 3.4 | 4.0 |
| | Load Impact (MW) | 1.8 | 2.0 |
| **Per SAID** | Reference (kW) | 484 | 575 |
| | Load Impact (kW) | 262 | 288 |
| | % Load Impact | 54.1% | 50.1% |

### 6.3.4 Current ex post versus current ex ante

Table 6.14 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 that way, the ex post and ex ante load impacts match. The key difference in the level (MW) and percentage load impacts is that the historical event occurred earlier in the day when program loads are high relative to the loads during the 1:00 to 4:00 p.m. ex ante event window. Therefore, the level of the ex ante load impacts is lower than the ex post load impacts.

Enrollments are not a factor because the customers enrolled during PY2014 are carried forward into the ex ante forecast. Weather is not a factor because the program reference load is not very weather sensitive.

**Table 6.14: SDG&E BIP Ex Post versus Ex Ante Factors, Typical Event Day**

| Factor | Ex Post | Ex Ante | Expected Impact |
|---|---|---|---|
| Weather | 89.6 degrees Fahrenheit during HE 12-14 on the May 16th event day | 80.0 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 12-14 | HE 14-18 in Apr-Oct. | Reference loads are higher earlier in the day, so the load impacts are higher in ex post even though the event-day loads relative to FSL are set to be the same. |
| % of resource dispatched | All | All | None |
| Enrollment | 7 service accounts | 7 service accounts | None. We assume that enrollment does not change in the forecast period. |
| Methodology | SAID-specific regressions using own within-subject analysis. | Reference loads are simulated from SAID-specific regressions. | Small differences between simulated ex ante and estimated ex post reference loads |

Table 6.15 shows a comparison of ex post and ex ante load impacts. The average reference loads and load impacts are calculated across the relevant event hours. This table illustrates the explanation above: that reference loads were higher during the earlier event window on the May 16th event day, causing the ex post load impacts to be higher than the forecast load impacts.

**Table 6.15: Comparison of Ex Post and Ex Ante Load Impacts, SDG&E**

| Date | Event Hours | Reference (MW) | Load Impact (MW) | Temp. | % LI |
|---|---|---|---|---|---|
| 5/16/2014 | HE 12-14 | 4.0 | 2.0 | 89.6 | 50.1% |
| Ex Ante TED 1-in-2 | HE 14-18 | 3.2 | 1.4 | 80.0 | 44.8% |

# 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. Note that Appendices E and H are not provided as publicly available files due to confidentiality concerns.

| | |
|---|---|
| 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 non-summer models. The weather variables include: temperature-humidity index (THI)[13]; the 24-hour moving average of THI; heat index (HI)[14]; the 24-hour moving average of HI; cooling degree hours (CDH)[15]; the 3-hour moving average of CDH; the 24-hour moving average of CDH; heating degree hours (HDH)[16]; the 24-hour moving average of HDH; the one-day lag of cooling degree days (CDD)[17]; the one-day lag of heating degree days (HDD)[18]; 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.

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[13] 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").

[14] 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.

[15] 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.

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

[17] 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.

[18] 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 | Non-Summer |
| 1 | THI | CDH60 HDH60 |
| 2 | HI | CDH65 HDH65 |
| 3 | CDH60 | CDH60 CDH60_MA24 HDH60 HDH60_MA24 |
| 4 | CDH65 | CDH65 CDH64_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 afternoon temperature (e.g., hours-ending 13 through 20 for PG&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 | Non-Summer | Non-Summer | Summer | Non-Summer |
| 5/1/2014 | 2/3/2014 | 11/22/2013 | 5/13/2014 | 12/12/2013 |
| 5/21/2014 | 2/4/2014 | 12/5/2013 | 7/24/2014 | 12/13/2013 |
| 9/10/2014 | 2/7/2014 | 12/6/2013 | 7/28/2014 | 12/20/2013 |
| 10/3/2014 | 2/26/2014 | 12/19/2013 | 8/27/2014 | 1/9/2014 |
| 10/6/2014 | 2/28/2014 | 2/3/2014 | 9/8/2014 | 2/4/2014 |
| 10/17/2014 | 3/31/2014 | | | 2/5/2014 |
| 10/22/2014 | 4/1/2014 | | | |

