**2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers:**

***Ex-post* and *Ex-ante* Report**

**CALMAC Study ID SCE0416**

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*Confidential information is redacted and denoted with black highlighting: -----------*

Table of Contents

[Abstract 1](#_Toc510091086)

[Executive Summary 3](#_Toc510091087)

[ES.1 Resources Covered 3](#_Toc510091088)

[Base Interruptible Program 3](#_Toc510091089)

[Enrollment 4](#_Toc510091090)

[ES.2 Evaluation Methodology 6](#_Toc510091091)

[ES.3 Ex-post Load Impacts 7](#_Toc510091092)

[ES.4 Ex-ante Load Impacts 7](#_Toc510091093)

[1. Introduction and Purpose of the Study 10](#_Toc510091094)

[2. Description of Resources Covered in the Study 10](#_Toc510091095)

[2.1 Program Descriptions 10](#_Toc510091096)

[SCE’s Base Interruptible Program 10](#_Toc510091097)

[PG&E’s Base Interruptible Program 11](#_Toc510091098)

[SDG&E’s Base Interruptible Program 11](#_Toc510091099)

[2.2 Participant Characteristics 12](#_Toc510091100)

[2.2.1 Development of Customer Groups 12](#_Toc510091101)

[2.2.2 Program Participants by Type 12](#_Toc510091102)

[2.3 Event Days 15](#_Toc510091103)

[3. Study Methodology 15](#_Toc510091104)

[3.1 Overview 15](#_Toc510091105)

[3.2 Description of methods 16](#_Toc510091106)

[3.2.1 Regression Model 16](#_Toc510091107)

[3.2.2 Development of Uncertainty-Adjusted Load Impacts 18](#_Toc510091108)

[4. Detailed Study Findings 18](#_Toc510091109)

[4.1 PG&E Load Impacts 19](#_Toc510091110)

[4.1.1 Average Event-hour Load Impacts by Industry Group and LCA 19](#_Toc510091111)

[4.1.2 Hourly Load Impacts 21](#_Toc510091112)

[4.2 SCE Load Impacts 22](#_Toc510091113)

[4.2.1 Average Event-hour Load Impacts by Industry Group and LCA 22](#_Toc510091114)

[4.2.2 Hourly Load Impacts 24](#_Toc510091115)

[4.3 SDG&E Load Impacts 25](#_Toc510091116)

[4.3.1 Average Event-hour Load Impacts 25](#_Toc510091117)

[4.3.2 Hourly Load Impacts 26](#_Toc510091118)

[5. Ex-ante Load Impact Forecast 28](#_Toc510091119)

[5.1 Ex-ante Load Impact Requirements 28](#_Toc510091120)

[5.2 Description of Methods 29](#_Toc510091121)

[5.2.1 Development of Customer Groups 29](#_Toc510091122)

[5.2.2 Development of Reference Loads and Load Impacts 29](#_Toc510091123)

[5.3 Enrollment Forecasts 33](#_Toc510091124)

[5.4 Reference Loads and Load Impacts 34](#_Toc510091125)

[5.4.1 PG&E 34](#_Toc510091126)

[5.4.2 SCE 36](#_Toc510091127)

[5.4.3 SDG&E 39](#_Toc510091128)

[6. Comparisons of Results 41](#_Toc510091129)

[6.1 PG&E 41](#_Toc510091130)

[6.1.1 Previous versus current ex-post 41](#_Toc510091131)

[6.1.2 Previous versus current ex-ante 42](#_Toc510091132)

[6.1.3 Previous ex-ante versus current ex-post 42](#_Toc510091133)

[6.1.4 Current ex-post versus current ex-ante 43](#_Toc510091134)

[6.2 SCE 44](#_Toc510091135)

[6.2.1 Previous versus current ex-post 44](#_Toc510091136)

[6.2.2 Previous versus current ex-ante 45](#_Toc510091137)

[6.2.3 Previous ex-ante versus current ex-post 45](#_Toc510091138)

[6.2.4 Current ex-post versus current ex-ante 46](#_Toc510091139)

[6.3 SDG&E 47](#_Toc510091140)

[6.3.1 Previous versus current ex-post 47](#_Toc510091141)

[6.3.2 Previous versus current ex-ante 48](#_Toc510091142)

[6.3.3 Previous ex-ante versus current ex-post 48](#_Toc510091143)

[6.3.4 Current ex-post versus current ex-ante 49](#_Toc510091144)

[7. Recommendations 50](#_Toc510091145)

[Appendices 51](#_Toc510091146)

[Appendix A. Validity Assessment 52](#_Toc510091147)

[A.1 Customer Weather Sensitivity 52](#_Toc510091148)

[A.2 Model Specification Tests 53](#_Toc510091149)

[A.2.1 Selection of Event-Like Non-Event Days 55](#_Toc510091150)

[A.2.2 Results from Tests of Alternative Weather Specifications 56](#_Toc510091151)

[A.2.3 Synthetic Event Day Tests 59](#_Toc510091152)

[A.3 Comparison of Predicted and Observed Loads on Event-like Days 60](#_Toc510091153)

[Appendix B. FSL Achievement by Industry Group 62](#_Toc510091154)

**Tables**

[Table 2.1: BIP Enrollees by Industry Group, PG&E 13](#_Toc508800208)

[Table 2.2: BIP Enrollees by Industry Group, SCE 13](#_Toc508800209)

[Table 2.3: BIP Enrollees by Industry Group, SDG&E 14](#_Toc508800210)

[Table 2.4: BIP Enrollees by Local Capacity Area, PG&E 14](#_Toc508800211)

[Table 2.5: BIP Enrollees by Local Capacity Area, SCE 14](#_Toc508800212)

[Table 2.6: BIP Event Days 15](#_Toc508800213)

[Table 3.1: Descriptions of Variables included in the Ex-post Regression Equation 17](#_Toc508800214)

[Table 4.1: Average Event-hour Load Impacts by Event, PG&E 19](#_Toc508800215)

[Table 4.2: Average Event-hour Observed Loads and FSLs by Event, PG&E 20](#_Toc508800216)

[Table 4.3: May 3, 2017 Load Impacts – PG&E BIP, by Industry Group 20](#_Toc508800217)

[Table 4.4: May 3, 2017 Load Impacts – PG&E BIP, by LCA 20](#_Toc508800218)

[Table 4.5: BIP Hourly Load Impacts for the May 3, 2017 Event Day, PG&E 21](#_Toc508800219)

[Table 4.6: Average Event-hour Load Impacts – SCE BIP, by Industry Group 23](#_Toc508800220)

[Table 4.7: Average Event-hour Observed Loads and FSLs, SCE 23](#_Toc508800221)

[Table 4.8: Average Event-hour Load Impacts – SCE BIP, by LCA 24](#_Toc508800222)

[Table 4.9: BIP Hourly Load Impacts for the May 3, 2017 Event Day, SCE 24](#_Toc508800223)

[Table 4.10: Average Event-hour Load Impacts, SDG&E 25](#_Toc508800224)

[Table 4.11: Average Event-hour Observed Loads and FSLs, SDG&E 25](#_Toc508800225)

[Table 4.12: August 31, 2017 Load Impacts – SDG&E BIP, by Industry Group 26](#_Toc508800226)

[Table 4.13: BIP Hourly Load Impacts for the August 31, 2017 Event Day, SDG&E 27](#_Toc508800227)

[Table 5.1: Descriptions of Terms included in the Ex-ante Regression Equation 31](#_Toc508800228)

[Table 5.2: Per-customer Ex-ante Load Impacts, 2018-2028, PG&E 36](#_Toc508800229)

[Table 5.3: Per-customer Ex-ante August 2018 Load Impacts by Scenario, SCE 39](#_Toc508800230)

[Table 5.4: Per-customer Ex-ante August 2018 Load Impacts by Scenario, SDG&E 41](#_Toc508800231)

[Table 6.1: Comparison of Ex-post Impacts in PY2016 and PY2017, PG&E 41](#_Toc508800232)

[Table 6.2: Comparison of Ex-ante Impacts from PY2016 and PY2017 Studies, PG&E 42](#_Toc508800233)

[Table 6.3: Comparison of Previous Ex-ante and Current Ex-post Impacts, PG&E 43](#_Toc508800234)

[Table 6.4: Comparison of Current Ex-post and Current Ex-ante Impacts, PG&E 43](#_Toc508800235)

[Table 6.5: PG&E Ex-post versus Ex-ante Factors 44](#_Toc508800236)

[Table 6.6: Comparison of Ex-post Impacts in PY2016 and PY2017, SCE 45](#_Toc508800237)

[Table 6.7: Comparison of Ex-ante Impacts from PY2016 and PY2017 Studies, SCE 45](#_Toc508800238)

[Table 6.8: Comparison of Previous Ex-ante and Current Ex-post Impacts, SCE 46](#_Toc508800239)

[Table 6.9: Comparison of Current Ex-post and Current Ex-ante Impacts, SCE 46](#_Toc508800240)

[Table 6.10: SCE Ex-post versus Ex-ante Factors 47](#_Toc508800241)

[Table 6.11: Comparison of Ex-post Impacts in PY2016 and PY2017, SDG&E 48](#_Toc508800242)

[Table 6.12: Comparison of Ex-ante Impacts from PY2016 and PY2017 Studies, SDG&E 48](#_Toc508800243)

[Table 6.13: Comparison of Previous Ex-ante and Current Ex-post Impacts, SDG&E 49](#_Toc508800244)

[Table 6.14: Comparison of Current Ex-post and Current Ex-ante Impacts, SDG&E 49](#_Toc508800245)

[Table 6.15: SDG&E BIP Ex-post versus Ex-ante Factors, Typical Event Day 50](#_Toc508800246)

[Table A.1: Weather Sensitive Customer Count by Industry Type, PG&E 52](#_Toc508800247)

[Table A.2: Weather Sensitive Customer Count by Industry Type, SCE 53](#_Toc508800248)

[Table A.3: Weather Sensitive Customer Count by Industry Type, SDG&E 53](#_Toc508800249)

[Table A.4: Weather Variables Included in the Tested Specifications for Weather Sensitive Customers 54](#_Toc508800250)

[Table A.5: Variables Included in the Tested Specifications for Non-Weather Sensitive Customers 55](#_Toc508800251)

[Table A.6: List of Event-Like Non-Event Days by IOU 56](#_Toc508800252)

[Table A.7: Specification Test Results for the Ex-Post analysis, PG&E 57](#_Toc508800253)

[Table A.8: Specification Test Results for the Ex-Post analysis, SCE 57](#_Toc508800254)

[Table A.9: Specification Test Results for the Ex-Post analysis, SDG&E 58](#_Toc508800255)

[Table A.10: Specification Test Results for the Ex-Ante analysis, PG&E 58](#_Toc508800256)

[Table A.11: Specification Test Results for the Ex-Ante analysis, SCE 59](#_Toc508800257)

[Table A.12: Specification Test Results for the Ex-Ante analysis, SDG&E 59](#_Toc508800258)

[Table A.13: Percentage of Statistically Significant Synthetic Event-Day Estimated Load Impacts 60](#_Toc508800259)

[Table B.1: May 3, 2017 Over/Under Performance – PG&E BIP, by Industry Group and Event Hour 62](#_Toc508800260)

[Table B.2: May 3, 2017 Over/Under Performance – SCE BIP, by Industry Group and Event Hour 63](#_Toc508800261)

[Table B.3: August 31, 2017 Over/Under Performance – SDG&E BIP, by Industry Group and Event Hour 63](#_Toc508800262)

**Figures**

[Figure ES.1: Distribution of BIP Enrolled Load by Industry Type, PG&E 4](#_Toc508800263)

[Figure ES.2: Distribution of BIP Enrolled Load by Industry Type, SCE 5](#_Toc508800264)

[Figure ES.3: Distribution of BIP Enrolled Load by Industry Type, SDG&E 6](#_Toc508800265)

[Figure ES.4: Average August Ex-Ante Load Impacts by Scenario, 2018-2028, PG&E 8](#_Toc508800266)

[Figure ES.5: Average August Ex-Ante Load Impacts by Year and Scenario, SCE 8](#_Toc508800267)

[Figure ES.6: Average August Ex-Ante Load Impacts by Scenario, 2018-2028, SDG&E 9](#_Toc508800268)

[Figure 4.1: BIP Loads for the May 3, 2017 Event Day, PG&E 22](#_Toc508800269)

[Figure 4.2: Hourly Load Impacts per Customer by Event, PG&E BIP 22](#_Toc508800270)

[Figure 4.3: BIP Load Impacts for the May 3, 2017 Event Day, SCE 25](#_Toc508800271)

[Figure 4.4: BIP August 31, 2017 Load Impacts, SDG&E 28](#_Toc508800272)

[Figure 5.1: Number of Enrolled Customers in Each Forecast Year, SCE 34](#_Toc508800273)

[Figure 5.2: PG&E Hourly Event Day Load Impacts for the August 2018 Event Day in a Utility-Specific 1-in-2 Weather 35](#_Toc508800274)

[Figure 5.3: Share of PG&E Load Impacts by LCA for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year 35](#_Toc508800275)

[Figure 5.4: Average August Ex-ante Load Impacts by Scenario, 2018-2028, PG&E 36](#_Toc508800276)

[Figure 5.5: SCE Hourly Event Day Load Impacts for the 2018 August Event Day in a Utility-Specific 1-in-2 Weather Year 37](#_Toc508800277)

[Figure 5.6: Share of SCE Load Impacts by LCA for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year 38](#_Toc508800278)

[Figure 5.7: Share of SCE Load Impacts by Notification Time for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year 38](#_Toc508800279)

[Figure 5.8: Average August Ex-ante Load Impacts by Scenario and Year, SCE 39](#_Toc508800280)

[Figure 5.9: SDG&E Hourly Event Day Load Impacts for the August 2018 Event Day in a Utility-Specific 1-in-2 Weather Year 40](#_Toc508800281)

[Figure 5.10: Average August Ex-ante Load Impacts by Scenario, 2018-2028, SDG&E 40](#_Toc508800282)

[Figure A.1: Average Predicted and Observed Loads on Event-like Days, PG&E 61](#_Toc508800283)

[Figure A.2: Average Predicted and Observed Loads on Event-like Days, SCE 61](#_Toc508800284)

[Figure A.3: Average Predicted and Observed Loads on Event-like Days, SDG&E 62](#_Toc508800285)

# 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 2017. The report provides estimates of *ex-post* load impacts that occurred during events called in 2017 and an *ex-ante* forecast of load impacts for 2018 through 2028 that is based on the IOU’s enrollment forecasts and the *ex-post* load impacts estimated for the 2017 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”).

