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2012 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report

CALMAC Study ID PGE0320

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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 2012. The report provides estimates of ex post load impacts that occurred during events called in 2012 and an ex ante forecast of load impacts for 2013 through 2023 that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2010 through 2012.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

DBP is a voluntary demand response bidding program that provides enrolled customers with the opportunity to receive financial incentives in payment for providing load reductions on event days. Credits are based on the difference between the customers' actual metered load during an event to a baseline load that is calculated from each customer's usage data prior to the event. Customers are notified of events by 12:00 noon on the previous day.

PG&E called three events, each of which had an hour-ending 13 to 20 event window. SCE called eight events, all of which were eight-hour events from hours ending 13 through 20. SDG&E called three events. The first two events spanned hours ending 14 through 18, while the third event was from hours ending 15 through 18. Enrollment in PG&E's DBP averaged 998 across the 2012 event days. The sum of enrolled customers' coincident maximum demands was 846 MW. Enrollment in SCE's DBP averaged 1,369 service accounts across the 2012 event days. The sum of enrolled customers' coincident maximum demands on these days was 1,075 MW. SDG&E's program consisted of a single customer.

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 total program load impact for PG&E's three events averaged 38 MW, or 4.6 percent of enrolled load. Event-specific load impacts ranged from a low of 33.7 MW to a high of 44.1 MW.

For SCE, average hourly program load impacts averaged approximately 83 MW across eight events, or 8.1 percent of the total reference load. The event-specific load impacts ranged from a low of 53.4 MW to a high of 102.2 MW.

We separately summarized average event-hour load impacts for customers participating in the Technical Assistance and Technology Incentives (TA/TI) program or the Automated Demand Response (AutoDR) program. For PG&E, an average of two TA/TI service accounts provided 0.9 MW of load impacts and the 35 AutoDR service accounts provided 18.5 MW. For SCE, 90 TA/TI service accounts provided 12.6 MW of load impacts and 127 AutoDR service accounts provided 29.8 MW.

The baseline analysis analyzed measures of *accuracy* (how close the program baseline is to the "true" baseline) and *bias* (whether the program baseline has a tendency to be above or below the "true" baseline). The analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment. There is some evidence from PG&E that more restrictive cap levels (e.g., 20 to 40 percent) prevent some of the larger baseline errors from occurring, with little apparent downside.

In the ex ante evaluation, SCE forecasts that DBP customer enrollment to decrease in 2014 due to the removal of “non-performing” customers (pending Resolution E-4563 approval), and then begin enrolling under-200kW customers in 2015. During the 2015 program year, SCE's average event-hour load impact is approximately 78 MW. For PG&E, DBP enrollment increases by 3.5 percent in 2014, after which the growth rate declines to approximately 0.8 percent by the end of the forecast timeframe. PG&E's program-level load impacts increase from 49.9 MW in 2013 to 57.0 MW in 2023. For both utilities, 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). For SCE, the portfolio-level load impact is 5.5 MW in 2015. For PG&E, the portfolio-level load impact increases from 2.6 MW in 2013 to 3.7 MW in 2023.

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 2012. The report provides estimates of ex post load impacts that occurred during events called in 2012 and an ex ante forecast of load impacts for 2013 through 2023 that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2010 through 2012.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2012?
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. How do alternative baseline methodologies perform?
6. What are the ex ante load impacts for 2013 through 2023?