## 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 non-summer), the tests are conducted by estimating one model for every event-like day (7 for PG&E, 5 for SCE, 5 for SDG&E summer, and 6 for SDG&E non-summer). 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 hours-ending 13 through 20 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 quite low with the exception of the SDG&E non-summer model. That high bias and the high error rates for both the SDG&E models is likely due to the fact that SDG&E's program contains only seven customers, 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 | 9 | 0.89 | 0.8% | 1.8% |
| PG&E | Non-Summer | 5 | 0.87 | -0.7% | 2.7% |
| SCE | Non-Summer | 5 | 0.87 | 1.7% | 3.0% |
| SDG&E | Summer | 9 | 0.92 | 0.1% | 12.2% |
| SDG&E | Non-Summer | 6 | 0.94 | 3.7% | 17.4% |

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.5 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 exception of SDG&E (shown in Figures A.4 and A.5), 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**

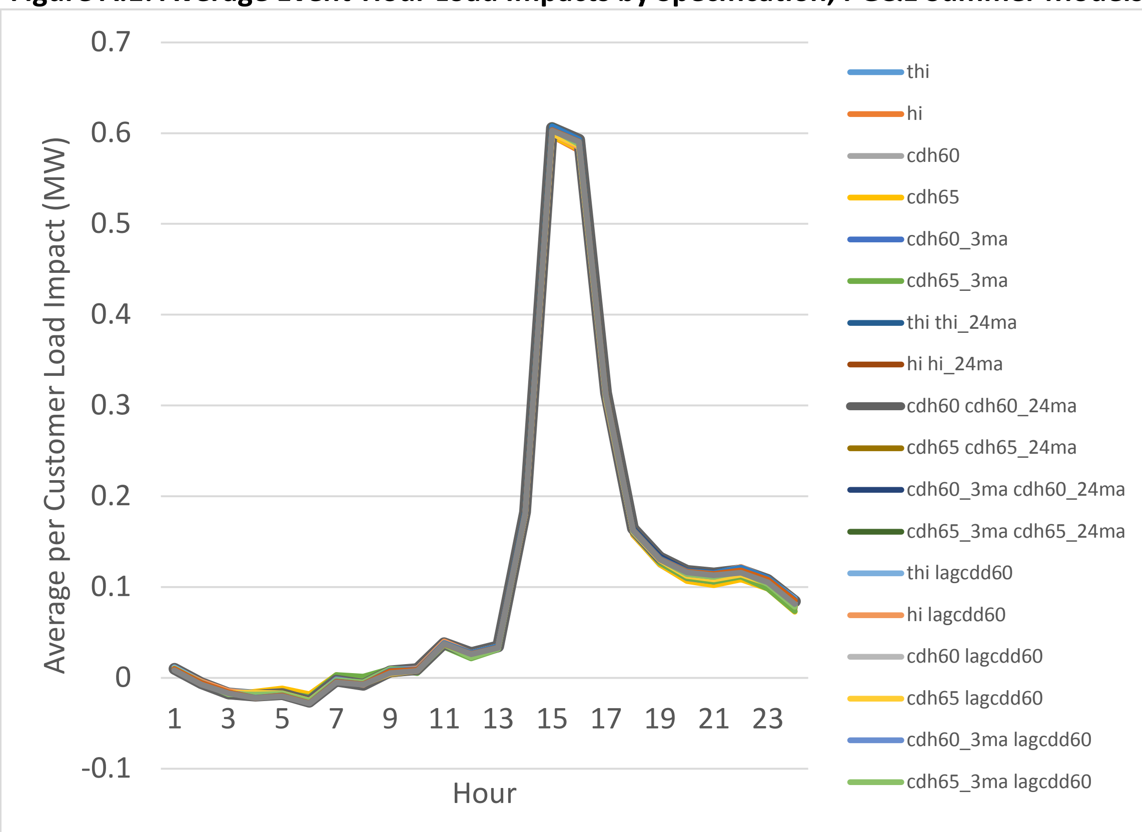


