2015 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-Post and Ex-Ante* Report

Public Version

CALMAC Study ID PGE0378

Daniel G. Hansen
Michael Ty Clark

April 1, 2016

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299

Voice 608.231.2266 Fax 608.231.2108

Table of Contents

Tables

Figures

Abstract

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Demand Bidding Program ("DBP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and an *ex-ante* forecast of load impacts for 2016 through 2026 that is based on utility enrollment forecasts and the *ex-post* load impacts estimated for program years 2013 through 2015.

The DBP is a voluntary bidding program that offers qualified participants the opportunity to receive incentive payments for reducing their energy usage when an event is triggered. Incentive payments are based on the difference between the customers' actual metered load during an event to a 10-in-10 baseline load that is calculated from each customer's usage data prior to the event. For the most part, customers are notified of events by 12:00 noon on the previous day. Day-of notice is provided for one of SDG&E's two DBP schedules.

PG&E called fifteen events. All but one event (August 26) was called for PG&E's entire service territory and the event hours varied across days. The events with the most common event window (hours-ending 14 to 21, or 1:00 p.m. to 9:00 p.m.) were selected to represent the typical event day, as defined for Protocol table purposes. SCE called ten eight-hour events from hours ending 13 through 20. SDG&E did not call any events in the 2015 program year. Average enrollment in PG&E's DBP decreased from 846 service accounts in PY2014 to 503 in PY2015. Enrollment in SCE's DBP fell from 944 service accounts in PY2014 to 794 in PY2015. The sum of enrolled customers' coincident maximum demands was 583 MW for PG&E and 705 MW for SCE. Each of SDG&E's programs consisted of a single customer, with multiple service accounts associated with each of them.

As in previous years, for most events only a portion of the enrolled customer accounts submitted bids. For PG&E, 107 service accounts submitted a bid for at least one event. At SCE, 558 individual and lead service accounts submitted at least one bid during 2015.

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. DBP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models.

The average program-level load impact for PG&E's full-dispatch events was 19 MW, or 3.3 percent of enrolled load. Event-specific load impacts ranged from a low of 10 MW to a high of 39 MW. Nearly all of the load impacts were provided by customers dually enrolled in another DR program. For SCE, average hourly program load impacts

averaged approximately 100 MW across ten events, amounting to 14.1 percent of the total reference load. The event-specific load impacts ranged from a low of 77 MW to a high of 131 MW.

In the *ex-ante* evaluation, SCE forecasts DBP customer enrollment to be 801 service accounts in 2016, with the program ending in 2016. PG&E forecasts DBP enrollment to drop slightly to 493 service accounts in 2016 and remain at that level through the 2016 to 2026 forecast period. PG&E's program-level load impacts are forecast to be 26.7 MW during a utility-specific 1-in-2 August peak day. The corresponding forecast for SCE is 112.3 MW. For both PG&E and SCE, the portfolio-level load impacts are substantially less than the program-level load impacts because of the high level of load response provided by customers dually enrolled in the Base Interruptible Program (BIP) and aggregator programs (*e.g.*, the Capacity Bidding Program or Aggregator Managed Portfolio). For SCE, the portfolio-level load impact is 6.6 MW in 2016. For PG&E, the portfolio-level load impact is 1.4 MW during a utility-specific 1-in-2 August peak day.

Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Demand Bidding Program ("DBP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and *ex-ante* forecasts of load impacts for 2016 through 2026 that are based on utility enrollment forecasts and the *ex-post* load impacts estimated for program years 2013 through 2015.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2015?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across local capacity areas?
4. What were the effects of Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) on customer-level load impacts?
5. What are the *ex-ante* load impacts for 2015 through 2025?

ES.1 Resources covered

Demand Bidding Program

The DBP is a voluntary bidding program that offers qualified participants the opportunity to receive incentive payments for reducing their energy usage when an event is triggered. First approved in CPUC D.01-07-025, modifications have been made to the program, including changes made for the 2006-2008 program cycle, at the direction of the CPUC in D.05-01-056. In that decision, the IOUs were directed to continue the DBPs. In addition, a new SDG&E DBP was authorized by resolution E-4511 on July 17, 2012 in response to the fact that San Onofre Nuclear Generating Station Unit 3 is offline.

The DBP is designed for non-residential bundled service, Community Choice Aggregation, and Direct Access ("DA") customers. Customers must have internet access and communicating interval metering or SmartMeter™ approved by each of the IOUs. A DBP event may occur at any time throughout the year. With the exception of one of SCE's DBPs (which offers day-of event notification), customers are given day-ahead notification of event days. At PG&E and SCE, DBP customers may participate in another demand response (DR) program, but that DR program must be a capacity-paying program with same day notification (*e.g.*, Base Interruptible Program or Capacity Bidding Program). For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of the DBP event.

PG&E called fifteen events. All but one event (August 26) was called for PG&E's entire service territory and the event hours varied across days. The events with the most common event window (hours-ending 14 to 21, or 1:00 p.m. to 9:00 p.m.) were selected to represent the typical event day, as defined for Protocol table purposes. SCE called ten eight-hour events from hours ending 13 through 20. SDG&E did not call any events in the 2015 program year.

Enrollment

Average enrollment in PG&E's DBP decreased from 846 service accounts in PY2014 to 503 in PY2015. The sum of enrolled customers' coincident maximum demands was 583 MW, or 1.16 MW for the average service account. Two industry groups made up approximately sixty percent of PG&E's DBP enrollment: manufacturing; and offices, hotels, health, services.

Enrollment in SCE's DBP fell from 944 service accounts in PY2014 to 794 in PY2015. These accounted for a total of 705 MW of maximum demand, or 0.89 MW per service account. Manufacturers continued to make up more than half of the enrolled load.

SDG&E's DBP-DO and DBP-DA programs each consist of service accounts associated with a single large customer.

Bidding Behavior

As in previous years, for most events only a portion of the enrolled customer accounts submitted bids. For PG&E, 107 service accounts submitted a bid for at least one event. At SCE, 558 individual and lead service accounts submitted at least one bid during 2015.

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.

DBP 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 averaged 19 MW, or 3.3 percent of enrolled load, for system-wide events. Event-specific load impacts ranged from a low of 10 MW to a high of 39 MW. Nearly all of the load impacts were provided by customers dually enrolled in another DR program. This is down from the 25 MW average load impact from the previous program year.

For SCE, average hourly program load impacts averaged approximately 100 MW across ten events, amounting to 14.1 percent of the total reference load. The event-specific load impacts ranged from a low of 77 MW to a high of 131 MW.

SDG&E did not call any DBP event dates during the 2015 program year.

ES.4 TA/TI and AutoDR Effects

We separately summarized average event-hour load impacts for customers participating in the Technical Assistance and Technology Incentives (TA/TI) program or the Automated Demand Response (AutoDR) program. For PG&E, an average of one TA/TI service account bid in each DBP event and provided an average of 0.9 MW of load impacts. For AutoDR, an average of 16 DBP service accounts bid in each event. The average hourly load impact for those accounts was 10.6 MW, or 22.7 percent of the reference load. For SCE, an average of 174 DBP service accounts participated in TA/TI, with an average of 28 of them submitting a bid during each event. The load impacts from TA/TI participants averaged 13.9 MW, or 17 percent of the total reference load (including TA/TI participants that did not submit a bid). Approximately 242 of SCE's DBP service accounts participated in AutoDR, with an average of 166 submitting bids during each event. Load impacts from these customers averaged 29.1 MW across the ten event days, or 15.4 percent of the total reference load.

ES.5 Ex-ante Load Impacts

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

PG&E forecasts DBP enrollment to drop slightly to 493 service accounts in 2016 and remain at that level through the 2016 to 2026 forecast period. SCE forecasts DBP customer enrollment to be 801 service accounts in 2016, with the program ending in 2016. SDG&E forecast 2016 enrollment consists of the currently enrolled customers, after which the program ends.

For the 2016 program year, SCE's average event-hour load impact is approximately 112.3 MW during a utility-specific 1-in-2 August peak day. PG&E's program-level load impacts are forecast to be 26.7 MW during a utility specific 1-in-2 August peak day. For both PG&E and SCE, the portfolio-level load impacts are substantially less than the program-level load impacts because of the high level of load response provided by customers dually enrolled in the Base Interruptible Program (BIP) and aggregator programs (*e.g.*, the Capacity Bidding Program or Aggregator Managed Portfolio). For SCE, the portfolio-level load impact is 6.6 MW in 2016. For PG&E, the portfolio-level load impact is 1.4 MW during a utility specific 1-in-2 August peak day.

Figures ES.1 and ES.2 show *ex-ante* load impacts for 2015 for PG&E and SCE, respectively, indicating large differences between *program-level* load impacts (which include all customers enrolled in DBP) and *portfolio-level* load impacts (which exclude customers dually enrolled in the Base Interruptible Program, or BIP and aggregator programs, including the Capacity Bidding Program), and smaller differences between weather scenarios.

Figure ES.1: Average August *Ex-ante* Load Impacts by Scenario, PG&E

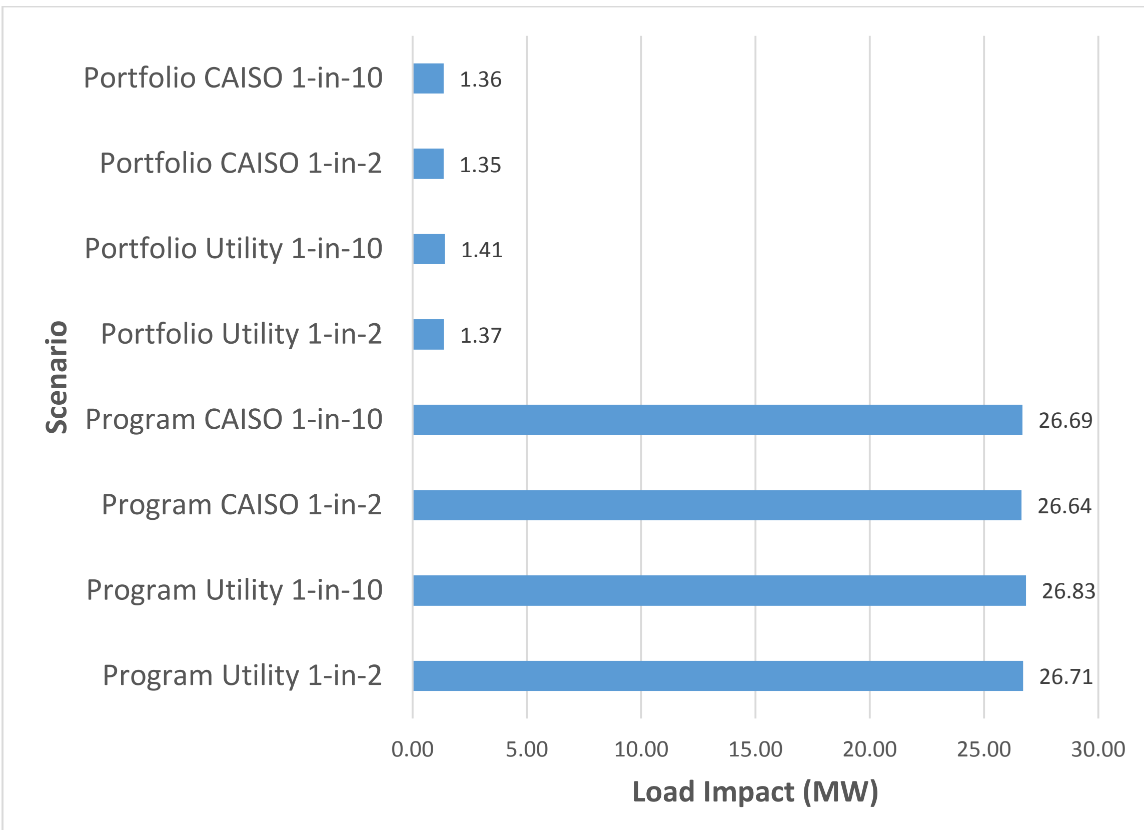
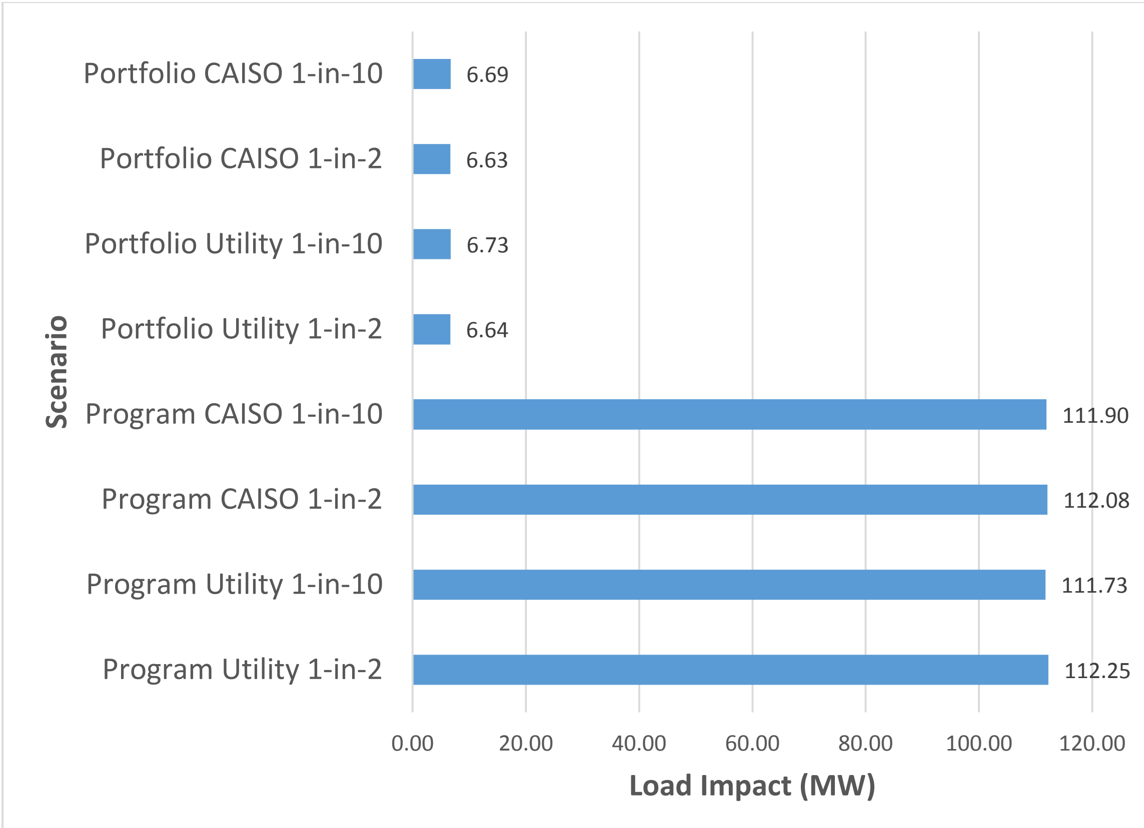


Figure ES.2: Average August *Ex-ante* Load Impacts by Scenario, SCE



1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide Demand Bidding Program ("DBP") in place at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2015. The report provides estimates of *ex-post* load impacts that occurred during events called in 2015 and an *ex-ante* forecast of load impacts for 2016 through 2026 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for program years 2013 through 2015. Note that SDG&E did not call any DBP events during 2015, so the report contains only an *ex-ante* forecast for their programs.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2015?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) on customer-level load impacts?
5. What are the *ex-ante* load impacts for 2016 through 2026?

The report is organized as follows: Section 2 contains a description of the programs, the enrolled customers, and the events called; Section 3 describes the methods used in the study; Section 4 contains the detailed *ex-post* load impact results, including estimates of TA/TI and AutoDR customer load impacts; Section 5 describes the *ex-ante* load impact forecast; Section 6 contains descriptions of differences in various scenarios of *ex-post* and *ex-ante* load impacts; and Section 7 provides recommendations. Appendix A contains an assessment of the validity of the study.

2. Description of Resources Covered in the Study

This section provides details on the Demand Bidding Programs, including the incentives paid, the characteristics of the participants enrolled in the programs, and the events called in 2015.

2.1 Program Descriptions

The DBP is a voluntary bidding program that offers qualified participants the opportunity to receive incentive payments for reducing their energy usage when an event is triggered. First approved in CPUC D.01-07-025, modifications have been made to the program, including changes made for the 2006-2008 program cycle, at the direction of the CPUC in D.05-01-056. In that decision, the IOUs were directed to continue the DBPs. In addition, a new SDG&E DBP was authorized by resolution E-4511 on July 17, 2012 in response to the fact that San Onofre Nuclear Generating Station Unit 3 is offline.

The DBP is designed for non-residential bundled service, Community Choice Aggregation, and Direct Access ("DA") customers. Customers must have internet access and communicating interval metering or SmartMeter™ approved by each of the IOUs. A DBP event may occur at any time throughout the year. With the exception of one of SCE's DBPs (which offers day-of event notification), customers are given day-ahead notification of event days. At PG&E and SCE, DBP customers may participate in another demand response (DR) program, but that DR program must be a capacity-paying program with same day notification (*e.g.*, Base Interruptible Program or Capacity Bidding Program). For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of the DBP event.

PG&E's Demand Bidding Program

PG&E's DBP is available to time-of-use customers with billed maximum demands of 50 kW or higher who commit to reduce load by a minimum of 10 kW for two consecutive hours during an event. Eligible customers must have an interval meter or SmartMeter™ capable of recording usage in 15-minute or shorter intervals and read remotely by PG&E. PG&E will provide and install the metering and communication equipment at no cost to the customers with a maximum demand of 200 kW or greater for at least one month in the past 12 billing months, except for DA customers. In the past, customers were allowed to aggregate service accounts for bidding and settlement purposes, but this is no longer allowed as of December 31, 2014.