In 2017, each utility called at least one event day: PG&E called an event May 3rd and two re-test events on July 11th and October 17th; SCE called one event on May 3rd; and SDG&E called one event on August 31st. On May 3rd, PG&E called 331 service accounts for its BIP, and only 76 and 2 on its July 11th and October 17th events, respectively. The highest aggregate reference load for any hour on each event day was 366 MW, -----------------------------------, with values declining on each event due to a lower number of accounts called. Enrollment in SCE’s BIP was 571 service accounts on the May 3rd event day. The aggregate reference load reached a high of 864 MW on that day. SDG&E’s BIP enrollment was 6 service accounts on the August 31st event day, and the highest aggregate reference load on that 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 May 3rd test event averaged 195 MW, or 57 percent of enrolled load. This was 75 percent of the reduction required to meet the aggregate FSL, calculated as the estimated load impact divided by the load impact that would have occurred if customers had (in aggregate) exactly attained their FSL.

For SCE, the load impact during the only full hour of its May 3rd Measurement and Evaluation event was 615 MW, or 78 percent of the total reference load, representing 89 percent of the reduction required to meet the aggregate FSL.

SDG&E’s total load impact for its August 31st test event averaged 2.5 MW, or 71 percent of enrolled load, representing 108 percent of the reduction required to meet the aggregate FSL.

In the *ex-ante* evaluation, PG&E forecasts BIP enrollment to remain constant from 2018 to 2028 at 362 service agreements. PG&E's average event-hour load impact is forecast to be 221 MW during a utility-specific 1-in-2 August 2018 typical event day. SCE forecasts BIP customer enrollment to decrease somewhat from 2018 through 2023 (due to opt outs from the program) and then remain constant through 2028. During the 2018 program year, SCE's average event-hour load impact is approximately 619 MW. SDG&E enrollment increases slightly throughout the forecast period. SDG&E's average event-hour load impact is forecast to be 1.3 MW during a utility-specific 1-in-2 August 2018 typical event day.

Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Base Interruptible Program (“BIP”) in place at Pacific Gas and Electric Company (“PG&E”), Southern California Edison (“SCE”), and San Diego Gas and Electric Company (“SDG&E”) in 2017. The report provides estimates of *ex-post* load impacts that occurred during events called in 2017 and an *ex-ante* forecast of load impacts for 2018 through 2028 that is based on the IOU’s enrollment forecasts and the *ex-post* load impacts estimated for the 2017 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2017?
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 2018 through 2028?

## 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 at least one full event in 2017: PG&E called an event May 3rd and two re-test events on July 11th and October 17th; SCE called one event on May 3rd; and SDG&E called one event on August 31st.

### Enrollment

Enrollment in PG&E’s BIP increased relative to PY2016, from 247 to 331 in 2017. The sum of enrolled customers’ coincident maximum demands was 365.8 MW, or 1.11 MW for the average service agreement. [[1]](#footnote-1) The Manufacturing industry group contains 62 percent of the enrolled load. Figure ES.1 illustrates the distribution of BIP load across the indicated industry types.

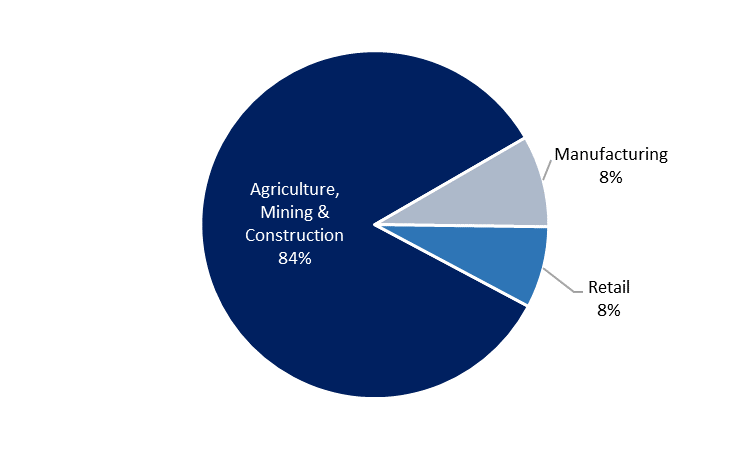
Figure ES.1: Distribution of BIP Enrolled Load by Industry Type, PG&E

SCE’s enrollment in BIP was 571 service accounts on the May 3, 2017 event day, which is a slight decrease relative to the 593 enrolled service accounts during PY2016. These accounted for a total of 863.5 MW of maximum demand, or 1.51 MW per service account. Manufacturers make up 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 6 service accounts on its August 31, 2017 event day, which is down from 7 service accounts enrolled during PY2016. These accounted for a total of 4.2 MW of maximum demand, or 0.70 MW per service account. Four Agriculture, Mining, and Construction customers make up 84 percent 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 May 3rd event averaged 195 MW, or 57 percent of enrolled load, representing 75 percent of the reduction required to meet the aggregate FSL. Total load Impact for the July 11th event averaged 69 MW, or 63 percent of enrolled load, representing 99 percent of the reduction required to meet the aggregate FSL.

For SCE, the load impact during the only full hour of its May 3rd event was 615 MW, or 78 percent of the total reference load. This was 89 percent of the reduction required to meet the aggregate FSL.

SDG&E’s total load impact for its August 31st test event averaged 2.5 MW, or 71 percent of enrolled load, representing 108 percent 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 results of the *ex-post* load impact evaluation.

PG&E forecasts BIP enrollments to remain constant from 2018 through 2028, with 362 enrolled customers. SCE projects BIP enrollments to decrease during 2018 through 2023 by a total of 9 percent and then remain constant through 2028. SDG&E forecasts a small increase in enrollments until 2022 and then remaining constant thereafter with 11 customers.

SDG&E’s *ex-ante* load impact for a typical event day under utility-specific 1-in-2 weather conditions is 1.3 MW.

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

Figure ES.4: Average August *Ex-Ante* Load Impacts by Scenario, 2018-2028, *PG&E*

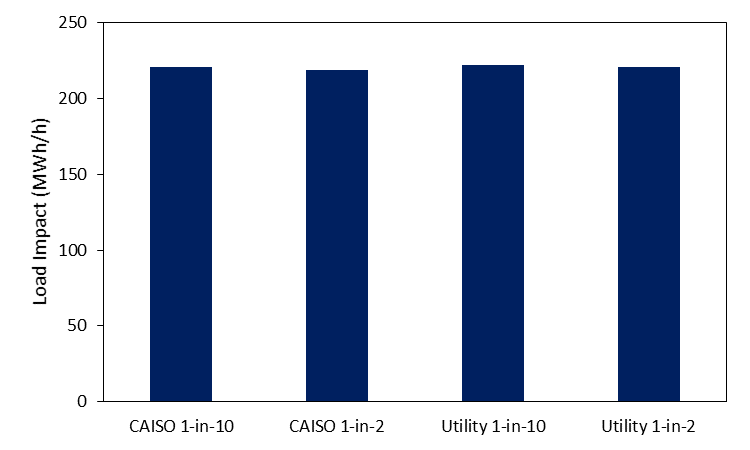


Figure ES.5: Average August *Ex-Ante* Load Impacts by Year and Scenario, *SCE*

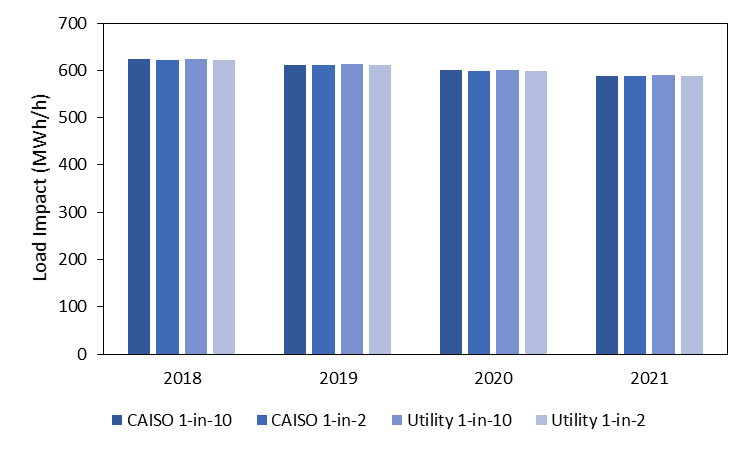
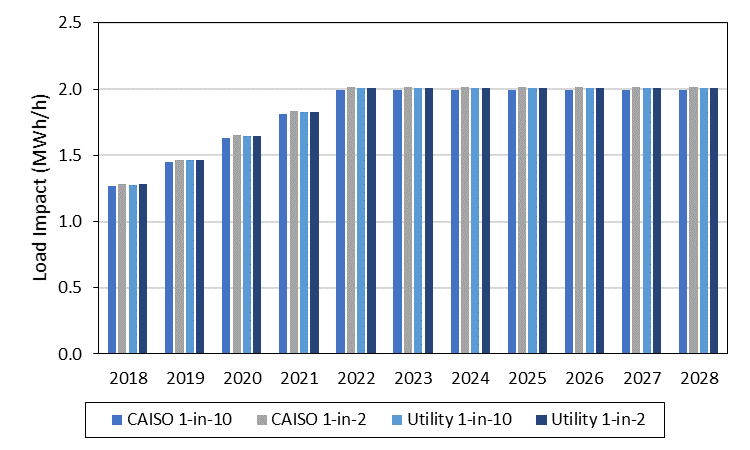


Figure ES.6: Average August *Ex-Ante* Load Impacts by Scenario, 2018-2028, *SDG&E*



1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Base Interruptible Program (“BIP”) in place at Pacific Gas and Electric Company (“PG&E”), Southern California Edison (“SCE”), and San Diego Gas and Electric Company (“SDG&E”) in 2017. The report provides estimates of *ex-post* load impacts that occurred during events called in 2017 and an *ex-ante* forecast of load impacts for 2018 through 2028 that is based on the IOU’s enrollment forecasts and the *ex-post* load impacts estimated for the 2017 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2017?
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 2018 through 2028?

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

# 2. Description of Resources Covered in the Study

This section provides details on the Base Interruptible Programs, including the characteristics of the participants enrolled in the programs and the events called in 2017.

## 2.1 Program Descriptions

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

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

### SCE’s Base Interruptible Program

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

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

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

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

### PG&E’s Base Interruptible Program

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

Participants who do not comply with the curtailment order are subject to a substantial excess energy charge on any power used above their contracted amount, or FSL. This potential energy charge has resulted in a high compliance rate. Effective January 2013, PG&E may require a customer that fails to reduce its load down to or below its FSL to re-test, modify its FSL, de-enroll from the program, or successfully comply with the re-test.

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

### SDG&E’s Base Interruptible Program

SDG&E’s BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. Non-residential customers who can commit to curtail 15 percent of monthly peak demand with a minimum load reduction of 100 kW are eligible for the program. Customers are notified no later than 20 minutes before the event. In 2017, the monthly incentive payments were $12 per kW during May through October and $2 per kW during all other months. Currently, the monthly incentive payments are $10.80 per kW during May through October and $1.80 per kW during all other months. Curtailment events for an individual BIP customer are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

Participation in SDG&E’s program has been low, consistent with the California Public Utilities Commission (“Commission” or “CPUC”) direction to focus marketing efforts on price responsive programs. There were no participants in 2006, three participants in 2007, five participants in 2008, 20 in 2009, 19 customers in 2010, 21 customers in 2011, 11 in 2012,[[2]](#footnote-2) seven participants in 2013 and 2014, five participants in 2015, seven in 2016, and six in 2017.

