CHRISTENSEN ASSOCIATES ENERGY CONSULTING

2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post and Ex-Ante* Report

CALMAC Study ID SCE0368

Daniel G. Hansen
David Armstrong
Steven D. Braithwait

April 1, 2015

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 2014. The report provides estimates of *ex-post* load impacts that occurred during events called in 2014 and an *ex-ante* forecast of load impacts for 2015 through 2025 that is based on the IOU’s enrollment forecasts and the *ex-post* load impacts estimated for program years 2012 through 2014.

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 twelve events, all of which had an hour-ending 13:00 to 20:00 event window. Three of the events were called for only a sub-set of customers in PG&E’s service territory. SCE called seven eight-hour events from hours ending 13:00 through 20:00. SDG&E called two day-ahead events and four day-of events. Average event-day enrollment in PG&E’s DBP decreased relative to PY2013, from 952 to 846. Enrollment in SCE's DBP fell from 1,312 service accounts in 2013 to 944 in 2014, largely as a result of removing “non-performing” accounts. The sum of enrolled customers’ coincident maximum demands on the average event day was 847 MW. 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, 99 service accounts submitted a bid for at least one event. At SCE, 370 individual and lead service accounts submitted at least one bid during 2014.

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 25 MW, or nearly 4 percent of enrolled load. Event-specific load impacts ranged from a low of 16 MW to a high of 40 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 107 MW across seven events, amounting to 13 percent of the

total reference load. The event-specific load impacts ranged from a low of 51 MW to a high of 143 MW.

In the *ex-ante* evaluation, SCE forecasts DBP customer enrollment to decrease in each year from 2015 to 2017 due to the removal of “non-performing” customers, resulting in approximately 900 service accounts in 2015, falling to approximately 700 accounts in 2017. During the 2015 program year, SCE's average event-hour load impact is approximately 110.4 MW. PG&E forecasts DBP enrollment to drop slightly to 784 service accounts in 2015 and remain at that level through the 2015 to 2025 forecast period. PG&E's program-level load impacts are forecast to be 32.5 MW during a 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 4.6 MW in 2015. For PG&E, the portfolio-level load impact is 1 MW during a 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 2014. The report provides estimates of *ex-post* load impacts that occurred during events called in 2014 and *ex-ante* forecasts of load impacts for 2015 through 2025 that are based on utility enrollment forecasts and the *ex-post* load impacts estimated for program years 2012 through 2014.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2014?
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 TA/TI and 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. 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 twelve events, all of which had an hour-ending 13:00 to 20:00 event window. Three of the events were called for only a sub-set of customers in PG&E's service territory. SCE called seven eight-hour events from hours ending 13:00 through 20:00. SDG&E called two day-ahead events and four day-of events.

Enrollment

Average event-day enrollment in PG&E's DBP decreased relative to PY2013, from 952 to 846 2014. The sum of enrolled customers' coincident maximum demands was 673 MW, or 0.80 MW for the average service account. Two industry groups made up approximately half of PG&E's DBP enrollment: manufacturing; and offices, hotels, health, services.

SCE's enrollment in DBP averaged 944 service accounts across the PY2014 event days, which is a significant decrease relative to the average of 1,312 enrolled service accounts across the PY2013 event days. These accounted for a total of 847 MW of maximum demand, or 0.90 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, 99 service accounts submitted a bid for at least one event. At SCE, 370 individual and lead service accounts submitted at least one bid during 2014.

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 25 MW, or nearly 4 percent of enrolled load, for system-wide events. Event-specific load impacts ranged from a low of

16 MW to a high of 40 MW. Nearly all of the load impacts were provided by customers dually enrolled in another DR program. This is down from the 36 MW average load impact from the previous program year.

For SCE, average hourly program load impacts averaged approximately 107 MW across seven events, amounting to 13 percent of the total reference load. The event-specific load impacts ranged from a low of 51 MW to a high of 143 MW.

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, one TA/TI service account participated in each DBP event and provided an average of 1.3 MW of load impacts. For AutoDR, an average of 81 DBP service accounts participated, though only about half typically submitted bids. The average hourly load impact for those accounts was 12.9 MW, or 18.4 percent of the reference load. For SCE, an average of 173 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 7.2 MW, or 9.8 percent of the total reference load (including TA/TI participants that did not submit a bid). Approximately 239 of SCE's DBP service accounts participated in AutoDR, with an average of 144 submitting bids during each event. Load impacts from these customers averaged 22.5 MW across the seven event days, or 10.8 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 784 service accounts in 2015 and remain at that level through the 2015 to 2025 forecast period. SCE forecasts DBP customer enrollment to decrease in each year from 2015 to 2017 due to the removal of "non-performing" customers, resulting in approximately 900 service accounts in 2015, falling to approximately 700 accounts in 2017. SDG&E forecast enrollment consists of the currently enrolled customers in all forecast years.

For the 2015 program year, SCE's average event-hour load impact is approximately 110.4 MW. PG&E's program-level load impacts are forecast to be 32.5 MW during a 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 4.6 MW in 2015. For PG&E, the portfolio-level load impact is 1 MW during a 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*

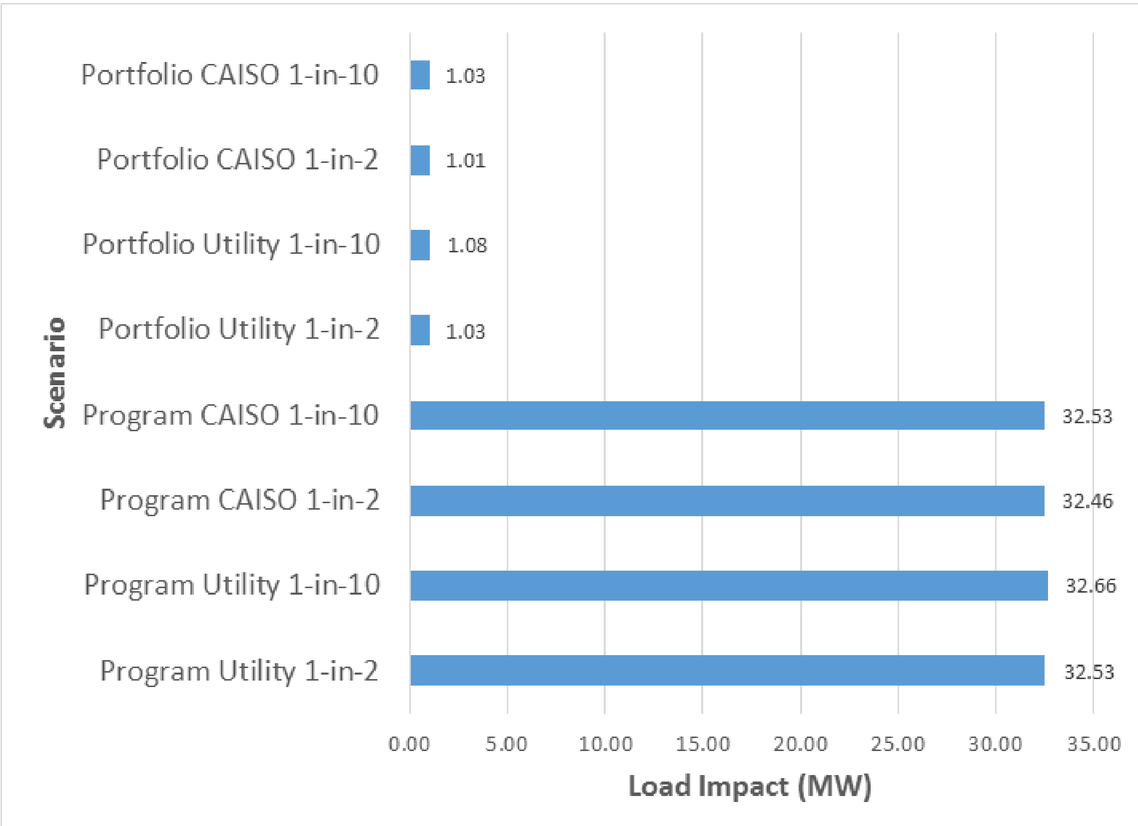
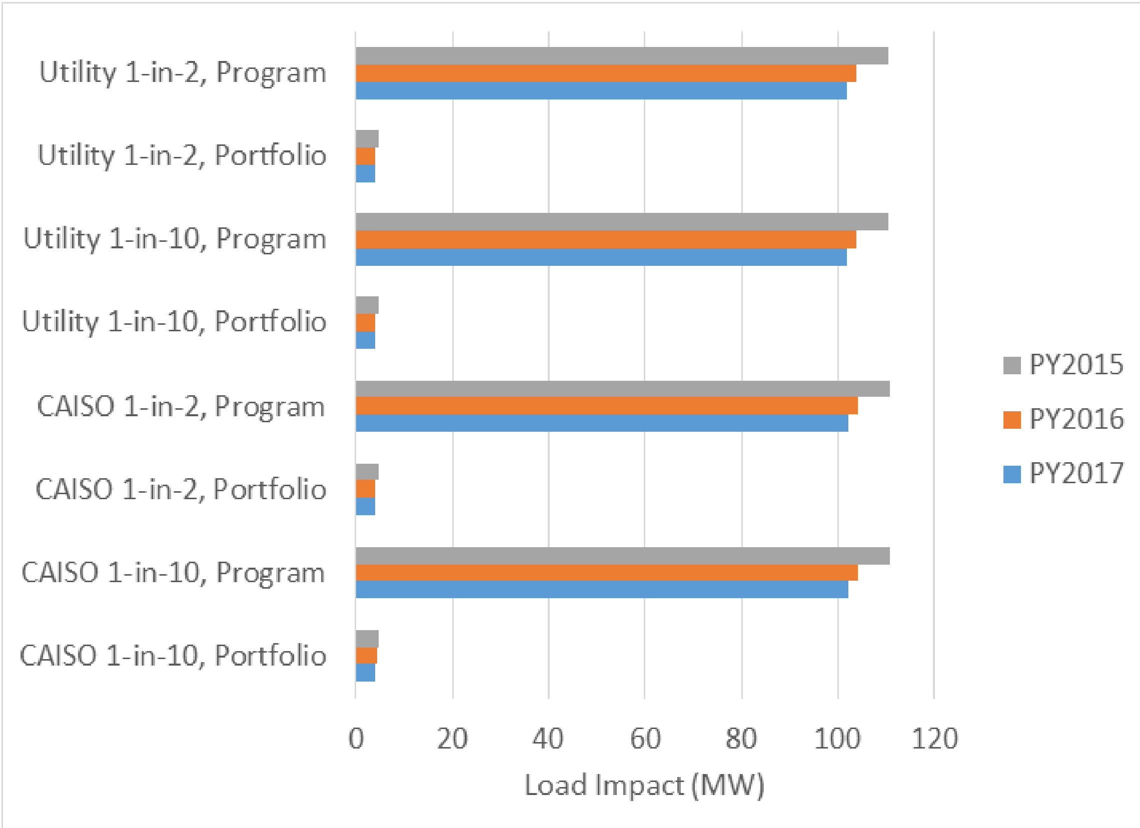


Figure ES.2: Average August *Ex-ante* Load Impacts by Year and Scenario, *SCE*



1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for the statewide 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 2014. The report provides estimates of *ex-post* load impacts that occurred during events called in 2014 and an *ex-ante* forecast of load impacts for 2015 through 2025 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for program years 2012 through 2014.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2014?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. What are the *ex-ante* load impacts for 2015 through 2025?

The report is organized as follows: Section 2 contains a description of the programs, the enrolled customers, and the events called; Section 3 describes the methods used in the study; Section 4 contains the detailed *ex-post* load impact results, 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 2014.

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. 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. Some aggregated customers remain in the 2014 program year, however.

The DBP operates year-round and can be called from 12:00 p.m. to 8:00 p.m. on weekdays, excluding holidays.[1] 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

[1] Effective December 31, 2014, the DBP operational hours became 6:00 a.m. to 10:00 p.m. on weekdays, excluding holidays.

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.

SDG&E's Demand Bidding Program

SDG&E has two DBP programs, as described below:
Schedule DBP-DA: Schedule DBP-DA provides day-ahead notice of event days. The DBP-DA incentive is $0.40 per kWh for customers who purchase commodity from the utility (bundled customers).

Schedule DBP-DO: A demand/energy bidding program that offers incentives to non-residential 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 have no limit to the number of Demand Bidding events per month or year. A customer may not participate simultaneously in DBP-DA or DBP-DO and any other DR rate or program.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

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

1. Agriculture, Mining and Oil and Gas, Construction: 11, 21, 23
2. Manufacturing: 31-33
3. Wholesale, Transport, other Utilities: 22, 42, 48-49

4. Retail stores: 44-45
5. Offices, Hotels, Finance, Services: 51-56, 62, 72
6. Schools: 61
7. Entertainment, Other services and Government: 71, 81, 92
8. Other or unknown.

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[2] 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.[3]

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows DBP enrollment by industry group for PG&E on the average event day. Enrollment in PG&E's DBP decreased relative to PY2013, from 952 to 846 in 2014.[4] The sum of enrolled customers' coincident maximum demands[5] was 673 MW, or 0.80 MW for the average service account. Two industry groups made up approximately half of PG&E's DBP enrollment: manufacturing; and offices, hotels, health, services. Note that some results have been removed due to confidentiality concerns.

---

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

[3] 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.

[4] "Enrollment" is defined as the average enrollment on event days during the 2014 program year. This differs from the pre-PY2012 load impact evaluation, in which we summarized the number of customers enrolled at any time during the program year. The change facilitates the summary of coincident demands (where the previous report summarized non-coincident demands) and improves consistency between the customer characteristics tables and the load impact summary tables.

[5] 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[6]	% of Max MW	Ave. Max MW[7]
1.Agriculture, Mining, Construction	91	30	4.5%	0.33
2.Manufacturing	175	295	43.8%	1.69
3.Wholesale, Transportation, Utilities	122	60	8.9%	0.49
4.Retail	82	11	1.7%	0.14
5.Offices, Hotels, Health, Services	250	186	27.6%	0.74
6.Schools				
7. Entertainment, Other Services, Government.	100	73	10.9%	0.73
8.Other				
TOTAL	**846**	**673**		**0.80**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP averaged 944 service accounts across the PY2014 event days, which is a significant decrease relative to the average of 1,312 enrolled service accounts across the PY2013 event days. The reduction in enrollment is largely due to SCE removing non-performing service accounts from the program. The enrolled customers accounted for a total of 847 MW of maximum demand, or 0.90 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				
2.Manufacturing	203	457.0	54.0%	2.25
3.Wholesale, Transportation, Utilities	90	67.0	7.9%	0.74
4.Retail	238	53.5	6.3%	0.23
5.Offices, Hotels, Health, Services	200	141.2	16.7%	0.71
6.Schools	141	34.6	4.1%	0.24
7.Entertainment, Other Services, Government.				
TOTAL	**944**	**846.8**		**0.90**

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.