The DBP operates year-round and can be called from 6:00 a.m. to 10:00 p.m. on weekdays, excluding holidays. Only one event may be called per day and the event duration may be four hours to eight hours. There is no limit to the number of days on which events may be called. Notification of an event day is provided on a day-ahead basis. Events are triggered with a California ISO Alert Notice for the following day when the peak demand forecast is 43,000 MW or greater, or when PG&E, in its own opinion, forecasts that resources may not be sufficient, forecasted temperature for a Load Zone exceeds the temperature threshold for that Load Zone, or to address a transmission or distribution reliability need. PG&E may also call up to two Demand Bidding test events per customer, per year. When an event is dispatched, enrolled customers may submit a load reduction bid or not participate without an excess energy charge.

The incentive payment is $0.50 per kWh reduced below the 10-in-10 baseline. Customers must reduce load by a minimum of 50 percent of their bid amount to qualify for an incentive, and they are paid for load reductions up to 150 percent of their bid amount. The hourly baseline for measuring load reductions is calculated as the average usage from the corresponding hour on the previous ten qualifying days (non-holiday, non-event weekdays), with the customer having the option to include a day-of adjustment based on their usage in pre-event hours. There is no charge for failing to comply with the terms of the submitted bid. Each bid must be for a minimum of two consecutive hours during the event. Bids must meet the threshold of 10 kW load reductions for each hour and customers may submit only one bid for each event notification.

Although PG&E customers enrolled in the DBP may participate in other DR programs (Day-of notice in AMP, CBP, BIP, and OBMC), they do not receive a day-ahead DBP incentive payment for those hours in which a day-of event from another DR program in which the customer is enrolled occur simultaneously.

SCE's Demand Bidding Program

SCE's DBP design is similar to PG&E's, with three exceptions: enrolled customers are required to commit to a minimum load reduction of 1 kW (versus 10 kW at PG&E); bidding customers are paid for load reductions up to twice their bid amount; and event hours are limited to 12:00 p.m. through 8:00 p.m. DBP participants may also participate in AP-I, BIP, SDP, CBP, or AMP (formerly DRC). However, the customer will not receive DBP incentive payments during overlapping event hours. In addition, SCE allows customers to aggregate loads across service accounts for settlement purposes. (PG&E discontinued this practice at the end of 2014.)

SDG&E's Demand Bidding Program

SDG&E has two Demand Bidding Programs described below:

Schedule DBP-DA: Schedule DBP-DA provides day-ahead notice of event days. This program is applicable to customers who are capable of providing at least a 2 MW load reduction based on the customer's specific baseline. The DBP-DA incentive is $0.40 per kWh for customers who purchase commodity from the utility (bundled customers).

Schedule DBP-DO: Demand/energy bidding program offers incentives to nonresidential customers for reducing energy consumption and demand during a specific Demand Bidding Event. This program is applicable to customers who are capable of providing at least a 5 MW load reduction based on the customer's specific baseline. The DBP-DA incentive is $0.50 per kWh for customers who purchase commodity from the Utility (bundled customers).

Schedule DBP-DO and DBP-DA programs are available year-round and there is no limit to the number of Demand Bidding Events per month or per year. A customer may not participate simultaneously in DBP-DA or DBP-DO and any other Demand Response rate or program. SDG&E will end these programs in 2016.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

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

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

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[1] Note that while we report load impacts by LCA as required by the Protocols, PG&E's DBP was recently modified to allow for locational dispatch, where the locations are determined by sub-LAP.[2]

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows DBP enrollment by industry group for PG&E on the average event day. Enrollment in PG&E's DBP decreased relative to PY2014, from 846 to 503 in 2015.[3] The sum of enrolled customers' coincident maximum demands[4] was 583 MW, or 1.16 MW for the average service account. Two industry groups made up approximately 60 percent of PG&E's DBP enrollment: manufacturing; and offices, hotels, health, services. Note that some results have been removed due to confidentiality concerns.

[1] Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently seven LCAs within PG&E's service area, 3 in SCE's service territory, and 1 representing SDG&E's entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA.

[2] In Ordering Paragraph 10 of Decision 12-06-025, dated June 21, 2012, the California Public Utility Commission (CPUC or Commission) stated the following: Pacific Gas and Electric Company's Aggregator Managed Program, Capacity Bidding Program and Demand Bidding Program shall be counted for Resource Adequacy in the 2013 Resource Adequacy compliance year. These programs must be locally dispatchable by May 1, 2013.

[3] "Enrollment" is defined as the average enrollment on event days during the 2015 program year.

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

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

Industry Type	# of Service Accounts	Sum of Max MW[5]	% of Max MW	Ave. Max MW[6]
1.Agriculture, Mining, Construction	60	45	7.8%	0.76
2.Manufacturing	160	283	48.6%	1.77
3.Wholesale, Transportation, Utilities	77	48	8.2%	0.62
4.Retail	[redacted]			
5.Offices, Hotels, Health, Services	148	144	24.7%	0.97
6.Schools	[redacted]			
7. Entertainment, Other Services, Government.	38	51	8.8%	1.34
8.Other	[redacted]			
TOTAL	**503**	**583**		**1.16**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP averaged 794 service accounts across the PY2015 event days, which is a significant decrease relative to the average of 944 enrolled service accounts across the PY2014 event days. The enrolled customers accounted for a total of 705 MW of maximum demand, or 0.89 MW per service account. Manufacturers continued to make up more than half of the enrolled load. Note that some results have been removed due to confidentiality concerns.

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

Industry Type	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
1.Agriculture, Mining, Construction	[redacted]			
2.Manufacturing	157	410.0	58.1%	2.62
3.Wholesale, Transportation, Utilities	86	44.6	6.3%	0.52
4.Retail	231	42.1	6.0%	0.18
5.Offices, Hotels, Health, Services	166	107.1	15.2%	0.64
6.Schools	99	14.2	2.0%	0.14
7. Entertainment, Other Services, Government.	[redacted]			
TOTAL	**794**	**705.2**		**0.89**

Tables 2.3 and 2.4 show DBP enrollment by local capacity area for PG&E and SCE, respectively. Note that some results have been removed due to confidentiality concerns.

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

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
Greater Bay Area	226	222	38.2%	0.98
Greater Fresno	[redacted]			
Humboldt				
Kern				
Northern Coast				
Not in any LCA	160	272	46.7%	1.71
Sierra	[redacted]			
Stockton				
TOTAL	**503**	**583**		**1.16**

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
LA Basin	650	460.9	65.3%	0.71
Outside LA Basin	[redacted]			
Ventura				
TOTAL	**794**	**705.3**		**0.89**

Tables 2.5 and 2.6 summarize average event-day bidding behavior by industry group. The average hourly bid is calculated first at the customer level, only over the hours in which the customer submitted a bid. The customer-level averages are then summed within industry group to arrive at the values in the tables. For both utilities, the manufacturing industry group had the highest amount of load that submitted a bid. Note that the total bid amounts shown in this table exceed the amount bid during any one event hour. A summary of bid amounts by event is included in Section 4. Some results have been removed due to confidentiality concerns.

Table 2.5: DBP Bidding Behavior, *PG&E*

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW[7]
1.Agriculture, Mining, Construction	[redacted]		
2.Manufacturing	27	30.5	10.8%
3.Wholesale, Transportation, Utilities	[redacted]		
4.Retail			
5.Offices, Hotels, Health, Services	27	4.0	2.8%
6.Schools	[redacted]		
7. Entertainment, Other Services, Government.			
TOTAL	**107**	**44.9**	**7.7%**

[7] "% of Enrolled Max MW" is calculated as "Avg. Hourly Bid MW" divided by the "Sum of Max MW" for the corresponding industry group in Table 2.1.

Table 2.6: DBP Bidding Behavior, *SCE*

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW
1.Agriculture, Mining, Construction	[redacted]		
2.Manufacturing	140	104.7	25.5%
3.Wholesale, Transportation, Utilities	86	17.5	39.3%
4.Retail	104	26.6	63.1%
5.Offices, Hotels, Health, Services	105	15.2	14.2%
6.Schools	77	6.8	48.2%
7. Entertainment, Other Services, Government.	[redacted]		
TOTAL	**558**	**179.0**	**25.4%**

SDG&E's programs each consist of service accounts associated with a single large customer. In the interest of customer confidentiality, we do not provide its LCA, industry group, or usage statistics.

2.3 Event Days

Tables 2.7a and 2.7b list DBP event days for the 2015 program year. As shown in Table 2.7a, PG&E called fifteen events. All but one event (August 26) was called for PG&E's entire service territory and the event hours varied across days. The events with the most common event window (hours-ending 14 to 21, or 1:00 p.m. to 9:00 p.m.) were selected to represent the typical event day, as defined for Protocol table purposes.[8]

As shown in Table 2.7b, SCE called ten eight-hour events from hours ending 13 through 20 (12:00 p.m. to 8:00 p.m.), all of which were called for SCE's entire service territory. Because SCE's event hours do not change across event days, all of the event days are included in the typical event day calculations.

Finally, SDG&E did not call any DBP event days during the 2015 program year.

[8] The inclusion of events with consistent event hours allows for the typical event day to display a more easily interpreted pattern of hourly load impacts.

Table 2.7a: PG&E DBP Event Days

Date	Day of Week	All Zones?	Start Hour	End Hour	Included as Typical Event Day
6/12/2015	Friday	Yes	17	21	
6/25/2015	Thursday	Yes	15	22	
6/26/2015	Friday	Yes	14	21	x
6/30/2015	Tuesday	Yes	14	21	x
7/1/2015	Wednesday	Yes	14	21	x
7/28/2015	Tuesday	Yes	15	22	
7/29/2015	Wednesday	Yes	15	22	
8/17/2015	Monday	Yes	15	21	
8/18/2015	Tuesday	Yes	14	21	x
8/26/2015	Wednesday	No	16	21	
8/27/2015	Thursday	Yes	15	21	
8/28/2015	Friday	Yes	16	19	
9/9/2015	Wednesday	Yes	14	21	x
9/10/2015	Thursday	Yes	14	21	x
9/11/2015	Friday	Yes	15	20	

Table 2.7b: SCE DBP Event Days

Date	Day of Week	All Zones?	Start Hour	End Hour	Included as Typical Event Day
7/1/2015	Wednesday	Yes	13	20	x
7/29/2015	Wednesday	Yes	13	20	x
7/30/2015	Thursday	Yes	13	20	x
8/17/2015	Monday	Yes	13	20	x
8/26/2015	Wednesday	Yes	13	20	x
8/27/2015	Thursday	Yes	13	20	x
8/28/2015	Friday	Yes	13	20	x
9/9/2015	Wednesday	Yes	13	20	x
9/10/2015	Thursday	Yes	13	20	x
9/11/2015	Friday	Yes	13	20	x

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 DBP hour 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[9]

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

3.2 Description of methods

3.2.1 Regression Model

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

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

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

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

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

The *OtherEvt* variables help the model explain load changes that occur on event days for programs in which the DBP 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. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of an event) for factors that affect pre-event usage, but are not accounted for by the other included variables.

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

Separate models were estimated for each customer. The load impacts were aggregated across customer accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group and local capacity area (LCA).

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.

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

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

In order to develop the uncertainty-adjusted load impacts associated with the *average* event hour (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), we estimated three additional sets of customer-specific regression models. In the first model, we estimated the average event-hour load impact for *each* event-day, by using a single event variable (rather than the hour-specific variables used in the primary model described above). The standard errors associated with these event-specific coefficients serve as the basis of the average event-hour uncertainty-adjusted load impacts for each *ex-post* event day, which are shown on the last row of event-specific tables. The second model includes a single set of 24 event-hour variables that apply to *all* event hours of the typical (or average) event day during the program year. The standard error associated with these estimates serve as the basis of the 24 event-hour uncertainty-adjusted load impacts for the typical *ex-post* event day. The third model includes a single event-hour variable that applies to *all* event hours of the typical (or average) event day during the program year. The standard error associated with this estimate serves as the basis of the average event-hour uncertainty-adjusted load impacts for the typical *ex-post* event day.[11] In each case, 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. These values are shown in the bottom row of the table for the typical event day.

4. Detailed Study Findings

The primary objective of the *ex-post* evaluation is to estimate the aggregate and per-customer DBP event-day load impacts for each IOU. In this section we first summarize the estimated DBP load impacts for each of the IOUs 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

[11] The typical event day is based on the average across all DBP event days for SCE. For PG&E, the typical event day includes event days with an hour-ending 14 to 21 event window and are not locationally dispatched.

figures that illustrate the reference loads, observed loads and estimated load impacts. The section concludes with an assessment of the effects of TA/TI and AutoDR.

On a summary level, the average event-hour load impact per enrolled customer was 37.9 kW for PG&E's program and 125.6 kW for SCE's program.

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 DBP events. Results are summarized separately across all customers (in the top panel) and those who were not dually enrolled in another DR program (in the bottom panel). The average hourly load impact across the events during which all DBP customers were called and that had an event window from hours-ending 14 to 21. (excluding the 6/12, 6/25, 7/28, 7/29, 8/17, 8/26, 8/27, 8/28, and 9/11 event days) was 19 MW, or an average of 3.3 percent of the total reference load. The load impacts were highest during the August 27th event, at 39.2 MW (6.7 percent of the reference load). The August 26th event day was a locationally dispatched event (*i.e.*, a subset of enrolled customers was called based upon location). The vast majority of the load impacts came from customers who were dually enrolled in another DR program and accounted for all but 1.5 MW of the average load impact on a typical event day. Note that some results have been removed due to confidentiality concerns.

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

Customer Group	Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
	1	6/12/2015	Friday	564.2	547.7	16.5	2.9%
	2	6/25/2015	Thursday	570.0	551.1	18.9	3.3%
	3	6/26/2015	Friday	574.0	557.8	16.2	2.8%
	4	6/30/2015	Tuesday	578.3	552.0	26.3	4.5%
	5	7/1/2015	Wednesday	578.0	559.6	18.4	3.2%
	6	7/28/2015	Tuesday	587.2	560.1	27.1	4.6%
	7	7/29/2015	Wednesday	589.0	566.9	22.1	3.7%
	8	8/17/2015	Monday	593.1	564.9	28.2	4.8%
All	9	8/18/2015	Tuesday	583.9	557.5	26.4	4.5%
	10	8/26/2015	Wednesday	[redacted]			
	11	8/27/2015	Thursday	585.4	546.2	39.2	6.7%
	12	8/28/2015	Friday	589.5	567.4	22.1	3.7%
	13	9/9/2015	Wednesday	596.1	582.9	13.2	2.2%
	14	9/10/2015	Thursday	587.9	574.1	13.8	2.3%
	15	9/11/2015	Friday	565.6	553.4	12.2	2.2%
	Average for Typical Event Day			**583.0**	**564.0**	**19.0**	**3.3%**
	Std. dev. for Typical Event Day					**7.5**	**1.3%**
	1	6/12/2015	Friday	287.5	286.8	0.6	0.2%
	2	6/25/2015	Thursday	285.8	284.9	0.9	0.3%
	3	6/26/2015	Friday	292.9	291.8	1.1	0.4%
	4	6/30/2015	Tuesday	302.1	300.1	2.0	0.7%
	5	7/1/2015	Wednesday	302.1	300.0	2.1	0.7%
	6	7/28/2015	Tuesday	310.7	310.1	0.7	0.2%
	7	7/29/2015	Wednesday	308.1	307.4	0.7	0.2%
Enrolled in DBP Only	8	8/17/2015	Monday	316.2	315.3	0.9	0.3%
	9	8/18/2015	Tuesday	306.4	306.3	0.0	0.0%
	10	8/26/2015	Wednesday	[redacted]			
	11	8/27/2015	Thursday	305.5	304.9	0.7	0.2%
	12	8/28/2015	Friday	312.5	311.1	1.3	0.4%
	13	9/9/2015	Wednesday	317.6	315.7	1.9	0.6%
	14	9/10/2015	Thursday	310.7	309.1	1.6	0.5%
	15	9/11/2015	Friday	301.8	300.6	1.2	0.4%
	Average for Typical Event Day			**305.3**	**303.8**	**1.5**	**0.5%**
	Std. dev. for Typical Event Day					**0.6**	**0.2%**

Table 4.2 compares the bid quantities to the estimated load impacts for each event. Across the events during which all customers were called, the bid amount averaged approximately 24.3 MW, while the estimated average hourly load impact was 20.7 MW. The average bid realization rate (i.e., the estimated load impacts as a percentage of bid amounts) across all event hours was 85 percent. The bid realization rate was lower for customers enrolled only in the DBP, averaging 72 percent across the event days for which all customers were called.