## 2.2 Participant Characteristics

### 2.2.1 Development of Customer Groups

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

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

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[[3]](#footnote-3)

### 2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows BIP enrollment by industry group for PG&E on the May 3, 2017 event day. Enrollment in PG&E’s BIP increased relative to PY2016, from 247 to 331.[[4]](#footnote-4) The sum of enrolled customers’ coincident maximum demands[[5]](#footnote-5) was 366 MW, or 1.11 MW for the average service agreement. The manufacturing industry group contains over 60 percent of the enrolled load.

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Industry** | **Enrolled** | **Sum of Max MWh/h[[6]](#footnote-6)** | **Percent of Max MWh/h** | **Average Max MWh/h[[7]](#footnote-7)** |
| Agriculture, Mining & Construction |  |  |  |  |
| Manufacturing | 95 | 225.9 | 61.8% | 2.38 |
| Wholesale, Transport, Other Utilities |  |  |  |  |
| Retail |  |  |  |  |
| Offices, Hotels, Finance, Services |  |  |  |  |
| Institutional/Government |  |  |  |  |
| Other or unknown |  |  |  |  |
| **Total** | **331** | **365.8** | **-** | **1.11** |

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE’s enrollment in BIP was 571 service accounts on the May 3, 2017 event day, which is a slight decrease relative to the 593 enrolled service accounts during PY2016. These accounted for a total of 863 MW of maximum demand, or 1.51 MW per service account. Manufacturers make up about two-thirds of the enrolled load.

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Industry** | **Enrolled** | **Sum of Max MWh/h** | **Percent of Max MWh/h** | **Average Max MWh/h** |
| Agriculture, Mining & Construction |  |  |  |  |
| Manufacturing | 344 | 566.3 | 65.6% | 1.65 |
| Wholesale, Transport, Other Utilities |  |  |  |  |
| Retail | 59 | 15.8 | 1.8% | 0.27 |
| Offices, Hotels, Finance, Services |  |  |  |  |
| Schools |  |  |  |  |
| Institutional/Government |  |  |  |  |
| **Total** | **571** | **863.5** | **-** | **1.51** |

Table 2.3 shows BIP enrollments for SDG&E. SDG&E’s enrollment in BIP was six service accounts on the August 31, 2017 event day. These accounted for a total of 4.2 MW of maximum demand, or 0.70 MW per service account. Agriculture, mining, and construction customers comprise the majority of the enrolled load.

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Industry** | **Enrolled** | **Sum of Max MWh/h** | **Percent of Max MWh/h** | **Average Max MWh/h** |
| Agriculture, Mining & Construction | 3 | 3.5 | 84.0% | 1.18 |
| Manufacturing | 1 | 0.4 | 8.5% | 0.36 |
| Retail | 2 | 0.3 | 7.6% | 0.16 |
| **Total** | **6** | **4.2** | **0.0%** | **0.70** |

Tables 2.4 and 2.5 show BIP enrollment by local capacity area for PG&E and SCE, respectively. (SDG&E consists of a single LCA.) The majority of PG&E’s enrolled load is in the Greater Bay Area or not in an LCA and 76 percent of SCE’s enrolled load is in the LA Basin.

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Local Capacity Area** | **Enrolled** | **Sum of Max MWh/h** | **Percent of Max MWh/h** | **Average Max MWh/h** |
| Greater Bay Area |  |  |  |  |
| Greater Fresno Area |  |  |  |  |
| Humboldt |  |  |  |  |
| Kern |  |  |  |  |
| North Coast / North Bay |  |  |  |  |
| Other (blank) | 109 | 107.9 | 29.5% | 0.99 |
| Sierra | 20 | 18.5 | 5.0% | 0.92 |
| Stockton | 23 | 30.1 | 8.2% | 1.31 |
| **Total** | **331** | **365.8** | **0.0%** | **1.11** |

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Local Capacity Area** | **Enrolled** | **Sum of Max MWh/h** | **Percent of Max MWh/h** | **Average Max MWh/h** |
| LA Basin | 480 | 653.9 | 75.7% | 1.36 |
| Outside Basin |  |  |  |  |
| Ventura |  |  |  |  |
| **Total** | **571** | **863.5** | **0.0%** | **1.51** |

## 2.3 Event Days

Table 2.6 lists BIP event days and hours for the three IOUs in 2017. PG&E and SCE called an emergency event on May 3, 2017. PG&E called two additional re-test events. SDG&E called one test event.

Table 2.6: BIP Event Days

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Date** | **Day of Week** | **PG&E** | **SCE** | **SDG&E** |
| 5/3/2017 | Wednesday | Emergency Event,  8:00-9:25 p.m. | Emergency Event,  6:58-9:18 p.m. |  |
| 7/11/2017 | Tuesday | Re-test,  6:00-8:00 p.m. |  |  |
| 8/31/2017 | Thursday |  |  | Test,  11:00 a.m.-3:00 p.m. |
| 10/17/2017 | Tuesday | Re-test,  6:00-8:00 p.m. |  |  |

# 3. Study Methodology

## 3.1 Overview

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

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

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each enrolled customer. As a result, the coefficients on the event day/hour variables are direct estimates of the *ex-post* load impacts. For example, a BIP hour 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[[8]](#footnote-8)

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

## 3.2 Description of methods

### 3.2.1 Regression Model

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



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

|  |  |
| --- | --- |
| **Variable Name** | **Variable Description** |
| *Qt* | the demand in hour *t* for a BIP customer |
| The various *b*’s | the estimated parameters |
| *hi,t* | an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day |
| *BIPt* | an indicator variable for program event days |
| *E* | the number of program event days that occurred during the program year |
|  | an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...) |
| *Weathert* | the weather variables selected using our model screening process |
| *MornLoadt* | a variable equal to the average of the day’s load in hours 1 through 10 (may be excluded via model screening) |
| *DTYPEj,t* | a series of indicator variables for each day of the week |
| *MONt, FRIt*, | indicator variables for Monday and Friday |
| *MONTHj,t* | a series of indicator variables for each month (model screening may include separate hourly profiles by month) |
| *SUMMERt* | an indicator variable for the summer pricing season[[9]](#footnote-9) |
| *et* | 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. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of an event) for factors that affect pre-event usage, but are not accounted for by the other included variables.

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

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

### 3.2.2 Development of Uncertainty-Adjusted Load Impacts

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

Specifically, we added the variances of the estimated load impacts across the customers who are called during the event in question. These aggregations were performed at either the program level, by industry group, or by LCA, as appropriate. The uncertainty-adjusted scenarios were then simulated under the assumption that each hour’s load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

In order to develop the uncertainty-adjusted load impacts associated with the average event hour (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), we estimated an additional set of customer-specific regression models in which each event day’s average event-hour load impact is estimated using a single variable (rather than the hour-specific variables used in the primary model described above). The standard error associated with these event-specific coefficients serves as the basis of the average event-hour uncertainty-adjusted load impacts for each *ex-post* event day. 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 590 kWh/h for PG&E's May 3rd event, 1,077 kWh/h for the full hour of SCE's event, and 424 kWh/h for SDG&E’s event.

## 4.1 PG&E Load Impacts

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

Table 4.1 summarizes average event-hour reference loads and load impacts at the program level for each of PG&E’s BIP events. Because the second and third events were re-tests, fewer service agreements were called. The highest load impact therefore occurred during the May 3rd event, with an average 195 MW load impact across the two event hours.[[10]](#footnote-10)

Table 4.1: Average Event-hour 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 | 5/3/2017 | Wed. | 331 | 343.6 | 148.2 | 195.4 | 56.9% |
| 2 | 7/11/2017 | Tues. |  |  |  |  |  |
| 3 | 10/17/2017 | Tues. |  |  |  |  |  |

Table 4.2 compares the observed loads and FSLs by event day. During the May 3rd event in which all service agreements were called, the observed program load was above the aggregate FSL. This was also true for the two re-test events, though the aggregate performance on those dates was significantly better than on the May 3rd event day. 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, a 100% value in that column would indicate that observed loads exactly matched the FSL (in aggregate, when averaged across event hours). A value less than 100% indicates aggregate under-performance (an observed load above the FSL).

It is possible that the relatively poor performance during the May 3rd event is due to the late event hours, perhaps because the energy manager for the customer’s facility was not present at the time. The FSL underachievement is largely due to lack of response from relatively few customers. ---------------------------------------------------------------------------------------------------------------[[11]](#footnote-11) ------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event** | **Date** | **Day of Week** | **Observed**  **Load (MW)** | **Firm Service**  **Level (MW)** | **Estimated LI /**  **LI at FSL** |
| 1 | 5/3/2017 | Wed. | 148.2 | 84.5 | 75% |
| 2 | 7/11/2017 | Tues. |  |  |  |
| 3 | 10/17/2017 | Tues. |  |  |  |

Table 4.3 summarizes average event-hour BIP load impacts by industry group for the May 3rd event day. The Manufacturing industry group accounted for the largest share of the load impacts, with a 117 MW average event-hour load reduction.

Table 4.3: May 3, 2017 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 |  |  |  |  |  |
| Manufacturing | 95 | 209.4 | 92.7 | 116.8 | 55.8% |
| Wholesale, Transportation, & Other Utilities |  |  |  |  |  |
| Retail Stores |  |  |  |  |  |
| Offices, Hotels, Health, Services |  |  |  |  |  |
| Schools |  |  |  |  |  |
| Entertainment, Government |  |  |  |  |  |
| Other or Unknown |  |  |  |  |  |
| **Total** | **331** | **343.6** | **148.2** | **195.4** | **56.9%** |

Table 4.4 summarizes May 3rd load impacts by local capacity area (LCA), --------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

Table 4.4: May 3, 2017 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 | 109 | 107.8 | 46.7 | 61.1 | 56.7% |
| Sierra | 20 | 16.0 | 7.6 | 8.4 | 52.5% |
| Stockton | 23 | 19.7 | 10.0 | 9.7 | 49.1% |
| **Total** | **331** | **343.6** | **148.2** | **195.4** | **56.9%** |

### 4.1.2 Hourly Load Impacts

Table 4.5 presents hourly PG&E BIP load impacts at the program level in the manner required by the Protocols. BIP load impacts were estimated from the individual customer regressions for customers enrolled at the time of the event. The table reflects the May 3, 2017 event day, which was the only event of the program year during which all customers were called.

Table 4.5: BIP Hourly Load Impacts for the May 3, 2017 Event Day, *PG&E*



Figure 4.1 illustrates the hourly reference load, observed load, and estimated load impact for the May 3rd event day. Figure 4.2 shows the estimated load impacts for the May 3rd event as well as the re-test event days, July 11th and October 17th, expressed in kWh per hour per customer. Note that fewer customers were called for the re-test events, so the load impacts are not comparable across 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 Loads for the May 3, 2017 Event Day, *PG&E*

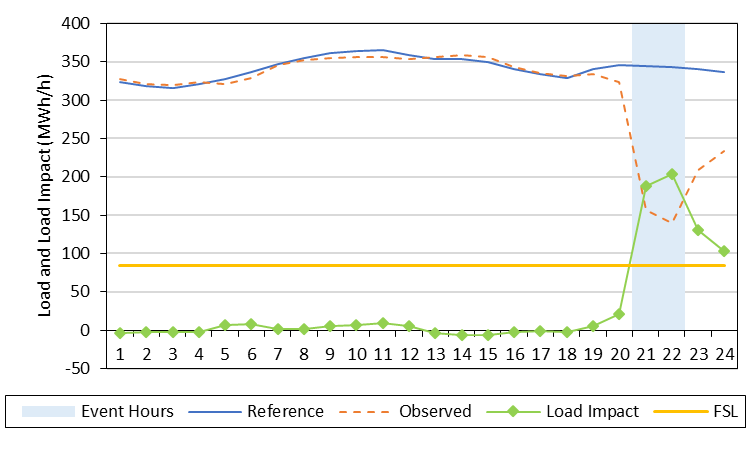
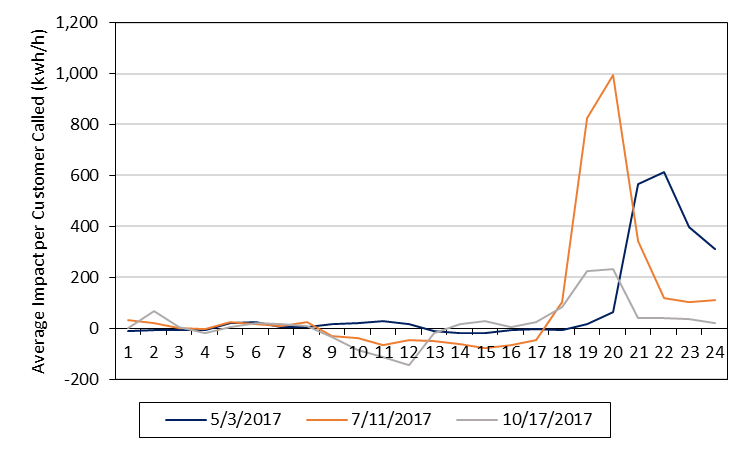


Figure 4.2: Hourly Load Impacts per Customer by Event, *PG&E BIP*



## 4.2 SCE Load Impacts

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

SCE’s only BIP event day was May 3, 2017. Table 4.6 shows the average event-hour load impact for that event day by industry group.[[12]](#footnote-12) The total row at the bottom of the table shows the total event-day load impact of 615 MW, or 78 percent of the reference load. The majority of the program’s load impact came from customers in the Manufacturing industry group.