[6] "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.
[7] "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	400	274	40.7%	0.68
Greater Fresno				
Humboldt				
Kern				
Northern Coast	48	20	2.9%	0.41
Not in any LCA	247	311	46.1%	1.26
Sierra				
Stockton				
TOTAL	**846**	**673**		**0.80**

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	751	549.4	64.9%	0.73
Outside LA Basin				
Ventura				
TOTAL	**944**	**846.8**		**0.90**

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. Note that 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[8]
1.Agriculture, Mining, Construction			
2.Manufacturing			
3.Wholesale, Transportation, Utilities			
4.Retail			
5.Offices, Hotels, Health, Services			
6.Schools			
7.Entertainment, Other Services, Government.			
TOTAL	**99**	**59.5**	**8.8%**

[8] "% of Enrolled Max MW" is calculated as "Avg. Hourly Bid MW" divided by the "Sum of Max MW" from 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			
2.Manufacturing	148	111.8	24.5%
3.Wholesale, Transportation, Utilities	61	19.7	29.3%
4.Retail			
5.Offices, Hotels, Health, Services	99	11.3	8.0%
6.Schools			
7.Entertainment, Other Services, Government.	25	3.1	3.9%
TOTAL	**370**	**152.7**	**18.0%**

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

2.3 Event Days

Table 2.7 lists DBP event days for the three IOUs in 2014. PG&E called twelve events, all of which had an hour-ending 13:00 to 20:00 event window. Three of the events were called for only a sub-set of customers in PG&E's service territory. SCE called seven eight-hour events from hours ending 13:00 through 20:00. SDG&E called two day-ahead events and four day-of events. SDG&E called two DBP-DA events and four DBP-DO events. The event hours varied across events and are shown in the fourth column.

Table 2.7: DBP Event Days

Date	Day of Week	SCE	PG&E	SDG&E	SDG&E Event Hours
2/6/2014	Thursday			1 (DO only)	HE17-21
2/7/2014	Friday			2 (DA only)	HE14-17
5/14/2014	Wednesday		1 (partial)	3 (DO only)	HE17-20
5/15/2014	Thursday			4 (DA only)	HE17-20
5/16/2014	Friday			5 (DO only)	HE12-19
6/30/2014	Monday		2		
7/7/2014	Monday		3		
7/14/2014	Monday	1	4 (partial)		
7/28/2014	Monday		5		
7/29/2014	Tuesday		6		
7/30/2014	Wednesday		7		
7/31/2014	Thursday		8		
8/1/2014	Friday		9		
9/8/2014	Monday	2			
9/10/2014	Wednesday	3			
9/12/2014	Friday		10 (partial)		
9/15/2014	Monday	4	11		
9/16/2014	Tuesday		12	6 (DO only)	HE16-19
9/17/2014	Wednesday	5			
10/2/2014	Thursday	6			
10/6/2014	Monday	7			

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 two 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 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 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 29.6 kW for PG&E's program and 124.7 kW for SCE's program.

[11] The typical event day is based on the average across all DBP event days for SCE, but excludes the three locationally dispatched events for PG&E. For SDG&E, the typical event day is based on a single event day for each program (May 15, 2014 for DBP-DA and May 16, 2014 for DBP-DO).

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 (excluding the 5/14, 7/14, and 9/12 event days) was 25 MW, or an average of 3.8 percent of the total reference load. The load impacts were highest during the June 30th event, at 39.6 MW (6.2 percent of the reference load). The vast majority of the load impacts came from customers who were dually enrolled in another DR program and accounted for all but 0.9 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
All	1	5/14/2014	Wednesday	168.6	163.2	5.3	3.2%
	2	6/30/2014	Monday	642.1	602.5	39.6	6.2%
	3	7/7/2014	Monday	619.8	604.1	15.7	2.5%
	4	7/14/2014	Monday				
	5	7/28/2014	Monday	665.0	635.4	29.7	4.5%
	6	7/29/2014	Tuesday	663.4	641.0	22.4	3.4%
	7	7/30/2014	Wednesday	676.0	652.1	24.0	3.5%
	8	7/31/2014	Thursday	678.8	652.6	26.1	3.9%
	9	8/1/2014	Friday				
	10	9/12/2014	Friday				
	11	9/15/2014	Monday				
	12	9/16/2014	Tuesday	626.2	599.4	26.8	4.3%
	Average when all called			**650.5**	**625.5**	**25.0**	**3.8%**
	Std. dev. when all called					**6.8**	**1.1%**
Enrolled in DBP Only	1	5/14/2014	Wednesday	127.0	126.6	0.4	0.3%
	2	6/30/2014	Monday	383.1	382.7	0.4	0.1%
	3	7/7/2014	Monday	375.6	374.8	0.8	0.2%
	4	7/14/2014	Monday				
	5	7/28/2014	Monday	397.5	396.4	1.1	0.3%
	6	7/29/2014	Tuesday	394.5	392.2	2.3	0.6%
	7	7/30/2014	Wednesday	396.8	395.4	1.5	0.4%
	8	7/31/2014	Thursday	401.8	400.8	0.9	0.2%
	9	8/1/2014	Friday	388.9	388.4	0.5	0.1%
	10	9/12/2014	Friday				
	11	9/15/2014	Monday	367.9	367.6	0.3	0.1%
	12	9/16/2014	Tuesday	362.4	362.2	0.2	0.1%
	Average when all called			**385.4**	**384.5**	**0.9**	**0.2%**
	Std. dev. when all called					**0.7**	**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 30.5 MW, while the estimated average hourly load impact was 25 MW. The average bid realization rate (i.e., the estimated load impacts as a percentage of bid amounts) across all event hours was 82 percent. The bid realization rate was somewhat lower for customers enrolled only in the DBP, averaging 41 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	5/14/2014	Wednesday	5.0	5.3	106%
	2	6/30/2014	Monday	38.0	39.6	104%
	3	7/7/2014	Monday	25.9	15.7	61%
	4	7/14/2014	Monday			
	5	7/28/2014	Monday	46.2	29.7	64%
	6	7/29/2014	Tuesday	36.2	22.4	62%
	7	7/30/2014	Wednesday	26.9	24.0	89%
	8	7/31/2014	Thursday	24.2	26.1	108%
	9	8/1/2014	Friday			
	10	9/12/2014	Friday			
	11	9/15/2014	Monday			
	12	9/16/2014	Tuesday	21.9	26.8	122%
	Average when all called			**30.5**	**25.0**	**82%**
Enrolled in DBP Only	1	5/14/2014	Wednesday	0.3	0.4	157%
	2	6/30/2014	Monday	2.0	0.4	21%
	3	7/7/2014	Monday	2.4	0.8	35%
	4	7/14/2014	Monday			
	5	7/28/2014	Monday	2.2	1.1	48%
	6	7/29/2014	Tuesday	2.1	2.3	111%
	7	7/30/2014	Wednesday	2.3	1.5	63%
	8	7/31/2014	Thursday	2.0	0.9	45%
	9	8/1/2014	Friday			
	10	9/12/2014	Friday	n/a	n/a	n/a
	11	9/15/2014	Monday	2.6	0.3	13%
	12	9/16/2014	Tuesday	2.1	0.2	10%
	Average when all called			**2.2**	**0.9**	**41%**

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 the average PG&E event. The Manufacturing industry group accounted for the largest share of the load impacts, with a 21.2 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	91	28.8	28.9	-0.1	(0.4%)
Manufacturing	175	285.2	264.0	21.2	7.4%
Wholesale, Transportation, & Other Utilities	122	61.4	59.1	2.2	3.6%
Retail Stores	82	12.1	12.1	0.0	0.2%
Offices, Hotels, Health, Services	250	177.1	176.0	1.1	0.6%
Schools	26	16.3	16.2	0.1	0.4%
Entertainment, Other Services, Government	100	68.5	68.0	0.4	0.6%
Other or Unknown	1	1.1	1.1	0.0	0.0%
Total	**846**	**650.5**	**625.5**	**25.0**	**3.8%**

Table 4.4 summarizes load impacts for the average event 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	400	264.3	260.8	3.5	1.3%
Greater Fresno					
Humboldt					
Kern					
Northern Coast	48	17.8	16.5	0.7	4.3%
Not in any LCA	247	301.5	280.8	20.7	6.9%
Sierra					
Stockton					
Total	**846**	**650.5**	**625.5**	**25.0**	**3.8%**

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 during which all DBP customers were called. The hourly load impact on the average event day ranges from 19.7 MW to 28.4 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 24.1 MW of the 25 MW total DBP load impact.

Table 4.5: DBP Hourly Load Impacts for the Average 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	541.4	540.2	1.3	69.6	0.2	0.9	1.3	1.7	2.4
2	534.8	535.0	-0.2	68.4	-1.0	-0.5	-0.2	0.2	0.7
3	529.5	529.7	-0.3	67.5	-1.0	-0.6	-0.3	0.0	0.5
4	530.0	530.2	-0.2	66.5	-0.9	-0.4	-0.2	0.1	0.5
5	539.2	540.3	-1.2	65.7	-1.9	-1.4	-1.2	-0.9	-0.5
6	560.4	561.8	-1.4	65.1	-2.2	-1.8	-1.4	-1.1	-0.7
7	591.6	592.5	-1.0	64.8	-1.8	-1.3	-1.0	-0.7	-0.2
8	612.3	612.4	-0.1	66.0	-0.9	-0.4	-0.1	0.2	0.7
9	631.5	629.0	2.5	68.7	1.6	2.1	2.5	2.9	3.4
10	650.2	647.2	2.9	72.0	2.1	2.6	2.9	3.3	3.8
11	659.7	656.0	3.7	75.6	2.7	3.3	3.7	4.1	4.7
12	669.3	660.0	9.3	78.8	8.3	8.9	9.3	9.8	10.4
13	667.4	639.4	28.1	81.5	26.9	27.6	28.1	28.5	29.2
14	673.3	644.9	28.4	83.8	27.2	27.9	28.4	28.9	29.6
15	672.3	646.2	26.1	85.1	24.9	25.6	26.1	26.6	27.3
16	659.5	633.2	26.3	85.7	25.0	25.8	26.3	26.8	27.5
17	651.3	625.4	26.0	85.8	24.7	25.5	26.0	26.5	27.3
18	637.3	613.2	24.1	85.2	22.7	23.6	24.1	24.7	25.6
19	625.5	604.0	21.5	83.1	20.1	20.9	21.5	22.1	23.0
20	617.3	597.6	19.7	80.1	18.3	19.1	19.7	20.3	21.1
21	611.9	600.0	11.9	76.8	10.5	11.3	11.9	12.5	13.3
22	603.1	596.6	6.5	74.2	5.1	5.9	6.5	7.1	7.9
23	589.4	584.2	5.2	72.4	3.7	4.6	5.2	5.8	6.7
24	575.4	569.9	5.5	70.9	4.1	4.9	5.5	6.1	7.0
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75°F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	14,634	14,389	245	76.6	n/a	n/a	n/a	n/a	n/a
Event Hours	650.5	625.5	25.0	70.4	23.3	24.3	25.0	25.7	26.8

Figure 4.1 illustrates the hourly reference load, observed load, and load impacts for the average 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 twelve event days.