Table 4.2: Average Event-Hour Bid Realization Rates by Event, *PG&E*

Customer Group	Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
All	1	6/12/2015	Friday	19.2	16.5	86%
	2	6/25/2015	Thursday	23.4	18.9	81%
	3	6/26/2015	Friday	20.5	16.2	79%
	4	6/30/2015	Tuesday	28.7	26.3	92%
	5	7/1/2015	Wednesday	22.3	18.4	83%
	6	7/28/2015	Tuesday	29.5	27.1	92%
	7	7/29/2015	Wednesday	24.4	22.1	91%
	8	8/17/2015	Monday	31.9	28.2	88%
	9	8/18/2015	Tuesday	35.7	26.4	74%
	10	8/26/2015	Wednesday	[redacted]		
	11	8/27/2015	Thursday	35.9	39.2	109%
	12	8/28/2015	Friday	29.1	22.1	76%
	13	9/9/2015	Wednesday	16.9	13.2	78%
	14	9/10/2015	Thursday	17.1	13.8	81%
	15	9/11/2015	Friday	20.6	12.2	59%
	Average (excluding 8/26)			**24.3**	**20.7**	**85%**
Enrolled in DBP Only	1	6/12/2015	Friday	0.9	0.6	66%
	2	6/25/2015	Thursday	1.1	0.9	79%
	3	6/26/2015	Friday	1.4	1.1	78%
	4	6/30/2015	Tuesday	2.6	2	76%
	5	7/1/2015	Wednesday	2.6	2.1	81%
	6	7/28/2015	Tuesday	1.0	0.7	71%
	7	7/29/2015	Wednesday	1.4	0.7	51%
	8	8/17/2015	Monday	1.3	0.9	69%
	9	8/18/2015	Tuesday	1.4	0	0%
	10	8/26/2015	Wednesday	[redacted]		
	11	8/27/2015	Thursday	1.3	0.7	53%
	12	8/28/2015	Friday	1.9	1.3	69%
	13	9/9/2015	Wednesday	1.4	1.9	132%
	14	9/10/2015	Thursday	1.5	1.6	110%
	15	9/11/2015	Friday	1.5	1.2	78%
	Average (excluding 8/26)			**1.5**	**1.0**	**72%**

Table 4.3 summarizes average event-hour DBP load impacts at the program level (*i.e.*, including both bidders and non-bidders) and by industry group for PG&E's typical event day (consisting of the days during which the event was from hours-ending 14 to 21). The Manufacturing industry group accounted for the largest share of the load impacts, with a 15.5 MW average event-hour load reduction.

Table 4.3: Average Event-Hour Load Impacts – PG&E DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	60	45.3	45.6	-0.3	-0.7%
Manufacturing	160	283.2	267.6	15.5	5.5%
Wholesale, Transportation, & Other Utilities	77	48.0	46.2	1.8	3.8%
Retail Stores	[redacted]				
Offices, Hotels, Health, Services	148	143.5	142.2	1.3	0.9%
Schools					
Entertainment, Other Services, Government	38	51.5	50.8	0.6	1.3%
Other or Unknown	[redacted]				
Total	**503**	**583.0**	**564.0**	**19.0**	**3.3%**

Table 4.4 summarizes typical event day load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from service accounts not associated with any LCA. Note that some results have been removed due to confidentiality concerns.

Table 4.4: Average Event-Hour Load Impacts – PG&E DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	226	222.5	220.2	2.3	1.0%
Greater Fresno	[redacted]				
Humboldt					
Kern					
Northern Coast					
Not in any LCA	160	272.0	256.0	16.1	5.9%
Sierra	[redacted]				
Stockton					
Total	**503**	**583.0**	**564.0**	**19.0**	**3.3%**

4.1.2 Hourly Load Impacts

Table 4.5 presents PG&E's hourly DBP load impacts at the program level in the manner required by the Protocols. The DBP load impacts were estimated from the individual customer regressions for customers enrolled at the time of the event. The table only includes data and results from the events included in the typical event day (*i.e.*, events in which all DBP customers were called and have event window hours ending 14 to 21). The hourly load impact on the typical event day ranges from 15.5 MW to 22.5 MW.

PG&E has two very different types of customers in the DBP: those who are dually enrolled in another DR program (*e.g.*, Base Interruptible Program (BIP) or an aggregator program) and those who are not. The dually enrolled customers, particularly those enrolled in both the DBP and the BIP, tend to be larger and much more demand responsive than the customers who are only enrolled in the DBP. On average, dually enrolled customers account for 17.6 MW of the 19 MW total DBP load impact.

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

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	508.3	506.9	1.4	72.6	-1.2	0.4	1.4	2.5	4.0
2	502.8	501.1	1.7	71.2	-0.7	0.7	1.7	2.6	4.0
3	496.8	494.9	2.0	69.9	-0.1	1.1	2.0	2.8	4.0
4	495.7	492.9	2.7	68.7	0.6	1.9	2.7	3.6	4.9
5	505.7	503.4	2.3	67.8	0.3	1.5	2.3	3.1	4.3
6	527.4	525.4	2.0	66.9	-0.2	1.1	2.0	2.8	4.1
7	553.8	552.8	1.0	66.8	-1.1	0.2	1.0	1.9	3.2
8	571.3	571.9	-0.6	68.2	-2.7	-1.5	-0.6	0.3	1.5
9	586.5	587.5	-1.0	71.8	-3.3	-1.9	-1.0	0.0	1.3
10	598.6	600.2	-1.6	76.0	-4.1	-2.6	-1.6	-0.6	0.9
11	608.7	609.4	-0.7	80.2	-4.0	-2.1	-0.7	0.6	2.5
12	614.8	614.8	0.0	83.8	-3.1	-1.3	0.0	1.3	3.2
13	610.6	603.1	7.5	86.7	3.7	5.9	7.5	9.1	11.3
14	614.8	593.5	21.3	89.0	16.3	19.3	21.3	23.3	26.2
15	609.5	587.0	22.5	90.2	17.3	20.4	22.5	24.6	27.7
16	599.7	578.3	21.4	90.6	16.7	19.5	21.4	23.3	26.0
17	593.3	573.4	19.9	90.4	15.6	18.2	19.9	21.7	24.3
18	579.5	560.3	19.2	89.4	14.7	17.3	19.2	21.0	23.7
19	564.5	548.5	16.1	87.1	11.4	14.2	16.1	18.0	20.7
20	555.2	539.7	15.5	83.4	10.7	13.5	15.5	17.5	20.3
21	547.6	531.0	16.6	79.8	11.7	14.6	16.6	18.5	21.4
22	541.0	530.9	10.1	77.2	4.8	7.9	10.1	12.3	15.4
23	527.9	523.5	4.4	75.1	-1.3	2.1	4.4	6.7	10.1
24	517.2	514.5	2.7	73.6	-2.8	0.4	2.7	4.9	8.1
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75°F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	13,431	13,245	186	128.7	n/a	n/a	n/a	n/a	n/a
Event Hours	583.0	564.0	19.0	99.8	17.3	18.3	19.0	19.7	20.8

Figure 4.1 illustrates the hourly reference load, observed load, and load impacts for the typical DBP event day, including only the events during which all customers were called. The scale for the load impacts is shown on the right-side y-axis. Figure 4.2 shows the variability of estimated load impacts across the fifteen event days. Notice that several of the event days (August 18, 27, and 28) have fairly high pre-event load impacts. This is due to one large and demand responsive service account keeping its load levels low

across consecutive event days. That is, they reduce load for the first event day and don't increase load until the last consecutive event is over.

The full set of tables required by the Protocols, including tables for each LCA, are in the Excel file attached as an Appendix to this report.

Figure 4.1: DBP Load Impacts for the Typical Event Day, *PG&E*

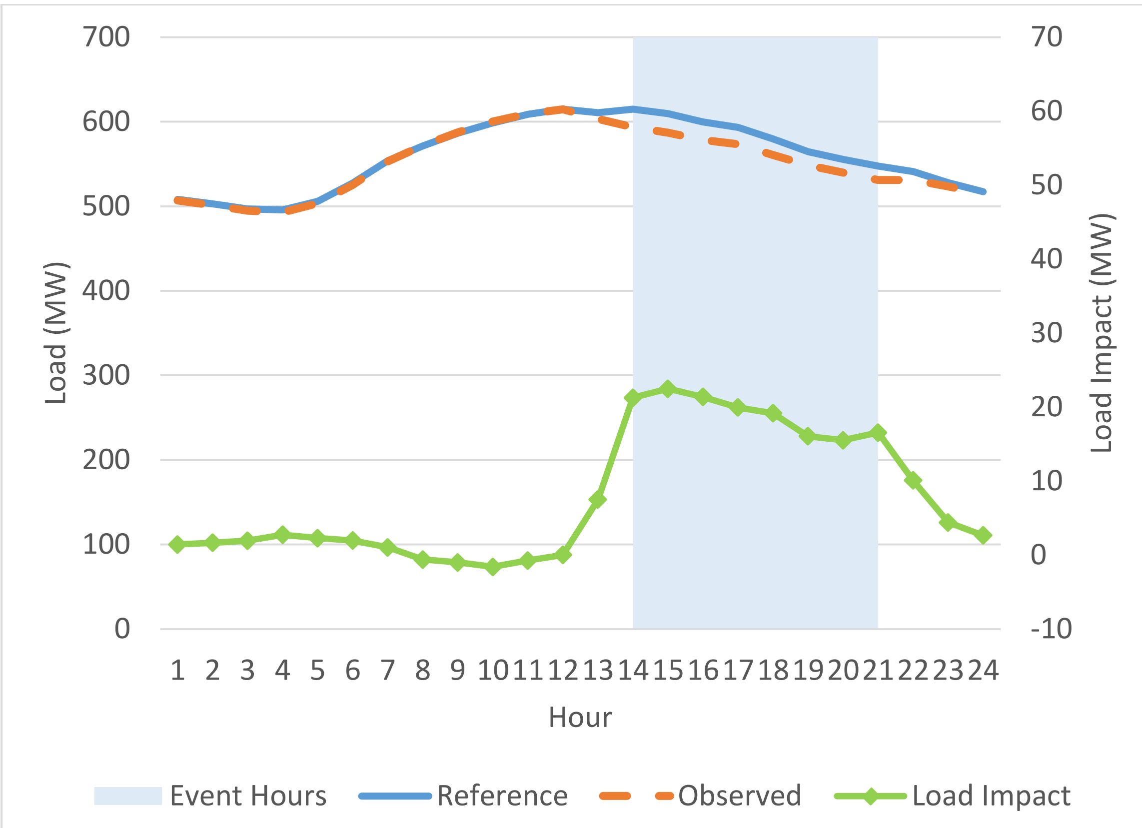
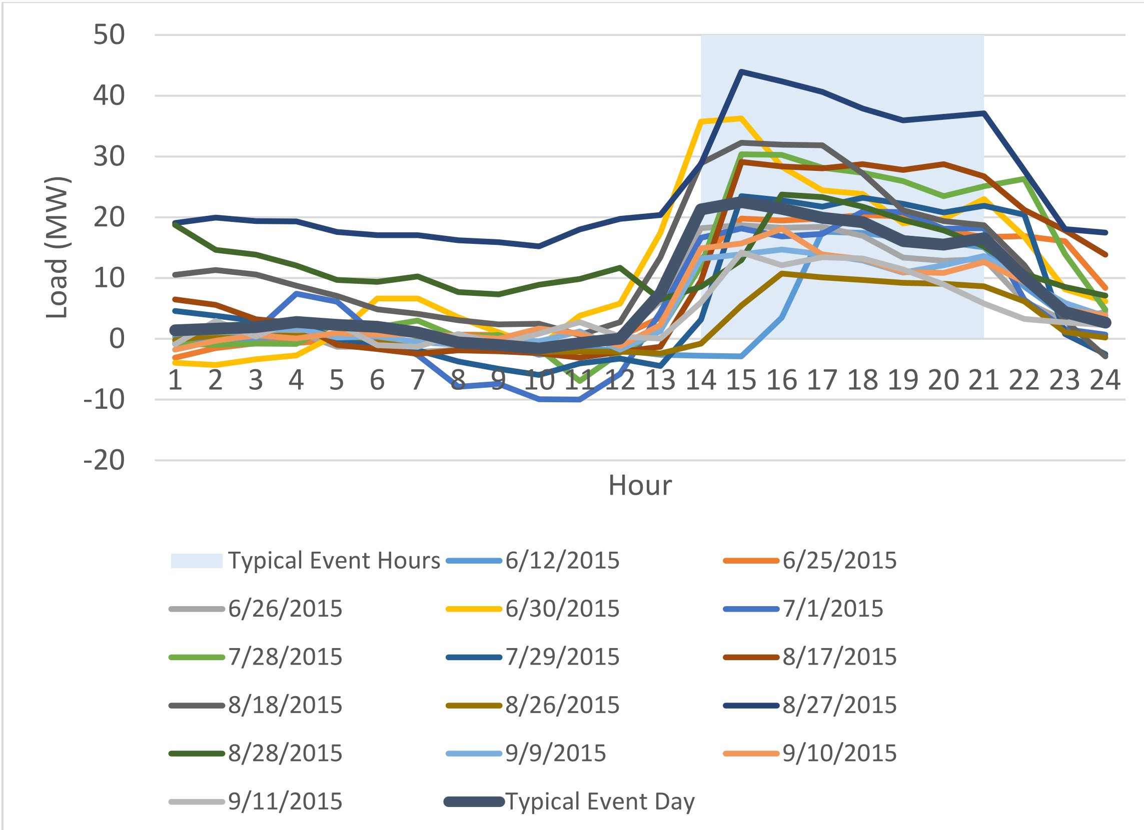


Figure 4.2: Hourly Load Impacts by Event, *PG&E DBP*



4.2 SCE Load Impacts

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

Table 4.6 summarizes average hourly reference loads and load impacts at the program level for each of SCE's ten DBP events. The top panel shows the results for all customers and the bottom panel shows the results for customers who were not dually enrolled in another DR program. Across all events, the average hourly load impact was approximately 99.7 MW. The load impacts varied across event days, with a low of 76.9 MW, a high of 131.4 MW, and a standard deviation of 15.7 MW. On average, the load impacts were 14.1 percent of the total reference load. The vast majority of the load impact came from customers dually enrolled in another DR program.

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

Customer Group	Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
All	1	7/1/2015	Wednesday	668.5	571.6	96.9	14.5%
	2	7/29/2015	Wednesday	683.1	578.5	104.6	15.3%
	3	7/30/2015	Thursday	707.4	608.7	98.7	14.0%
	4	8/17/2015	Monday	697.5	597.2	100.3	14.4%
	5	8/26/2015	Wednesday	717.0	602.9	114.1	15.9%
	6	8/27/2015	Thursday	717.4	620.6	96.8	13.5%
	7	8/28/2015	Friday	696.1	619.2	76.9	11.1%
	8	9/9/2015	Wednesday	726.7	595.4	131.4	18.1%
	9	9/10/2015	Thursday	726.4	627.2	99.2	13.7%
	10	9/11/2015	Friday	712.8	634.3	78.6	11.0%
			Average	**705.3**	**605.6**	**99.7**	**14.1%**
			Std. Dev.			**15.7**	**2.2%**
Enrolled in DBP Only	1	7/1/2015	Wednesday	297.9	281.0	17.0	5.7%
	2	7/29/2015	Wednesday	285.8	281.7	4.1	1.4%
	3	7/30/2015	Thursday	295.9	293.9	2.0	0.7%
	4	8/17/2015	Monday	296.7	291.0	5.7	1.9%
	5	8/26/2015	Wednesday	302.4	296.4	6.0	2.0%
	6	8/27/2015	Thursday	301.5	299.6	2.0	0.6%
	7	8/28/2015	Friday	289.7	287.2	2.5	0.9%
	8	9/9/2015	Wednesday	321.2	312.9	8.3	2.6%
	9	9/10/2015	Thursday	323.1	322.2	1.0	0.3%
	10	9/11/2015	Friday	306.0	303.0	2.9	1.0%
			Average	**302.0**	**296.9**	**5.1**	**1.7%**
			Std. Dev.			**4.7**	**1.6%**

Table 4.7 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 115.7 MW, while the estimated average hourly load impact was 99.7 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 86.2 percent. The bottom panel of Table 4.7 shows that the bid realization rate is much lower (29.4 percent) for the customers who were not enrolled in another DR program.

Two event days have notable bid realization rates: September 9 is over 100 percent for the entire program; and July 1 has a much higher bid realization rate (98 percent) for DBP-only customers relative to the other events. For September 9, there are a few service accounts that respond on that day, but are not consistent responders across all event days, elevating the bid realization rate. In addition, there is one service account that had very large response on that date, well above its bid amount (~15 MW in demand response vs. ~1.2 MW bid). The metered load data for this customer indicate a clear reduction during the event hours of that day, with no other obvious explanation.

Regarding the July 1 event day for the DBP-only customers, the most significant difference for that event day is a large load impact from one service account that does not have large load impacts on other event days. It is difficult to tell from the customer's load data whether the load impact estimate is reasonable (their load is quite variable from day to day), so it is possible that the "true" load impact on that event day is lower than our estimates reflect.

Table 4.7: Average Event-Hour Bid Realization Rates by Event, *SCE*

Customer Group	Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
All	1	7/1/2015	Wednesday	104.4	96.9	92.8%
	2	7/29/2015	Wednesday	128.2	104.6	81.6%
	3	7/30/2015	Thursday	118.8	98.7	83.1%
	4	8/17/2015	Monday	126.3	100.3	79.4%
	5	8/26/2015	Wednesday	126.5	114.1	90.2%
	6	8/27/2015	Thursday	120.1	96.8	80.6%
	7	8/28/2015	Friday	92.0	76.9	83.6%
	8	9/9/2015	Wednesday	126.7	131.4	103.7%
	9	9/10/2015	Thursday	115.7	99.2	85.7%
	10	9/11/2015	Friday	98.0	78.6	80.1%
			Average	**115.7**	**99.7**	**86.2%**
Enrolled in DBP Only	1	7/1/2015	Wednesday	17.3	17.0	98.1%
	2	7/29/2015	Wednesday	16.7	4.1	24.4%
	3	7/30/2015	Thursday	17.3	2.0	11.7%
	4	8/17/2015	Monday	16.7	5.7	33.9%
	5	8/26/2015	Wednesday	18.2	6.0	32.7%
	6	8/27/2015	Thursday	17.4	2.0	11.2%
	7	8/28/2015	Friday	18.0	2.5	14.0%
	8	9/9/2015	Wednesday	16.8	8.3	49.6%
	9	9/10/2015	Thursday	17.9	1.0	5.4%
	10	9/11/2015	Friday	18.4	2.9	16.0%
			Average	**17.5**	**5.1**	**29.4%**

Tables 4.8 and 4.9 summarize average hourly load impacts for the average event by industry group and LCA. Table 4.9 includes additional rows of data that summarize the load impacts for South Orange County, South of Lugo, and the remainder of the

system.[12] Manufacturing service accounts accounted for the largest share of the load impacts. By region, the highest share of the average load impact came from the LA Basin. Note that some results have been removed due to confidentiality concerns.