**Figure A.2: Average Event-Hour Load Impacts by Specification, PG&E Non-Summer Models**

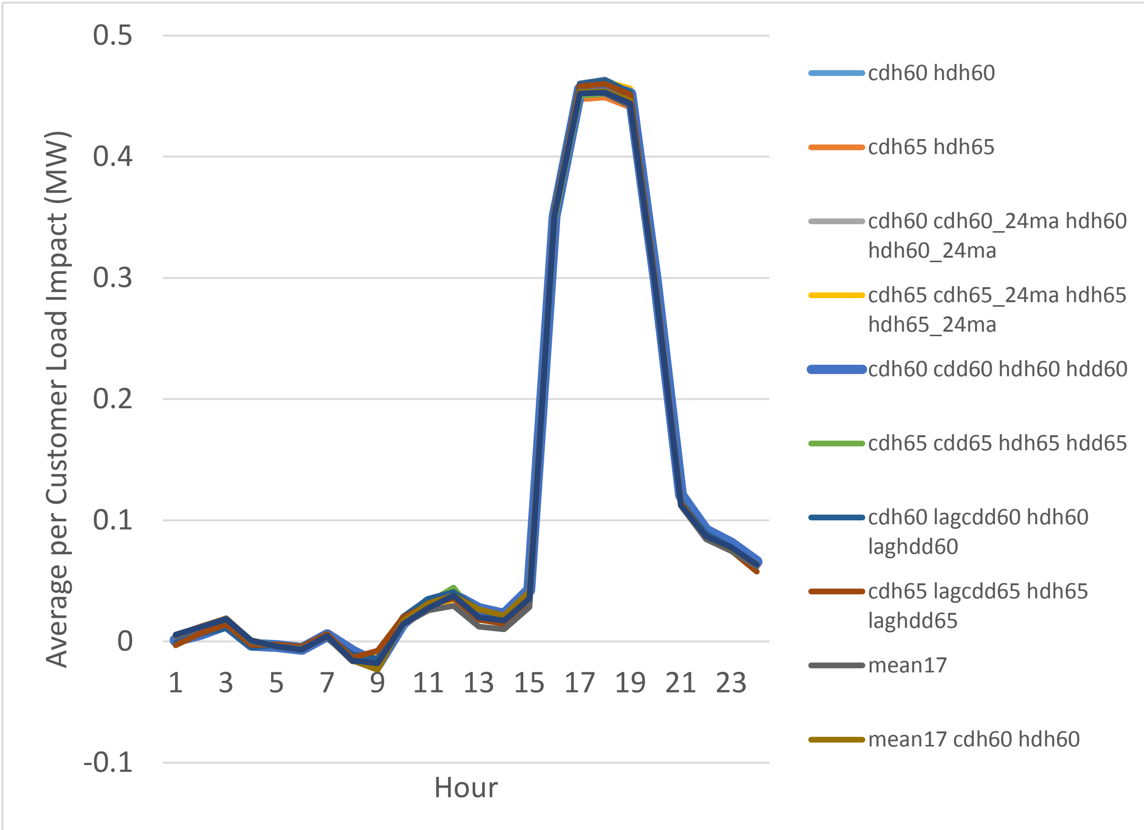


**Figure A.3: Average Event-Hour Load Impacts by Specification, SCE Non-Summer Models**

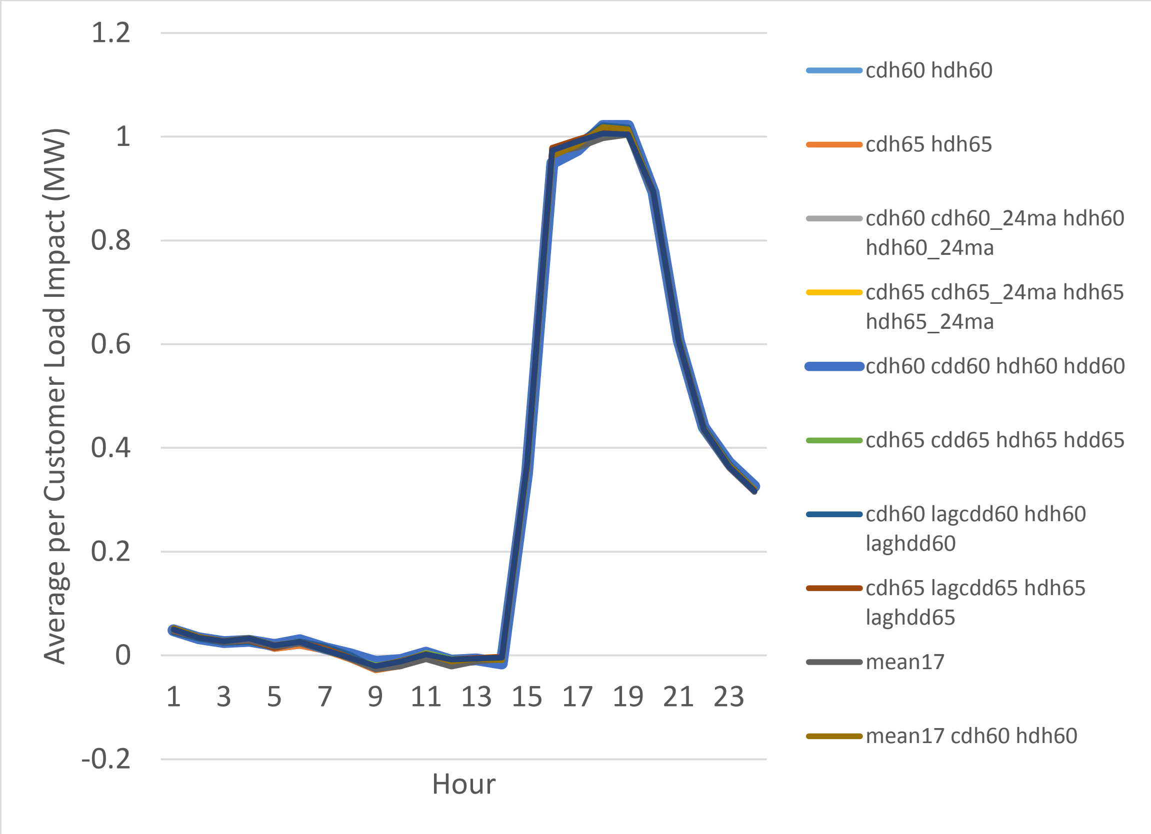



**Figure A.4: Average Event-Hour Load Impacts by Specification, SDG&E Summer Models**

Results removed due to confidentiality concerns.

**Figure A.5: Average Event-Hour Load Impacts by Specification, SDG&E Non-Summer Models**

Results removed due to confidentiality concerns.

### 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 12 through 21, 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 results for SDG&E contain some statistically significant results, but the models perform well overall. PG&E's and SCE's results indicate that the specifications passed the test in all hours, as none of the event-like load impacts is statistically significant.

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

| Hour | PG&E | | SCE | SDG&E | |
|---|---|---|---|---|---|
| | Summer | Non-Summer | Non-Summer | Summer | Non-Summer |