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 Average Event Day, *PG&E*

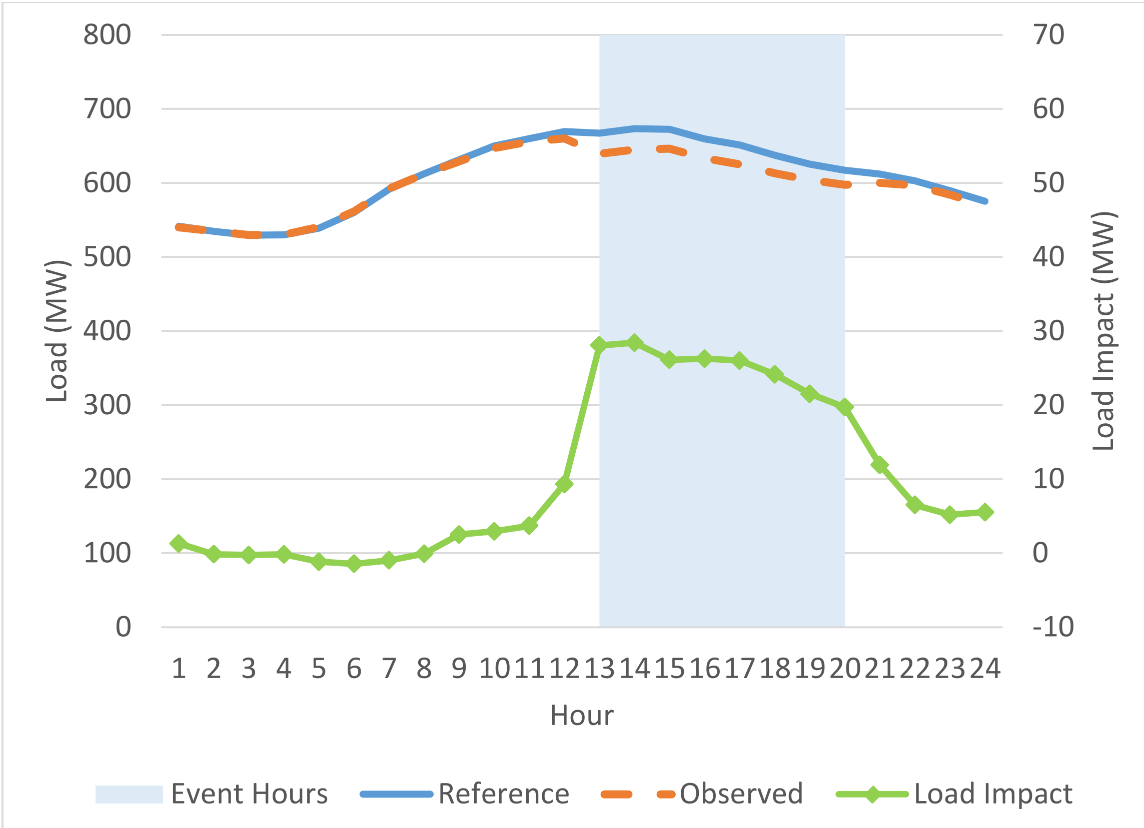
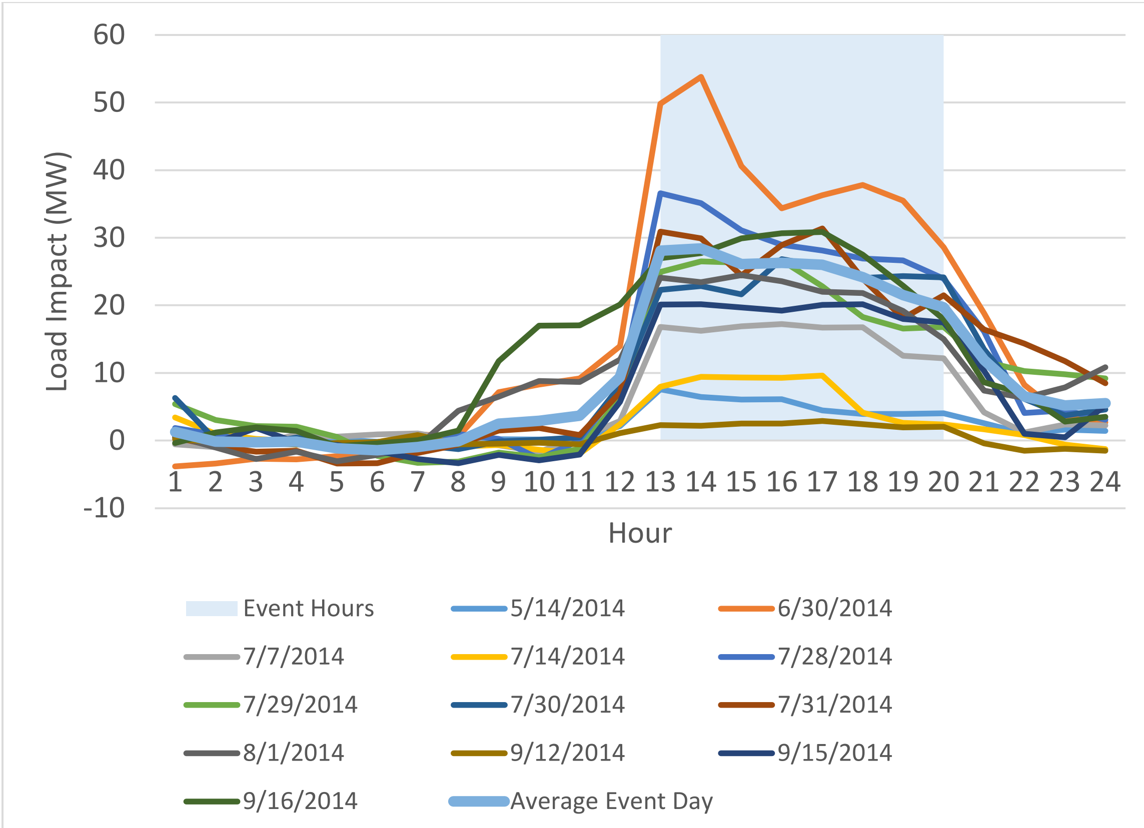


Figure 4.2: Hourly Load Impacts by Event, *PG&E DBP*



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 seven 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 106.7 MW. The load impacts varied across event days, with a low of 51.2 MW, a high of 142.9 MW, and a standard deviation of 35.6 MW. On average, the load impacts were 13.1 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	7/14/2014	Monday	890.0	747.1	142.9	16.1%
	2	9/8/2014	Monday	809.5	666.8	142.6	17.6%
	3	9/10/2014	Wednesday	819.6	728.5	91.1	11.1%
	4	9/15/2014	Monday	846.4	713.1	133.4	15.8%
	5	9/17/2014	Wednesday	827.0	717.0	110.1	13.3%
	6	10/2/2014	Thursday	756.3	680.7	75.6	10.0%
	7	10/6/2014	Monday	746.1	695.0	51.2	6.9%
			Average	**813.6**	**706.9**	**106.7**	**13.1%**
			Std. Dev.			**35.6**	**4.4%**
Enrolled in DBP Only	1	7/14/2014	Monday	411.5	406.6	4.9	1.2%
	2	9/8/2014	Monday	345.4	335.0	10.4	3.0%
	3	9/10/2014	Wednesday	334.6	333.0	1.6	0.5%
	4	9/15/2014	Monday	375.5	370.9	4.6	1.2%
	5	9/17/2014	Wednesday	370.7	363.1	7.6	2.1%
	6	10/2/2014	Thursday	320.4	314.7	5.7	1.8%
	7	10/6/2014	Monday	322.3	320.3	2.0	0.6%
			Average	**354.3**	**349.1**	**5.3**	**1.5%**
			Std. Dev.			**3.1**	**0.9%**

Table 4.7 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 133.1 MW, while the estimated average hourly load impact was 106.7 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 80.1 percent. The bottom panel of Table 4.7 shows that the bid realization rate is much lower (29 percent) for the customers who were not enrolled in another DR program.

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	7/14/2014	Monday	162.0	142.9	88.2%
	2	9/8/2014	Monday	138.7	142.6	102.8%
	3	9/10/2014	Wednesday	113.5	91.1	80.3%
	4	9/15/2014	Monday	153.8	133.4	86.7%
	5	9/17/2014	Wednesday	123.6	110.1	89.1%
	6	10/2/2014	Thursday	109.9	75.6	68.8%
	7	10/6/2014	Monday	130.3	51.2	39.3%
			Average	**133.1**	**106.7**	**80.1%**
Enrolled in DBP Only	1	7/14/2014	Monday	21.5	4.9	22.9%
	2	9/8/2014	Monday	18.1	10.4	57.5%
	3	9/10/2014	Wednesday	17.0	1.6	9.2%
	4	9/15/2014	Monday	17.7	4.6	26.2%
	5	9/17/2014	Wednesday	17.4	7.6	43.6%
	6	10/2/2014	Thursday	17.1	5.7	33.5%
	7	10/6/2014	Monday	17.1	2.0	11.5%
			Average	**18.0**	**5.3**	**29.3%**

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 and South of Lugo. 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					
Manufacturing	203	443.3	355.6	87.7	19.8%
Wholesale, Transportation, & Other Utilities	90	66.9	53.2	13.7	20.4%
Retail Stores	238	57.6	57.3	0.3	0.6%
Offices, Hotels, Health, Services	200	129.0	126.0	3.0	2.3%
Schools	141	23.8	23.3	0.5	2.2%
Entertainment, Other Services, Government					
Total	**944**	**813.6**	**706.9**	**106.7**	**13.1%**

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	751	518.0	450.7	67.4	13.0%
Outside LA Basin					
Ventura					
Total	**944**	**813.6**	**706.9**	**106.7**	**13.1%**
South Orange County	198	149.0	97.0	52.0	34.9%
South of Lugo	284	160.4	158.0	2.4	1.5%
Rest of System	462	504.2	451.8	52.4	10.4%

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 93 MW to 112 MW.

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	641.4	617.3	24.0	72.0	17.9	21.5	24.0	26.5	30.1
2	638.9	615.4	23.5	71.1	17.6	21.1	23.5	25.9	29.3
3	632.4	615.6	16.8	70.3	12.4	15.0	16.8	18.6	21.1
4	630.0	634.9	-4.9	69.8	-10.5	-7.2	-4.9	-2.6	0.7
5	649.5	661.1	-11.6	69.4	-16.7	-13.7	-11.6	-9.5	-6.4
6	690.6	700.6	-10.0	69.1	-14.2	-11.7	-10.0	-8.3	-5.8
7	748.3	750.0	-1.6	70.1	-7.7	-4.1	-1.6	0.9	4.5
8	781.1	768.7	12.5	73.0	6.4	10.0	12.5	15.0	18.5
9	808.2	796.1	12.1	76.7	6.1	9.6	12.1	14.5	18.1
10	830.1	815.1	14.9	80.1	6.8	11.6	14.9	18.2	23.0
11	836.6	816.0	20.5	83.0	12.7	17.3	20.5	23.8	28.4
12	846.8	783.6	63.2	85.3	55.1	59.9	63.2	66.4	71.2
13	841.5	734.1	107.4	87.1	99.4	104.1	107.4	110.7	115.5
14	846.3	734.7	111.6	88.0	103.9	108.4	111.6	114.8	119.3
15	841.5	736.7	104.9	88.6	97.2	101.7	104.9	108.0	112.5
16	832.1	722.6	109.5	88.3	101.4	106.2	109.5	112.8	117.5
17	820.3	708.1	112.2	87.0	105.0	109.2	112.2	115.1	119.3
18	802.7	692.4	110.3	84.6	102.6	107.2	110.3	113.4	117.9
19	770.1	665.5	104.6	81.4	95.9	101.0	104.6	108.2	113.4
20	754.2	661.0	93.2	78.9	84.2	89.6	93.2	96.9	102.3
21	748.1	694.4	53.7	77.0	44.5	49.9	53.7	57.5	62.9
22	733.1	700.5	32.7	75.6	23.2	28.8	32.7	36.6	42.2
23	707.7	681.9	25.9	74.3	16.1	21.9	25.9	29.9	35.6
24	676.0	663.7	12.2	73.1	4.3	9.0	12.2	15.5	20.1
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	18,107	16,970	1,138	111.6	n/a	n/a	n/a	n/a	n/a
Event Hours	813.6	706.9	106.7	83.8	102.4	105.0	106.7	108.5	111.0

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*

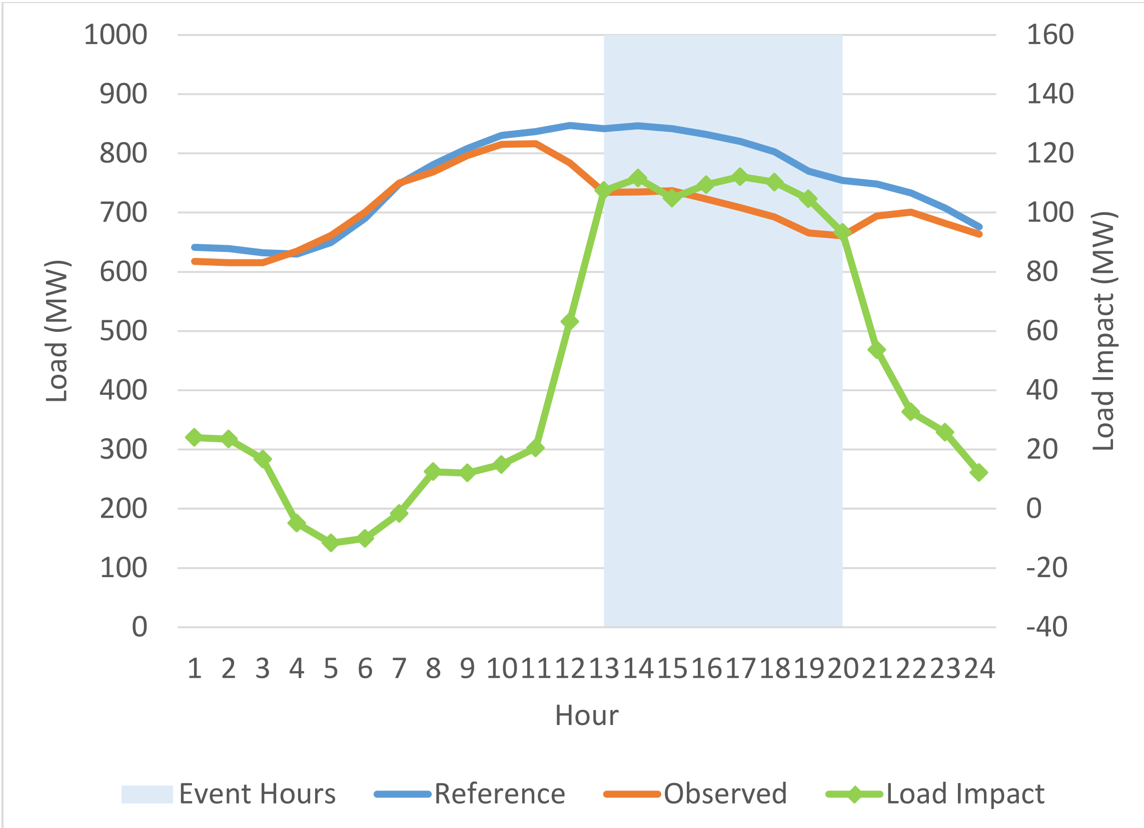
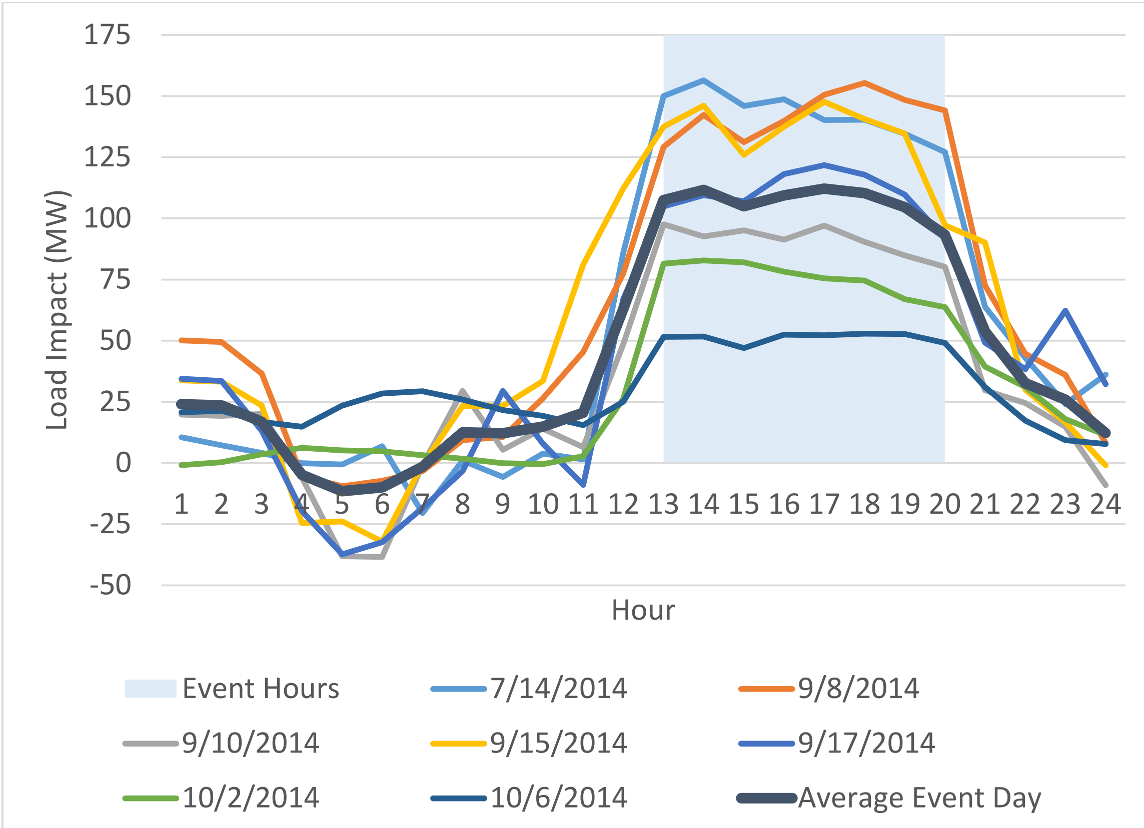


Figure 4.4: Hourly Load Impacts by Event, *SCE DBP*



4.3 SDG&E Load Impacts

4.3.2 Hourly Load Impacts

Recall that SDG&E has two DBP programs, each of which consists of a small number of service accounts

Table 4.13: DBP Hourly Load Impacts for the September 16th Event Day, *SDG&E DO*

These results have been removed due to confidentiality concerns.