Table 4.8: Average Event-Hour Load Impacts – SCE DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	[redacted]				
Manufacturing	157	410.0	319.5	90.5	22.1%
Wholesale, Transportation, & Other Utilities	86	44.6	40.5	4.1	9.1%
Retail Stores	231	42.1	41.8	0.3	0.7%
Offices, Hotels, Health, Services	166	107.1	106.0	1.1	1.1%
Schools	99	14.2	14.2	0.0	-0.3%
Entertainment, Other Services, Government	[redacted]				
Total	**794**	**705.3**	**605.6**	**99.7**	**14.1%**

Table 4.9: Average Event-Hour Load Impacts – SCE DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin	650	460.9	372.5	88.4	19.2%
Outside LA Basin	[redacted]				
Ventura					
Total	**794**	**705.3**	**605.6**	**99.7**	**14.1%**
South Orange County	166	80.8	79.6	1.2	1.5%
South of Lugo	257	196.5	128.6	67.9	34.5%
Rest of System	372	428.0	397.3	30.7	7.2%

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts at the program level for the average DBP event in the manner required by the Protocols. The hourly load impact on the average event day ranges from 87.6 MW to 104.5 MW.

[12] Reporting for these locations was requested in response to concerns about reliability after the San Onofre Nuclear Generating Station (SONGS) was taken offline.

Table 4.10: DBP Hourly Load Impacts for the Average Event Day, *SCE*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	568.3	552.6	15.7	78.6	11.0	13.8	15.7	17.6	20.4
2	564.9	549.8	15.1	77.6	10.6	13.3	15.1	17.0	19.7
3	559.9	546.4	13.5	76.8	9.3	11.8	13.5	15.2	17.6
4	562.6	547.5	15.1	75.8	11.4	13.6	15.1	16.5	18.7
5	583.9	565.5	18.4	75.1	13.2	16.3	18.4	20.6	23.6
6	623.3	620.6	2.6	74.4	-4.2	-0.1	2.6	5.4	9.4
7	670.8	666.7	4.1	73.9	-0.7	2.1	4.1	6.1	8.9
8	691.1	685.3	5.8	73.9	1.3	4.0	5.8	7.7	10.3
9	708.6	704.7	3.9	75.8	-1.4	1.7	3.9	6.0	9.1
10	727.5	722.9	4.6	79.1	-0.5	2.5	4.6	6.7	9.7
11	744.4	729.7	14.7	82.7	8.1	12.0	14.7	17.5	21.4
12	739.4	691.3	48.1	85.5	40.1	44.8	48.1	51.3	56.1
13	733.6	632.6	101.0	87.7	93.0	97.7	101.0	104.2	108.9
14	733.9	630.2	103.6	89.3	95.2	100.2	103.6	107.1	112.0
15	731.8	629.5	102.3	90.5	93.1	98.5	102.3	106.1	111.5
16	717.8	616.0	101.8	90.7	92.9	98.2	101.8	105.4	110.6
17	706.9	602.4	104.5	90.3	95.6	100.9	104.5	108.2	113.4
18	689.8	589.7	100.1	89.5	91.0	96.4	100.1	103.8	109.2
19	667.0	569.9	97.1	88.7	87.5	93.2	97.1	101.0	106.6
20	661.7	574.1	87.6	86.6	78.3	83.8	87.6	91.4	96.9
21	645.3	604.7	40.6	84.0	27.6	35.3	40.6	45.9	53.6
22	620.7	598.0	22.6	81.8	10.8	17.8	22.6	27.5	34.4
23	596.5	578.7	17.7	80.2	8.4	13.9	17.7	21.6	27.1
24	582.4	566.9	15.5	78.8	8.1	12.4	15.5	18.5	22.9
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75°F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	15,832	14,776	1,056	169.9	n/a	n/a	n/a	n/a	n/a
Event Hours	705.3	605.6	99.7	113.2	96.6	98.4	99.7	101.0	102.9

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the average DBP event. The scale for the hourly load impacts is shown on the right-hand side of the figure. Figure 4.4 shows the variability of estimated load impacts across events.

Figure 4.3: DBP Load Impacts for the Average Event Day, *SCE*

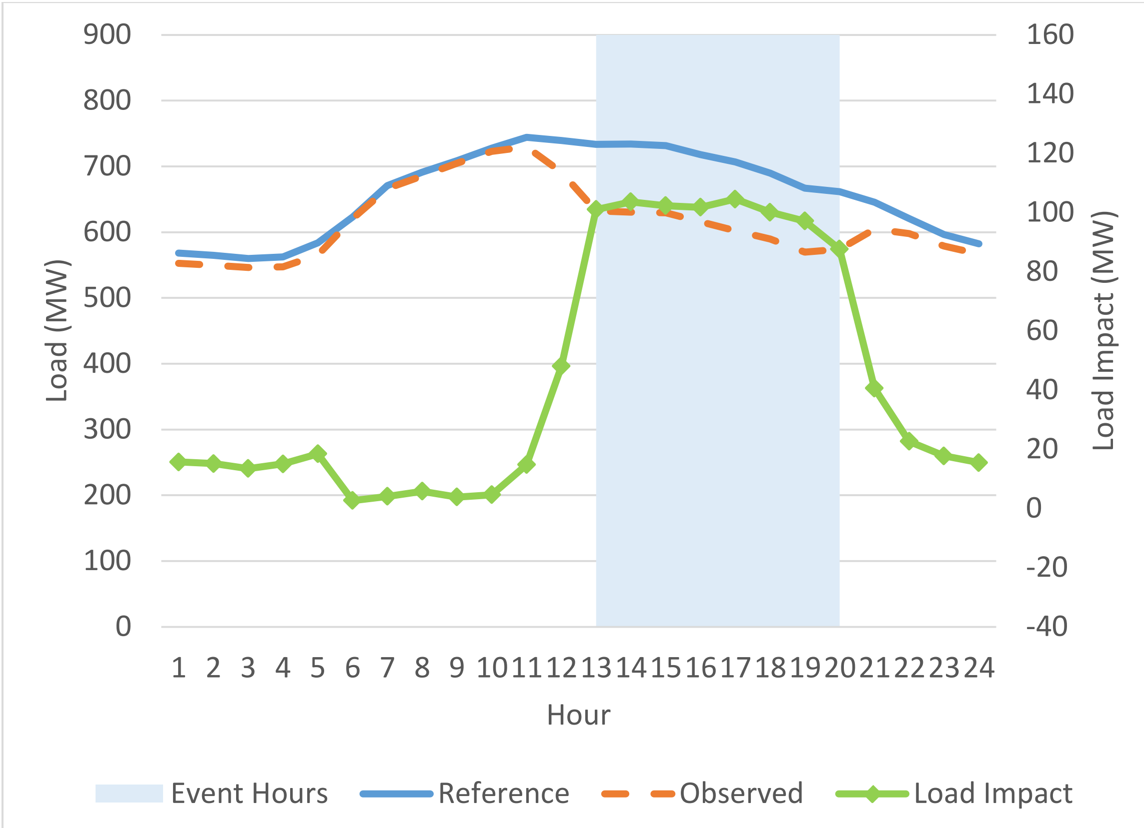
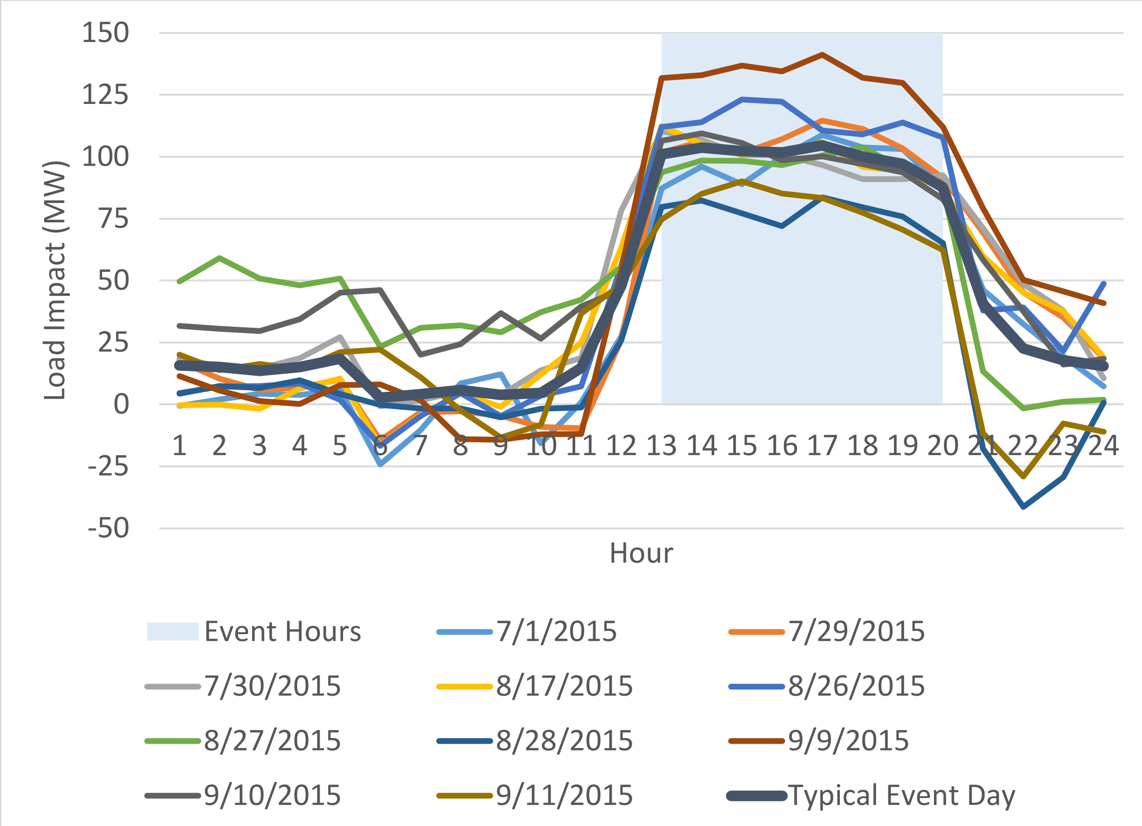


Figure 4.4: Hourly Load Impacts by Event, *SCE DBP*



4.3 SDG&E Load Impacts

SDG&E did not call any DBP event days during the 2015 program year.

4.4 Summary of TA/TI and AutoDR on Load Impacts

This section describes the *ex-post* load impacts achieved by DBP customer accounts that participated in TA/TI or AutoDR at some point in the past.

The Technical Assistance and Technology Incentives (TA/TI) program is no longer offered by the IOUs, but we summarize load impacts from customers that received program incentives in the past. The program had two parts: technical assistance in the form of energy audits, and technology incentives. The objective of the TA portion of the program was to subsidize customer energy audits that had the objective of identifying ways in which customers could reduce load during DR events. The TI portion of the program provided incentive payments for the installation of equipment or control software supporting DR.

The Automated Demand Response (AutoDR) program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention.

In the sub-sections below, we summarize *total* load impacts for service accounts that received TA/TI or AutoDR incentives at some point prior to the DR event(s) summarized. These are simply the sum of the estimated load impacts for customers in each program, as estimated using the methods described in Section 3.2.1.

PG&E

TA/TI

According to data provided by PG&E, seven DBP service accounts participated in the TA/TI program at some point in the past. However, no more than two of these service accounts submitted a bid during each event day.

Table 4.11 shows the event-specific load impact for the past TA/TI participants. [redacted] The rightmost column ("Approved MW for bidders") shows the total MW approved following the TA/TI DR test. These results have been removed due to confidentiality concerns.

Table 4.11: Average Event-Hour Load Impacts by Event, *PG&E TA/TI*

Event Date	Number of Notified SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
6/12/2015	[redacted]						
6/25/2015							
6/26/2015							
6/30/2015							
7/1/2015							
7/28/2015							
7/29/2015							
8/17/2015							
8/18/2015							
8/26/2015							
8/27/2015							
8/28/2015							
9/9/2015							
9/10/2015							
9/11/2015							
Average when all called							

AutoDR

[redacted] Table 4.12 shows the average hourly load impact for the AutoDR participants. [redacted] These results have been removed due to confidentiality concerns.

Table 4.12: Average Event-Hour Load Impacts by Event, *PG&E AutoDR*

Event Date	Number of Notified SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
6/12/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/25/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/26/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/30/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/28/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/29/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/17/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/18/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/26/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/27/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/28/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/10/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/11/2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average when all called	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

SCE

TA/TI

Table 4.13 shows the DBP load impacts provided by SCE's service accounts that participated in TA/TI at some point in the past. An average of 174 service accounts participated in TA/TI, with an average of 28 participants submitting a bid during each event. The load impacts from TA/TI participants averaged 13.9 MW, or 17 percent of the total reference load (including TA/TI participants that did not submit a bid). These results have been removed due to confidentiality concerns.

Table 4.13: Average Event-Hour Load Impacts by Event, *SCE TA/TI*

Event Date	Number of SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
7/1/2015	174	[redacted]					
7/29/2015	174						
7/30/2015	174						
8/17/2015	174						
8/26/2015	174						
8/27/2015	174						
8/28/2015	174						
9/9/2015	174						
9/10/2015	174						
9/11/2015	174						
Average	**174**	**28**	**81.2**	**67.3**	**13.9**	**17.0%**	**21.8**

AutoDR

Table 4.14 shows the total DBP load impacts for SCE's AutoDR participants. Approximately 242 DBP service accounts participated in AutoDR, with an average of 166 participants bidding during each event. Load impacts from these customers averaged 29.1 MW across the ten event days, or 15.4 percent of the reference load (including Auto-DR customers that did not submit a bid).

Table 4.14: Average Event-Hour Load Impacts by Event, *SCE AutoDR*

Event Date	Number of SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
7/1/2015	234	156	177.7	154.5	23.1	13.0%	78.7
7/29/2015	234	155	183.4	153.2	30.2	16.5%	77.4
7/30/2015	234	159	188.6	159.6	29.0	15.4%	78.6
8/17/2015	245	155	191.6	153.6	38.0	19.8%	76.8
8/26/2015	245	169	187.2	157.2	30.0	16.0%	79.5
8/27/2015	245	171	191.3	160.9	30.3	15.9%	80.3
8/28/2015	245	171	187.6	167.1	20.5	10.9%	80.1
9/9/2015	245	182	197.0	151.8	45.2	22.9%	80.2
9/10/2015	245	179	194.6	165.9	28.7	14.8%	80.2
9/11/2015	245	166	190.5	174.2	16.3	8.6%	77.7
Average	**242**	**166**	**189.0**	**159.8**	**29.1**	**15.4%**	**78.9**

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 DR 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 percentage load impacts for a typical event day.

5.2.1 Development of Customer Groups

For PG&E, 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).

SCE provided a total enrollment number for the program, which we apportion to the three LCAs according to the ratios observed in the *ex-post* study. Because the ex-ante enrollment is quite close to the ex-post enrollment, this should result in reasonable shares of customers by LCA.

For SDG&E, we assume that the currently enrolled customers continue to participate in DBP, 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 percentage load impacts from *ex-post* results;
4. Apply percentage load impacts 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 the DBP during the 2015 program year. The percentage load impacts are developed using the estimated *ex-post* load impacts for the same customers, using data from up to three program years (2013 through 2015). For SDG&E, only 2013 and 2014 are used since no DBP events were called in the 2015 program year.[13]

For each service account, we determine the appropriate size group, LCA, and dual enrollment status. Service accounts that are dually enrolled in the BIP or an aggregator program (*e.g.*, the Aggregated Managed Portfolio or Capacity Bidding Program) will have their reference loads and load impacts counted in the *program-specific* scenarios (in which each DR program is assumed to be called in isolation), but not in the *portfolio-level* scenarios (in which all DR programs are assumed to have been called).

2. Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations for each enrolled service 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 use CDH65 as the weather variables in place of the lagged CDH variables used in the *ex-post* regressions. 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.

[13] The entire SDG&E *ex-ante* forecast matches the one produced for the PY2014 evaluation, because the same customers are enrolled in the program and there were no PY2015 events to add information about their demand responsiveness.

Because DBP 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 HDH_t and HDD_t variables, where the summer model does not; and the month dummies relate to a different set of months. Table 6.1 describes the terms included in the equation.

$$Q_t = a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DBP} \times h_{i,t} \times DBP_t) + \sum_{DR} \sum_{i=1}^{24} (b_i^{DR} \times h_{i,t} \times OtherEvt^{DR}{}_{i,t})$$
$$+ \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times CDH_t) + \sum_{i=1}^{24} (b_i^{CDD} \times h_{i,t} \times CDD_t) + \sum_{i=1}^{24} (b_i^{HDH} \times h_{i,t} \times HDH_t)$$
$$+ \sum_{i=1}^{24} (b_i^{HDD} \times h_{i,t} \times HDD_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t})$$
$$+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=2-5,10-12} (b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

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

Variable Name	Variable Description
Q_t	the demand in hour *t* for a customer enrolled in DBP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	a dummy variable for hour *i*
DBP_t	an indicator variable for program event days
$OtherEvt^{DR}{}_t$	equals one on the event days of other demand response programs in which the customer is enrolled
CDH_t	cooling degree hours
CDD_t	cooling degree days
HDH_t	heating degree hours[14]
HDD_t	heating degree days[15]
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$DTYPE_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
e_t	the error term.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. Much of the

[14] Heating degree hours (HDH) was defined as MAX[0, 60 – TMP], where TMP is the hourly temperature expressed in degrees Fahrenheit. Customer-specific HDH values are calculated using data from the most appropriate weather station.