| 12 | -0.015<br>(0.32) | -0.001<br>(0.96) | -0.033<br>(0.23) | -0.014<br>(0.62) | 0.037<br>(0.10) |
| 13 | -0.011<br>(0.49) | -0.004<br>(0.82) | -0.047<br>(0.12) | -0.062<br>(0.03) | 0.039<br>(0.08) |
| 14 | -0.013<br>(0.39) | -0.006<br>(0.76) | -0.028<br>(0.31) | -0.060<br>(0.04) | 0.055<br>(0.01) |
| 15 | -0.010<br>(0.53) | 0.003<br>(0.86) | -0.040<br>(0.18) | -0.065<br>(0.02) | 0.062<br>(0.01) |
| 16 | -0.006<br>(0.69) | 0.031<br>(0.10) | -0.039<br>(0.18) | 0.026<br>(0.35) | 0.045<br>(0.04) |
| 17 | -0.011<br>(0.48) | 0.027<br>(0.16) | -0.022<br>(0.41) | 0.072<br>(0.01) | -0.025<br>(0.27) |
| 18 | -0.016<br>(0.30) | 0.016<br>(0.38) | -0.049<br>(0.06) | 0.039<br>(0.17) | -0.025<br>(0.27) |
| 19 | -0.012<br>(0.42) | 0.013<br>(0.45) | -0.030<br>(0.22) | 0.021<br>(0.46) | -0.015<br>(0.50) |
| 20 | -0.007<br>(0.62) | 0.015<br>(0.38) | -0.016<br>(0.51) | 0.012<br>(0.68) | -0.016<br>(0.47) |
| 21 | -0.006<br>(0.71) | -0.001<br>(0.99) | -0.014<br>(0.55) | -0.002<br>(0.94) | -0.017<br>(0.45) |

## *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.6 through A.10 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.