Table 4.14: DBP Hourly Load Impacts for the February 7th Event Day, *SDG&E DA*

These results have been removed due to confidentiality concerns.

Figures 4.5 and 4.6 illustrate the hourly reference load, observed load, and load impact for the most responsive DO and DA DBP event days. The scale for the load impacts is on the right-hand side of the figure.

Figure 4.5: DBP September 16, 2014 Load Impacts, *SDG&E DO*

These results have been removed due to confidentiality concerns.

Figure 4.6: DBP February 7, 2014 Load Impacts, *SDG&E DA*

These results have been removed due to confidentiality concerns.

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 two demand response incentive programs: TA/TI and AutoDR.

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.

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.

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 4.15 shows the event-specific load impact for the past TA/TI participants. These customers averaged load impacts of 11.5 percent across the nine system-wide event days (i.e., when the entire DBP program was notified), with the highest response of 3.2 MW occurring on the June 30th event day. 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 4.15: 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
5/14/2014							
6/30/2014							
7/7/2014							
7/14/2014							
7/28/2014							
7/29/2014							
7/30/2014							
7/31/2014							
8/1/2014							
9/12/2014							
9/15/2014							
9/16/2014							
Average when all called							

AutoDR

According to data provided by PG&E, an average of 81 DBP service accounts participated in the AutoDR program. During any one event when all DBP customers were notified, a maximum of 49 of these submitted a bid. Table 4.16 shows the average hourly load impact for the AutoDR participants, which was 12.9 MW, or 18.4 percent of the reference load. Some results have been removed due to confidentiality concerns.

Table 4.16: 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
5/14/2014							
6/30/2014	82	49	70.4	56.2	14.2	20.1%	37.6
7/7/2014	82	42	67.6	54.2	13.5	19.9%	37.6
7/14/2014							
7/28/2014	83	41	70.0	54.6	15.4	22.0%	37.6
7/29/2014	83	31	72.4	59.0	13.4	18.5%	37.6
7/30/2014	83	40	72.0	59.4	12.5	17.4%	37.6
7/31/2014	82	32	71.3	58.8	12.5	17.5%	37.6
8/1/2014	82	32	68.7	55.4	13.3	19.4%	37.6
9/12/2014							
9/15/2014	75	40	69.1	64.3	4.8	6.9%	37.2
9/16/2014	75	31	68.2	51.8	16.5	24.1%	37.2
Average when all called	**81**	**38**	**70.0**	**57.1**	**12.9**	**18.4%**	**37.5**

SCE

TA/TI

Table 4.17 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 173 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 7.2 MW, or 9.8 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 4.17: 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
7/14/2014	175						
9/8/2014	173						
9/10/2014	173						
9/15/2014	173						
9/17/2014	172						
10/2/2014	172						
10/6/2014	172						
Average	**173**	**28**	**73.2**	**66.1**	**7.2**	**9.8%**	**23.0**

AutoDR

Table 4.18 shows the total DBP load impacts for SCE's AutoDR participants. Approximately 239 DBP service accounts participated in AutoDR, with an average of 144 participants bidding during each event. Load impacts from these customers averaged 22.5 MW across the seven event days, or 10.8 percent of the reference load (including Auto-DR customers that did not submit a bid).

Table 4.18: 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
7/14/2014	238	148	204.2	174.8	29.4	14.4%	81.7
9/8/2014	239	143	200.1	183.4	16.8	8.4%	82.4
9/10/2014	239	141	205.5	190.1	15.4	7.5%	81.0
9/15/2014	239	143	218.2	195.0	23.2	10.6%	83.0
9/17/2014	239	144	212.0	188.3	23.7	11.2%	83.5
10/2/2014	239	145	211.0	183.1	27.9	13.2%	83.9
10/6/2014	239	143	199.2	178.2	21.0	10.5%	83.0
Average	**239**	**144**	**207.2**	**184.7**	**22.5**	**10.8%**	**82.6**

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, 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).

For SCE, the analysis accounts for the removal of "non-performing" customers from the program in early 2015 (and to a lesser extent the following two years). Based on current estimates, approximately 140 service accounts will be removed from DBP between February and April 2015. SCE provided a list of the non-performing service accounts, which we have removed from our *ex-ante* forecasting process beginning in April 2015 (when 128 of the 140 removals are expected to occur).

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 2014 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 (2012 through 2014; only 2013 and 2014 are available for SDG&E).

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 CDH60 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.

Because DBP events may be called in any month of the year, we estimated separate regression models to allow us to simulate non-summer reference loads. The non-summer model is shown below. This model is estimated separately from the summer *ex-ante* model. It only differs from the summer model in two ways: it includes HDH_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.

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

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
HDH_t	heating degree hours[12]
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 differences across scenarios can be attributed to varying weather conditions. This is the first program year in which the evaluation includes two sets of 1-in-2 and 1-in-10 weather years. The sets are differentiated according to whether they correspond to utility-specific conditions or CAISO-coincident conditions. The weather conditions used in prior evaluations corresponded to the utility-specific scenarios. All of the weather scenarios (including the utility-specific scenarios) were newly generated in a separate project as part of this year's evaluation process.

[12] Heating degree hours (HDH) was defined as MAX[0, 50 – 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.

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 2012 through 2014. SDG&E used only 2013 and 2014, as the program did not exist in 2012. Specifically, we examined only customers enrolled in PY2014, but included load impact estimates from the previous two program years for the PY 2014 program participants that also participated in the program in 2012 and 2013. 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 PY12 through PY14. 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 window (Noon to 6:00 p.m.), we needed to adjust the historical percentage load impacts for use in the *ex-ante* study. Specifically, in summer months, we adapted the 8-hour historical event window to the 5-hour forecast event window using the correspondence shown in Table 5.2.

Table 5.2: Method of Adapting the *Ex-post* Event Window to the *Ex-ante* Window, *PG&E and SCE*

Ex-ante Hour	*Ex-post* Hour(s)
14	13
15	14, 15
16	16, 17
17	18, 19
18	20

For the non-summer months, the summer hourly percentage load impacts were shifted forward three hours, so that the event hours matched the required 4:00 to 9:00 p.m. window.

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 2025, with separate enrollments provided at the program and portfolio level (the latter excludes dually enrolled customers) by LCA and size group. SCE provided monthly enrollments for 2015, 2016, and 2017. We assume that the 2017 enrollments apply through 2025. In addition, SCE provided the list of service accounts that they expect to exclude beginning in 2015 due to non-performance. SDG&E assumes that current enrollments persist through the end of the analysis period. 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

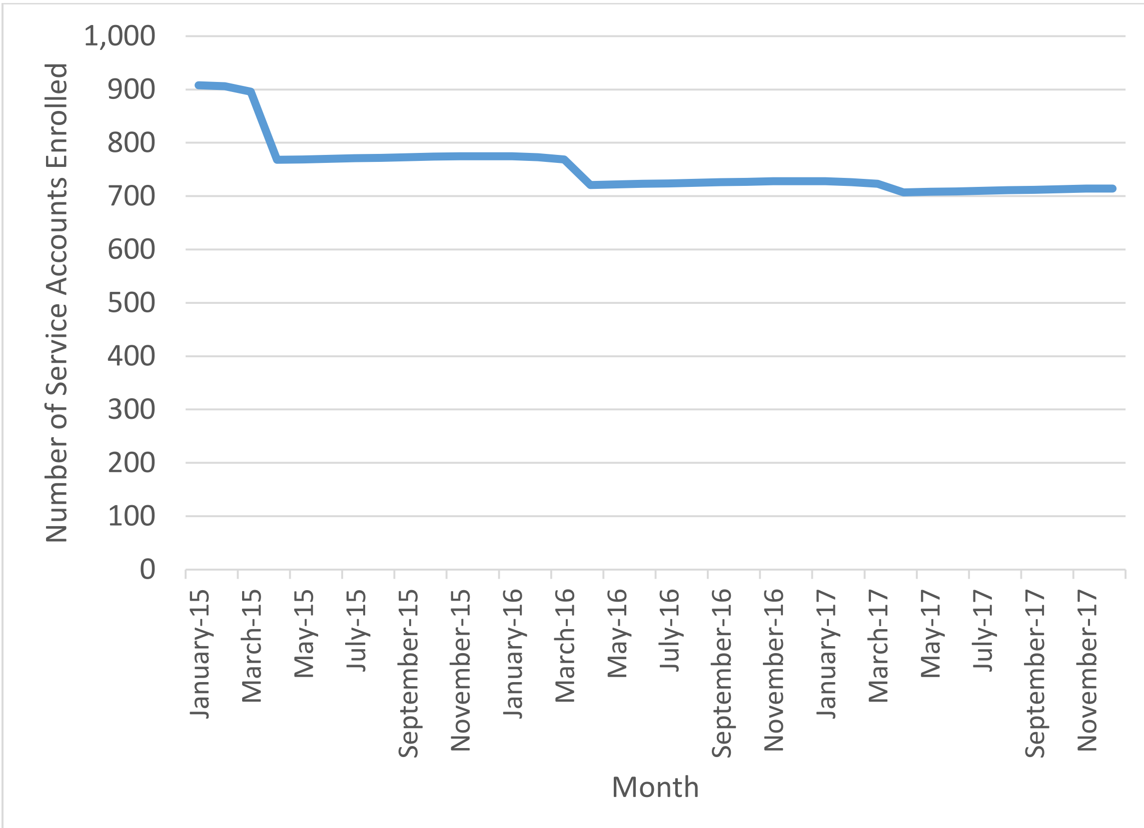
PG&E

PG&E forecasts DBP enrollments to remain constant from 2015 through 2025, with 784 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 580 service accounts during the summer months and 698 service accounts during non-summer months.

SCE

Figure 5.1 shows SCE's monthly forecast DBP enrollments from 2015 to 2017. The drop in enrollments that occurs in the early part of each year is due to SCE removing non-performing accounts.

Figure 5.1: SCE Forecast DBP Enrollments by Month



SDG&E

We assumed that the currently enrolled customers continue to be enrolled in their respective DBP programs.

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 5.2 shows the program-level August 2015 forecast load impacts for a typical event day in a utility-specific 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 32.5 MW, which represents 4.9 percent of the enrolled reference load. Figure 5.3 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 31.5 MW (relative to the program-level load impact) to 1.0 MW and the percentage load impact goes down to 0.3 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 5.2: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-specific 1-in-2 Weather Year for August 2015, Program Level

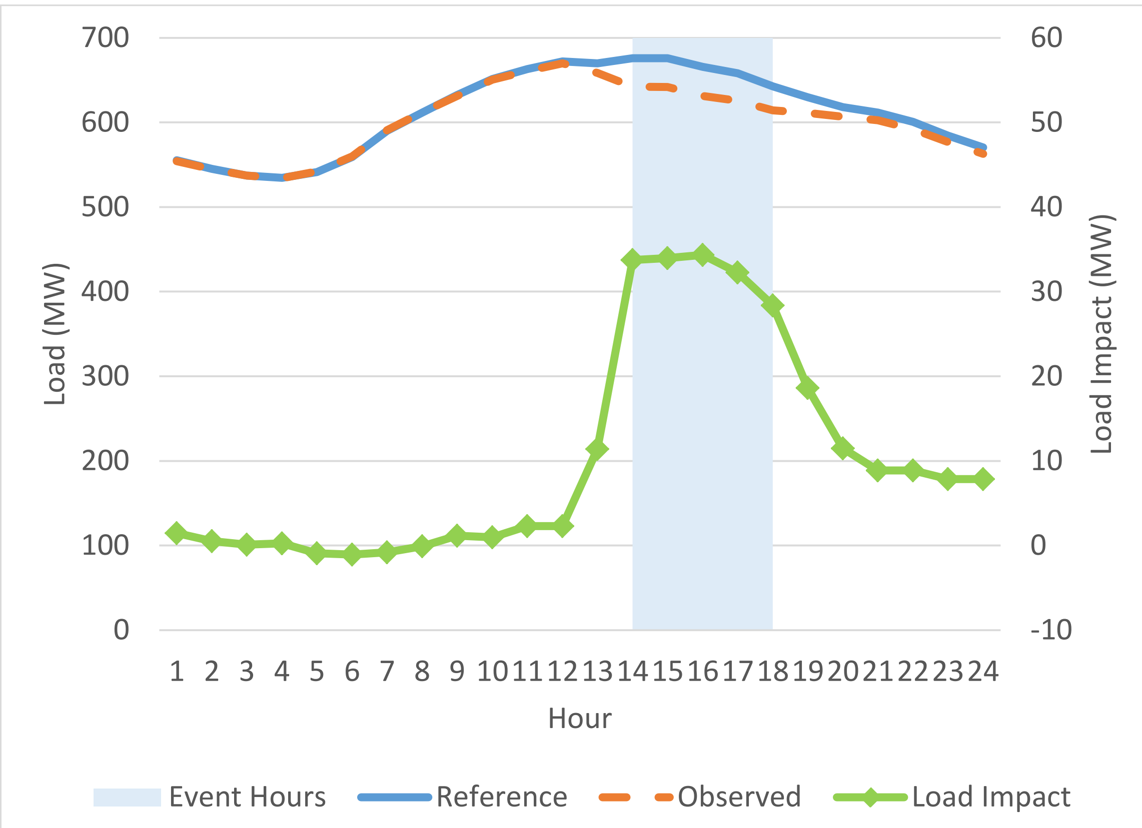


Figure 5.3: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a Utility-specific 1-in-2 Weather Year for August 2015, Portfolio Level