[15] Heating degree days (HDD) was defined as MAX[0, 60 – Avg. Temp.], where "Avg. Temp." is the average of the daily maximum and minimum temperatures expressed in degrees Fahrenheit. Customer-specific HDD values are calculated using data from the most appropriate weather station.

differences across scenarios can be attributed to varying weather conditions. This is the second program year in which the evaluation includes two sets of 1-in-2 and 1-in-10 weather years. The sets are differentiated according to whether they correspond to utility-specific conditions or CAISO-coincident conditions.

3. Calculate forecast percentage load impacts

For both PG&E and SCE, the percentage load impacts were based on *ex-post* load impact estimates program years 2013 through 2015. SDG&E used only 2013 and 2014, as the program did not call any DBP events in 2015. Specifically, we examined only customers enrolled in PY2015, but included load impact estimates from the previous two program years for the PY2015 program participants that also participated in the program in 2013 and 2014. This method allowed us to base the *ex-ante* load impacts on a larger sample of events, which helps improve the reliability and consistency of the load impacts across forecasts.

For each service account, we collect the hourly *ex-post* load impact estimates and observed loads for every event available from PY2013 through PY2015. Within each service account, we then calculated the average hourly load impact and observed load profile, as well as the variance of the each hour's load impact across the event days. The average load impacts and their associated variances are converted to percentages by dividing them into the customer's average *ex-post* reference load for the corresponding hour. These percentages are applied to the customer's *ex-ante* (forecast) reference load for each required scenario (e.g., the August peak month day during a utility-specific 1-in-2 weather year).

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 the Greater Bay Area, who are not dually enrolled in BIP or an aggregator program), 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 windows we needed to adjust the historical percentage load impacts for use in the *ex-ante* study. Specifically, we estimate average load impact percentages over five hour categories:

1. Hours preceding event hours, not including the hour immediately preceding the event hours;
2. The hour immediately preceding the called event hours;
3. Event hours;
4. The hour immediately following the called event hours; and
5. Hours following the event hours, not including the hour immediately following the event hours.

The average load impact percentage (from *ex-post* results) is subsequently applied to each hour of the *ex-ante* reference loads by the corresponding hour category. The methodology is equivalently applied for summer and winter months.

The uncertainty-adjusted load impacts (i.e., the 10th, 30th, 50th, 70th, and 90th percentile scenarios of load impacts) are based on the variability of each customer's response across event days. That is, we calculate the standard deviation of each customer's percentage load impact across the available event days. The square of this (*i.e.*, the variance) is added across customers within each required subgroup. Each uncertainty-adjusted scenario was 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 variability of load impacts across event days. For the average event hour, the variability of the load impacts across the scenarios is set to match the variability across the average of the individual event-hours.

4. *Apply percentage load impacts to reference loads for each event scenario*.

In this step, the percentage load impacts were applied to the reference loads for each scenario to produce all of the required reference loads, estimated event-day loads, and scenarios of load impacts.

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

The IOUs provided enrollment forecasts. PG&E provided monthly enrollments through 2026, with separate enrollments provided at the program and portfolio level (the latter excludes dually enrolled customers) by LCA and size group. SCE provided a single enrollment number for 2016. SDG&E assumes that current enrollments persist through the end of 2016. Both SCE and SDG&E have indicated plans to discontinue the program at the end of 2016. The enrollments are then used to scale up the reference loads and load impacts for each required scenario and customer subgroup.

5.3 Enrollment Forecasts

PG&E

PG&E forecasts DBP enrollments to remain constant from 2016 through 2026, with 493 service accounts enrolled at the program level. Recall that the portfolio-level analysis excludes customers dually enrolled in the DBP and another DR program (*e.g.*, BIP, AMP, or CBP). Because the CBP and AMP are summer-only programs, portfolio-level enrollments vary by season. PG&E forecasts portfolio-level enrollments to be 354 service accounts during the summer months and 413 service accounts during winter months.

SCE

SCE forecasts 801 service accounts to be enrolled in 2016. The enrollment forecast thereafter is zero since SCE is seeking to eliminate DBP in 2017. As part of SCE's DSM strategy, one of the guiding principles is to increase the amount of DR integrated into the CAISO market. The reason for recommending DBP be discontinued is that SCE has determined the costs and operational challenges of integrating DBP into the CAISO market outweigh the benefits. The zero enrollment forecast beginning in 2017 assumes the CPUC will approve SCE's 2017 DR Bridge Funding proposal filed on February 1, 2016.

SDG&E

We assumed that the currently enrolled customers continue to be enrolled in their respective DBP programs through the end of 2016, at which point the programs are assumed to end.

5.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information: the hourly profile of reference loads and load impacts for typical event days; the level of load impacts across years; and the distribution of load impacts by LCA.

Together, these figures provide a useful indication of the anticipated changes in the forecast load impacts across the various scenarios represented in the Protocol tables. All of the tables required by the Protocols are provided in an Appendix.

5.4.1 PG&E

Figure 5.1 shows the program-level August 2016 forecast load impacts for a typical event day in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 26.7 MW, which represents 4.3 percent of the enrolled reference load. Figure 5.2 shows the same load impacts at the portfolio level (*i.e.*, when all DR programs are simultaneously called). On average, the load impacts are reduced by 25.3 MW (relative to the program-level load impact) to 1.4 MW and the percentage load impact goes down to 0.4 percent. The large difference between program and portfolio load impacts is due to the contribution of customers dually enrolled in the DBP and the BIP or an aggregator program. In the portfolio analysis (when BIP and aggregator events are assumed to be called at the same time as the DBP event), the load impacts for the dually enrolled customers are removed from the DBP, dramatically reducing the load impact.

Figure 5.1: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August 2016, Program Level

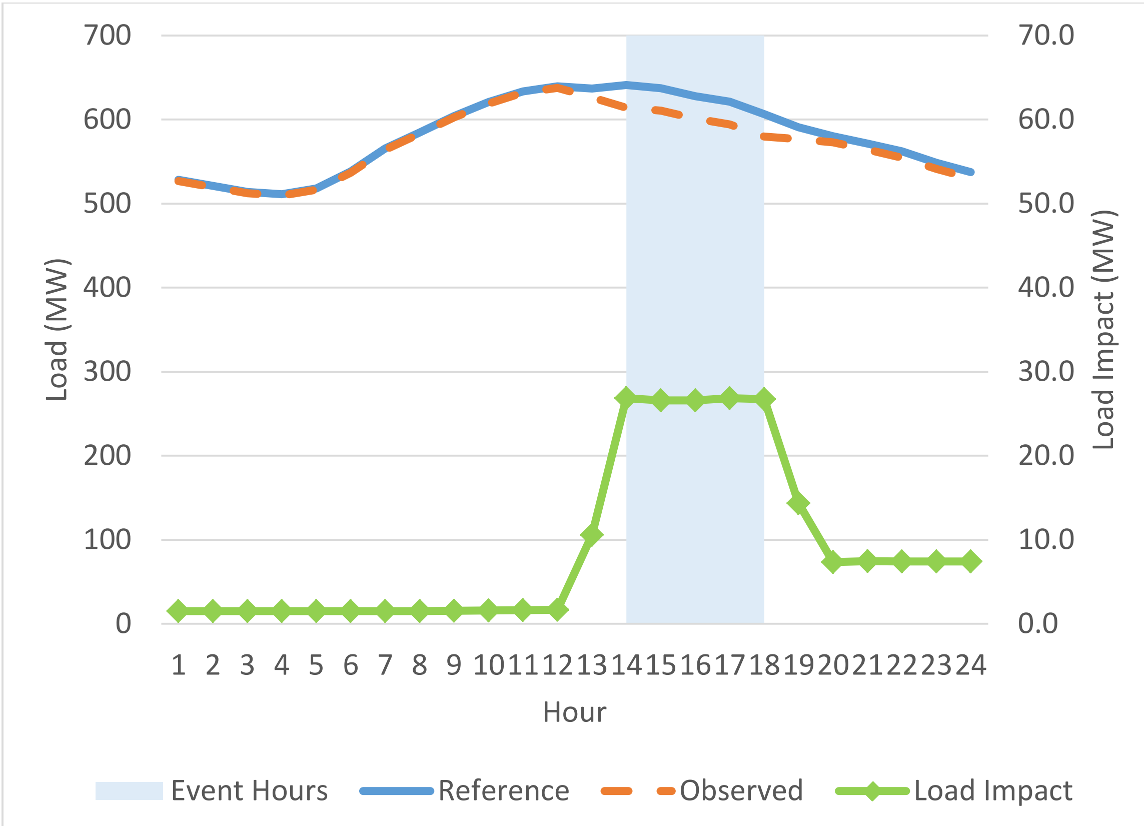


Figure 5.2: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August 2016, Portfolio Level

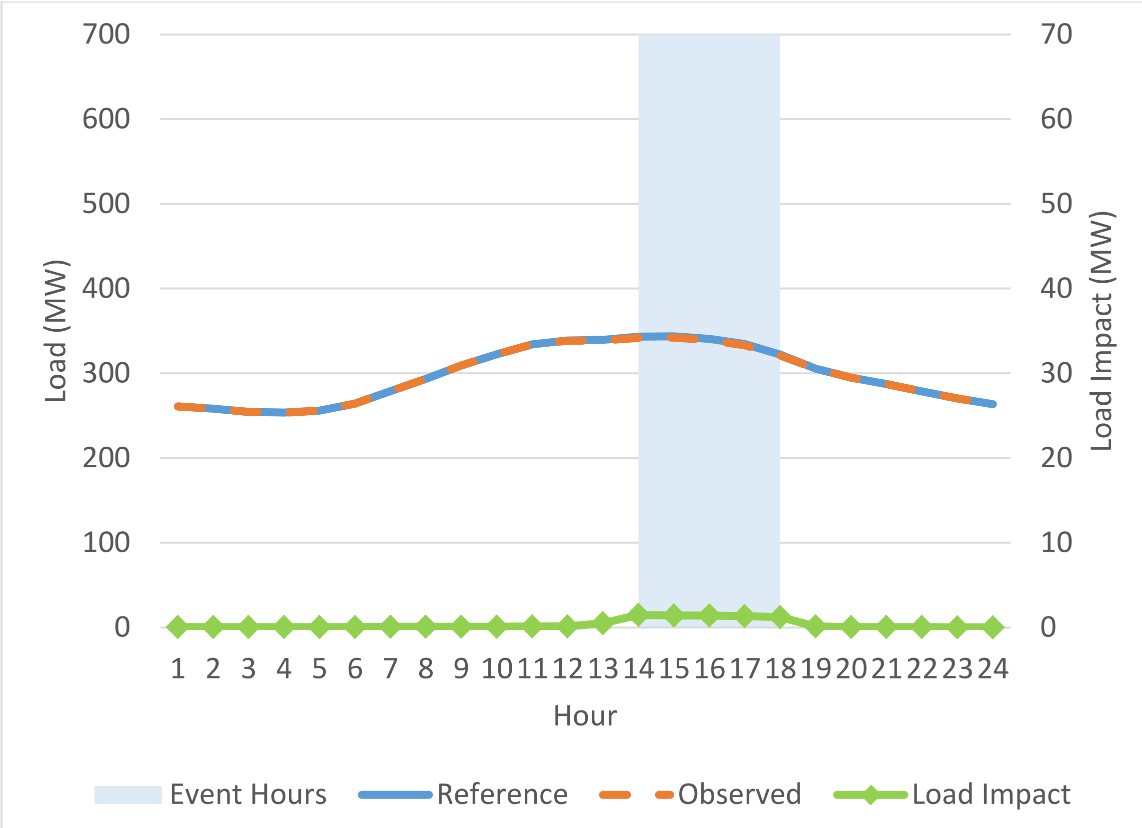


Figure 5.3 shows the share of load impacts by LCA, assuming a typical event day in an August 2016 utility-specific 1-in-2 weather year. Customers not in any LCA account for the largest share, with 85 percent of the load impacts.

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

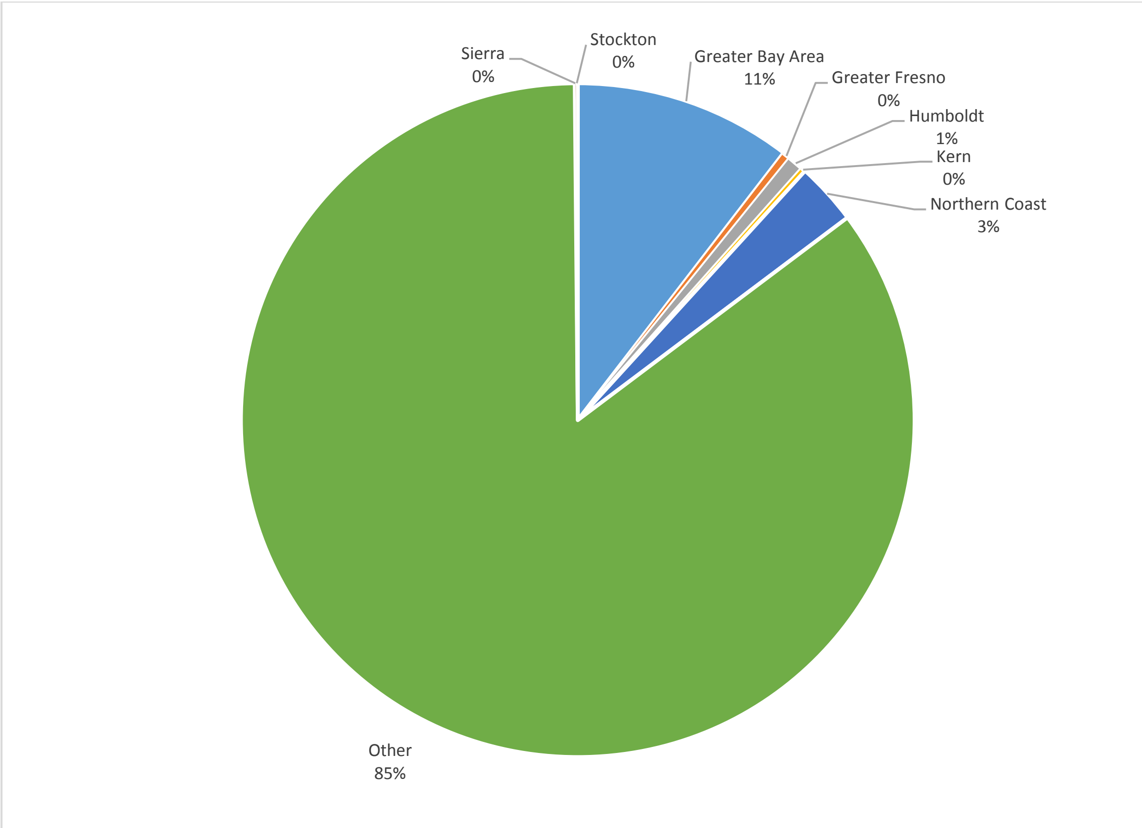


Figure 5.4 illustrates August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions, utility-specific versus CAISO-coincident peak conditions, and portfolio- versus program-level load impacts. Recall that the enrollment forecast does not change across the 2016-2026 window, so these load impacts apply to August across the forecast years. There is a very small difference in load impacts across weather scenarios, but the portfolio-level load impacts are much lower than the program-level load impacts (due to the removal of the customers dually enrolled in the BIP or an aggregator program).

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

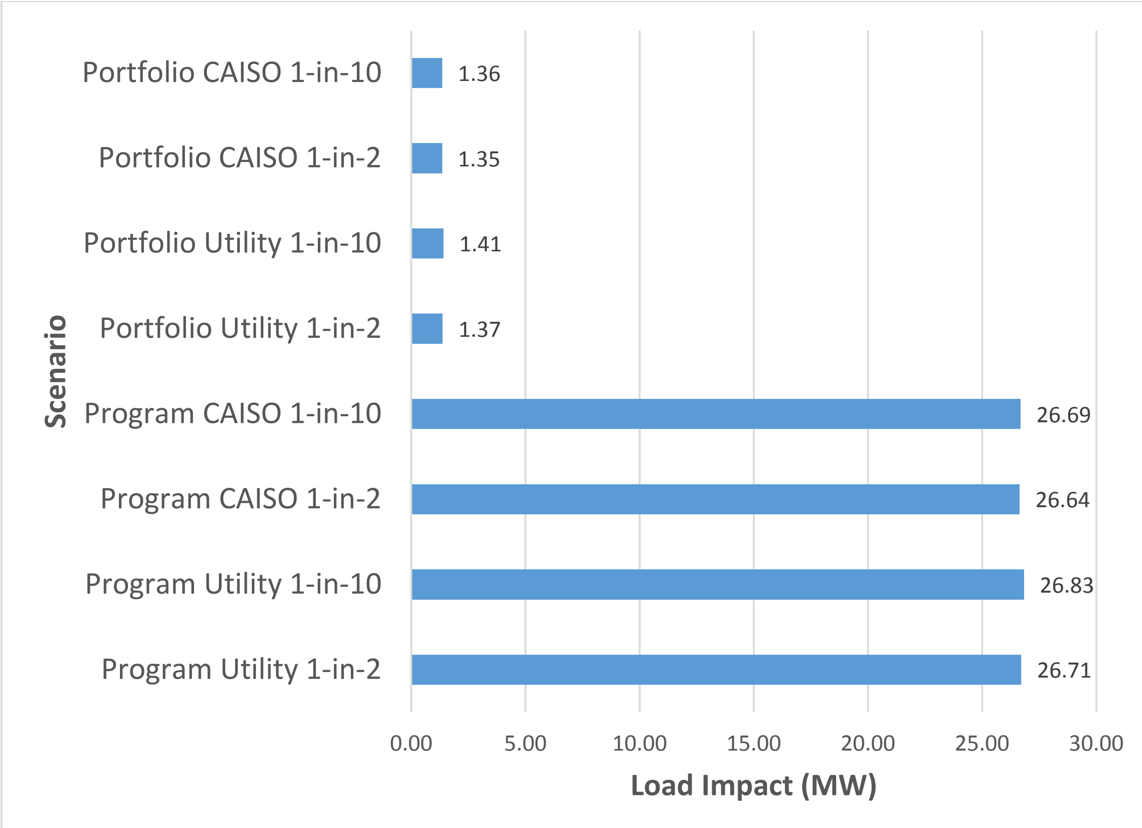


Table 5.2 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August monthly peak day.