ES.1 Resources covered

DBP Program

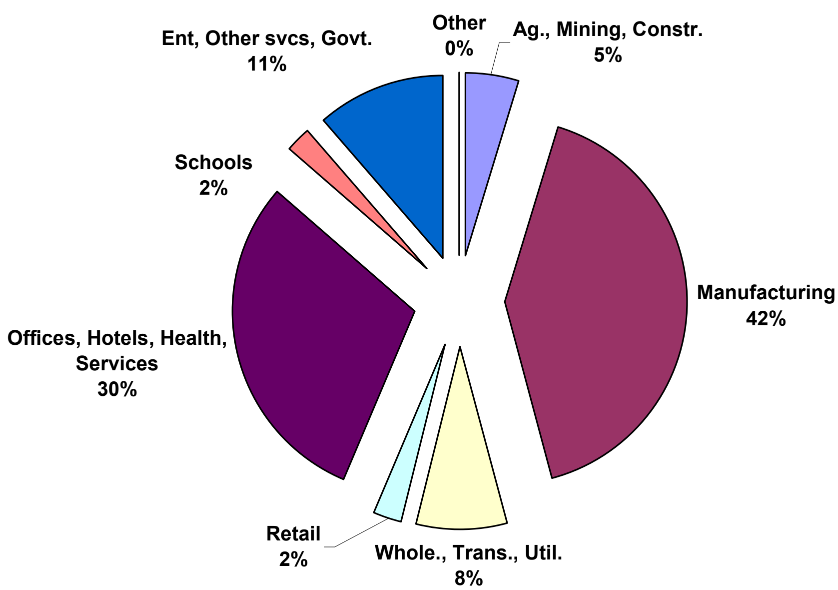
DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing power when a DBP event is triggered. First approved in CPUC D.01-07-025, modifications have been made to the program, including changes made for the 2006-2008 program cycle at the direction of the CPUC in D.05-01-056. In that decision, the Joint Utilities were directed to continue their DBP programs. The utility's DBP programs are designed for non-residential customers, both bundled service and direct access customers. Customers must have internet access and communicating interval metering systems approved by each of the Joint Utilities. A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 pm and are triggered on a day-ahead basis. These events may occur at any time throughout the year. 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). For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of DBP.

PG&E called three events, each of which had an hour-ending 13 to 20 event window. SCE called eight events, all of which were eight-hour events from hours ending 13 through 20. SDG&E called three events. The first two events spanned hours ending 14 through 18, while the third event was from hours ending 15 through 18.

Enrollment

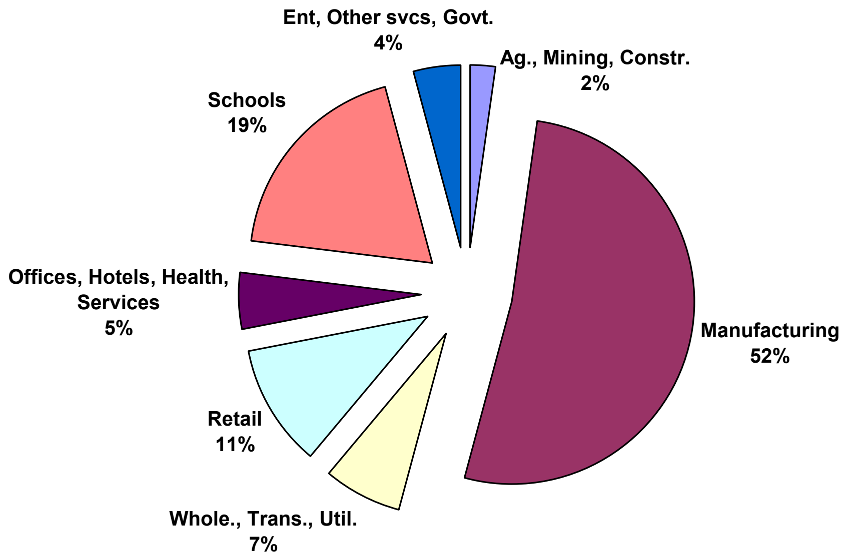
Enrollment in PG&E's DBP decreased slightly relative to PY2011, from 1,039 to 998 in 2012. The sum of enrolled customers' coincident maximum demands was 846 MW, or 0.85 MW for the average service account. The manufacturing and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment. Figure ES.1 illustrates the distribution of DBP load across the indicated industry types.

Figure ES.1 Distribution of DBP Enrollment by Industry Type, *PG&E*



SCE's enrollment in DBP averaged 1,369 service accounts on the PY2012 event days, which is a slight increase relative to the average of 1,354 enrolled service accounts during the PY2011 event days. These accounted for a total of 1,075 MW of maximum demand, or 0.79 MW per service account. Manufacturers continued to make up more than half of the enrolled load. Figure ES.2 illustrates the distribution of SCE's DBP load across the indicated industry types.

Figure ES.2 Distribution of DBP Enrollment by Industry Type, *SCE*



Bidding Behavior

As in previous years, for most events, a relatively small percentage of the customer accounts enrolled in DBP actually submitted bids. For PG&E, 97 service accounts submitted a bid for at least one event. At SCE, 395 individual and lead service accounts submitted at least one bid during 2012.