Figures A.6 through A.8 show that the PG&E and SCE predicted loads are quite close to the observed loads for the event-like non-event days. Figures A.9 and A.10 show that the SDG&E predicted loads are somewhat different from the observed loads during the afternoon. In this case, much of the prediction error (and the observed spike in the early morning hours) is due to an odd observed load profile on September 6. A limited number of comparable event-like days prevents us from replacing this day in the analysis.

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

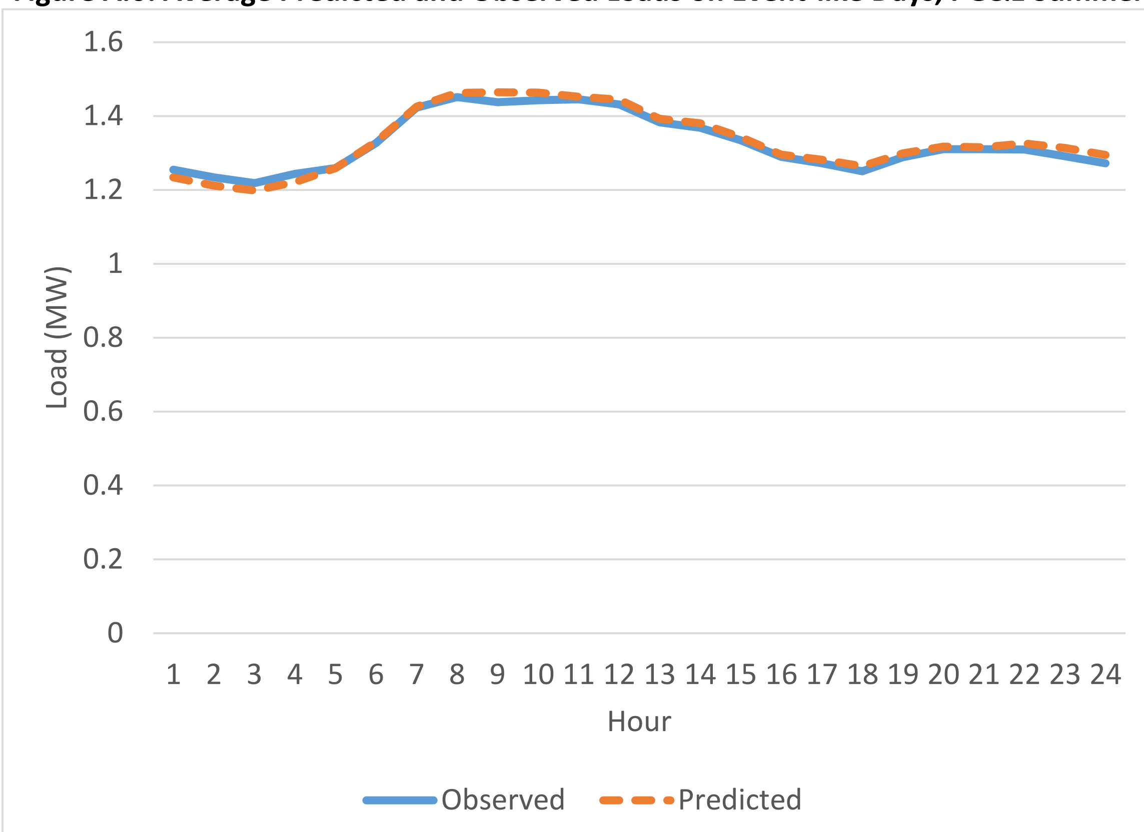


**Figure A.7: Average Predicted and Observed Loads on Event-like Days, PG&E Non-Summer**

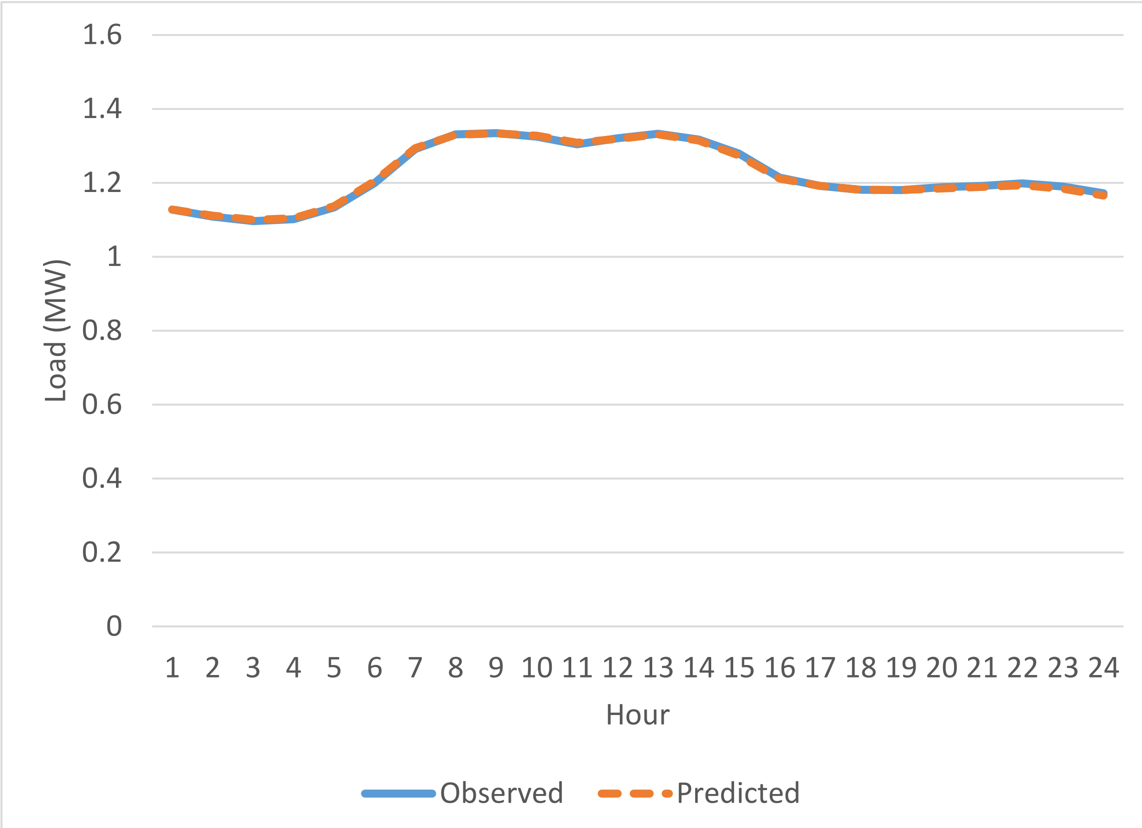


**Figure A.8: Average Predicted and Observed Loads on Event-like Days, SCE Non-Summer**

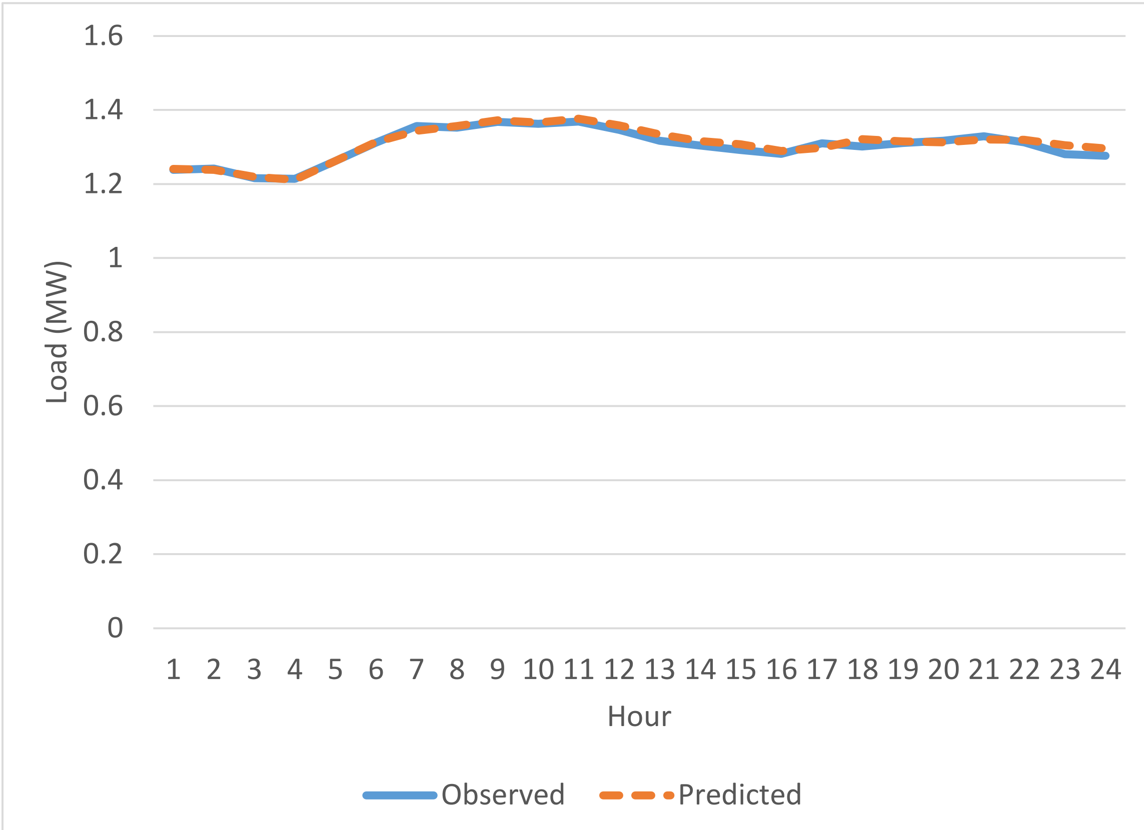