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Group** | **Enrolled** | **Estimated Reference Load (MWh/h)** | **Observed Load (MWh/h)** | **Estimated Load Impact (MWh/h)** | **Percent Load Impact** |
| Agriculture, Mining & Construction |  |  |  |  |  |
| Manufacturing | 344 | 501.6 | 114.4 | 387.2 | 77.2% |
| Wholesale, Transport, other utilities |  |  |  |  |  |
| Retail stores | 59 | 15.0 | 13.6 | 1.3 | 8.8% |
| Offices, Hotels, Finance, Services |  |  |  |  |  |
| Schools |  |  |  |  |  |
| Institutional/Government |  |  |  |  |  |
| **Total** | **571** | **789.5** | **174.8** | **614.7** | **77.9%** |

Table 4.7 compares the observed loads and FSLs for the May 3rd event day. In aggregate, SCE’s BIP program achieved 89 percent of the reduction required to meet its FSL.

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event** | **Date** | **Day of Week** | **Observed**  **Load (MW)** | **Firm Service**  **Level (MW)** | **Estimated LI /**  **LI at FSL** |
| 1 | 5/3/2017 | Wednesday | 174.8 | 98.0 | 89% |

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.

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Group** | **Enrolled** | **Estimated Reference Load (MWh/h)** | **Observed Load (MWh/h)** | **Estimated Load Impact (MWh/h)** | **Percent Load Impact** |
| LA Basin | 480 | 582.5 | 147.3 | 435.1 | 74.7% |
| Outside Basin |  |  |  |  |  |
| Ventura |  |  |  |  |  |
| **Total** | **571** | **789.5** | **174.8** | **614.7** | **77.9%** |
| South OC |  |  |  |  |  |
| South of Lugo | 201 | 275.1 | 63.1 | 212.0 | 77.1% |
| Remainder of System | 315 | 407.3 | 79.8 | 327.4 | 80.4% |

### 4.2.2 Hourly Load Impacts

Table 4.9 presents hourly load impacts for the May 3rd BIP event in the manner required by the Protocols.

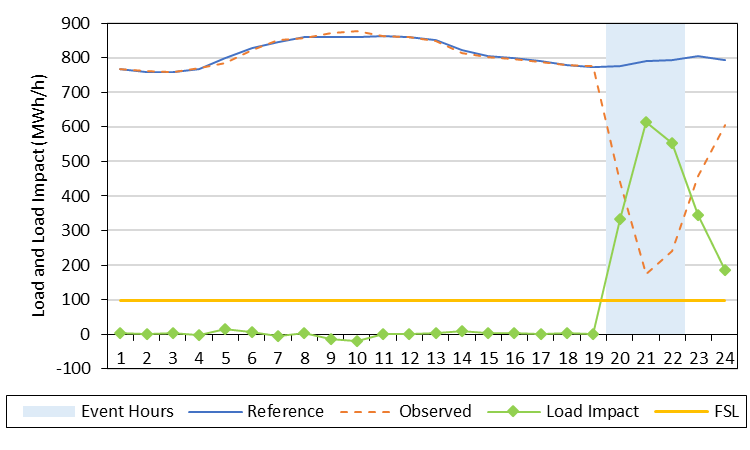
Table 4.9: BIP Hourly Load Impacts for the May 3, 2017 Event Day, *SCE*



\* The highlighting indicates all hours affected by the event. However, hour-ending 21 was the only hour during which customers were required to respond for the full hour.

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the May 3rd BIP event.

Figure 4.3: BIP Load Impacts for the May 3, 2017 Event Day, *SCE*



## 4.3 SDG&E Load Impacts

### 4.3.1 Average Event-hour Load Impacts

Average event-hour reference loads and load impacts for SDG&E single event (August 31, 2017) are summarized in Table 4.10. The average load impact over the four-hour event was 2.5 MW.

Table 4.10: Average Event-hour Load Impacts, *SDG&E*

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event** | **Date** | **Day of Week** | **Estimated Reference Load (MW)** | **Observed Load (MW)** | **Estimated Load Impact (MW)** | **% LI** |
| 1 | 8/31/2017 | Thursday | 3.6 | 1.0 | 2.5 | 71.1% |

Table 4.11 compares the average observed load to the FSL on the event day. The observed load was below the FSL throughout the event.

Table 4.11: Average Event-hour Observed Loads and FSLs*, SDG&E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event** | **Date** | **Day of Week** | **Observed**  **Load (MW)** | **Firm Service**  **Level (MW)** | **Estimated LI /**  **LI at FSL** |
| 1 | 8/31/2017 | Thursday | 1.0 | 1.2 | 108% |

Table 4.12 shows the load impacts for the August 31st event day by industry group. The three service accounts in the agriculture, mining, and construction group accounted for the entire BIP load impact. Note that the two retail stores were below their FSL the entire day, which may explain the absence of a load impact. Similarly, the sole manufacturing customer had a load near its FSL the entire day.

Table 4.12: August 31, 2017 Load Impacts – SDG&E BIP, *by Industry Group*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Group** | **# of Service Accounts** | **Estimated Reference Load (MWh/h)** | **Observed Load (MWh/h)** | **Estimated Load Impact (MWh/h)** | **% LI** |
| Agriculture, Mining, & Construction | 3 | 2.9 | 0.4 | 2.5 | 87.7% |
| Manufacturing | 1 | 0.4 | 0.3 | 0.0 | 8.8% |
| Retail Stores | 2 | 0.3 | 0.3 | 0.0 | -2.1% |
| **Total** | **6** | **3.6** | **1.0** | **2.5** | **71.1%** |

### 4.3.2 Hourly Load Impacts

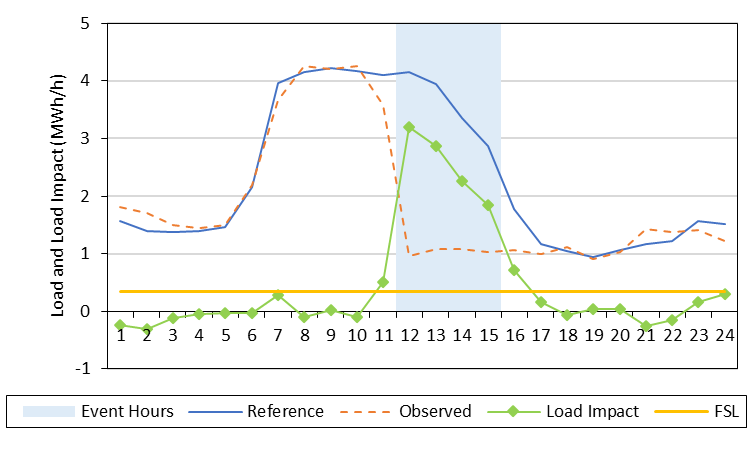
Table 4.13 presents hourly load impacts for the August 31st event day in the manner required by the Protocols.

Table 4.13: BIP Hourly Load Impacts for the August 31, 2017 Event Day, *SDG&E*



Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the August 31st event day.

Figure 4.4: BIP August 31, 2017 Load Impacts, *SDG&E*



# 5. *Ex-ante* Load Impact Forecast

## 5.1 Ex-ante Load Impact Requirements

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

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

under both:

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

at both:

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

## 5.2 Description of Methods

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

### 5.2.1 Development of Customer Groups

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

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

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

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

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

### 5.2.2 Development of Reference Loads and Load Impacts

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

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

Each of these steps is described below.

1. *Define data sources*

The reference loads are developed using data for customers enrolled in BIP at the start of the 2018 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the start of the 2018 program year, based on their estimated *ex-post* load impacts during program year 2017.

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.

1. *Simulate reference loads*

In order to develop reference loads, we first re-estimated regression equations for each enrolled customer account using data for the current program year. The resulting estimates were used to simulate reference loads for each service account under the various scenarios required by the Protocols (*e.g.*, the typical event day in a utility-specific 1-in-2 weather year).

For the summer months, the re-estimated regression equations were similar in design to the *ex-post* load impact equations described in Section 3.2, differing in two ways. First, the *ex-ante* models excluded the morning-usage variables. While these variables are useful for improving accuracy in estimating *ex-post* load impacts for particular events, they complicate the use of the equations in *ex-ante* simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the *ex-post* and *ex-ante* models is that the *ex-ante* models do not use weather variables using information from prior days.[[13]](#footnote-13) The primary reason for this is that the *ex-ante* weather days were not selected based on weather from the prior day, restricting the use of lagged weather variables to construct the *ex-ante* scenarios.

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



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

|  |  |
| --- | --- |
| **Variable Name** | **Variable Description** |
| *Qt* | the demand in hour *t* for a customer enrolled in BIP prior to the last event date |
| The various *b*’s | the estimated parameters |
| *hi,t* | an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day |
| *BIPt* | an indicator variable for program event days |
| *E* | the number of program event days that occurred during the program year |
|  | an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = DBP Event 1, DBP Event 2, ...) |
| *Weathert* | the weather variables selected using our model screening process |
| *DTYPEj,t* | a series of indicator variables for each day of the week |
| *MONt, FRIt*, | indicator variables for Monday and Friday |
| *MONTHj,t* | a series of indicator variables for each month |
| *et* | the error term |

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

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

1. *Calculate forecast load impacts*

Each service account’s FSL achievement rate is defined as the estimated load impact divided by the difference between the reference load and the FSL. A result of 100 percent implies that the customer dropped its load exactly to its FSL. Values greater than 100 percent imply event-day loads lower than the FSL, and values less than 100 percent imply event-day loads higher than the FSL.[[14]](#footnote-14)

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

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

Because the forecast event window (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 utilities and event days), we needed to adjust the historical load impacts for use in the *ex-ante* study. Load impacts are assumed to be zero until the hour prior to the beginning of the event, at which time we apply the customer’s historical FSL performance rate to the forecast window to best represent the pattern of customer response given the limitations of the observed events. We develop forecast load impacts through the end of the event day because customers load reductions often persist well after the end of the event hours.

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

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

In this step, the customer-specific FSL achievement rates are applied to the reference loads for each scenario to produce all of the required estimated event-day loads and load impacts. For customers for which an achievement rate cannot be calculated, either because their reference loads were below their FSLs, the average achievement rate among all customers is used. The FSL achievement rate is assumed to be 100% for newly enrolled customers, as well as for customers that change their FSL in the beginning of 2018. The *ex-post* FSL achievement rates for each utility are summarized in Appendix B, with the results differentiated by industry group (and hour relative to the called event window).

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

The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2028, with separate enrollments provided at the program and portfolio level (which are identical for BIP), by LCA and size group. SCE provided annual enrollments by notice level (15 versus 30 minute) for 2018 through 2028. We assume that the *ex-post* shares of customers (LCA and location) hold throughout the forecast period. SDG&E forecasts BIP enrollments to increase by one in each year until 2022, at which time enrollment is forecast to remain constant at eleven service accounts through 2028.

## 5.3 Enrollment Forecasts

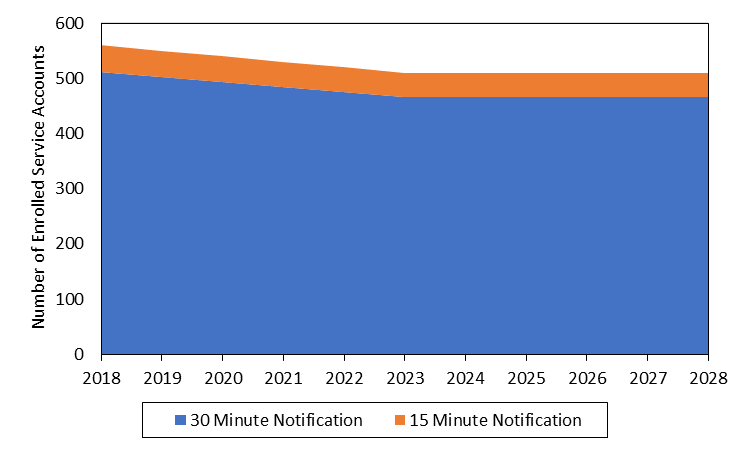
*PG&E*

PG&E forecasts BIP enrollments to remain constant from 2018 through 2028, with 355 enrolled service agreements. Of these, 257 are in the large customer group (over 200 kW) while the rest are in the medium customer group (20 to 200 kW). The total enrollment forecast of 355 is a slight increase over the 331 service agreements enrolled for the May 3, 2017 test day. The proportion of large customers is reduced from 77% to 72%.