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's three events averaged 38 MW, or 4.6 percent of enrolled load. This is significantly lower than the 57 MW average load impact from the previous program year. The primary cause for the difference appears to be a change in customer bidding behavior. All but 2.7 MW of the load impacts came from customers dually enrolled in DBP and either BIP or an aggregator program (AMP or CBP). Event-specific load impacts ranged from a low of 33.7 MW to a high of 44.1 MW.

For SCE, average hourly program load impacts averaged approximately 83 MW across eight events, or 8.1 percent of the total reference load. All but 3.5 MW of the load impacts came from customers dually enrolled in DBP and either BIP or an aggregator program (DRC). The event-specific load impacts ranged from a low of 53.4 MW to a high of 102.2 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, the number of participating TA/TI service accounts ranged from 1 to 3 accounts over the three events and provided an average of 0.9 MW of load impacts. Similarly, for AutoDR, the number of participating service accounts ranged from 22 to 27 over the three events and provided an average of 18.5 MW of load impacts. For SCE, TA/TI service accounts provided 12.6 MW of load impacts and AutoDR service accounts provided 29.8 MW.

ES.5 Baseline Analysis

DBP uses a 10-in-10 baseline method, including an optional day-of adjustment based on the ratio of the current day's pre-event usage level to the usage level in the same period for the 10-in-10 baseline.[1] The tariff language currently limits this adjustment to +/- 20 percent. As required by Decision 12-04-045, this report studies the following alternative baseline methodologies: unadjusted baselines, and day-of adjusted baselines with cap percentages of 20, 30, 40, and 50 percent, as well as an uncapped adjustment.

Two sets of days are examined: PY2012 event days; and a set of event-like non-event days. For the event days, the baselines are compared to the estimated baseline load implied by the customer-specific regression models developed in the course of the DBP load impact evaluation. The baseline implied by the regression model for a particular customer was derived by adding the estimated hourly load impact coefficients from the regression equation to that customer's *observed load* during the event hours. Measures of *accuracy* (how close the program baseline is to the "true" baseline) and *bias* (whether

[1] The 10-in-10 baseline is calculated as the average energy usage for each hour across the ten most recent non-event weekdays. The day-of adjustment is calculated using average hourly consumption in the first three hours of the four hours prior to the event period.

the program baseline has a tendency to be above or below the "true" baseline) were used in the evaluation.

The analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment. There is some evidence from PG&E that more restrictive cap levels (e.g., 20 to 40 percent) prevent some of the larger baseline errors from occurring, with little apparent downside.

ES.6 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 its DBP enrollments to increase by 3.5 percent in 2014, with the growth rate declining steadily through 2023. By the end of the forecast timeframe, the annual increase in enrollments is 0.8 percent.

SCE forecasts DBP customer enrollment to decrease in 2014 due to the removal of “non-performing” customers (pending Resolution E-4563 approval). Because SCE will allow smaller (under-200 kW) customers to enroll in DBP beginning in 2015, program enrollment is forecast to increase in that year, adding approximately 980 under-200 kW customers to the program. From 2017 through 2023, total enrollment is forecast to be 3,428 customers.

Figures ES.3 and ES.4 show the ex ante load impacts for PG&E and SCE, respectively. Both figures illustrate the large difference 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). This is because customers dually enrolled in BIP tend to be larger and more demand responsive than other DBP customers.