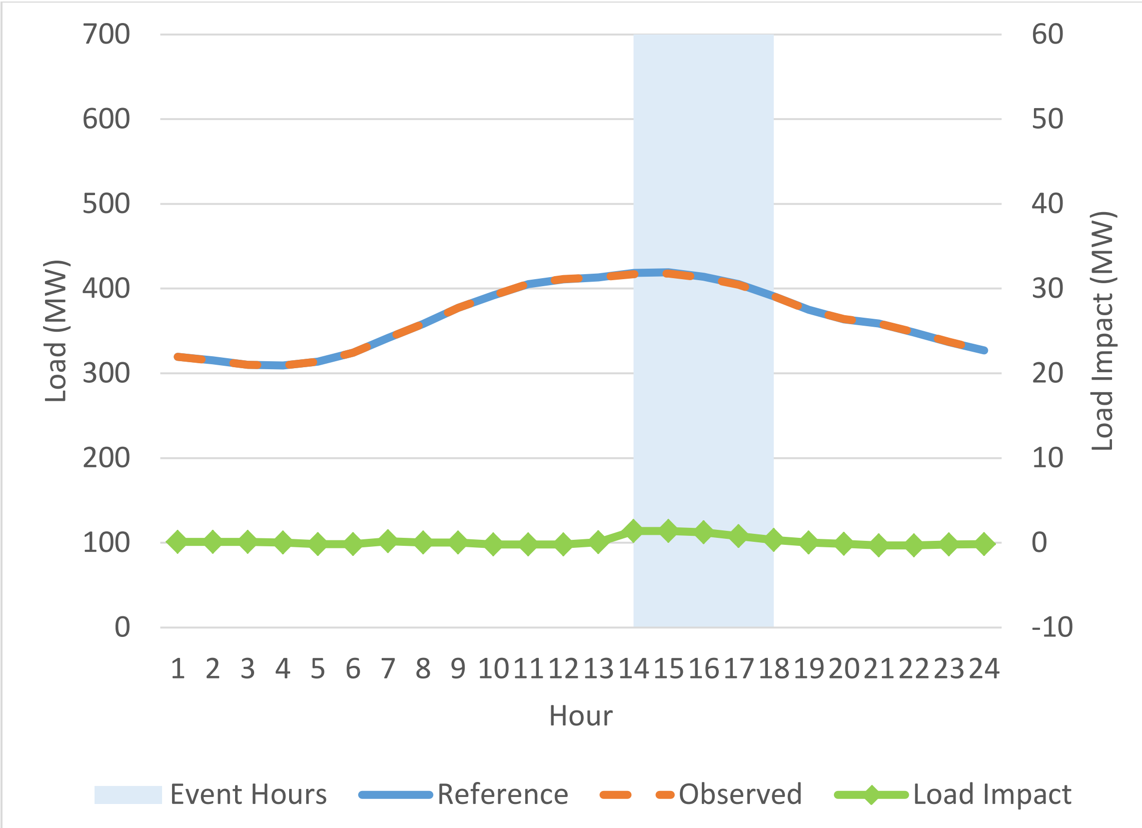


Figure 5.4 shows the share of load impacts by LCA, assuming a typical event day in an August 2015 1-in-2 weather year. Customers not in any LCA account for the largest share, with 77 percent of the load impacts.

Figure 5.4: Share of PG&E Load Impacts by LCA for the August 2015 Typical Event Day in a Utility-specific 1-in-2 Weather Year

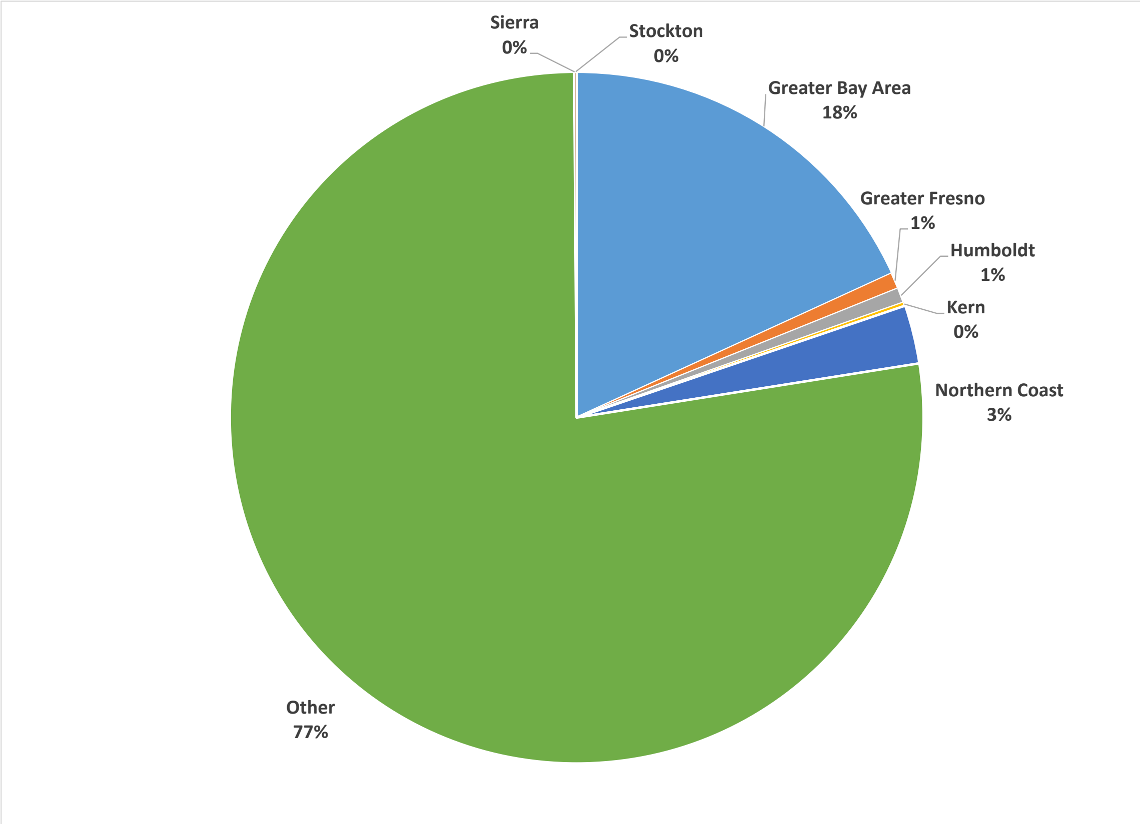


Figure 5.5 illustrates August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions, utility-specific versus CAISO-coincident peak conditions, and portfolio- versus program-level load impacts. Recall that the enrollment forecast does not change across the 2015-2025 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 5.5: Average Hourly *Ex-ante* Load Impacts by Scenario for August, *PG&E*

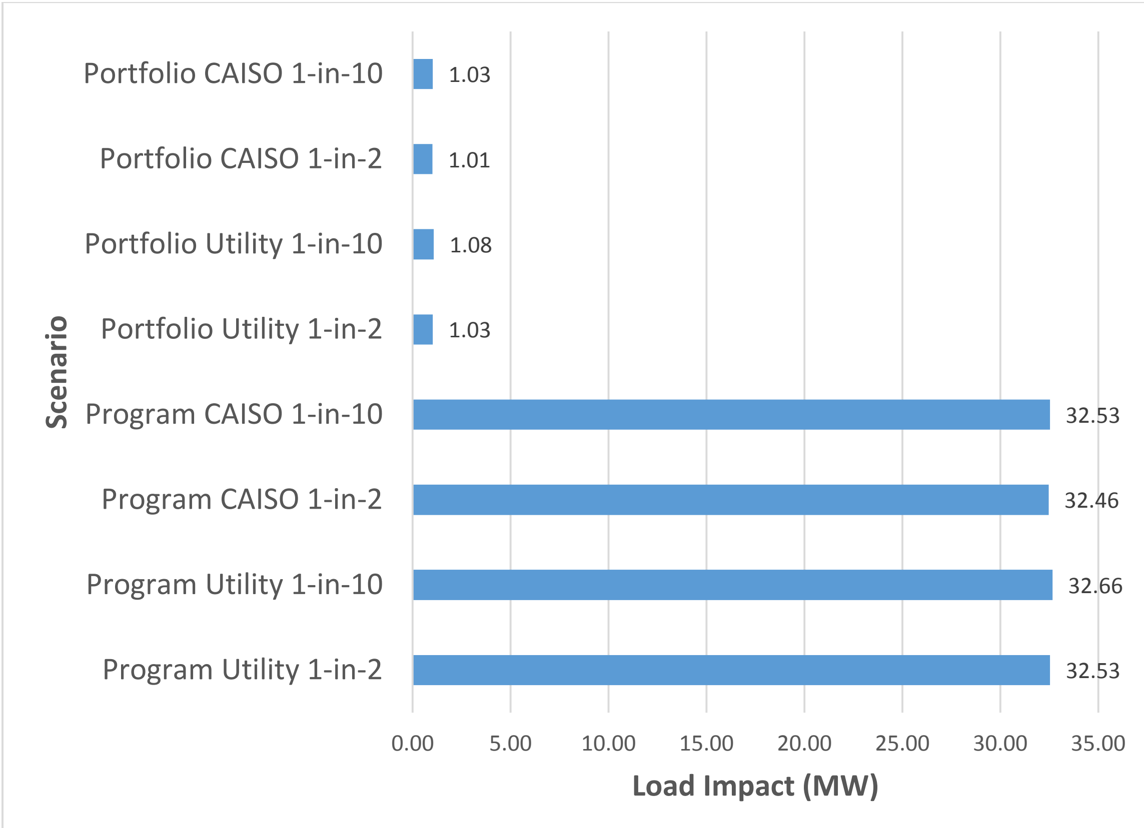


Table 5.3 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August monthly peak day.

Table 5.3: 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	846.5	41.5	4.9%
	Utility 1-in-10	862.3	41.7	4.8%
	CAISO 1-in-2	837.9	41.4	4.9%
	CAISO 1-in-10	848.3	41.5	4.9%
Portfolio-based	Utility 1-in-2	706.2	1.8	0.3%
	Utility 1-in-10	723.9	1.9	0.3%
	CAISO 1-in-2	695.5	1.7	0.2%
	CAISO 1-in-10	707.9	1.8	0.2%

5.4.2 SCE

Figure 5.6 shows the program-level forecast reference loads and load impacts for the August 2015 peak day in a utility-specific 1-in-2 weather year. The average program-level load impact is 110.4 MW, or 15.8 percent of the reference load.

Figure 5.7 shows the portfolio-level forecast for the August 2015 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 4.6 MW (a reduction of 105.8 MW relative to the program-level load impacts), or 1.6 percent of reference load.