**Figure A.9: Average Predicted and Observed Loads on Event-like Days, SDG&E Summer**

Results removed due to confidentiality concerns.

**Figure A.10: Average Predicted and Observed Loads on Event-like Days, SDG&E Non-Summer**

Results removed due to confidentiality concerns.

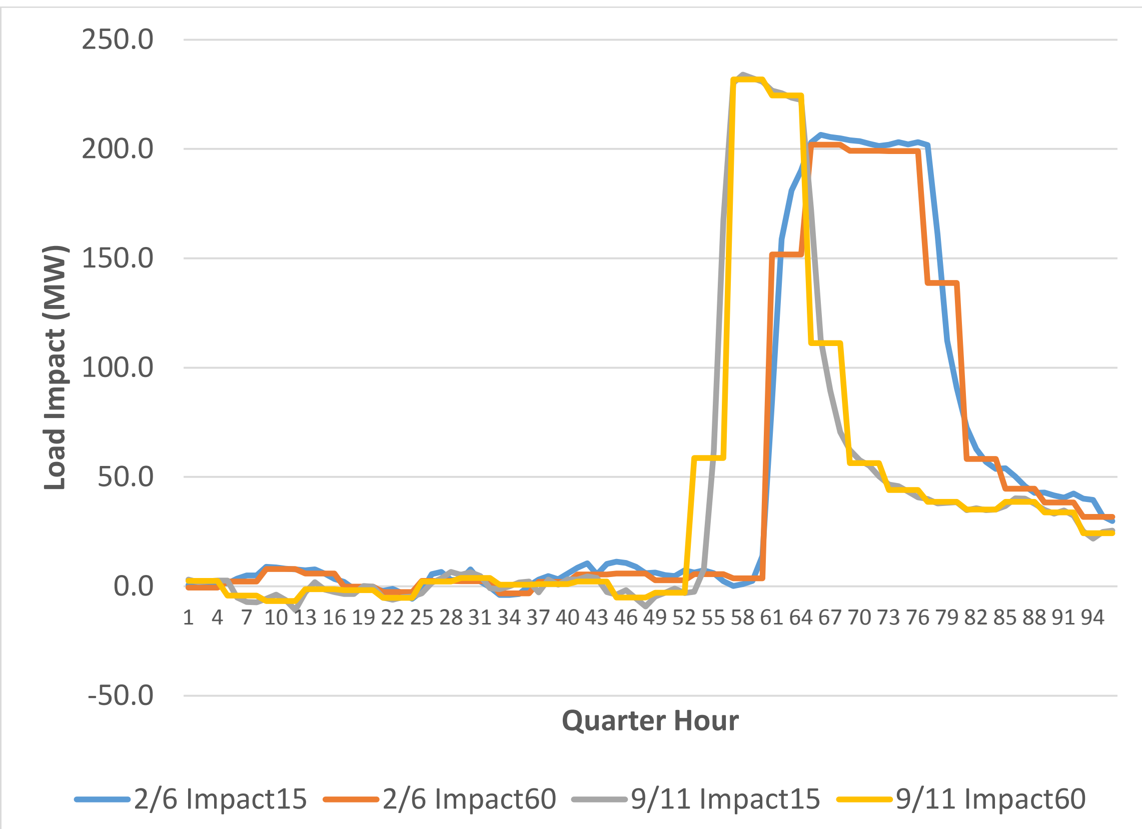
## *A.3 Refinement of Customer-Level Models*