Figure ES.3: Average Ex Ante Load Impacts by Year and Scenario, *PG&E*

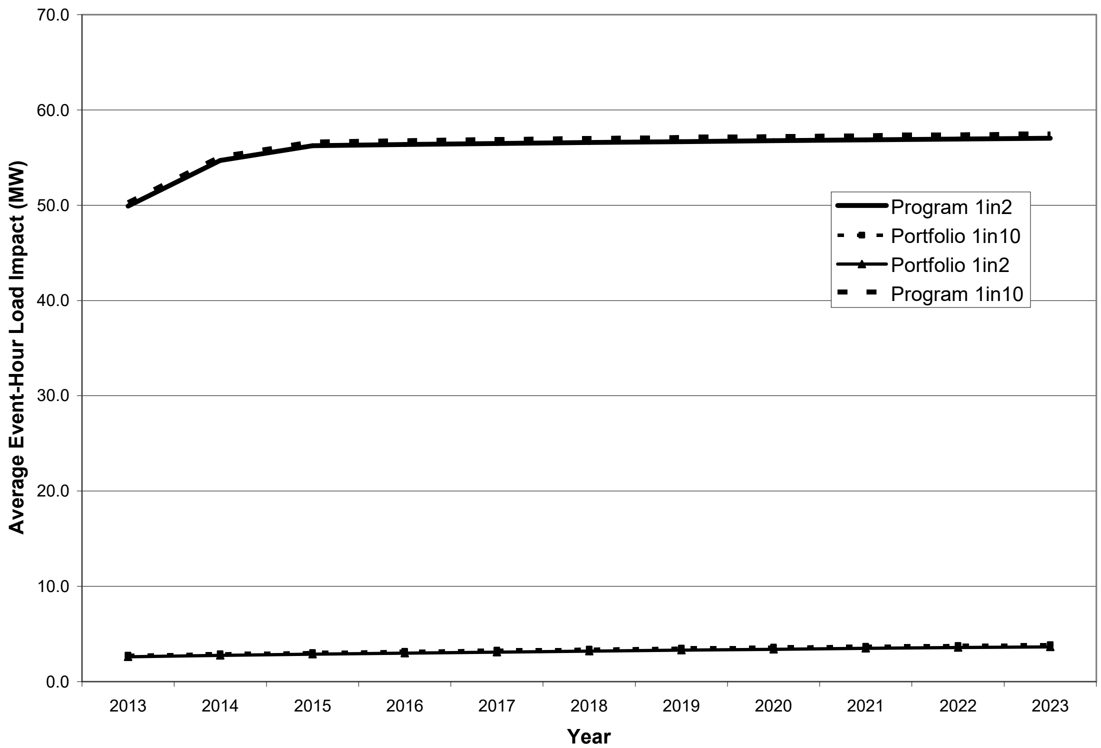
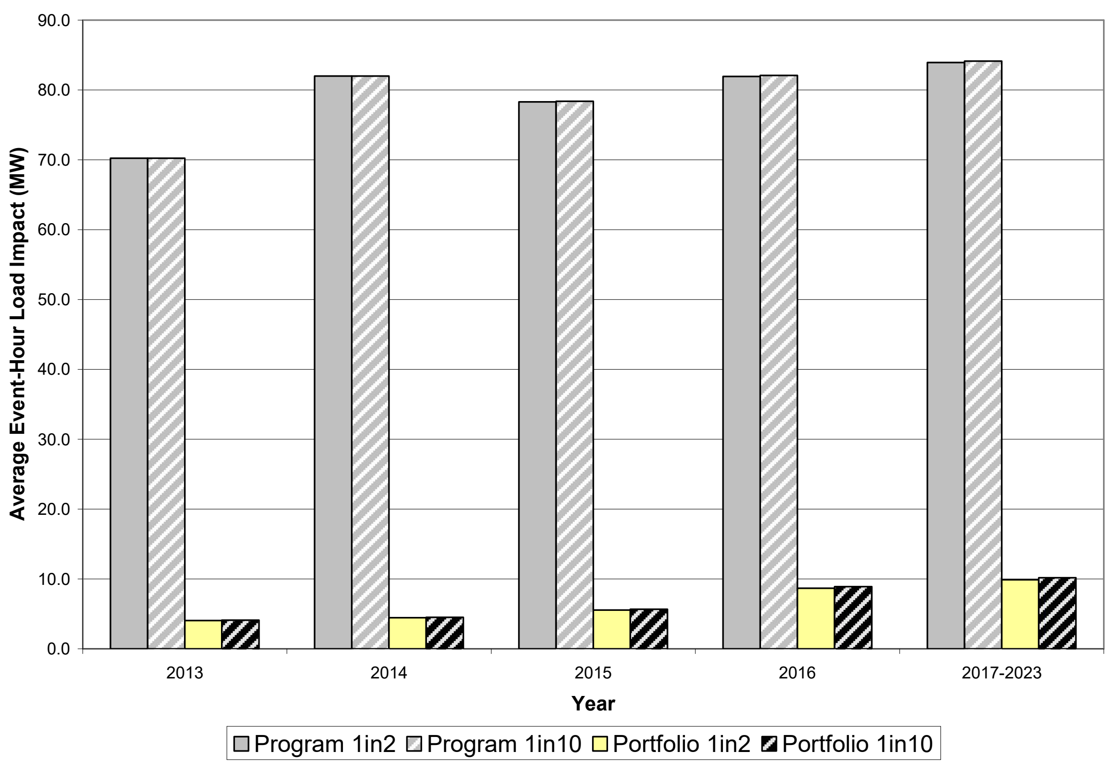