*SCE*

Figure 5.1 shows SCE’s forecast of enrollments by year, broken down by notification time. SCE projects BIP enrollments to decrease during 2018 through 2023 and remain constant thereafter. SCE signed a Settlement Agreement in which the CPUC and IOUs agreed to a cap on RA value for reliability DR MWs. A recruiting effort to add new BIP accounts would violate the spirit of that agreement, in addition to putting SCE at risk of exceeding the cap.

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



*SDG&E*

SDG&E forecasts BIP enrollments to increase by one in each year until 2022, at which time enrollment is forecast to remain constant at eleven service accounts through 2028.

## 5.4 Reference Loads and Load Impacts

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

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

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

### 5.4.1 PG&E

Figure 5.2 shows the August 2018 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 221 MW, which represents 71.4 percent of the enrolled reference load. The program-level FSL is 75.5 MW, compared to the average event-hour program load of 88.3 MW. The FSL achievement rate of 94.5% is higher than the achievement rate of 75.4% on the May 3, 2017 event day because customers that were re-tested achieved higher performance in the later events.

Figure 5.2: PG&E Hourly Event Day Load Impacts for the August 2018 Event Day in a Utility-Specific 1-in-2 Weather

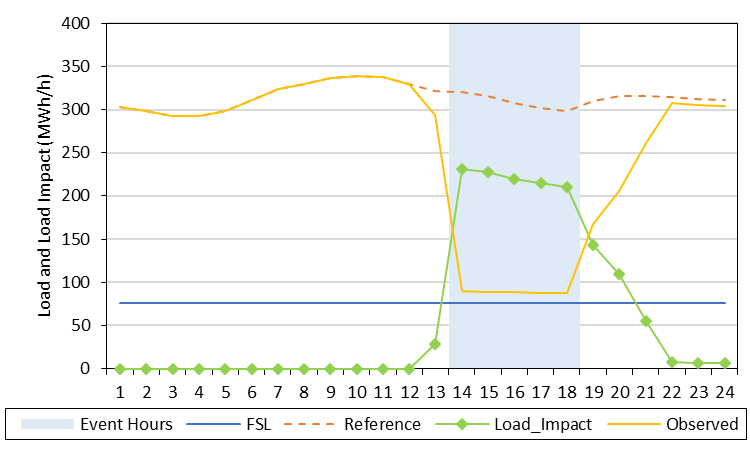


Figure 5.3 shows the share of load impacts by local capacity area, assuming a 2018 August event day in a utility-specific 1-in-2 weather year. Customers the Greater Bay Area LCA account for the largest share, with 29 percent of the load impacts, followed closely by customers not in any LCA, also with 27 percent after rounding.

Figure 5.3: Share of PG&E Load Impacts by LCA for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year

Figure 5.4 illustrates August average event-hour 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 2018 to 2028 window, so these load impacts stay constant for August across the forecast years. The differences between the scenarios is minimal because the largest customers are not weather sensitive. (Recall that customers are first sorted according to their weather sensitivity.) The smallest load impact is 219 MW in the CAISO 1-in-2 weather scenario while the largest load impact is 222 MW in the Utility 1-in-10 weather scenario.

Figure 5.4: Average August *Ex-ante* Load Impacts by Scenario, 2018-2028, *PG&E*

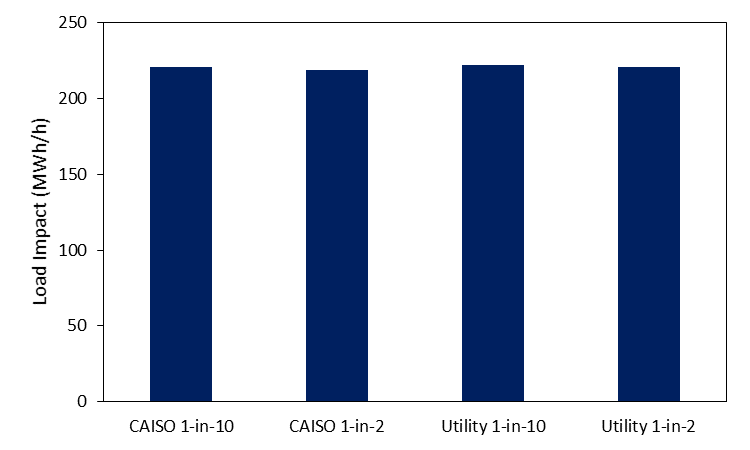


Table 5.2 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August event day.

Table 5.2: Per-customer *Ex-ante* Load Impacts, 2018-2028, *PG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Weather Year** | **Reference Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** |
| Utility 1-in-2 | 853.2 | 609.3 | 71.4% |
| Utility 1-in-10 | 858.2 | 614.4 | 71.6% |
| CAISO 1-in-2 | 848.5 | 604.7 | 71.3% |
| CAISO 1-in-10 | 855.2 | 611.1 | 71.5% |

### 5.4.2 SCE

Figure 5.5 shows the August 2018 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 619 MW, which represents 76.5 percent of the enrolled reference load. The program-level FSL is 106.4 MW, compared to the average event-hour program load of 190.2 MW. This under-performance at the program level is consistent with our estimates for the May 3, 2017 event day that serves as the basis for the *ex-ante* load impacts.

Figure 5.5: SCE Hourly Event Day Load Impacts for the 2018 August Event Day in a Utility-Specific 1-in-2 Weather Year

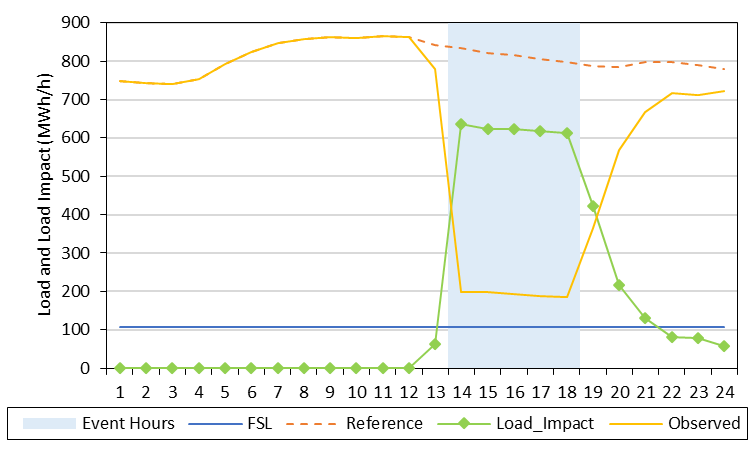


Figure 5.6 shows the share of load impacts by local capacity area for an August 2018 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 74 percent of the load impacts.

Figure 5.6: Share of SCE Load Impacts by LCA for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year

Figure 5.7 shows the share of load impacts by notification time, assuming an August 2018 event day in a utility-specific 1-in-2 weather year. Customers required to reduce demand to their FSL within 15 minutes of a Notice of Interruption make up ----------------------------------------------------------------------------------------------------------------

Figure 5.7: Share of SCE Load Impacts by Notification Time for the August 2018 Event Day in a Utility-specific 1‑in‑2 Weather Year

Figure 5.8 illustrates August event day load impacts for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. These load impacts are shown for forecast years 2018 through 2021. The load impact is not sensitive to weather conditions, but it decreases until 2023 due to forecasted reductions in enrollment, at which point it remains constant.

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

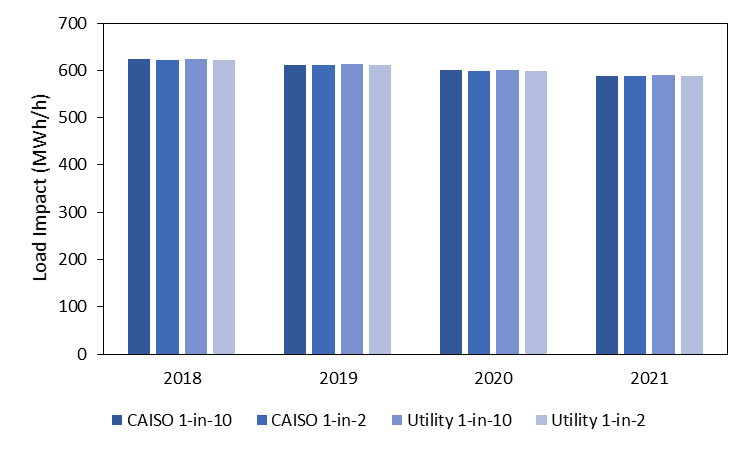


Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2018 event day.

Table 5.3: Per-customer *Ex-ante* August 2018 Load Impacts by Scenario, *SCE*

|  |  |  |  |
| --- | --- | --- | --- |
| **Weather Year** | **Reference Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** |
| Utility 1-in-2 | 1,455.3 | 1,111.2 | 76.4% |
| Utility 1-in-10 | 1,461.8 | 1,114.9 | 76.3% |
| CAISO 1-in-2 | 1,453.5 | 1,110.2 | 76.4% |
| CAISO 1-in-10 | 1,458.2 | 1,113.0 | 76.3% |

### 5.4.3 SDG&E

Figure 5.9 shows the load impact forecast for an August 2018 event day in a utility-specific 1-in-2 weather year. The average hourly load impact from 1:00 to 6:00 p.m. is forecast to be 1.3 MW, which represents 52.7 percent of the enrolled reference load. The average event-hour program load of 1.1 MW is lower than the program-level FSL of 1.4 MW. Customers over-perform throughout all event hours, consistent with our *ex-post* estimates for the August 31, 2017 event day that serves as the basis for the *ex-ante* load impacts.

Figure 5.9: SDG&E Hourly Event Day Load Impacts for the August 2018 Event Day in a Utility-Specific 1-in-2 Weather Year

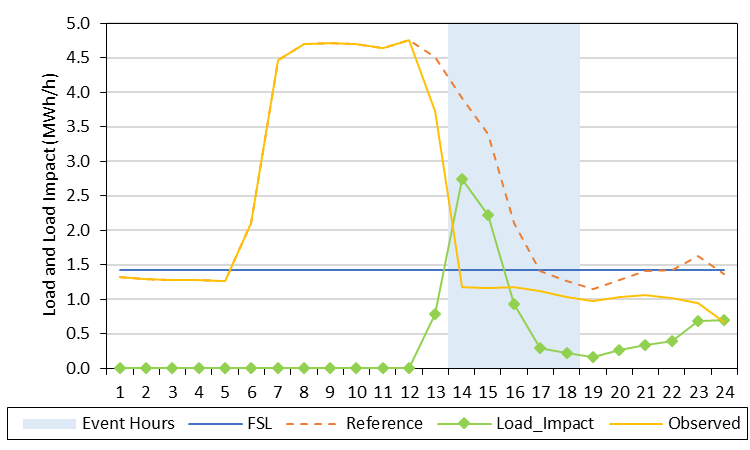


Figure 5.10 illustrates 2018 to 2028 August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The enrollment forecast slightly increases until 2022 and then remains constant. These load impacts are consistent with the increases in enrollments and the load impacts found in the *ex-post* analysis.

Figure 5.10: Average August *Ex-ante* Load Impacts by Scenario, 2018-2028, *SDG&E*

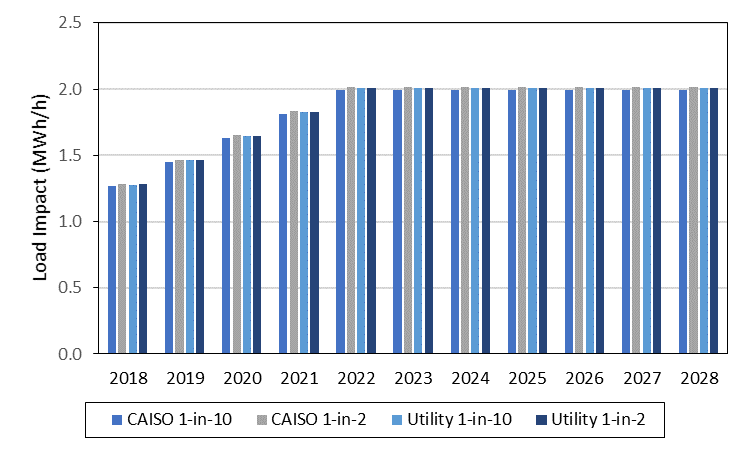


Table 5.4 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the 2018 August event day. The lack of variation across scenarios indicates that the reference loads (and therefore the load impacts) are not very sensitive to weather conditions.

Table 5.4: Per-customer *Ex-ante* August 2018 Load Impacts by Scenario, *SDG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Weather Year** | **Reference Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** |
| Utility 1-in-2 | 345.1 | 182.8 | 53.0% |
| Utility 1-in-10 | 347.3 | 182.6 | 52.6% |
| CAISO 1-in-2 | 346.6 | 183.5 | 52.9% |
| CAISO 1-in-10 | 343.8 | 181.1 | 52.7% |

# 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 2017 program year; and “previous study” refers to the report that was developed following the 2016 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 PY2016 and PY2017. The PY2016 load impacts are based on the four event hours on July 26, 2016. The PY2017 load impacts are based on the two event hours on May 3, 2017.