Figure 5.6: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Program Level

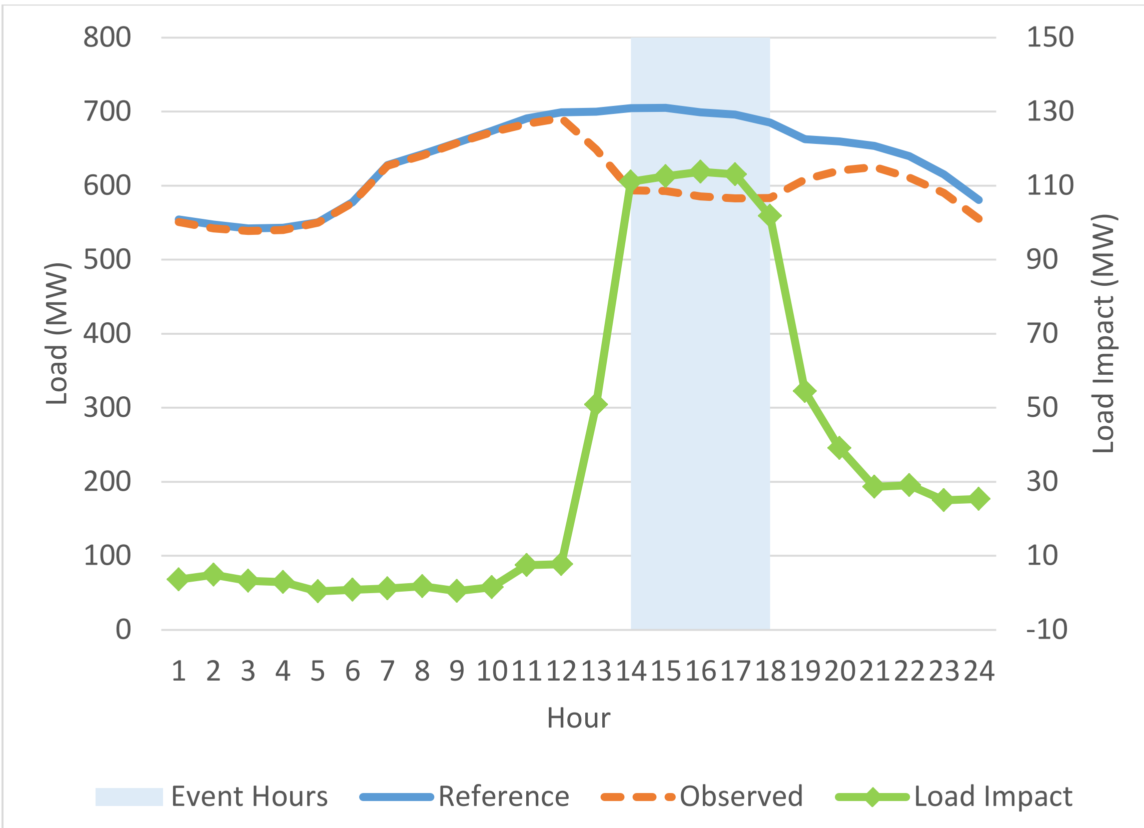


Figure 5.7: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Portfolio Level

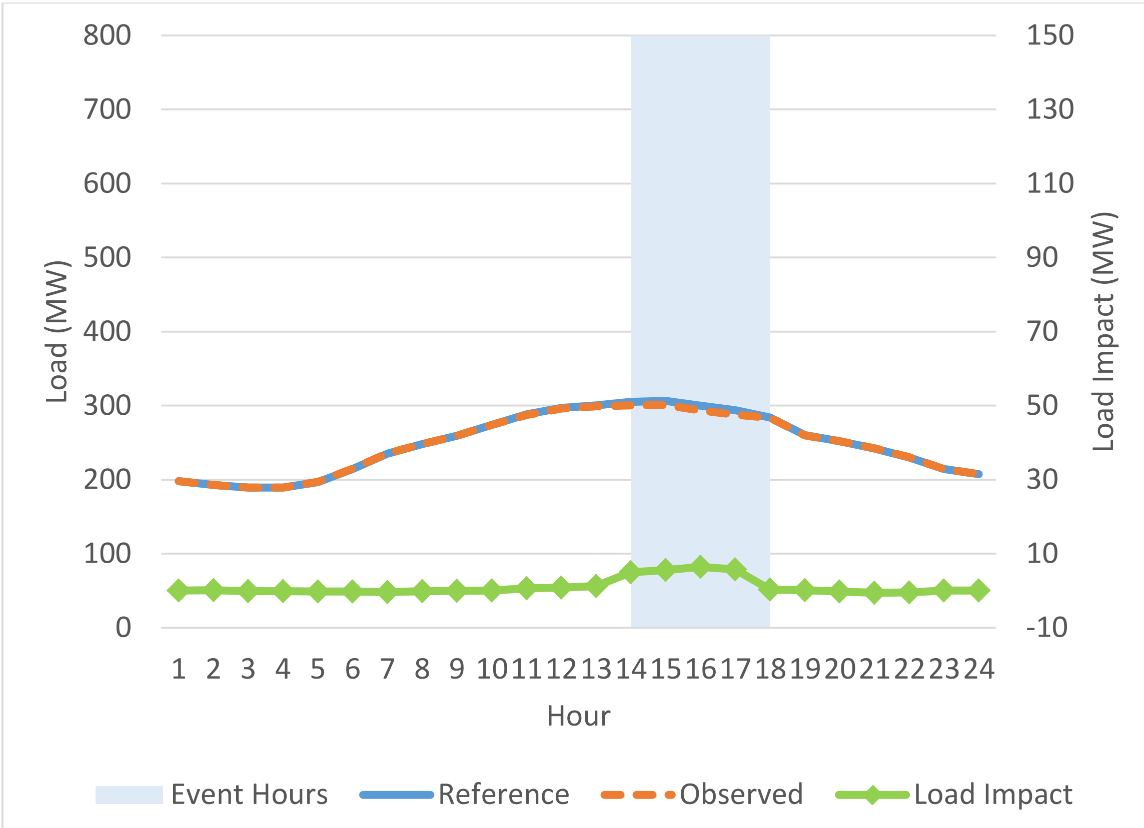


Figure 5.8 shows the distribution of utility-specific 1-in-2 August 2015 program-level load impacts across local capacity areas. The LA Basin accounts for the largest share, with 69 percent of the total load impacts.

Figure 5.8: Share of SCE DBP Load Impacts by Local Capacity Area

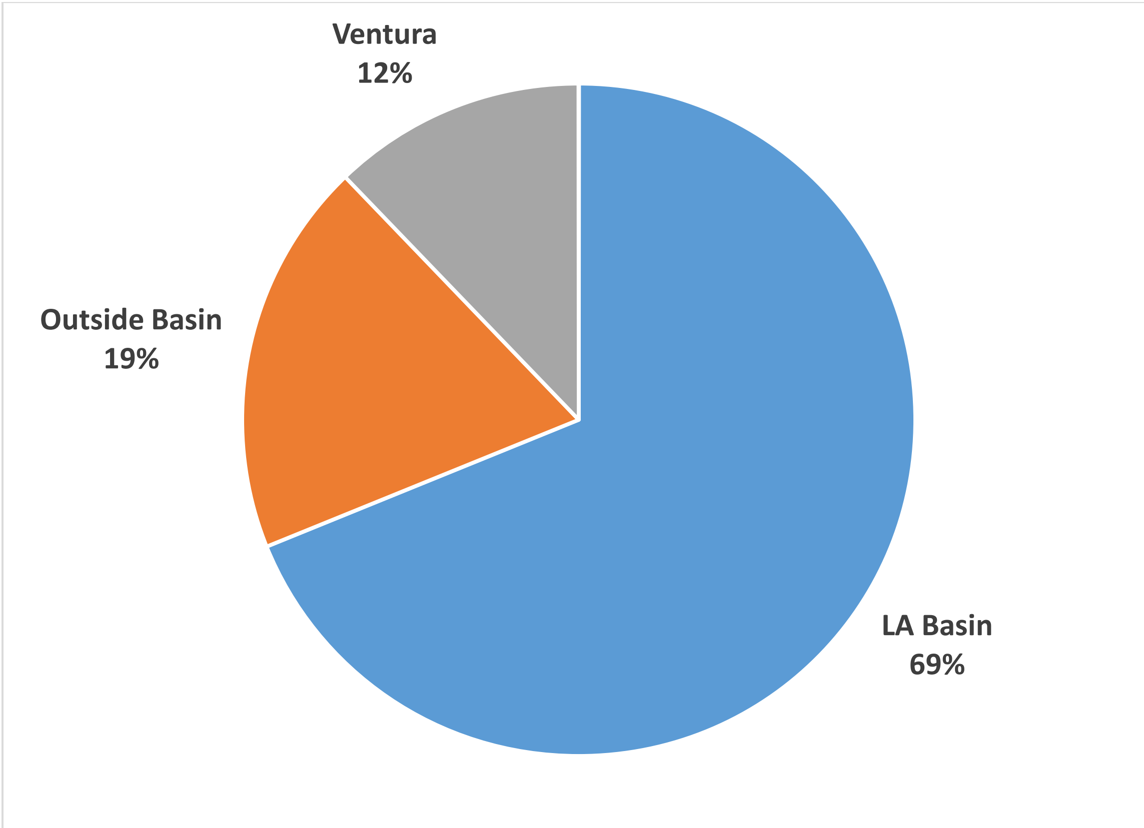


Figure 5.9 illustrates the average August hourly load impact across scenarios and year. The load impacts are not very weather sensitive, so the differences across the various weather scenarios are small. The reduction in load impacts across years is directly related to the declining enrollment forecast. 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 5.9: Average Hourly *Ex-ante* Load Impacts by Scenario and Year, *SCE*

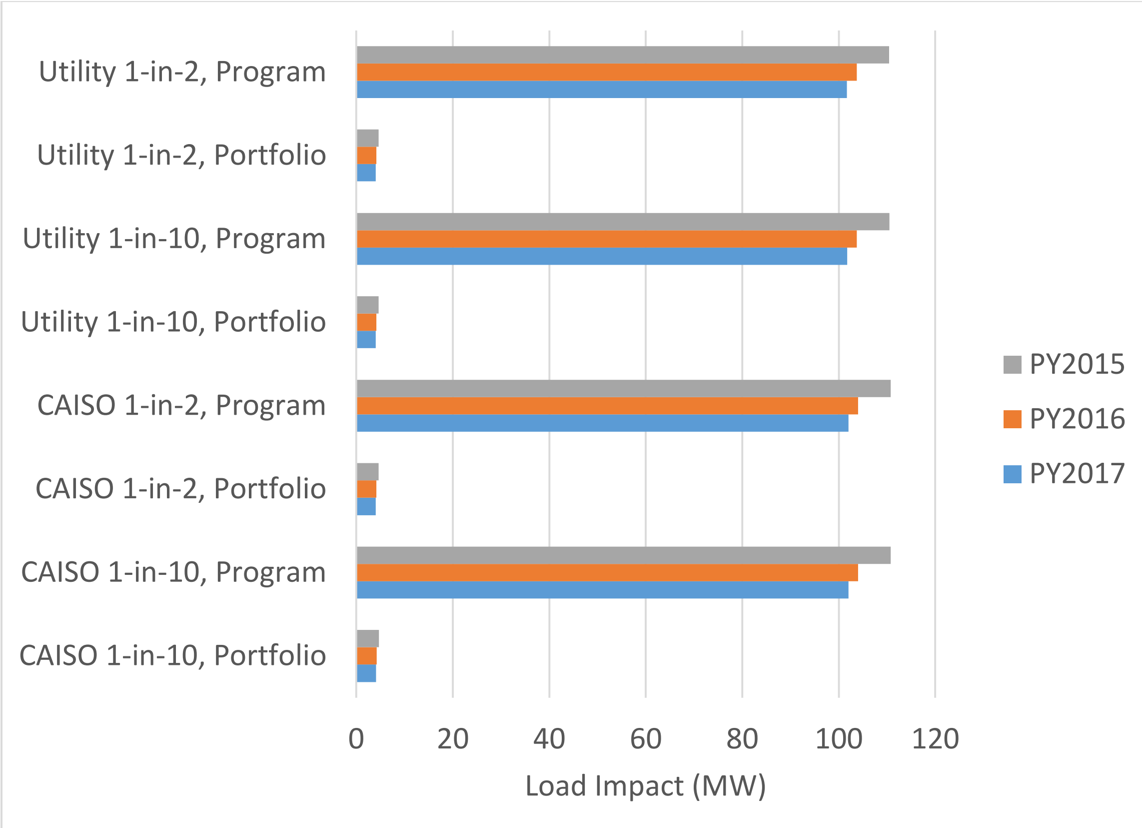


Table 5.4 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August 2015 monthly peak day.

Table 5.4: Per-customer *Ex-ante* Load Impacts, *SCE*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Program-based	Utility 1-in-2	904	143	15.8%
	Utility 1-in-10	914	143	15.7%
	CAISO 1-in-2	905	143	15.9%
	CAISO 1-in-10	909	143	15.8%
Portfolio-based	Utility 1-in-2	609	9	1.6%
	Utility 1-in-10	620	10	1.5%
	CAISO 1-in-2	608	9	1.6%
	CAISO 1-in-10	614	10	1.6%

5.4.3 SDG&E

SDG&E is forecasting that enrollment in its two DBP programs will continue at current levels for the entire forecast period. 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.

SDG&E differs from the DBPs in place at SCE and PG&E in that the event hours vary from event to event and across the DA and DO variants. Therefore, when constructing the *ex-ante* load impacts from the *ex-post* estimates, we followed the methods we have implemented in the aggregator programs (e.g., CBP), which also have varying event hours. Specifically, 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. Because the customer had higher response during PY2013, our *ex-ante* load impacts are higher than we estimated for the *ex-post* events. The DBP-DO load impacts have varied somewhat as well, but more consistently show significant load reductions.

Figures 5.10 and 5.11 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 5.10: 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

These results have been removed due to confidentiality concerns.

Figure 5.11: 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

These results have been removed due to confidentiality concerns.

Figures 5.12 and 5.13 show the monthly forecast of monthly load impacts for each of SDG&E's Demand Bidding Programs by weather year type. Because enrollments are forecast to remain the same during the *ex-ante* forecast timeframe, these results apply to each of 2015 through 2025.

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 *ex-post* estimates, the increase in the load in those months has a noticeable effect on the program-level load impact.

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

These results have been removed due to confidentiality concerns.

Figure 5.13 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 5.13: SDG&E DBP-DO Load Impacts by Month and Weather Year

These results have been removed due to confidentiality concerns.

6. Comparisons of Results

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

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

In the above "current study" refers to this report, which is based on findings from the 2014 program year; and "previous study" refers to the report that was developed following the 2013 program year.

6.1 PG&E

6.1.1 Previous versus current *ex-post*

Table 6.1 shows the average event-hour reference loads and load impacts for the three previous program years. Note that in both PY2013 and PY2014 there were the three locational events dispatched (which only applied to a sub-set of PG&E's service territory) that are excluded from the calculations. The event window was hours-ending 13 through 20 for the included events in all three program years.

Table 6.1: Comparison of Average Event-day *Ex-post* Impacts (in MW) in PY 2012 through PY 2014, *PG&E*

Level	Outcome	PY2012	PY2013	PY2014
Total	# SAIDs	998	952	846
	Reference (MW)	817	826	651
	Load Impact (MW)	38	36	25
Per SAID	Reference (kW)	819	867	769
	Load Impact (kW)	38	38	30
	% Load Impact	4.6%	4.3%	3.8%

The *ex-post* load impacts were quite similar for PY2012 and PY2013. The load impacts for PY2014 are somewhat lower in both MW and as a percentage of the reference load. Examining the customer-level load impacts between PY2013 and PY2014, we find that most of this difference is due to changes in load impacts for customers enrolled in both years. Specifically, the load impacts for customers enrolled in both years are 11.8 MW lower in PY2014, with three service accounts comprising 9.6 MW of this total. Customers leaving the program between program years resulted in a 0.7 MW reduction in total load impacts, while customers joining the program in 2014 accounted for 1.7 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 PY 2013 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.2 contains this comparison for the August 2015 utility-specific 1-in-2 peak month day forecast. 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 2013 and PY 2014 Studies, *PG&E*

Level	Outcome	Program Level		Portfolio Level	
		Previous Study - 2015	Current Study - 2015	Previous Study - 2015	Current Study – 2015
Total	# SAIDs	923	784	682	580
	Reference (MW)	847	664	568	410
	Load Impact (MW)	43	33	3	1
Per SAID	Reference (kW)	918	847	833	706
	Load Impact (kW)	46	41	5	2
	% Load Impact	5.0%	4.9%	0.6%	0.3%

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 PY2011 through PY2013, while the current study used PY2012 through PY2014. It happened to be the case that load impacts decreased for some of the large responders. For example, the three service accounts with the largest decrease in load impacts across forecasts account for a 6.3 MW decrease in the program-level load impact.