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. In this evaluation, we modified the estimated load impacts for only PG&E's 2/6/2014 event for two SAIDs as a result of these inspections. For these customer/events, a 5-in-5 baseline appeared to better reflect the customer's behavior on the event day. For example, one of the customers had significantly higher loads somewhat after the event day, which increased the reference load in the regression-based models. In contrast, the 5-in-5 baseline method appeared to more correctly reflect the customer's usage level around the date of the event.

## A.4 Comparison of 15-minute and 60-minutes Estimates

PG&E provided 15-minute interval data, which allowed us to estimate load impacts using a 15-minute resolution in addition to the typical 60-minute resolution. Because the BIP events don't always line up neatly to one-hour increments, it can be useful to compare the 15-minute and 60-minute estimates. Figure A.11 shows the estimated load impacts for the two full-program events (February 6 and September 11) using both data resolutions. Encouragingly, the estimates from the two methods match up quite well.

**Figure A.11: Comparison of 15-minute and 60-minute Load Impact Estimates, PG&E**



# Appendix B. FSL Achievement by Industry Group

This appendix contains tables showing the FSL achievement by industry group and hour (relative to the called event window) for the events used as the basis for the ex ante load impacts. 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: September 11, 2014 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 | 29% | 101% | 104% | 61% |
| Manufacturing | 26% | 101% | 102% | 56% |
| Wholesale, Transportation, & Other Utilities | 26% | 99% | 101% | 41% |
| Retail Stores | 16% | 65% | 79% | 10% |
| Offices, Hotels, Health, Services | 14% | 114% | 115% | 31% |
| Entertainment, Other Services, Government | 17% | 83% | 85% | 26% |
| Other or Unknown | 17% | 101% | 101% | 76% |
| **All Customers** | **26%** | **101%** | **103%** | **52%** |

(HE14, HE15, HE16, and HE17 shown)

**Table B.2: February 6, 2014 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 | 28% | 98% | 100% | 91% |
| Manufacturing | 38% | 90% | 95% | 82% |
| Wholesale, Transportation, & Other Utilities | 41% | 96% | 96% | 73% |
| Retail Stores | 20% | 58% | 52% | 23% |
| Offices, Hotels, Health, Services | 34% | 93% | 69% | 63% |
| Schools | 25% | 72% | 72% | 25% |
| Entertainment, Other Services, Government | 33% | 159% | 175% | 52% |
| **All Customers** | **35%** | **91%** | **94%** | **80%** |

(HE15, HE16, HE19, and for the hour after, (4*HE20 – HE19)/3 is used to account for event ending at 19:14)

**Table B.3: May 16, 2014 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 | 16% | 35% | 100% | -6% |
| Manufacturing | n/a | 5% | 75% | -157% |
| Wholesale, Transportation, & Other Utilities | n/a | n/a | n/a | n/a |
| Retail Stores | n/a | n/a | n/a | n/a |
| **All Customers** | **18%** | **35%** | **102%** | **-13%** |

(HE11, HE12, HE14, HE16 for an event scheduled for around 10:45 through 14:45, with no clear way to adjust for the partial hour as we did with SCE due to the observed loads around the end of the event window)