Table 6.1: Comparison of *Ex-post* Impacts in PY2016 and PY2017, *PG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-post* PY2016** | ***Ex-post* PY2017** |
| **Total** | # Customers | 247 | 331 |
| Reference (MWh/h) | 332.6 | 343.6 |
| Load Impact (MWh/h) | 253.8 | 195.4 |
| **Per Customer** | Reference (kWh/h) | 1,346.6 | 1,038.2 |
| Load Impact (kWh/h) | 1,027.5 | 590.4 |
| % Load Impact | 76.3% | 56.9% |

There are more service accounts in PY2017, with the added customers contributing to lower per-customer reference loads and load impacts in PY2017. In addition, the later event hours in PY2017 (HE 21 through 22) may correspond with a period when customers are less responsive to events.

### 6.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 6.2 contains this comparison for the August 2018 utility-specific 1-in-2 typical event day forecast.

Table 6.2: Comparison of *Ex-ante* Impacts from PY2016 and PY2017 Studies, *PG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2018  Typical Event Day, *Previous Study*** | ***Ex-ante* 2018 Typical Event Day, *Current Study*** |
|
|
|
| **Total** | # Customers | 330 | 362 |
| Reference (MWh/h) | 386.6 | 308.8 |
| Load Impact (MWh/h) | 300.1 | 220.5 |
| FSL (MW) | 87.5 | 75.5 |
| **Per Customer** | Reference (kWh/h) | 1,172 | 853 |
| Load Impact (kWh/h) | 910 | 609 |
| % Load Impact | 77.6% | 71.4% |

While the current study includes 32 additional service agreements, the reference loads and load impacts are lower than in PY2016. This is because the composition of BIP customers changed across years, with lower-use customers joining BIP and some high-use customers de-enrolling. For instance, there are 35 customers that de-enroll in BIP between 2017 and 2018. If these customers had remained on BIP, their forecasted aggregate load impact would be 50 MW. The per-customer reference loads demonstrate that while the current study has more enrollees, the size of these customers is much smaller at 853 kWh/h versus 1,172 kWh/h.

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

Table 6.3 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 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 May 3, 2017 event day.

The aggregate forecast from the previous study and the current *ex-post* load impacts are not the same because the per-customer reference loads and percentage load impacts are smaller in the current *ex-post* analysis.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2017 Typical Event Day, Previous Study** | ***Ex-post*** |
| ***PY2017*** |
|
| **Total** | # Customers | 330 | 331 |
| Reference (MWh/h) | 386.6 | 343.6 |
| Load Impact (MWh/h) | 300.1 | 195.4 |
| **Per Customer** | Reference (kWh/h) | 1,171.6 | 1,038.2 |
| Load Impact (kWh/h) | 909.5 | 590.4 |
| % Load Impact | 77.6% | 56.9% |

### 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 2018 typical event day with utility-specific 1-in-2 weather conditions. Load impacts as a percentage of reference load are significantly higher in the *ex-ante* analysis, with a lower reference load but a higher load impact per customer. The higher *ex-ante* percentage load impact is due to the fact that we based the forecast on each customer’s most recent *ex-post* event and some of the customers who participated in the May 3rd event were re-tested (and performed better). Specifically, the *ex-post* FSL achievement rate for customers that remain in BIP and were not re-tested (*i.e.,* their only event day was May 3rd) was 90%. The program *ex-ante* FSL achievement rate is 94.5%, which is increased because customers that were re-tested on July 11th or October 17th achieved a higher FSL achievement rate for these events. As mentioned previously, the average size of customers has decreased in the *ex-ante* forecast because of new enrollees are smaller on average, as well as larger customers that de-enrolled.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-post*** | ***Ex-ante* 2018 Typical Event Day, Current Study** |
| **PY2017** |
| **Total** | # Customers | 331 | 362 |
| Reference (MWh/h) | 343.6 | 308.8 |
| Load Impact (MWh/h) | 195.4 | 220.5 |
| FSL (MWh/h) | 84.5 | 75.5 |
| **Per Customer** | Reference (kWh/h) | 1,038.2 | 852.9 |
| Load Impact (kWh/h) | 590.4 | 609.0 |
| % Load Impact | 56.9% | 71.4% |

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

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Factor** | ***Ex-post*** | ***Ex-ante*** | **Expected Impact** |
| Weather | 77.7 degrees on 5/3/2017, 91.7 degrees on 7/11/2017, during event hours. | 96.0 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day. | Little to no impact because most customers are categorized as not weather sensitive. |
| Event window | HE 21-22 on 5/3/2017,  HE 19-20 on 7/11/2017. | HE 14-18 in Apr-Oct; | Slightly higher average reference loads for *ex-ante*. |
| HE 17-21 in Nov-Mar. |
| % of resource dispatched | All on the 5/3/2017 event. | Assume all customers are called. | None. The *ex-ante* method assumes that all enrolled customers are dispatched. |
| Enrollment | 327 customers during the 5/3/2017 event day; 75 customers during the 7/11/2017 event day. | 362 customers. | 70 smaller-than-average customers joined BIP, while 35 larger-than-average customers de-enrolled, increasing aggregate reference loads and load impacts somewhat while decreasing per-customer reference loads. |
| Methodology | Customer-specific regressions using own within-subject analysis. | Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day. | *Ex-ante* per-customer load impacts are higher because re-tested customers attained higher FSL achievement rate than 5/3 event day. |

## 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 PY2016 and PY2017. Only one BIP event was called in each year: July 26, 2016 (4 hours in duration); and May 3, 2017. While the May 3rd event included parts of three hours, results are summarized only for 8 to 9 p.m., as this was the only hour in which customers were expected to meet their FSL for the entire hour.

The reference loads and load impacts are slightly lower in PY2017, which is consistent with the lower enrollment during that year. Per-customer reference loads and load impacts are slightly higher in PY2017, but the percentage load impact is nearly identical in the two years.

Table 6.6: Comparison of *Ex-post* Impacts in PY2016 and PY2017, *SCE*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-post* PY2016** | ***Ex-post* PY2017** |
| **Total** | # Customers | 593 | 571 |
| Reference (MWh/h) | 807.4 | 789.5 |
| Load Impact (MWh/h) | 627.5 | 614.7 |
| **Per C**ustomer | Reference (kWh/h) | 1,361.6 | 1,382.6 |
| Load Impact (kWh/h) | 1,058.2 | 1,076.5 |
| % Load Impact | 77.7% | 77.9% |

### 6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 6.7 represents the forecast for the August 2018 utility-specific 1-in-2 typical event day.

Table 6.7: Comparison of *Ex-ante* Impacts from PY2016 and PY2017 Studies, *SCE*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2018 Typical Event Day, *Previous Study*** | ***Ex-ante* 2018 Typical Event Day, *Current Study*** |
|
|
|
| **Total** | # **C**ustomers | 619 | 560 |
| Reference (MWh/h) | 838.2 | 809.1 |
| Load Impact (MWh/h) | 658.1 | 619.0 |
| FSL (MWh/h) | 104.1 | 106.4 |
| **Per C**ustomer | Reference (kWh/h) | 1,354.1 | 1,445 |
| Load Impact (kWh/h) | 1,063.2 | 1,105 |
| % Load Impact | 78.5% | 76.5% |

The forecasts of per-customer reference loads and load impacts are slightly higher in the current study despite a decrease in enrollment. That decrease in enrollment causes a reduction in the total reference load and load impact.

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

Table 6.8 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 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 May 3, 2017 event day.

The forecast per-customer reference loads, per-customer load impacts, and percentage load impacts were quite close to the *ex-post* estimates. However, forecast enrollment was significantly higher than ex-post enrollment, leading to lower-than-forecast *ex-post* load impacts.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2017 Typical Event Day, Previous Study** | ***Ex-post*** |
| ***PY2017*** |
|
| **Total** | # **C**ustomers | 630 | 571 |
| Reference (MWh/h) | 852.5 | 789.5 |
| Load Impact (MWh/h) | 669.5 | 614.7 |
| **Per C**ustomer | Reference (kWh/h) | 1,353.2 | 1,382.6 |
| Load Impact (kWh/h) | 1,062.7 | 1,076.5 |
| % Load Impact | 78.5% | 77.9% |

### 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 (May 3, 2017) and the *ex-ante* load impact represents the 2018 typical event day in a utility-specific 1-in-2 weather year.

The forecast calls for a slight decrease in the number of enrollments, but a small increase in reference loads and load impacts. This is due to larger customers remaining on the program (and perhaps hotter temperatures during the *ex-ante* forecast period, though most customers are not weather sensitive).

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-post*** | ***Ex-ante* 2018 Typical Event Day, Current Study** |
| **PY2017** |
| **Total** | # **C**ustomers | 571 | 560 |
| Reference (MWh/h) | 789.5 | 809.1 |
| Load Impact (MWh/h) | 614.7 | 619.0 |
| FSL (MWh/h) | 98.0 | 106.4 |
| **Per C**ustomer | Reference (kWh/h) | 1,382.6 | 1,445 |
| Load Impact (kWh/h) | 1,076.5 | 1,105 |
| % Load Impact | 77.9% | 76.5% |

Table 6.10 lays out all the potential sources of differences between the *ex-post* and *ex-ante* load impacts, but it is using the single event hour FSL achievement rate that primarily accounts for the differences, as explained above.

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

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-post* | *Ex-ante* | Expected Impact |
| Weather | 74 degrees Fahrenheit during event window. | 89.6 degrees Fahrenheit during event hours on utility-specific 1-in-2 Aug typical event day. | Higher temperatures result in higher references loads for weather sensitive customers. There is little effect on the load impact because most responsive customers are categorized as not weather sensitive. |
| Event window | HE 21 is the only full event hour (though the event spans parts of the surrounding hours). | HE 14-18 in Apr-Oct;  HE 17-21 in Nov-Mar. | The slightly later *ex-post* event window tends toward slightly lower reference loads and load impacts relative to the *ex-ante* window. |
| % of resource dispatched | All customers were called. | Assume all customers are called. | None. The *ex-ante* method assumes that all enrolled customers are dispatched. |
| Enrollment | 571 customers during the *ex-post* event day. | 560 customers in August 2018. | Lower enrollment reduces the aggregate load impact but increases the per-customer impacts for a net positive effect. |
| Methodology | customer-specific regressions using own within-subject analysis. | Reference loads are simulated from customer-specific regressions. Load impacts are based on the customer-specific load impacts from the PY2017 event day during HE 21. | Using the single *ex-post* event hour FSL achievement rate provides a larger *ex-ante* load impact than if using that of the average event hour*.* |

## 6.3 SDG&E

### 6.3.1 Previous versus current *ex-post*

Table 6.11 compares *ex-post* load impacts between PY2016 and PY2017. The PY2016 load impacts are based on the September 26, 2016 event with event hours-ending 14 through 17, while the PY2017 load impacts are based on the single August 31, 2017 event with event hours-ending 12 through 15. Enrollment has dropped from seven to six, yet loads have increased slightly. The increase in reference loads occurs because the earlier event hours in PY2017correspond to a period of higher loads for the enrolled customers.

Table 6.11: Comparison of *Ex-post* Impacts in PY2016 and PY2017, *SDG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-post* PY2016** | ***Ex-post* PY2017** |
| **Total** | # Customers | 7 | 6 |
| Reference (MWh/h) | 2.6 | 3.6 |
| Load Impact (MWh/h) | 1.5 | 2.5 |
| **Per Customer** | Reference (kWh/h) | 371.4 | 596.5 |
| Load Impact (kWh/h) | 221.0 | 423.8 |
| % Load Impact | 59.5% | 71.1% |

### 6.3.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 6.12 presents this comparison for the *ex-ante* forecasts of the utility-specific 1-in-2 August typical event day. Reference loads and load impacts significantly lower in the current study.