On average, the PY2014 event days had a lower amount of bids (30.5 MW versus 41.2 in PY2013) and a slightly lower bid realization rate (82 percent versus 87 percent in PY2013). 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 2014 load impacts prepared following PY2013 and the PY2014 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the typical event day during a 1-in-2 weather year. The *ex-post* load impacts are averaged across the nine PY2014 event days during which all DBP customers were given the opportunity to bid (June 30, July 7, July 28, July 29, July 30, July 31, August 1, September 15, and September 16).

The forecast included somewhat more customers than were enrolled during PY2014 (923 versus 846), but the difference is not large enough to account for the substantial difference in load impacts. The forecast called for an average load impact of 43 MW, whereas we estimated an average load impact of 25 MW during PY2014.

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

Level	Outcome	*Ex-ante* for TED in PY2014, following PY2013 Study	*Ex-post* Average Event Day, PY2014
Total	# SAIDs	923	846
	Reference (MW)	847	651
	Load Impact (MW)	43	25
Per SAID	Reference (kW)	918	769
	Load Impact (kW)	46	30
	% Load Impact	5.0%	3.8%

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 three service accounts account for the bulk of the difference between last year's *ex-ante* forecast and this year's *ex-post* load impacts. The service account that is the largest contributor responded to a lower percentage of events during PY2014 than it had in previous years, and the magnitude of its response was somewhat lower even when it did participate in an event.

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

Table 6.4 compares the PY2014 *ex-post* load impacts (based on the average event day using the nine events during which all customers were called) and the 2015 forecast of typical event day load impacts in a utility-specific 1-in-2 weather year.

The customers that left DBP were smaller than average (approximately 345 kW per customer, compared to 769 kW for the program as a whole) and provided no load impacts during PY2014 event days. Therefore, the effect of their departure is to increase per-customer reference loads and load impacts. The increase in program-level load impacts from 25 to 33 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* Average Event Day, PY2014	*Ex-ante* Typical Event Day, 2015
Total	# SAIDs	846	784
	Reference (MW)	651	664
	Load Impact (MW)	25	33
Per SAID	Reference (kW)	769	847
	Load Impact (kW)	30	41
	% Load Impact	3.8%	4.9%

Table 6.5 reviews the potential sources of differences between PY 2014 *ex-post* average event day and *ex-ante* load impacts for the 2015 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 PY2012 through PY2014 as the basis for our *ex-ante* load impacts. In some cases, performance changes across years. One large and responsive service account contributes nearly 40 percent of the difference in *ex-post* and *ex-ante* load impacts. During the six events of PY2012 and PY2013 we included in the *ex-ante* study, this customer reduced its load by 100 percent from a reference load that averaged 15.7 MW. During the nine PY2014 events we include in the *ex-ante* forecast, this same customer averaged a 67 percent load impact. When this lower PY2014 performance is averaged together with the higher performance from PY2012 and PY2013, the customer's average percentage load impact is 80 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 3 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	83.8 degrees Fahrenheit during event hours.	90.7 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 13-20.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; non-summer load impacts are speculative as we have not observed events in those months.
% of resource dispatched	9 events with full dispatch; 3 with locational dispatch.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	846 SAIDs during the average event day.	784 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 PY14 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 contain the *ex-post* load impacts for the average event day and hour. The second row shows the effect of using only the PY2014 *ex-post* load impacts as the basis of the *ex-ante* forecast. Doing this reduces the program load impact from 32.5 MW to 27.5 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 784 customer enrollment amount), the program load impact is

further reduced to 26.6 MW. This is quite similar to the *ex-post* load impact of 25 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 PY2012-14	663.7	32.5	4.9%
Ex-ante using only PY2014	661.1	27.5	4.2%
Ex-ante using only PY2014, keep SAIDs	661.9	26.6	4.0%
Ex-post load impact	650.5	25.0	3.8%

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 PY2013 and PY2014, which reduced the total number of service accounts without removing load impacts. In addition, a number of service accounts were added (226 by our count), which added 35 MW of load impact that was not in the program during PY2013. The majority of the incremental load impact (~30 MW) comes from one service account that joined DBP in March 2014.

Table 6.7 Comparison of Average Event-day *Ex-post* Impacts (in MW) in PY 2012 through PY 2014, *SCE*

Level	Outcome	PY2012	PY2013	PY2014
Total	# SAIDs	1,369	1,312	944
	Reference (MW)	1,027	994	814
	Load Impact (MW)	83	99	107
Per SAID	Reference (kW)	751	758	862
	Load Impact (kW)	60	76	113
	% Load Impact	8.1%	10.0%	13.1%

6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY 2013 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.8 represents the forecast for the August 2015 utility-specific 1-in-2 peak month day. Both program-level and portfolio-level forecasts are included in the table.

Table 6.8: Comparison of *Ex-ante* Impacts from PY 2013 and PY 2014 Studies, *SCE*

Level	Outcome	Program Level		Portfolio Level	
		Previous Study 2015	Current Study 2015	Previous Study 2015	Current Study 2015
Total	# SAIDs	710	772	559	489
	Reference (MW)	643	698	349	298
	Load Impact (MW)	87	110	5	5
Per SAID	Reference (kW)	906	904	625	609
	Load Impact (kW)	123	143	8	9
	% Load Impact	13.5%	15.8%	1.3%	1.6%

There are several notable differences between the previous and current *ex-ante* forecasts. First, the enrollment numbers have changed, such that this study includes more service accounts overall and a higher percentage of them are dually enrolled in another DR program (as evidenced by the lower enrollments in the portfolio-level scenarios).[13] As described above, the most notable change to the program across years was the addition of a very large and responsive service account.

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

Table 6.9 provides a comparison of the *ex-ante* forecast of 2014 load impacts prepared following PY2013 and the PY2014 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the typical event day during a 1-in-2 weather year. The *ex-post* load impacts are averaged across the seven PY2014 event days.

Notice that the *ex-ante* forecast assumed fewer customers than were enrolled during PY2014, but the forecast customers were similar to the observed customers on average (in both average size and demand responsiveness). The higher estimated load impact appears to be due to the addition of responsive customers to the program, which we described in Section 6.2.1.

[13] It appears that a number of service accounts (approximately 380) that had been identified for removal from DBP remained on the program, which may explain the difference in enrollments across studies.

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

Level	Outcome	*Ex-ante* for TED in PY2014, following PY2013 Study	*Ex-post* Average Event Day, PY2014
Total	# SAIDs	740	944
	Reference (MW)	670	814
	Load Impact (MW)	91	107
Per SAID	Reference (kW)	906	862
	Load Impact (kW)	123	113
	% Load Impact	13.5%	13.1%

Table 6.10 compares the bid realization rates from PY2012 through PY2014. The total bid load reduction increases across the years even though the total bid amount remains fairly constant. This results in an increasing bid realization rate over time. This is what one would expect to occur as SCE removes non-performing customers from the program.

Table 6.10 Comparison of Bid Realization Rates from PY2012 to PY2014, *SCE*

Outcome	PY2012	PY2013	PY2014
Avg. Bid Amount	134.3	134.2	133.1
Avg. Load Impact	82.8	99.5	106.7
Realization Rate	61.7%	74.1%	80.1%

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 seven 2014 event days and the *ex-ante* load impacts are based on the 2015 typical event day in a utility-specific 1-in-2 weather year. Recall that a number of non-performing customers are removed from the program in early 2015, which explains the lower *ex-ante* enrollment and reference load values. However, because the removed customers did not provide load impacts during 2014, the program-level load impact remains quite constant, at 111 MW versus the 107 MW estimated for the PY2014 event days. As expected, the removal of the non-performing customers also increases the average customer size, load impact, and the program-level percentage load impact.

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

Level	Outcome	*Ex-post* Average Event Day, PY2014	*Ex-ante* Typical Event Day, 2015
Total	# SAIDs	944	772
	Reference (MW)	814	691
	Load Impact (MW)	107	111
Per SAID	Reference (kW)	862	895
	Load Impact (kW)	113	144
	% Load Impact	13.1%	16.0%

Table 6.12 describes the sources of differences between the *ex-post* and *ex-ante* load impacts, using the 2015 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	85.5 degrees Fahrenheit during event hours.	89.7 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; non-summer 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	944 SAIDs during the average event day.	772 SAIDs in August 2015.	Removal of non-performing customers reduces enrollment reference load, but not program-level 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 increases percentage load impacts relative to current-year *ex-post* estimates because PY14 had lower %LI than PY12-13.[14]

The *ex-post* and *ex-ante* load impacts are quite close at the program level (107 vs. 111 MW, respectively). The differences are primarily due to three factors, which are illustrated in Table 6.13. First, the use of three years of *ex-post* results in the *ex-ante* analysis increases the program-level load impact. As the table shows, the *ex-post* load impact excluding the large customer who enrolled in PY2014 is 77 MW. The *ex-ante* forecast using only PY2014 *ex-post* load impacts is nearly identical. When the PY2012 to PY2014 *ex-post* load impacts are used, the *ex-ante* load impact increases to 90 MW (largely because a handful of large customers were more responsive in the earlier years).

[14] The reduction in percentage load impacts in PY2014 seems to contradict to Table 6.7, which summarizes the load impacts from all DBP customers in each year. The reduction in percentage load impacts in PY2014 is true for the SAIDs that remain in the program across the three program years, and removing the new large and responsive customer from consideration (which by itself increases the program-level percentage load impact).

The second factor is the load impact for the new large responder, which was approximately 30 MW during events in which it responded, but is “de-rated” to 24.3 MW in the *ex-ante* forecast because of the two events in which it did not respond.

The third factor is due to scaling the load impacts to the forecast enrollment figure of 772. This is slightly fewer SAIDs than we observe in the program by the end of the PY2014, so the program load impact is scaled down from 114 MW to 111 MW.

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

Scenario	Program Load Impact
Ex-post, all customers	107 MW
Ex-post excluding new large responder	77 MW
Ex-ante excluding new large responder + using only PY2014 *ex-post* LI	77 MW
Ex-ante excluding new large responder + using PY2012 to 2014 *ex-post* LI	90 MW
Ex-ante including new large responder + using PY2012 to 2014 *ex-post* LI	114 MW
Scaling *ex-ante* to forecast enrollment	111 MW

6.3 SDG&E

This section has been removed due to confidentiality concerns.

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	SDG&E Ex-Post Load Impact Tables
DBP Study Appendix E	PG&E Ex-Ante Load Impact Tables
DBP Study Appendix F	SCE Ex-Ante Load Impact Tables
DBP Study Appendix G	SDG&E Ex-Ante Load Impact Tables

Appendix A. Validity Assessment

A.1 Model Specification Tests

A range of model specifications were tested before arriving at the 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)[15]; the 24-hour moving average of THI; heat index (HI)[16]; the 24-hour moving average of HI; cooling degree hours (CDH)[17], 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)[18]; 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.

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

[16] 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.

[17] 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.

[18] 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 event-hour temperature (e.g., hours-ending 13 through 20 for PG&E), 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.

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

PG&E	SCE	SDG&E
5/13/2014	7/15/2014	5/1/2014
6/5/2014	7/24/2014	5/2/2014
7/8/2014	7/28/2014	5/12/2014
7/24/2014	8/15/2014	5/13/2014
8/8/2014	8/21/2014	8/28/2014
8/14/2014	8/22/2014	9/8/2014
8/15/2014	9/18/2014	9/15/2014
8/27/2014	9/24/2014	
8/28/2014		
9/10/2014		
9/17/2014		

A.1.2 Results from Tests of Alternative Weather Specifications

For each utility, we tested 21 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each utility (and separately for SDG&E's DBP-DA and DBP-DO) 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 (4), specification (21), and event-like day (11 for PG&E, 8 for SCE, and 7 for SDG&E DBP-DA and DBP-DO). 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) the winning specification for each program. The bias is quite low for the PG&E and SCE model, but quite high for the SDG&E models. The high bias and error rates for the SDG&E models is likely due to the fact that it contains only one customer that displays somewhat large variations in load across days. Model performance tends to improve as the sample size increases, since customer-specific idiosyncrasies get averaged out. This helps explain the superior performance of the PG&E and SCE models, which are much larger programs than either SDG&E program.

Table A.3: Specification Test Results

Utility/Program	Selected Specification Number	Adjusted R^2	MPE	MAPE
PG&E	10	0.85	1.2%	3.1%
SCE	10	0.90	0.3%	2.1%
SDG&E DA	10	0.37	-3.7%	16.9%
SDG&E DO	10	0.70	24.7%	26.4%

For each specification, we estimated a single model that included all of the days (i.e., not withholding any event-like days), but using a single set of actual event variables (i.e., a 24-hour profile of the average event-day load impacts). Figures A.1 through A.4 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. Even for the SDG&E models (which do not produce very good results in Table A.3), the results of these tests indicated that very little is at stake when selecting from the specifications, as the load impact profile was quite stable across them.