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

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Program-based	Utility 1-in-2	1,270	54.2	4.3%
	Utility 1-in-10	1,288	54.4	4.2%
	CAISO 1-in-2	1,257	54.0	4.3%
	CAISO 1-in-10	1,269	54.1	4.3%
Portfolio-based	Utility 1-in-2	950	3.9	0.4%
	Utility 1-in-10	969	4.0	0.4%
	CAISO 1-in-2	936	3.8	0.4%
	CAISO 1-in-10	949	3.8	0.4%

5.4.2 SCE

Figure 5.5 shows the program-level forecast reference loads and load impacts for the August 2016 peak day in a utility-specific 1-in-2 weather year. The average program-level load impact is 112.3 MW, or 16 percent of the reference load.

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

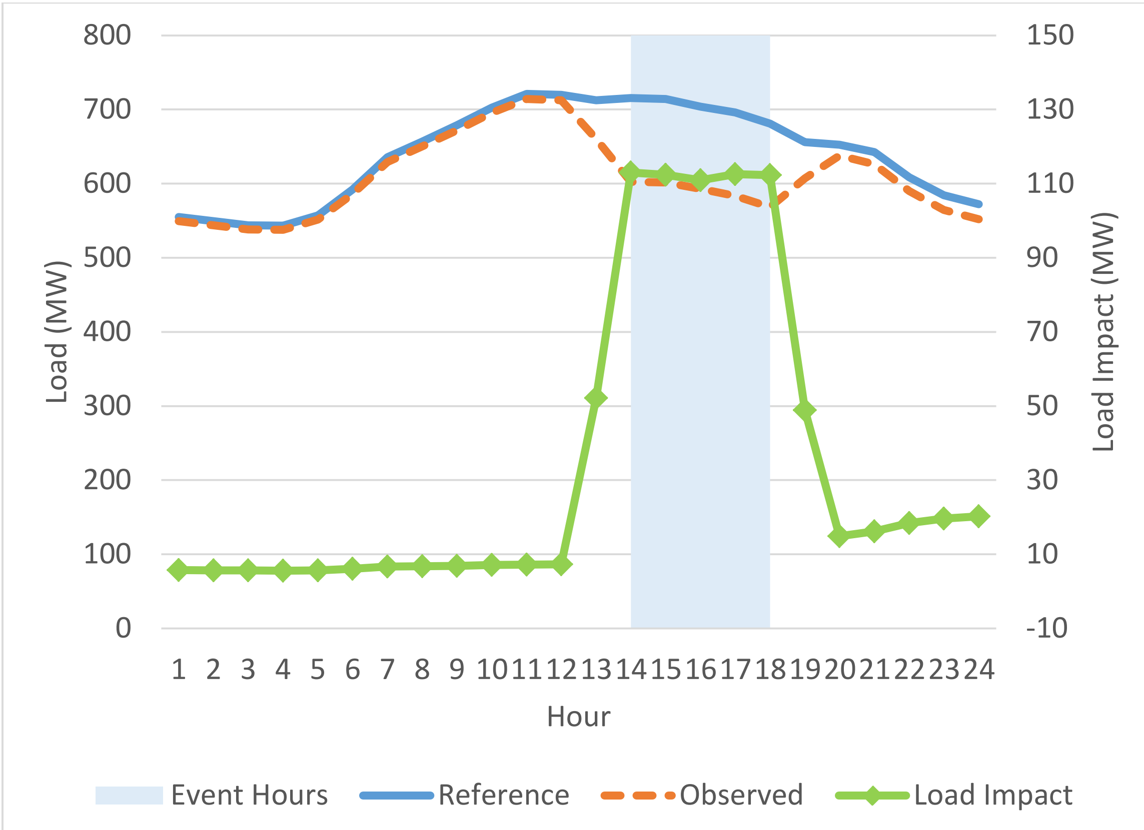


Figure 5.6 shows the portfolio-level forecast for the August 2016 peak day in a utility-specific 1-in-2 weather year. This forecast differs from the program-level forecast by excluding customers who are dually enrolled in DBP and BIP or AMP/DRC. Because the dually enrolled customers are much more demand responsive than the DBP-only customers, the load impacts are much lower in the portfolio-based scenario. Event-hour load impacts average 6.6 MW (a reduction of 105.7 MW relative to the program-level load impacts), or 2.2 percent of reference load.

Figure 5.6: SCE Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August 2016, Portfolio Level

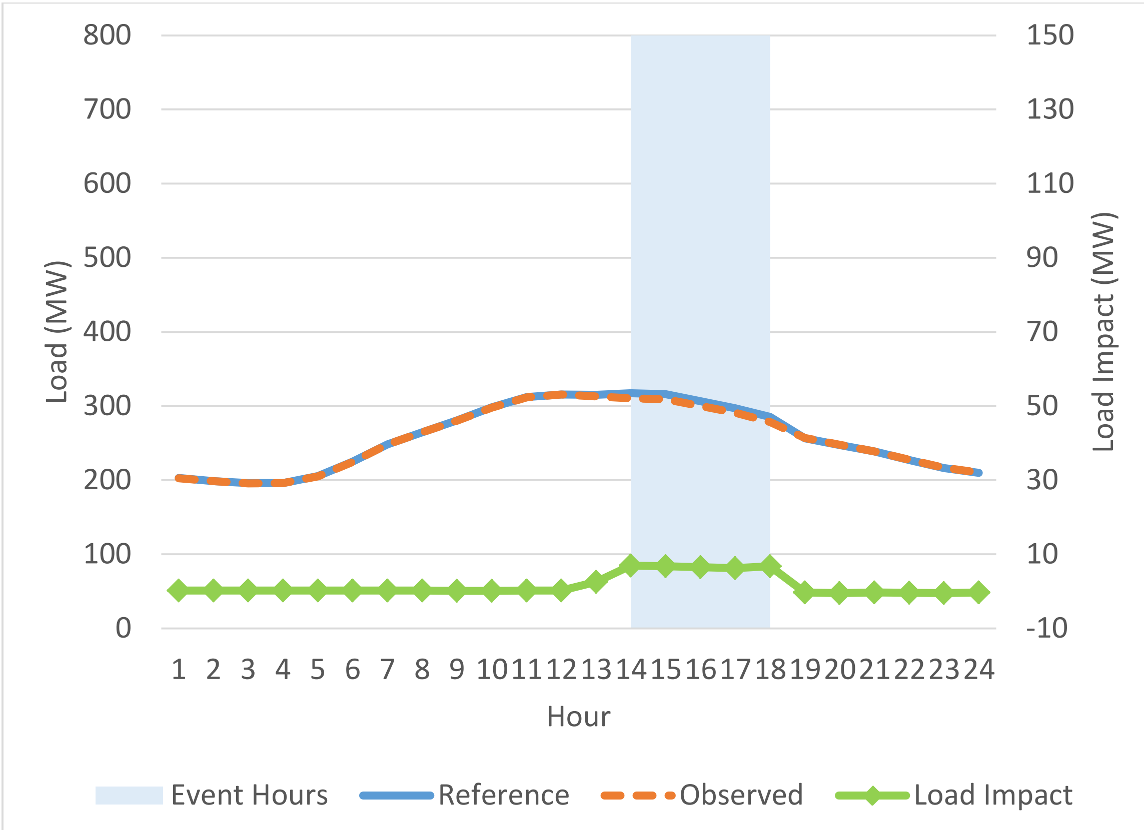


Figure 5.7 shows the distribution of utility-specific 1-in-2 August 2016 program-level load impacts across local capacity areas. The LA Basin accounts for the largest share, with 78 percent of the total load impacts.

Figure 5.7: Share of SCE DBP Load Impacts by Local Capacity Area

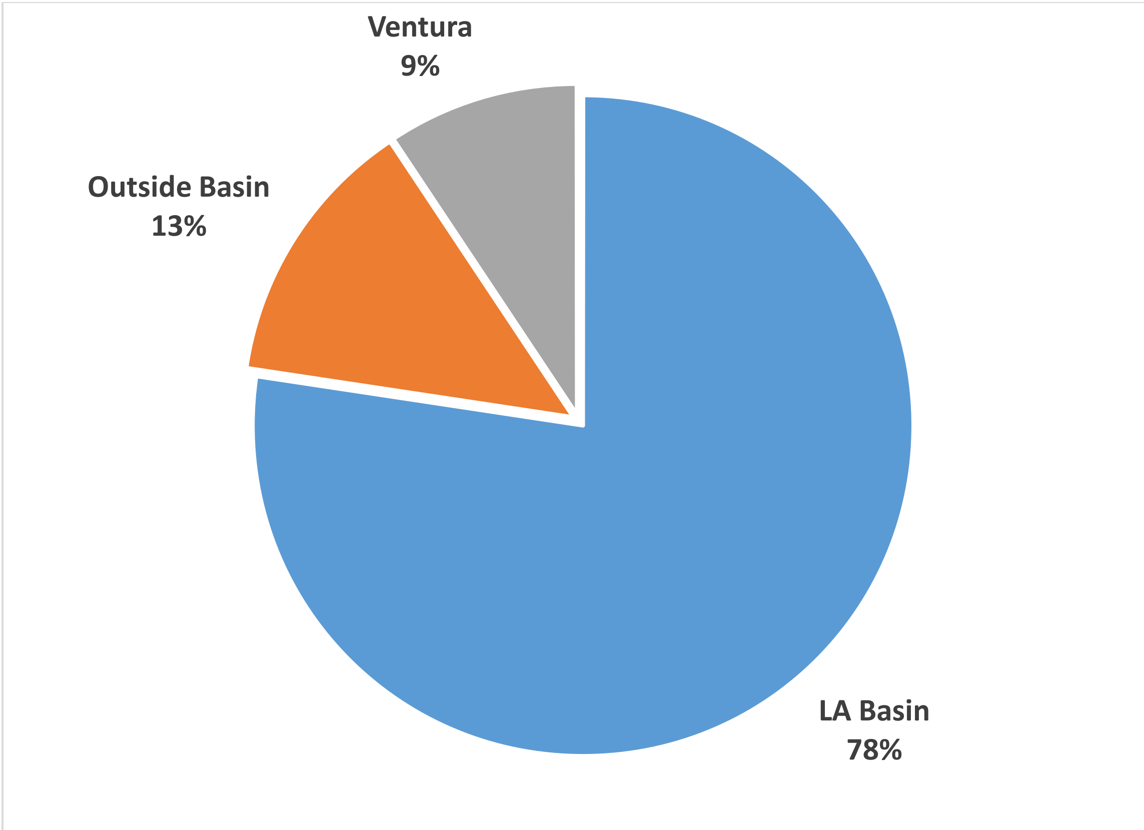


Figure 5.8 illustrates the average August hourly load impact across scenarios. The load impacts are not very weather sensitive, so the differences across the various weather scenarios are small. The large difference between program-level and portfolio-level load impacts is due to the fact that the most responsive customers are dually enrolled in another DR program (typically BIP).

Figure 5.8: Average Hourly *Ex-ante* Load Impacts by Scenario, *SCE*

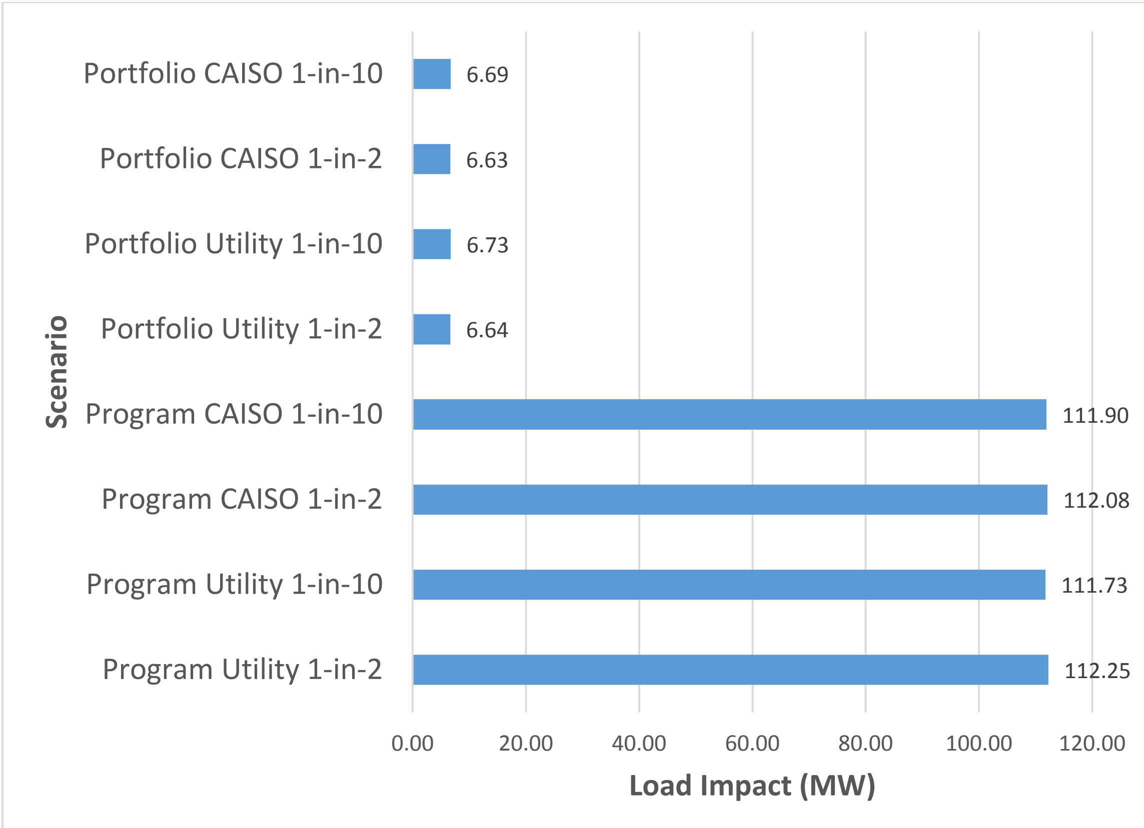


Table 5.3 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August 2016 monthly peak day.

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

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Program-based	Utility 1-in-2	877	140	16.0%
	Utility 1-in-10	884	139	15.8%
	CAISO 1-in-2	874	140	16.0%
	CAISO 1-in-10	878	140	15.9%
Portfolio-based	Utility 1-in-2	642	14	2.2%
	Utility 1-in-10	655	14	2.2%
	CAISO 1-in-2	640	14	2.2%
	CAISO 1-in-10	647	14	2.2%

5.4.3 SDG&E

SDG&E is forecasting that enrollment in its two DBP programs will continue at current levels for the forecast year 2016. The SDG&E DA and DO DBPs will be terminated at the end of 2016. Because enrollments do not vary across years and SDG&E consists of only one LCA, fewer results are presented for SDG&E than for PG&E and SCE.

Because SDG&E's event hours differ from event to event, the methodology resembles that used for PG&E. That is, we forecast percentage load impacts for four hour types: pre-event hours, event hours, the hour following the event, and all subsequent hours. These period-specific percentage load impacts are then applied to the reference loads in the corresponding hours of the *ex-ante* period (in which the event window is 1:00 to 6:00 p.m. from April through October and 4:00 to 9:00 p.m. from November to March).

Note that DBP-DA load impacts have been highly variable across the PY2013 and PY2014 events. The DBP-DO load impacts have varied somewhat as well, but more consistently show significant load reductions.

Figures 5.9 and 5.10 show the August utility-specific 1-in-2 *ex-ante* hourly reference loads, observed loads, and load impacts for the DBP-DA and DBP-DO programs, respectively.

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

[redacted]

Figure 5.10: SDG&E DBP-DO Hourly Event Day Load Impacts for the Typical Event Day in a Utility-Specific 1-in-2 Weather Year for August

[redacted]

Figures 5.11 and 5.12 show the monthly forecast of monthly load impacts for each of SDG&E's Demand Bidding Programs by weather year type.

For the DBP-DA program, the level of the load impact is significantly higher in November and December than the other months. This is because one of the service accounts has very low loads in January through October compared to November and December. Because we have estimated a high percentage load impact for this service account in the PY2014 *ex-post* estimates, the increase in the load in those months has a noticeable effect on the program-level load impact.

Figure 5.11: SDG&E DBP-DA Load Impacts by Month and Weather Year

[redacted]

Figure 5.12 shows the same information for DBP-DO. This customer is quite weather sensitive, as reflected in the occasionally large differences in load impacts across weather scenarios. In addition, the customer's load varies significantly from month to month (and sometimes day to day), so that the level of the load impact displays substantial variation across months and weather scenarios.