Table 6.12: Comparison of *Ex-ante* Impacts from PY2016 and PY2017 Studies, *SDG&E*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2018 Typical Event Day, *Previous Study*** | ***Ex-ante* 2018 Typical Event Day, *Current Study*** |
|
|
|
| **Total** | # Customers | 8 | 7 |
| Reference (MWh/h) | 9.2 | 2.4 |
| Load Impact (MWh/h) | 6.1 | 1.3 |
| FSL (MWh/h) | 3.2 | 1.4 |
| **Per Customer** | Reference (kWh/h) | 1,153.6 | 340.7 |
| Load Impact (kWh/h) | 765.6 | 178.8 |
| % Load Impact | 66.4% | 52.5% |

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

Table 6.13 compares the *ex-ante* forecast prepared following PY2016 to the PY2017 *ex-post* load impact estimates contained in this report for the August 31, 2017 event day. The *ex-ante* load impacts are based on the typical event day in a utility-specific 1-in-2 weather year. The differences in reference loads and load impacts occur because of the different event hours represented. For example, the average reference load for the current *ex-post* analysis over the previous study *ex-ante* period (HE 14-18) is 2 MW, which is equivalent to the previous study.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-ante* 2017 Typical Event Day, Previous Study** | ***Ex-post*** |
| ***PY2017*** |
|
| **Total** | # Customers | 6 | 6 |
| Reference (MW) | 2.0 | 3.6 |
| Load Impact (MW) | 0.7 | 2.5 |
| **Per Customer** | Reference (kW) | 327.5 | 596.5 |
| Load Impact (kW) | 122.5 | 423.8 |
| % Load Impact | 37.4% | 71.1% |

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

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

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Ex-post** | **Ex-ante 2018 Typical Event Day, Current Study** |
| **PY2017** |
| **Total** | # Customers | 6 | 7 |
| Reference (MW) | 3.6 | 2.4 |
| Load Impact (MW) | 2.5 | 1.3 |
| FSL (MW) | 1.2 | 1.4 |
| **Per Customer** | Reference (kW) | 596.5 | 340.7 |
| Load Impact (kW) | 423.8 | 178.8 |
| % Load Impact | 71.1% | 52.5% |

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

The *ex-ante* forecast is based on the *ex-post* FSL achievement (*i.e.*, observed loads) relative to the FSL during event hours. In terms of achievement relative to the FSL, the *ex-post* and *ex-ante* load impacts for the six continuing customers match by design. However, the forecast reference loads may differ from the *ex-post* event-hour reference loads for various reasons. For instance, forecast reference loads are lower partly due to a difference in event windows, as the historical event was earlier than the *ex-ante* event window (hours-ending 12 to 15 vs. 14 to 18, respectively). The later *ex-ante* window includes hours with relatively low loads, which reduces the load impact because the FSL does not change across hours.

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

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-post* | *Ex-ante* | Expected Impact |
| Weather | 93.9 degrees Fahrenheit during HE 12 to 15 on the August 31st event day | 86.4 degrees Fahrenheit during HE 14 to 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 to 15 | HE 14 to 18 in Apr-Oct. | Reference loads are substantially lower by 4 p.m. relative to earlier in the day, so the inclusion of hour-ending 17 and 18 tends to drag down the average *ex-ante* reference loads and load impacts relative to *ex-post*. |
| % of resource dispatched | All | All | None |
| Enrollment | 6 service accounts | 7 service accounts | Increase aggregate reference load and load impact. No increase in per-customer reference load or load impacts because results are scaled by enrollments. |
| Methodology | Customer-specific regressions using own within-subject analysis. | Reference loads are simulated from customer-specific regressions. | Possible difference between simulated *ex-ante* and estimated *ex-post* reference loads. In this case, however, the aggregate differences are minimal. |

# 7. Recommendations

BIP continues to perform well, with its customers providing substantial load impacts with short notice. The later event hours for the (non-test) PG&E and SCE events this year provided some information about customer response later in the day. Utilities may want to consider the timing (both time of year and time of day) of future test events to expand the understanding of the variation in program load impacts.

# Appendices

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

BIP Study Appendix C PG&E *Ex-post* Load Impact Tables

BIP Study Appendix D SCE *Ex-post* Load Impact Tables

BIP Study Appendix E SDG&E *Ex-post* Load Impact Tables

BIP Study Appendix F PG&E *Ex-ante* Load Impact Tables

BIP Study Appendix G SCE *Ex-ante* Load Impact Tables

BIP Study Appendix H SDG&E *Ex-ante* Load Impact Tables

# Appendix A. Validity Assessment

## A.1 Customer Weather Sensitivity

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

where *Qt* represents the average customer usage during hours-ending 13 through 20 on day *t* in the summer months of June through September. *DTYPEi,t* represents the day of week, while *MONTHi,t* represents each month. The *EVTi,t* variables control for any event days a customer faces (DBP, BIP, CPP, *etc*.). The variable of importance is *Weathert*, which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient (*bWeather*) is positive and statistically significant for any of the three separate weather specifications. Tables A.1 through A.3 provides the number of customers that are categorized as weather sensitive by industry group and utility. The proportion of customers classified as non-weather sensitive is 68%, 57%, and 33% for PG&E, SCE, and SDG&E, respectively.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Industry Type** | **Weather Sensitive** | **Non-Weather Sensitive** | **Total** |
| 1. Agriculture, Mining, Construction | 38 | 88 | 126 |
| 2. Manufacturing | 21 | 74 | 95 |
| 3. Wholesale, Transportation, Utilities | 20 | 49 | 69 |
| 4. Retail | 9 | 1 | 10 |
| 5. Offices, Hotels, Health, Services | 14 | 5 | 19 |
| 7. Entertainment, Other Services, Government. | 4 | 0 | 4 |
| 8. Other | 1 | 7 | 8 |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Industry Type** | **Weather Sensitive** | **Non-Weather Sensitive** | **Total** |
| 1. Agriculture, Mining, Construction | 11 | 43 | 54 |
| 2. Manufacturing | 103 | 241 | 344 |
| 3. Wholesale, Transportation, Utilities | 35 | 34 | 69 |
| 4. Retail | 58 | 1 | 59 |
| 5. Offices, Hotels, Health, Services | 28 | 4 | 32 |
| 6. Schools | 4 | 1 | 5 |
| 7. Entertainment, Other Services, Government. | 7 | 1 | 8 |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Industry Type** | **Weather Sensitive** | **Non-Weather Sensitive** | **Total** |
| 1. Agriculture, Mining, Construction | 1 | 2 | 3 |
| 2. Manufacturing | 1 | 0 | 1 |
| 3. Retail | 2 | 0 | 2 |

## A.2 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the *ex-post* load impact analysis. A separate set of specifications was also tested to be used in the *ex-ante* load impact analysis.[[15]](#footnote-15) The tests are conducted using average-customer data by industry group and weather-sensitivity. Separate model specifications were tested for weather sensitive and non-weather sensitive customers. Model variations for weather sensitive customers include 17 combinations of weather-related variables for *ex-post* and 7combinations for *ex-ante;* and 5 different specifications of non-weather-related variables for non-weather sensitive customers.

The basic structure of the model for weather sensitive customers is shown in Section 3.2.1 for *ex-post* and Section 5.2.2 for *ex-ante*. The weather variables include: temperature-humidity index (THI)[[16]](#footnote-16); heat index (HI)[[17]](#footnote-17); cooling degree hours (CDH)[[18]](#footnote-18), including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[[19]](#footnote-19), including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we tested for weather sensitive customers is provided in Table A.4, including 17 specifications for the *ex-post* analysis and 7 for *ex-ante* analysis.

Table A.4: Weather Variables Included in the Tested Specifications   
for Weather Sensitive Customers

|  |  |  |
| --- | --- | --- |
| **Model Number** | ***Ex-post* Analysis** | ***Ex-ante* Analysis** |
| 1 | THI | CDH60 |
| 2 | HI | CDH65 |
| 3 | CDH60 | CDD60 |
| 4 | CDH65 | CDD65 |
| 5 | CDD60 | Mean17 |
| 6 | CDD65 | CDH60, Mean17 |
| 7 | Mean 17 | CDH65, Mean17 |
| 8 | CDH60\_MA3 |  |
| 9 | CDH65\_MA3 |  |
| 10 | THI Lag\_CDD60 |  |
| 11 | HI, Lag\_CDD60 |  |
| 12 | CDH60, Lag\_CDD60 |  |
| 13 | CDH65, Lag\_CDD60 |  |
| 14 | CDH60\_MA3, Lag\_CDD60 |  |
| 15 | CDH65\_MA3, Lag\_CDD60 |  |
| 16 | CDH60, Mean17 |  |
| 17 | CDH65, Mean17 |  |

The model specifications tested for non-weather sensitive customers do not include any weather variables, but have different combinations of non-weather-related variables. The variables include combinations of indicator variables and interactions of month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is shown in Table A.5, where an “X” between two variables represents the interaction of these two variables. Each specification includes the following variables in common: hour indicators, day type indicators, and events interacted with hour indicators. For the *ex-ante* analysis, we exclude the specifications with the morning load variable.

Table A.5: Variables Included in the Tested Specifications   
for Non-Weather Sensitive Customers

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

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

1. Ability to predict usage on event-like *non-event days*. Specifically, we identified a set of days that were similar to event days, but were not called as event days (*i.e.*, “test days”). The use of non-event test days allows us to test model performance against known “reference loads,” or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for all of the test days. The model fit (*i.e.*, the difference between the actual and predicted loads on the test days, during afternoon hours in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.
2. Performance on *synthetic* event days (*e.g.*, event-like non-event days that are treated as event days in estimation), to test for “event” coefficients that demonstrate statistically significant bias, as opposed to expected non-significance, since customers have no reason to modify usage on days that are not actual events. This is an extension of the previous test. The same test days are used, with a set of hourly “synthetic” event variables included in addition to the rest of the specification to test whether non-zero load impacts are estimated for these days. A successful test involves synthetic event load impact coefficients that are not statistically significantly different from zero.

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

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

We selected days according to the average typical event-hours, omitting holidays, weekends, and event days for programs in which DBP customers are dually enrolled (*e.g.*, BIP). For the most part, the selection involved selecting the hottest qualifying days. Table A.6 lists the event-like non-event days selected.

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

|  |  |  |
| --- | --- | --- |
| **PG&E** | **SCE** | **SDG&E** |
| 5/2/2017 | 5/2/2017 | 6/26/2017 |
| 5/23/2017 | 5/4/2017 | 6/27/2017 |
| 7/10/2017 | 5/22/2017 | 7/6/2017 |
| 7/12/2017 | 5/23/2017 | 7/7/2017 |
| 7/14/2017 | 6/2/2017 | 8/2/2017 |
| 7/20/2017 | 6/15/2017 | 8/3/2017 |
| 7/21/2017 | 6/28/2017 | 8/28/2017 |
| 7/24/2017 | 7/3/2017 | 8/29/2017 |
| 7/26/2017 | 9/29/2017 | 8/30/2017 |
| 7/28/2017 |  | 9/11/2017 |
| 7/31/2017 |  |  |
| 8/25/2017 |  |  |
| 8/30/2017 |  |  |

### A.2.2 Results from Tests of Alternative Weather Specifications

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

The tests are conducted by estimating one model for every industry, weather sensitivity, specification (17 for weather sensitive customers, 5 for non-weather sensitive customers), and event-like day. Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Tables A.7 through A.9 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for each industry by weather sensitivity type (specified in Tables A.4 and A.5) for specifications in the *ex-post* analysis.

Table A.7: Specification Test Results for the *Ex-Post* analysis, PG&E

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 7 | 0.6% | 5.4% | 38 |
| 2. Manufacturing | 3 | -0.5% | 1.3% | 21 |
| 3. Wholesale, Transportation, Utilities | 7 | 0.0% | 4.0% | 20 |
| 4. Retail | 3 | 0.0% | 0.8% | 9 |
| 5. Offices, Hotels, Health, Services | 1 | 0.0% | 2.2% | 14 |
| 7. Institutional/Government | 5 | 0.0% | 3.1% | 4 |
| 8. Other | 5 | -0.7% | 2.6% | 1 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 1 | 0.0% | 2.1% | 88 |
| 2. Manufacturing | 1 | -0.5% | 2.9% | 74 |
| 3. Wholesale, Transportation, Utilities | 1 | 0.3% | 6.0% | 49 |
| 4. Retail | 3 | -0.4% | 9.2% | 1 |
| 5. Offices, Hotels, Health, Services | 5 | 1.4% | 5.4% | 5 |
| 8. Other | 3 | -1.2% | 4.9% | 7 |

Table A.8: Specification Test Results for the *Ex-Post* analysis, SCE

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 7 | 0.1% | 2.7% | 11 |
| 2. Manufacturing | 5 | 2.4% | 4.8% | 103 |
| 3. Wholesale, Transportation, Utilities | 4 | 0.8% | 3.8% | 35 |
| 4. Retail | 6 | -1.3% | 1.9% | 58 |
| 5. Offices, Hotels, Health, Services | 7 | 0.4% | 1.7% | 28 |
| 6. Schools | 4 | -0.9% | 3.7% | 4 |
| 7. Institutional/Government | 2 | -0.6% | 10.1% | 7 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 1 | -0.7% | 1.9% | 43 |
| 2. Manufacturing | 1 | 1.4% | 8.1% | 241 |
| 3. Wholesale, Transportation, Utilities | 2 | 1.6% | 9.6% | 34 |
| 4. Retail | 2 | 6.0% | 27.3% | 1 |
| 5. Offices, Hotels, Health, Services | 2 | 14.0% | 23.0% | 4 |
| 6. Schools | 2 | -4.5% | 18.0% | 1 |

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 7 | 80.7% | 102.2% | 1 |
| 2. Manufacturing | 7 | 2.0% | 9.4% | 1 |
| 4. Retail | 3 | 0.2% | 1.4% | 2 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 2 | 11.4% | 29.2% | 2 |

Tables A.10 through A.12 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and customer count of the winning specification for each industry by weather sensitivity type (specified in Tables A.4 and A.5) for specifications included in the *ex-ante* analysis.