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

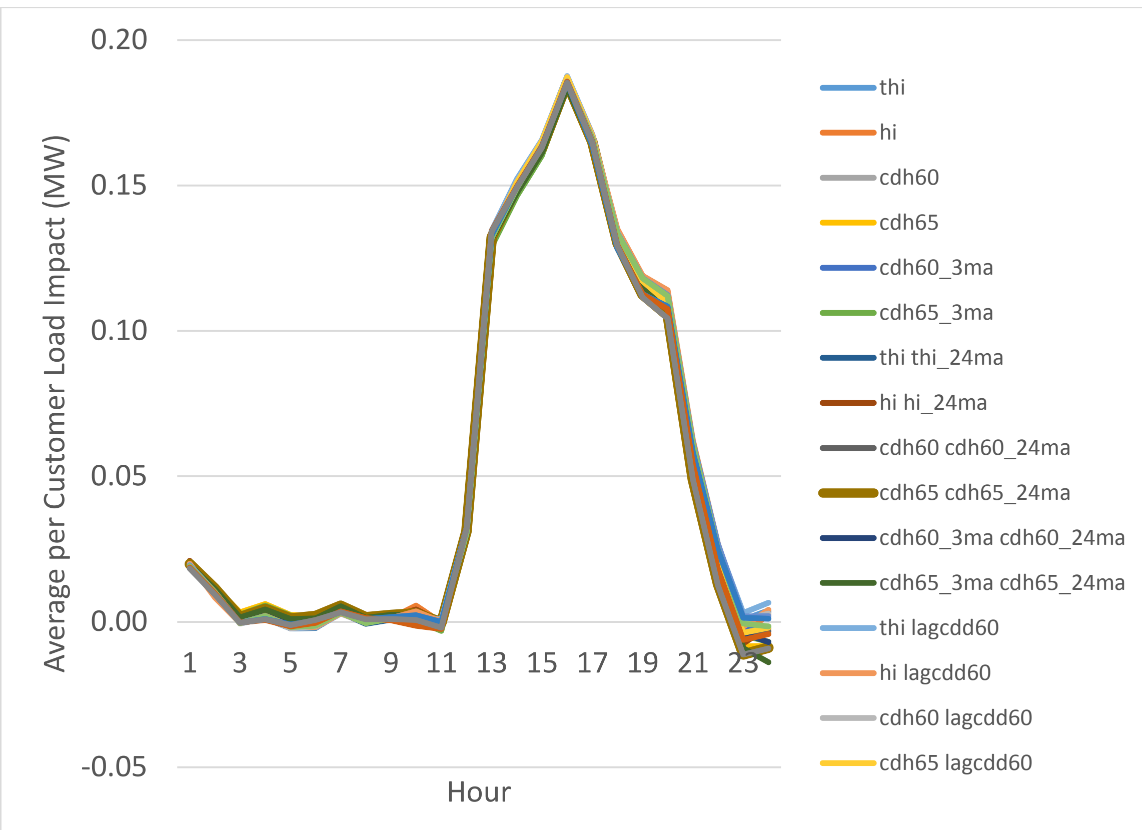


Figure A.2: Average Event-Hour Load Impacts by Specification, *SCE Models*

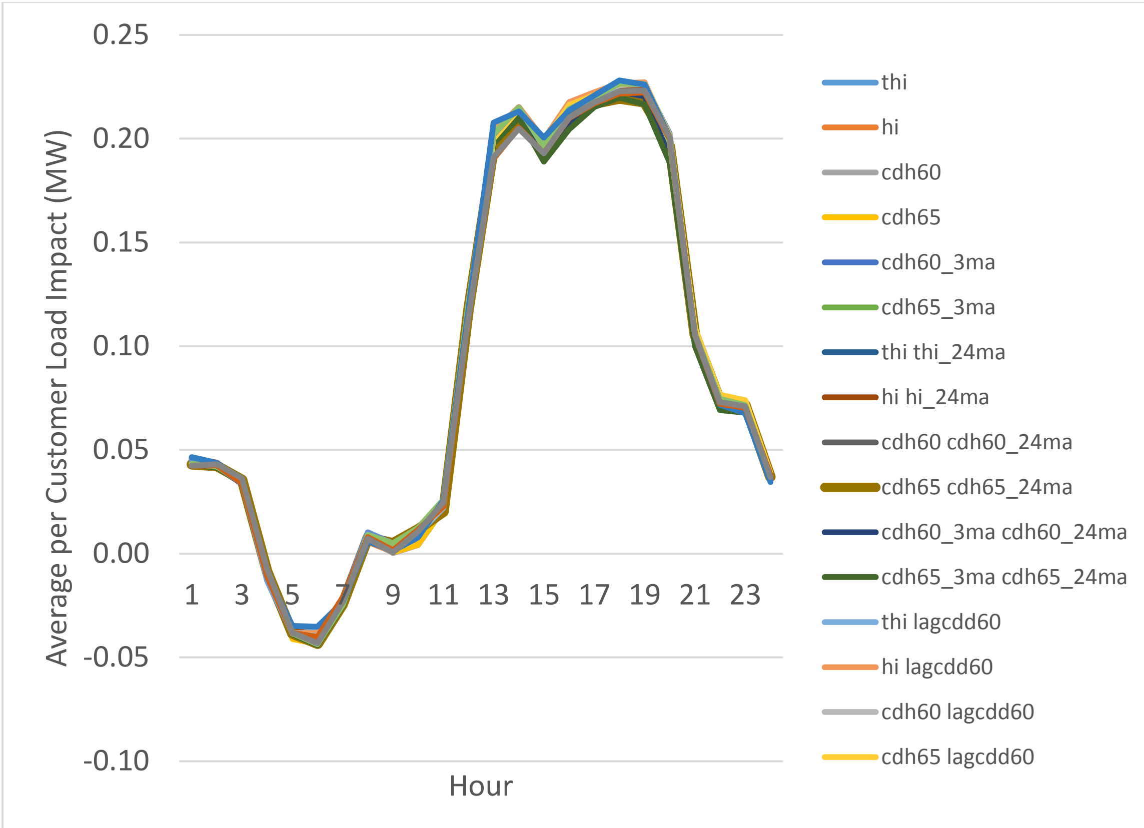


Figure A.3: Average Event-Hour Load Impacts by Specification, *SDG&E DA Models*

These results have been removed due to confidentiality concerns.

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

These results have been removed due to confidentiality concerns.

A.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section A.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data (averaged across all customers who submitted a bid on at least one event day), including a set of 24 hourly “synthetic” event-day variables. These variables equaled one 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 the event window (e.g., hours-ending 13 through 20 for PG&E and SCE; 17 to 20 to cover SDG&E DBP-DA event hours; and 12 to 20 for SDG&E DBP-DO). 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. The results for PG&E and SCE contain a couple of statistically significant results, but the models perform well overall. SDG&E's DBP-DA results do not indicate bias during the event hours, though the DBP-DO results do. This load has large variations (e.g., hour-ending 17 usage varying from 3.7 MW to 31.0 MW across days during which that hour's temperature was 75 degrees Fahrenheit), making it very difficult for the model to accurately predict the customer's load. 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) drove large and unpredictable changes in the customers load. It would be wise to exercise caution in the use of the estimates for SDG&E, perhaps by interpreting them in comparing them to baseline-based estimates.

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

Hour	PG&E	SCE	SDG&E DA	SDG&E DO
12				-2.849 (0.02)
13	0.006 (0.72)	0.024 (0.04)		-2.443 (0.05)
14	-0.006 (0.73)	-0.006 (0.62)		-2.190 (0.08)
15	-0.016 (0.34)	-0.009 (0.46)		-2.673 (0.03)
16	-0.026 (0.12)	-0.013 (0.27)		-3.487 (0.00)
17	-0.029 (0.08)	0.003 (0.77)	0.181 (0.47)	-3.916 (0.00)
18	-0.026 (0.12)	-0.001 (0.92)	0.104 (0.69)	-4.075 (0.00)
19	-0.024 (0.15)	-0.015 (0.20)	0.099 (0.68)	-3.395 (0.00)
20	-0.026 (0.12)	-0.003 (0.81)	0.188 (0.42)	-2.471 (0.02)

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

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.5 through A.8 illustrate the average predicted and observed loads across the event-like days. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model.

Figures A.5 and A.6 show that the PG&E and SCE predicted loads are quite close to the observed loads for the event-like non-event days. Figures A.7 and A.8 show that the SDG&E predicted loads have some notable deviations from the observed loads. The format for these figures differs from those of PG&E and SCE, in that they show predicted and observed loads for each of the seven event-like days, along with the temperature conditions on those days (represented by CDDs). These show how observed load can fluctuate in ways that aren't always consistent with temperatures, and how the models do much better predicting observed loads on some days than others.

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

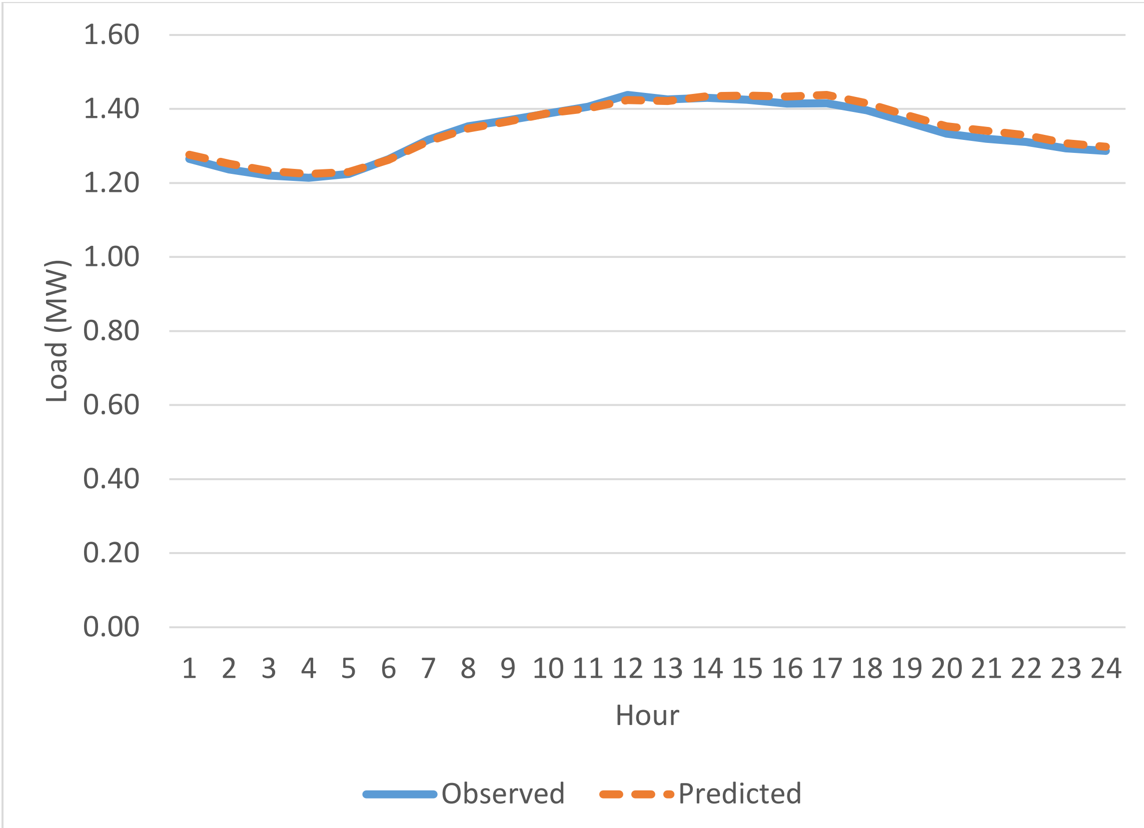


Figure A.6: Average Predicted and Observed Loads on Event-like Days, *SCE*

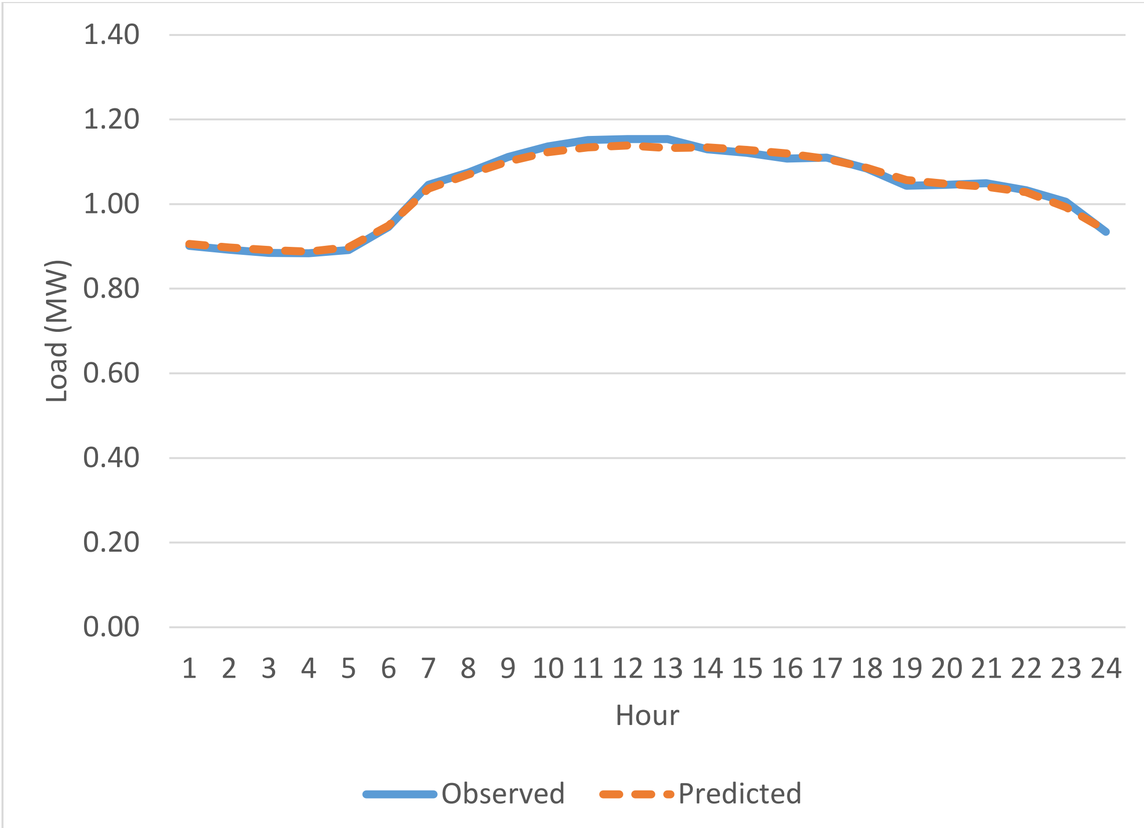


Figure A.7: Average Predicted and Observed Loads on Event-like Days, *SDG&E DA*

These results have been removed due to confidentiality concerns.

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

These results have been removed due to confidentiality concerns.

A.3 Refinement of Customer-Level Models

While the specification tests described in Section A.1 were conducted on aggregated load profiles for each utility, the *ex-post* load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a "day matching" load impact that may be compared to the estimated load impacts. In this evaluation, we modified one PG&E *ex-post* load impact. This customer had an underestimated load impact for the September 16 event day. It appeared that the customer responded to the September 15 event day and chose to maintain its low load level through the following event day. The inclusion of the morning load variable reduces the implied reference load estimated in the regression models, reducing the load impact estimate. For this customer / event day, 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.