Figure 5.12: SDG&E DBP-DO Load Impacts by Month and Weather Year

[redacted]

6. Comparisons of Results

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

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

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

6.1 PG&E

6.1.1 Previous versus current *ex-post*

Table 6.1 shows the average event-hour reference loads and load impacts for the three previous program years. Note that there were three locational events dispatched in PY2013 and PY2014, and one dispatched in PY2015; these locational events are excluded from the calculations. The event window was hours-ending 13 through 20 for the included events in PY2013 and PY2014. The event window differs by event date in PY2015 (as shown in Table 2.7a).

Table 6.1: Comparison of Average Event-day *Ex-post* Impacts (in MW) in PY 2013 through PY 2015, *PG&E*

Level	Outcome	PY2013	PY2014	PY2015
Total	# SAIDs	952	846	503
	Reference (MW)	826	651	583
	Load Impact (MW)	36	25	19
Per SAID	Reference (kW)	867	769	1,160
	Load Impact (kW)	38	30	38
	% Load Impact	4.3%	3.8%	3.3%

The *ex-post* load impacts in MW and as a percentage relative to the reference load have decreased each year. While substantially fewer customers enrolled in DBP during PY2015 vs. PY2014, the customers who left were not demand responsive. Therefore, the bulk of the difference in the program-level load impact across years is due to changes in load impacts for customers who were enrolled during both years. Specifically, the load impacts for customers enrolled in both years are 6 MW lower in PY2015, with two service accounts comprising 4.6 MW of this total. Customers leaving the program between program years (373 service accounts) resulted in a 0.03 MW reduction in total load impacts, while customers joining the program in 2015 (11 service accounts) accounted for 0.02 MW of added load impacts.

6.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2014 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.2 contains this comparison for the August 2016 utility-specific 1-in-2 peak month day forecast. Both the program-level and portfolio-level load impacts are presented. Note that the portfolio-level load impacts (which exclude dually enrolled customers) are much lower than the program-level load impacts in both forecasts.

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

Level	Outcome	Program Level		Portfolio Level	
		Previous Study - 2016	Current Study - 2016	Previous Study - 2016	Current Study – 2016
Total	# SAIDs	784	493	580	354
	Reference (MW)	671	626	410	336
	Load Impact (MW)	32	27	1	1
Per SAID	Reference (kW)	856	1,270	706	950
	Load Impact (kW)	41	54	2	4
	% Load Impact	4.8%	4.3%	0.3%	0.4%

Even though forecast enrollments are substantially lower in the current forecast, this has little effect on the forecast load impacts because the vast majority of the load impacts come from a core of large responders who are present in both forecasts. The load impacts in the current forecast are lower than the load impacts in the previous forecast because of changes in customer demand responsiveness over time. The previous study based *ex-ante* load impacts on *ex-post* load impacts from PY2012 through PY2014, while the current study used PY2013 through PY2015. It happened to be the case that load impacts decreased for some of the large responders. For example, the two service accounts with the largest decrease in load impacts across forecasts account for a 4.8 MW decrease in the program-level load impact. Furthermore, one of these service accounts only bid in half of the event days for which they were called in PY2015, where previously they had bid on all event days in PY2013 and PY2014. The *ex-ante* forecast assumes a historical bidding pattern; therefore, a reduction in the share of event days in which a service account bids will result in a lower *ex-ante* forecast.

On average, the PY2015 event days had a lower amount of bids (24.3 MW versus 30.5 in PY2014); however, the bid realization rate was slightly higher (85 percent versus 82 percent in PY2014). These factors contributed to the reduction in the forecast load impacts across studies.

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

Table 6.3 provides a comparison of the *ex-ante* forecast of 2015 load impacts prepared following PY2014 and the PY2015 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are averaged across the six PY2015 event days included in the typical event day (June 26, June 30, July1, August 18, September 9, and September 10).

The forecast called for an average load impact of 32 MW, whereas we estimated an average load impact of 19 MW during PY2014. The forecast included more customers than were enrolled during PY2014 (784 versus 503), nonetheless, the load impacts from service accounts that were in the PY2014 analysis and not in the current ex-post study only account for 0.1 MW of the difference. Therefore, the difference in load impacts is driven by service accounts that are present in both analyses.

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

Level	Outcome	*Ex-ante* for TED in PY2015, following PY2014 Study	*Ex-post* TED PY2015
Total	# SAIDs	784	503
	Reference (MW)	671	583
	Load Impact (MW)	32	19
Per SAID	Reference (kW)	856	1,160
	Load Impact (kW)	41	38
	% Load Impact	4.8%	3.3%

Our exploration of the underlying (SAID-level) data found that the primary source of the difference is a change in load impacts for a handful of service accounts. Specifically, differences between the forecast and estimated load impacts for four service accounts account for about 11.8 MW of the difference between last year's *ex-ante* forecast and this year's *ex-post* load impacts.

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

Table 6.4 compares the PY2015 *ex-post* load impacts (based on the six event days that are included in the typical event day) and the 2015 forecast of typical event day load impacts in a utility-specific 1-in-2 weather year. The increase in program-level load impacts from 19 to 27 MW is largely due to differences in *ex-post* and *ex-ante* load impacts for a small number of customers, as described below.

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

Level	Outcome	*Ex-post* TED PY2015	*Ex-ante* TED 2016
Total	# SAIDs	503	493
	Reference (MW)	583	627
	Load Impact (MW)	19	27
Per SAID	Reference (kW)	1,160	1,271
	Load Impact (kW)	38	54
	% Load Impact	3.3%	4.3%

Table 6.5 reviews the potential sources of differences between PY 2015 *ex-post* typical event day and *ex-ante* load impacts for the 2016 utility-specific 1-in-2 typical event day. As the table describes, the primary driver of differences in program-level load impacts is the use of three years of *ex-post* load impacts when developing the *ex-ante* forecast.

That is, we use each customer's performance during every event from PY2013 through PY2015 as the basis for our *ex-ante* load impacts. In some cases, performance changes across years. One large and responsive service account contributes nearly 37 percent of the difference in *ex-post* and *ex-ante* load impacts. During the three events in PY2013 we included in the *ex-ante* study, this customer reduced its load by 100 percent from a reference load that averaged 15.3 MW. This same customer reduced its load on average of 67 percent during the nine PY2014 events and 53 percent during the fifteen PY2015 events we include in the *ex-ante* forecast. When this lower PY2015 performance is averaged together with the higher performance from PY2013 and PY2014, the customer's average percentage load impact is 64 percent.

This difference in percentage load impacts, combined with a difference in the customer's simulated reference load compared to its *ex-post* reference load (which is due to seemingly random variations in its load level across days), means that this customer's *ex-ante* load impact is 2.7 MW higher than its *ex-post* load impact.

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

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	87.5 degrees Fahrenheit during event hours.	95.0 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day.	Hotter *ex-ante* weather increases the reference load somewhat but has little effect on load impacts because the majority of the LI comes from non-weather sensitive customers.
Event window	HE 14-21 for the typical event day.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; winter load impacts are speculative as we have not observed events in those months.
% of resource dispatched	The entire program was dispatched on all of the typical event days.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	503 SAIDs during the average event day.	493 SAIDs.	Departing customers tended to be smaller than average and provided no LI. Their absence increases per-customer reference loads and load impacts.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on (up to) 3-years of SAID-specific load impacts.	Use of 3 years of load impacts tends to increase load impacts relative to current-year *ex-post* estimates because PY15 has lower %LI for some large responders.

Table 6.6 decomposes the major contributing factors of the differences between the *ex-post* and *ex-ante* load impacts. The top row contains the *ex-ante* forecast (again for the

utility-specific 1-in-2 typical event day). The bottom row contains the *ex-post* load impacts for the typical event day and hour. The second row shows the effect of using only the PY2015 *ex-post* load impacts as the basis of the *ex-ante* forecast. Doing this reduces the program load impact from 26.7 MW to 23.2 MW. The third row shows the effect of the change in customer composition between the *ex-post* and *ex-ante* load impacts. Recall that small and non-responsive customers left the program and are not included in the *ex-ante* forecast. If we instead include those customers (but continue to scale load impacts to the 493 customer enrollment amount), the program load impact is further reduced to 22.1 MW. The remaining difference is due to differences between *ex-post* and *ex-ante* reference load levels, which can occur due to idiosyncratic factors our models are not capable of explaining. That is, large customer loads can fluctuate from day-to-day by multiple megawatts, for reasons we cannot observe (*i.e.*, not weather, season, day type, or hour type). Because our methods assume constant percentage load impacts, differences in reference loads lead to corresponding differences in load impacts.

Table 6.6: Reconciling *Ex-post* and *Ex-ante* Load Impacts, PG&E

Scenario	Reference Load	Load Impact	% LI
Ex-ante using PY2013-15	626.6	26.7	4.3%
Ex-ante using only PY2015	626.6	23.1	3.7%
Ex-ante using only PY2015, keep SAIDs	614.9	22.1	3.6%
Ex-post load impact	583.0	19.0	3.3%

6.2 SCE

6.2.1 Previous versus current *ex-post*

Table 6.7 compares *ex-post* load impacts for the typical event day across the three most recent program years. SCE removed non-performing customers between PY2014 and PY2015, which reduced the total number of service accounts without significantly reducing load impacts. The total load impact for customers who left DBP following PY2014 was 1.4 MW. Customers who joined DBP in 2015 added only 0.7 MW to the average event-hour load impact. In contrast, the accounts that were enrolled in DBP in both PY2014 and PY2015 reduced their load impacts by 6.5 MW. There does not appear to be a simple explanation for that change. For example, 6 service accounts decreased their average load impact by 1 MW or more while 9 service accounts increased their average load impact by 1 MW or more across program years.

Table 6.7 Comparison of Average Event-day *Ex-post* Impacts (in MW) in PY 2013 through PY 2015, *SCE*

Level	Outcome	PY2013	PY2014	PY2015
Total	# SAIDs	1,312	944	794
	Reference (MW)	994	814	705
	Load Impact (MW)	99	107	100
Per SAID	Reference (kW)	758	862	888
	Load Impact (kW)	76	113	126
	% Load Impact	10.0%	13.1%	14.1%

6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY 2014 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.8 represents the forecast for the August 2016 utility-specific 1-in-2 peak month day. Both program-level and portfolio-level forecasts are included in the table.

Table 6.8: Comparison of *Ex-ante* Impacts from PY 2014 and PY 2015 Studies, *SCE*

Level	Outcome	Program Level		Portfolio Level	
		Previous Study 2016	Current Study 2016	Previous Study 2016	Current Study 2016
Total	# SAIDs	725	801	442	474
	Reference (MW)	656	702	268	304
	Load Impact (MW)	104	112	4	7
Per SAID	Reference (kW)	904	877	607	642
	Load Impact (kW)	143	140	9	14
	% Load Impact	15.8%	16.0%	1.6%	2.2%

The three most important factors contributing to the difference between the two *ex-ante* forecasts are as follows. First, there is a change in customer composition. Thirty-nine service accounts totaling 10.6 MW in load impacts left DBP between PY2014 and PY2015. Fifty service accounts totaling 0.6 MW in load impacts joined DBP in PY2015. That change in enrollment contributes to a reduction in load impacts across years that is more than offset by the next two factors. The second major source of differences is that the customers who are in both forecasts increased their load impacts by 4.1 MW. Many service accounts contribute to this change, but the largest source is one service account (the most responsive in the program) that increased its load impacts in PY2015 versus PY2014 (in PY2014 it did not respond on two of the event days, but it responded on all of the PY2015 event days). Finally, the third major source of differences across years is in the enrollment forecast. SCE enrollment forecast for 2016 is lower now than it was in the previous study, which causes the program-level load impact to be scaled down proportionately.

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

Table 6.9 provides a comparison of the *ex-ante* forecast of 2015 load impacts prepared following PY2014 and the PY2015 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the typical event day during a 1-in-2 weather year. The *ex-post* load impacts are averaged across the ten PY2015 event days.

The lower *ex-post* load impacts (relative to the prior *ex-ante* forecast) are largely driven by the behavior of the biggest responders. Three service accounts "under-performed" their forecast by 5 MW or more, while only one over-performed by 5 MW or more.

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

Level	Outcome	*Ex-ante* for TED in PY2015, following PY2014 Study	*Ex-post* Average Event Day, PY2015
Total	# SAIDs	772	794
	Reference (MW)	691	705
	Load Impact (MW)	111	100
Per SAID	Reference (kW)	895	888
	Load Impact (kW)	144	126
	% Load Impact	16.0%	14.1%

Table 6.10 compares the bid realization rates from PY2013 through PY2015, showing that the total bid amount decreased in PY2015. Because our forecasts assume that previous bidding behaviors continue in the forecast years, the reduction in bid MW in PY2015 helps explain why the *ex-post* load impacts were lower than expected in the previous *ex-ante* forecast.

Table 6.10 Comparison of Bid Realization Rates from PY2013 to PY2015, *SCE*

Outcome	PY2013	PY2014	PY2015
Avg. Bid Amount	134.2	133.1	115.7
Avg. Load Impact	99.5	106.7	99.7
Realization Rate	74.1%	80.1%	86.2%

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

Table 6.11 compares the *ex-post* and *ex-ante* load impacts from this study, where the *ex-post* impacts are based on an average across the ten 2015 event days and the *ex-ante* load impacts are based on the 2016 typical event day in a utility-specific 1-in-2 weather year.

Table 6.11 Comparison of Current *Ex-post* and *Ex-ante* Impacts, *SCE*

Level	Outcome	*Ex-post* Average Event Day, PY2015	*Ex-ante* Typical Event Day, 2016
Total	# SAIDs	794	801
	Reference (MW)	705	693
	Load Impact (MW)	100	112
Per SAID	Reference (kW)	888	866
	Load Impact (kW)	126	140
	% Load Impact	14.1%	16.2%

Table 6.12 describes the sources of differences between the *ex-post* and *ex-ante* load impacts, using the *ex-ante* 2016 typical event day with utility-specific 1-in-2 weather conditions as the benchmark for comparison.

Table 6.12: SCE *Ex-post* versus *Ex-ante* Factors

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	89.1 degrees Fahrenheit during event hours.	90.1 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day.	Hotter *ex-ante* weather increases the reference load somewhat but has a smaller effect on load impacts since the most responsive customers are not weather sensitive.
Event window	HE 13-20.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; winter load impacts are speculative as we have not observed events in those months.
% 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	794 SAIDs during the average event day.	801 SAIDs in August 2016.	Small effect because composition remains the same and the *ex-ante* includes less than 1 percent more customers.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on (up to) 3-years of SAID-specific load impacts.	Use of 3 years of load impacts increases percentage load impacts relative to current-year *ex-post* estimates because of differences in response across years for some large responders.

Only one of the categories in Table 6.12 has a material effect on the load impact estimates: the use of three years of *ex-post* load impacts rather than only the most recent year. Table 6.13 shows that if the *ex-ante* forecast is re-run using only PY2015 *ex-post* load impacts, the result is very close to the *ex-post* load impacts. Two service accounts contribute a large portion of this effect. The first one consistently bid (and performed) during PY2013 and PY2014, but only bid for one of the ten events in PY2015. The second service account has a significantly higher *ex-ante* load impact because their forecast reference load is higher than the observed loads on event days. This can occur for customers with highly variable loads. Our reference load simulation models factor in usage patterns across all days, while the *ex-post* events occur on only a fraction of days. This can lead to differences between *ex-post* and *ex-ante* reference loads.

Table 6.13: Reconciling *Ex-post* to *Ex-ante* Load Impacts, *SCE*

Scenario	Program Load Impact
Ex-post, all customers	100 MW
Ex-ante using only PY2015 *ex-post* load impacts	99 MW
Ex-ante using PY2013 to PY2015 *ex-post* load impacts	112 MW

6.3 SDG&E

SDG&E did not call any DBP event days during the 2015 program year. Consequently, no comparison of results is needed.

7. Recommendations

Based on the performance of dually enrolled customers, the utilities should continue to encourage customers in BIP and the aggregator programs (AMP and CBP) to enroll in DBP. They tend to be the most responsive customers in DBP and provide a means for the utilities to increase the amount of demand response that can be obtained on DBP-only event days.

Appendices

The following Appendices accompany this report. Appendix A is the validity assessment associated with our *ex-post* load impact evaluation. The additional appendices are Excel files that can produce the tables required by the Protocols.

DBP Study Appendix B	PG&E *Ex-post* Load Impact Tables
DBP Study Appendix C	SCE *Ex-post* Load Impact Tables
DBP Study Appendix D	PG&E *Ex-ante* Load Impact Tables
DBP Study Appendix E	SCE *Ex-ante* Load Impact Tables
DBP Study Appendix F	SDG&E *Ex-ante* Load Impact Tables

Appendix A. Validity Assessment[16]

A.1 Model Specification Tests

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

[16] This appendix contains the model validation descriptions for PG&E and SCE. Because SDG&E did not call any events in PY2015, we do not provide a model validation for their programs.

[17] THI = $T - 0.55 \times (1 - HUM) \times (T - 58)$ if $T>=58$ or THI = T if $T<58$, where T = ambient dry-bulb temperature in degrees Fahrenheit and HUM = relative humidity (where 10 percent is expressed as "0.10").

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

[19] Cooling degree hours (CDH) 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.