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 6 | 2.6% | 6.7% | 38 |
| 2. Manufacturing | 2 | -1.0% | 2.1% | 21 |
| 3. Wholesale, Transportation, Utilities | 7 | 2.2% | 5.3% | 20 |
| 4. Retail | 1 | 0.0% | 0.7% | 9 |
| 5. Offices, Hotels, Health, Services | 7 | 0.0% | 2.2% | 14 |
| 7. Institutional/Government | 3 | 0.2% | 3.4% | 4 |
| 8. Other | 2 | -1.4% | 3.5% | 1 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 2 | -0.1% | 2.9% | 88 |
| 2. Manufacturing | 1 | -0.8% | 3.7% | 74 |
| 3. Wholesale, Transportation, Utilities | 2 | 0.9% | 6.2% | 49 |
| 4. Retail | 2 | -0.9% | 9.2% | 1 |
| 5. Offices, Hotels, Health, Services | 2 | 2.3% | 5.1% | 5 |
| 8. Other | 2 | 3.2% | 10.7% | 7 |

Table A.11: Specification Test Results for the *Ex-Ante* analysis, SCE

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 2 | 0.4% | 2.8% | 11 |
| 2. Manufacturing | 4 | 3.6% | 6.7% | 103 |
| 3. Wholesale, Transportation, Utilities | 4 | 1.4% | 3.0% | 35 |
| 4. Retail | 7 | -0.1% | 1.6% | 58 |
| 5. Offices, Hotels, Health, Services | 7 | 0.8% | 1.5% | 28 |
| 6. Schools | 7 | 4.0% | 7.8% | 4 |
| 7. Institutional/Government | 7 | 6.6% | 12.7% | 7 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 1 | 0.5% | 1.5% | 43 |
| 2. Manufacturing | 1 | 2.7% | 8.8% | 241 |
| 3. Wholesale, Transportation, Utilities | 2 | 1.7% | 9.2% | 34 |
| 4. Retail | 2 | 2.4% | 19.2% | 1 |
| 5. Offices, Hotels, Health, Services | 2 | 13.1% | 22.4% | 4 |
| 6. Schools | 1 | -4.5% | 18.0% | 1 |

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Group** | **Industry Type** | **Selected Specification** | **MPE** | **MAPE** | **Number of Customers** |
| Weather Sensitive | 1. Agriculture, Mining, Construction | 3 | 92.7% | 115.3% | 1 |
| 2. Manufacturing | 2 | 2.1% | 9.3% | 1 |
| 4. Retail | 1 | 0.9% | 1.8% | 2 |
| Non-Weather Sensitive | 1. Agriculture, Mining, Construction | 1 | 11.4% | 29.2% | 2 |

### A.2.3 Synthetic Event Day Tests

For the specification selected using the testing described in Section A.2.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data by industry and weather sensitivity (averaged across all applicable customers), including a set of 24 hourly “synthetic” event-day variables. These variables equaled one on the days listed in Table A.6, with a separate estimate for each hour of the day.

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

Table A.13 presents the results of this test, showing the percentage of statistically significant synthetic event-day coefficients for each hour during the event window (hours not in the event are represented with a “n/a”). The synthetic event-day load impacts are estimated using the chosen model specification shown in Tables A.7 through A.9. The “Average Event Hour” row at the bottom of the table shows the percentage of statistically significant estimates across all event hours. As the table shows, the models perform quite well on this test.

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Hour** | **Percent Statistically Significant** | | |
| **PG&E** | **SCE** | **SDG&E** |
| 12 | n/a | n/a | 0.0% |
| 13 | n/a | n/a | 33.3% |
| 14 | n/a | n/a | 0.0% |
| 15 | n/a | n/a | 0.0% |
| 20 | 0.0% | 10.2% | n/a |
| 21 | 0.0% | 10.2% | n/a |
| 22 | n/a | 15.1% | n/a |
| Average Event Hour | 0.0% | 11.8% | 8.3% |

## A.3 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.1 through A.3 illustrate each utility’s average predicted and observed loads across the event-like days using the specification chosen (by industry and weather sensitivity) for each customer. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

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

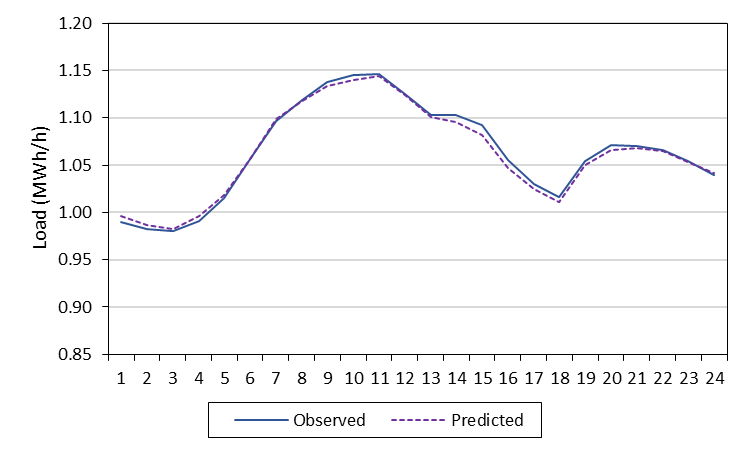


Figure A.2: Average Predicted and Observed Loads on Event-like Days, SCE

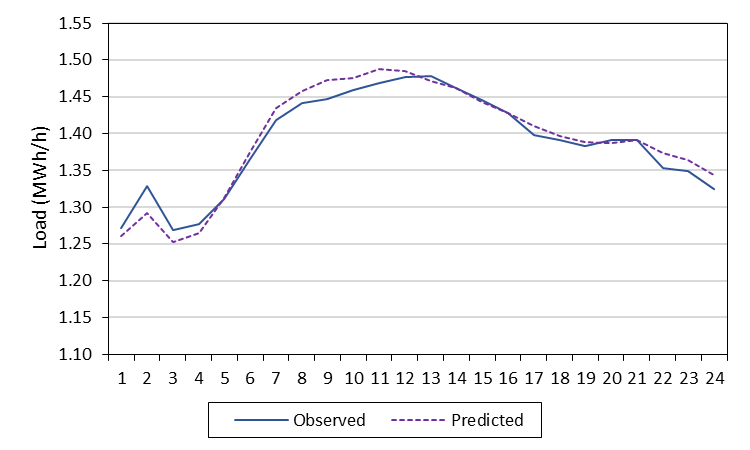
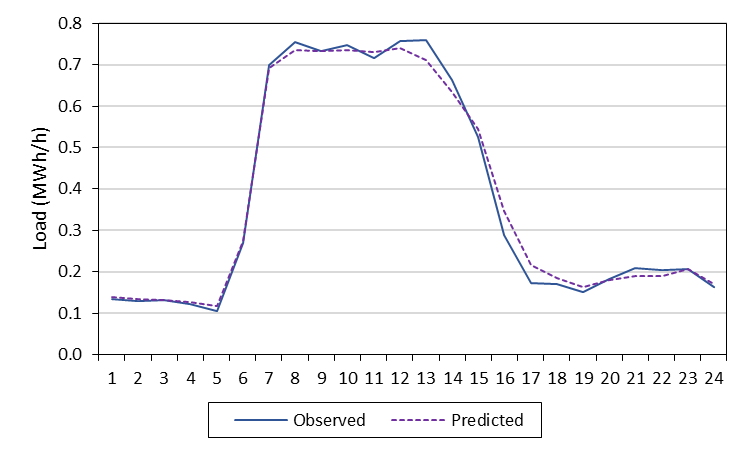


Figure A.3: Average Predicted and Observed Loads on Event-like Days, SDG&E



# Appendix B. FSL Achievement by Industry Group

This appendix contains tables showing the FSL achievement by industry group and hour (relative to the called event window) for the events used as the basis for the *ex-ante* load impacts. 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: May 3, 2017 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** |
| 1. Agriculture, Mining, Construction |  |  |  |  |
| 2. Manufacturing | 40.4% | 76.8% | 70.2% | 55.3% |
| 3. Wholesale, Transportation, Utilities |  |  |  |  |
| 4. Retail |  |  |  |  |
| 5. Offices, Hotels, Health, Services |  |  |  |  |
| 7. Institutional/Government |  |  |  |  |
| 8. Other |  |  |  |  |

(HE20, HE21, HE22, HE23 shown. Note that HE22 is a partial event hour because the event ended at 9:25 p.m.)

Table B.2: May 3, 2017 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** |
| 1. Agriculture, Mining, Construction |  |  |  |  |
| 2. Manufacturing | 1.1% | 52.8% | 79.6% | 49.3% |
| 3. Wholesale, Transportation, Utilities |  |  |  |  |
| 4. Retail | -2.7% | 4.2% | 3.8% | -3.0% |
| 5. Offices, Hotels, Health, Services |  |  |  |  |
| 7. Institutional/Government |  |  |  |  |
| 8. Other |  |  |  |  |

(HE19, HE20, HE21, and HE22 are shown. Note that HE22 is a partial event hour because the event ended at 9:18 p.m.)

Table B.3: August 31, 2017 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** |
| 1. Agriculture, Mining, Construction | 16.3% | 99.8% | 99.8% | 102.0% |
| 2. Manufacturing | n/a | 238.7% | n/a | -62.6% |
| 3. Wholesale, Transportation, Utilities | n/a | n/a | n/a | n/a |

(HE11, HE12, HE15, HE16 shown. “n/a” indicates total reference load is below the FSL.)

1. A customer’s coincident maximum demand (“Enrolled Load” in Figures ES.1-3) is defined as its demand during the hour with the highest aggregate demand on the typical event day, including the estimated load impacts (*i.e.*, using the reference loads). [↑](#footnote-ref-1)
2. Previously SDG&E offered a BIP option B which required that participating customer be notified at least three hours before the event but SDG&E discontinued this option in 2012. [↑](#footnote-ref-2)
3. Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently seven LCAs within PG&E’s service area, 3 in SCE’s service territory, and 1 representing SDG&E’s entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA. [↑](#footnote-ref-3)
4. "Enrollment" is defined as the enrollment on the May 3, 2017 event day for PG&E and SCE; and the August 31, 2017 event day for SDG&E. [↑](#footnote-ref-4)
5. Customer-level demand (“Sum of Max MW” in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 4—demand during the hour with the highest aggregate demand that day—including the estimated load impacts (*i.e.*, using the reference loads). [↑](#footnote-ref-5)
6. "Sum of Max MW" is defined as the sum of the event-day coincident maximum demands across service accounts. The reported values include the estimated load impacts. [↑](#footnote-ref-6)
7. "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts." [↑](#footnote-ref-7)
8. 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. [↑](#footnote-ref-8)
9. The summer pricing season is June through September for SCE, June through October for SDG&E, and May through October for PG&E. [↑](#footnote-ref-9)
10. The May 3, 2017 event day was called from 8:00 to 9:25 p.m., so the second hour of the average load impact for that event day corresponds to a partial event hour. However, the estimated load impact during that hour is actually higher than the estimated load impact during the full event hour that preceded it. [↑](#footnote-ref-10)
11. ------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------- [↑](#footnote-ref-11)
12. Note that customers were notified at 6:58 p.m. but not required to meet their FSLs until 15 to 30 minutes later, and the event ended at 9:25 p.m. Therefore, hour-ending 21 (8:00 to 9:00 p.m.) is the only hour for which customers were required to meet their FSLs during the entire hour. For this reason, hour-ending 21 alone is used to calculate all event-hour summary measures for SCE’s one event. [↑](#footnote-ref-12)
13. In particular, where CDH60 and CDH60\_MA24, the 24-hour moving average of CDH60, are used together for summer *ex-post* regressions, only CDH60 is used for the *ex-ante* models. Similarly, where CDH60\_MA3, the three-hour moving average, is used for *ex-post* regressions, CDH60 is used for the *ex-ante* analysis. See Appendix A for weather variable details. [↑](#footnote-ref-13)
14. It is not possible to calculate an achievement rate for customers with reference loads below their FSLs throughout an event period—the event effectively has no effect on them. [↑](#footnote-ref-14)
15. Recall that the *ex-ante* set of specifications eliminate the use of morning load variables as well as weather variables using information from prior days. [↑](#footnote-ref-15)
16. THI = *T* – 0.55 x (1 – *HUM*) x (*T* – 58) if *T*>=58 or THI = *T* if *T*<58, where *T* = ambient dry-bulb temperature in degrees Fahrenheit and *HUM* = relative humidity (where 10 percent is expressed as “0.10”). [↑](#footnote-ref-16)
17. HI = *c*1 + *c*2*T* + *c*3*R* + *c*4*TR* + *c*5*T*2 + *c*6*R*2 + *c*7*T*2*R* + *c*8*TR*2 + *c*9*T*2*R*2 + *c*10*T*3 + *c*11*R*3 + *c*12*T*3*R* + *c*13*TR*3 + *c*14*T*3*R*2 + *c*15*T*2*R*3 + *c*16*T*3*R*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>. [↑](#footnote-ref-17)
18. Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station. [↑](#footnote-ref-18)
19. Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station. [↑](#footnote-ref-19)