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

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

Model Number	Included Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDH60_MA3
6	CDH65_MA3
7	THI THI_MA24
8	HI HI_MA24
9	CDH60 CDH60_MA24
10	CDH65 CDH65_MA24
11	CDH60_MA3 CDH60_MA24
12	CDH65_MA3 CDH65_MA24
13	THI Lag_CDD60
14	HI Lag_CDD60
15	CDH60 Lag_CDD60
16	CDH65 Lag_CDD60
17	CDH60_MA3 Lag_CDD60
18	CDH65_MA3 Lag_CDD60
19	Mean17
20	CDH60 Mean17
21	CDH65 Mean17

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

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

A.1.1 Selection of Event-Like Non-Event Days

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

We selected days according to the average typical event-hour temperature (*e.g.*, hours-ending 14 through 21 for PG&E and 13 through 20 for SCE), 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.2 lists the event-like non-event days selected for each IOU. Recall that SDG&E did not did not call a DBP event in 2015 resulting in no validity assessment being necessary.

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

PG&E	SCE
6/11/2015	7/20/2015
7/3/2015	7/24/2015
7/15/2015	8/4/2015
7/17/2015	8/5/2015
7/20/2015	8/12/2015
7/27/2015	8/24/2015
8/25/2015	8/25/2015
9/8/2015	9/21/2015
9/21/2015	9/23/2015
9/24/2015	9/30/2015
9/25/2015	

A.1.2 Results from Tests of Alternative Weather Specifications

For each utility, we tested 21 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each utility and included only customers who submitted a bid on at least one event day.

The tests are conducted by estimating one model for every utility/program (2), specification (21), and event-like day (11 for PG&E and 10 for SCE). 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.

Table A.3 summarizes the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) of the winning specification for each program. The bias is quite low for the PG&E and SCE model.

Table A.3: Specification Test Results

Utility/Program	Selected Specification Number	Adjusted R^2	MPE	MAPE
PG&E	10	0.86	-0.1%	2.6%
SCE	13	0.90	-1.2%	2.0%

For each specification, we estimated a single model that included all of the days (*i.e.*, not withholding any event-like days), but using a single set of actual event variables (*i.e.*, a 24-hour profile of the average event-day load impacts). Figures A.1 and A.2 show the estimated hourly load impacts for each of the 21 models by IOU and program. The load impacts for the selected specification are highlighted in bold in each of the figures. The results of these tests indicated that very little is at stake when selecting from the specifications, as the load impact profile was quite stable across them. (Note that the odd hourly pattern for PG&E is due to the fact that the event hours change from event to event.)

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

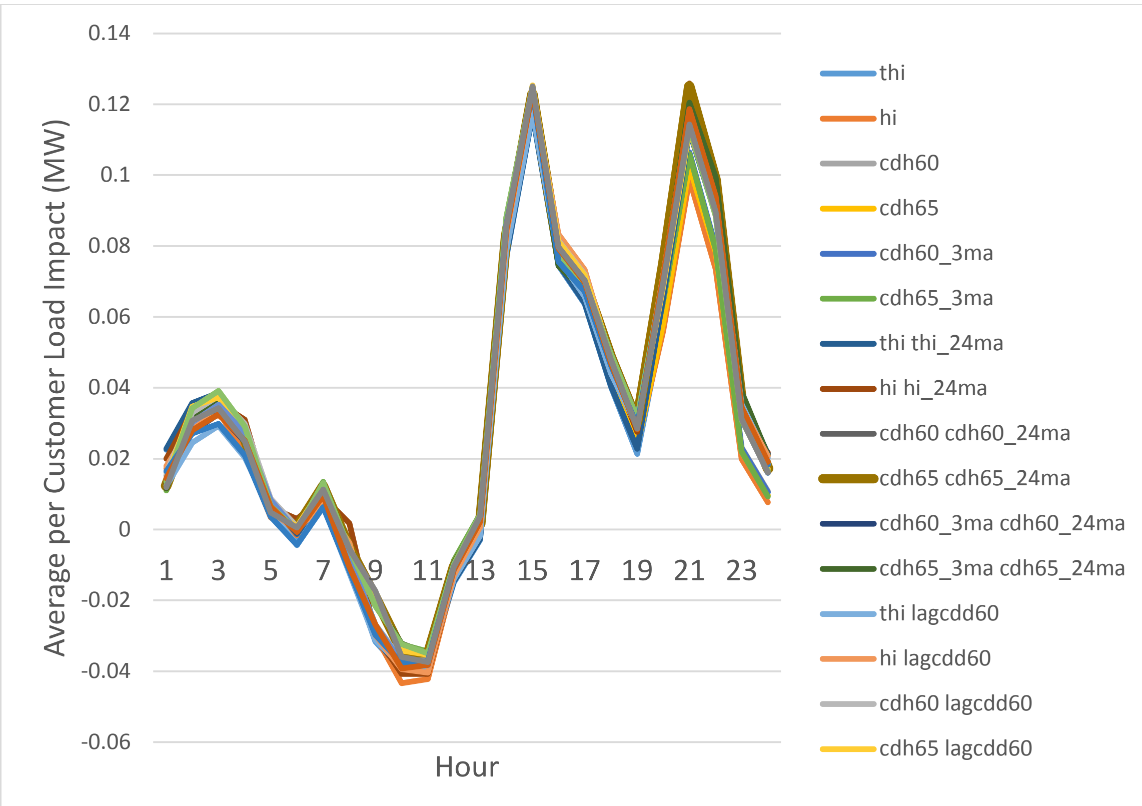
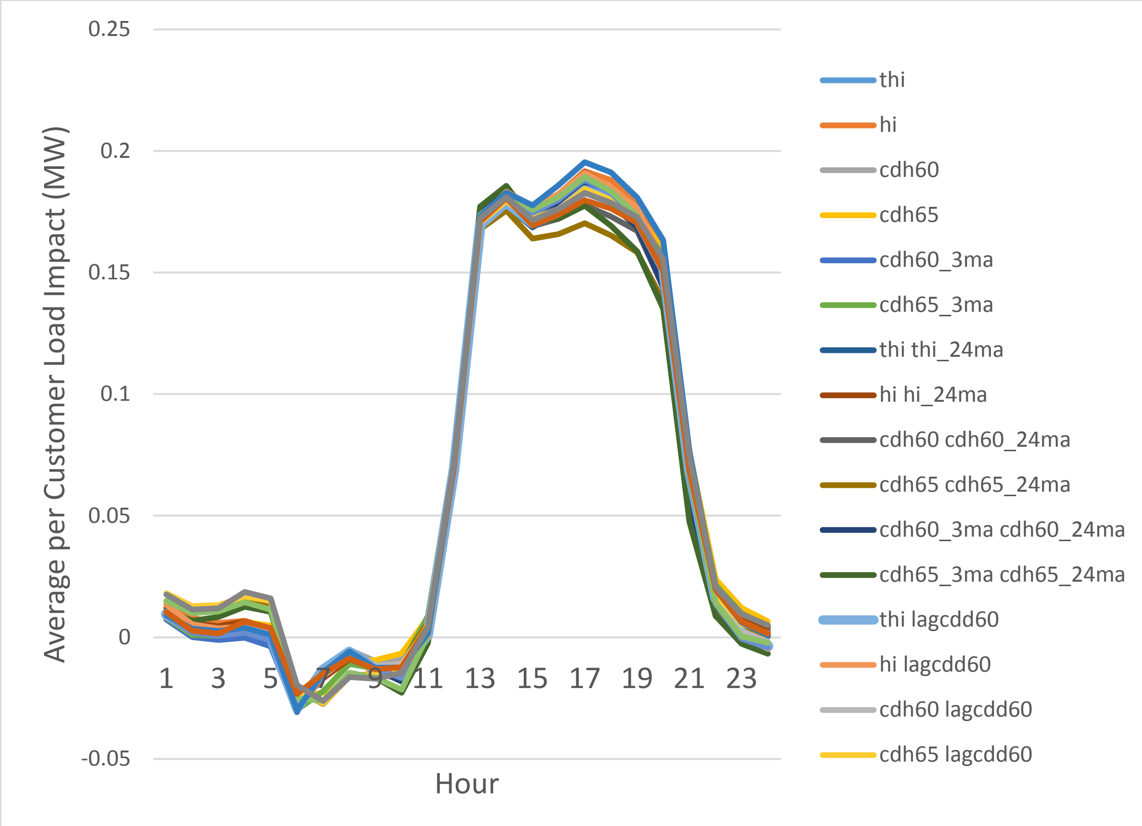


Figure A.2: Average Event-Hour Load Impacts by Specification, *SCE Models*



A.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section A.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data (averaged across all customers who submitted a bid on at least one event day), including a set of 24 hourly "synthetic" event-day variables. These variables equaled one on the days listed in Table A.2, with a separate estimate for each hour of the day.

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

Table A.4 presents the results of this test for each utility, showing only the coefficients during event windows (e.g., hours-ending 14 through 22 for PG&E and 13 through 20 for SCE). The coefficients represent the estimated load change during the synthetic event hour, where negative values indicate a load reduction. The values in parentheses are p-values, or measures of statistical significance. A p-value less than 0.05 indicates that the estimated coefficient is statistically significantly different from zero with 90 percent confidence. None of the results are statistically significant for PG&E. The results for SCE, however, contain two statistically significant results at the end of their event window, but the models perform well overall. While we selected event-like non-event days with closely matching temperature conditions to the event days, the other factors affecting the customer's behavior (which are unknown to us) may drive large and unpredictable changes in the customers load.

Table A.4: Synthetic Event-Day Estimated Load Impact Coefficients and p-values by Program

Hour	PG&E	SCE
13		0.009 (0.41)
14	-0.002 (0.94)	0.015 (0.16)
15	0.008 (0.72)	0.025 (0.02)
16	0.017 (0.43)	0.014 (0.18)
17	-0.002 (0.92)	0.009 (0.39)
18	-0.011 (0.63)	0.012 (0.06)
19	0.008 (0.70)	0.022 (0.05)
20	0.011 (0.62)	0.023 (0.03)
21	0.029 (0.19)	n/a
22	0.035 (0.12)	n/a

A.2 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.3 and A.4 illustrate the average predicted and observed loads across the event-like days. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model.

Figures A.3 and A.3 show that the PG&E and SCE predicted loads are quite close to the observed loads for the event-like non-event days, though SCE's predicted loads are consistently slightly below the observed loads during the middle of the day.

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

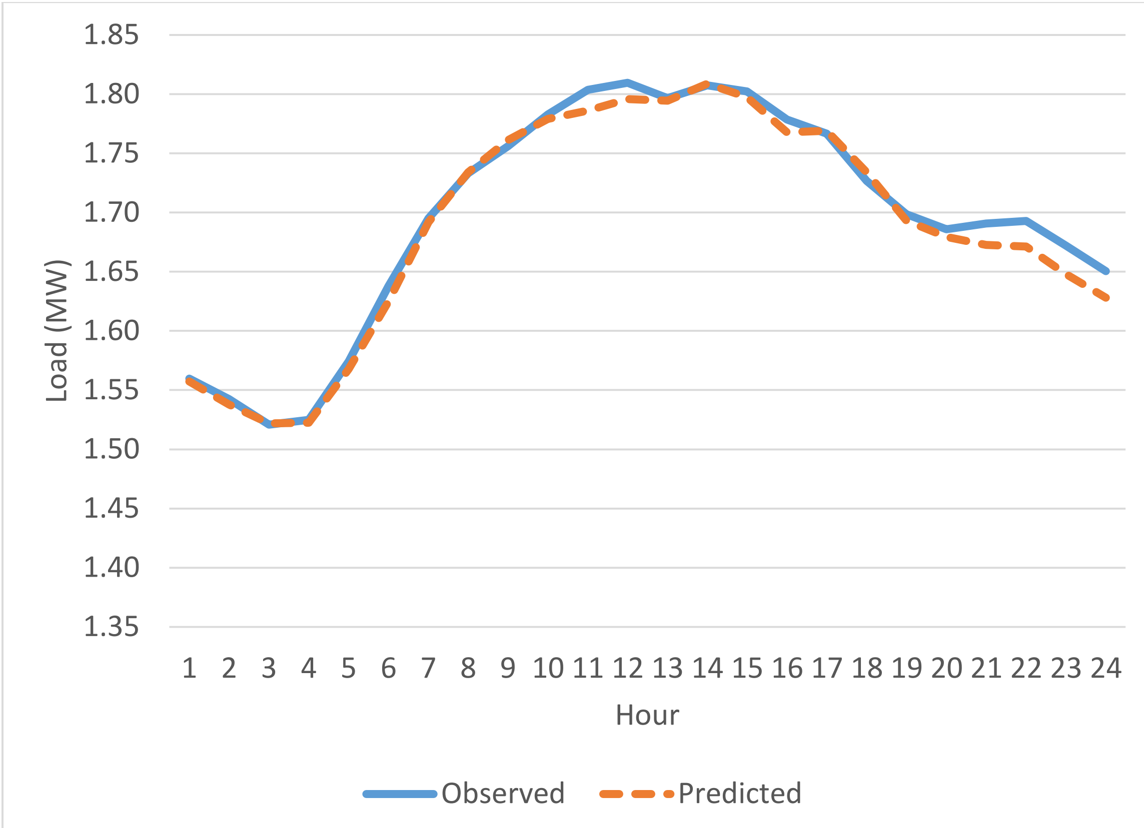
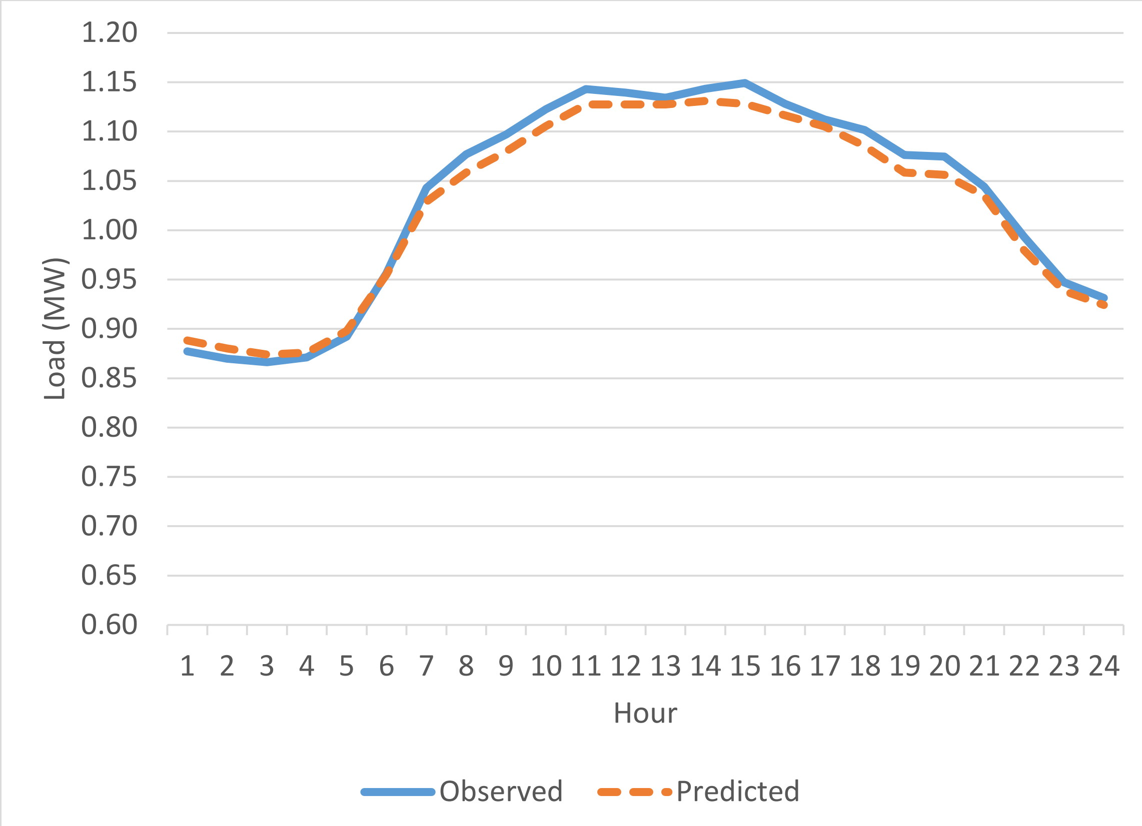


Figure A.4: Average Predicted and Observed Loads on Event-like Days, *SCE*



A.3 Refinement of Customer-Level Models

While the specification tests described in Section A.1 were conducted on aggregated load profiles for each utility, the *ex-post* load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a "day matching" load impact that may be compared to the estimated load impacts. In this evaluation, we modified one PG&E customer's *ex-post* load impacts. This customer had an underestimated load impact for the August 18, 27, and 28 event days. It appeared that the customer responded to the August 17 event day and chose to maintain its low load level through the following event day, August 18. Likewise, the service account responded to the August 26 event day and maintained a low load level for the next two consecutive event days, August 27 and August 28. The inclusion of the morning load variable reduces the implied reference load estimated in the regression models, reducing the load impact estimate. For these customer / event days, we replaced our regression estimate with the load impacts based on the 10-in-10 baseline methodology, which appeared to more correctly reflect the customer's event-day behavior. We examined the rest of PG&E's load impacts to determine whether other customers remained at low load levels between consecutive event days, but could not find evidence that it occurred on other occasions.

While evaluating SCE load impacts, we modified *ex-post* load impacts for three service accounts. In all but one of these cases, the estimated load impacts were underestimated for event days that subsequently followed an event in which the service account responded (*e.g.*, event days 7/30, 8/27, 9/10, 9/11). In other words, the service accounts responded to an event and then maintained low load levels for the entire following event day. As mentioned previously, the morning load variable in our regression analysis reduces the implied reference load, thus reducing the load impact. There was one service account and event day that did not follow the pattern above, in which case the service account was switching between two load points around the event day (July 1) and our model overestimated the load impact. We replaced the load impact estimates for each of these cases with load impacts based on the 10-in-10 baseline methodology, which appeared to more correctly reflect the customer's event-day behavior.