Figure ES.4: Average Ex Ante Load Impacts by Year and Scenario, *SCE*



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 2012. The report provides estimates of ex post load impacts that occurred during events called in 2012 and an ex ante forecast of load impacts for 2013 through 2023 that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2010 through 2012.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2012?
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. How do alternative baseline methodologies perform?
6. What are the ex ante load impacts for 2013 through 2023?

The report is organized as follows. Section 2 contains a description of the DBP 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 contains a study of the program baseline methodologies; Section 6 describes the ex ante load impact forecast; Section 7 contains an assessment of the validity of the study; and Section 8 provides recommendations.

2. Description of Resources Covered in the Study

This section provides details on the Demand Bidding Programs, including the credits paid, the characteristics of the participants enrolled in the programs, and the events called in 2012.

2.1 Program Descriptions

DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing power when a DBP 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 Joint Utilities were directed to continue their DBP programs. In addition, a new SDG&E DBP was authorized by resolution E-4511 on July 17, 2012 in response to the fact that SONGS Unit 3 is offline. This program contains only one (large) customer.

The utility's DBP programs are designed for non-residential customers, both bundled service and direct access customers. Customers must have internet access and communicating interval metering systems approved by each of the Joint Utilities. A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 p.m. and are triggered on a day-ahead basis. These events may occur at any time throughout the year. 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). For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of DBP.

PG&E's Demand Bidding Program

At PG&E, DBP is available to time-of-use customers with billed maximum demands of 200 kW or higher (less for aggregated customer service accounts) who commit to reduce load by a minimum of 50 kW in each hour for two consecutive hours during a DBP event. Eligible customers must have an interval meter which is paid for by PG&E, except for direct access customers. For aggregated customer service accounts, there must be at least one service agreement with a maximum demand of 200 kW or greater for at least one or more of the past 12 billing months within each aggregated group that will be designated as the primary service agreement for the aggregated group.

The DBP program operates year-round and can be called from 12:00 p.m. to 8:00 p.m. on weekdays, excluding holidays. There is no limit to the number of days on which DBP 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 California ISO's day-ahead peak demand forecast is 43,000 MW or greater, or when PG&E, in its own opinion, forecasts that its other resources may not be sufficient or otherwise too costly to procure. PG&E may also activate up to two DBP test events with a simulated emergency event trigger. When an event is called, enrolled customers may choose to bid a load reduction for the event or not to participate for that event.

The incentive payment is $0.50 per kWh reduced below a baseline level. Customers must reduce load by a minimum of 50 percent of their bid amount to qualify for a credit, and they are paid for load reductions up to 150 percent of their bid amount. The hourly baseline for load reductions is calculated as the average usage from 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 penalty for failing to comply with the terms of the submitted bid. Each bid must be a minimum of two consecutive hours during the event. Bids must meet the threshold of 50 kW for each hour and customers may submit only one bid for each event notification.

Although PG&E customers enrolled in 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 program design is similar to PG&E's, with two exceptions: enrolled customers are required to commit to a minimum load reduction of 30 kW (versus 50 kW at PG&E); and bidding customers are paid for load reductions up to twice their bid amount. DBP participants may also participate in AP-I, BIP, SDP, or AMP (DRC). However, the customer will not receive DBP incentive payments during overlapping event hours.

SDG&E's Demand Bidding Program

SDG&E's 2012 DBP program is limited to customers capable of providing at least 5 MW load reductions during event hours. The baseline is calculating as the usage during the immediately preceding "similar day" prior to the event.[2] The customer is paid $0.50 per kWh below the program baseline. As with PG&E's program, customers must reduce load by a minimum of 50 percent of their bid amount to qualify for a credit, and they are paid for load reductions up to 150 percent of their bid amount.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

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

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

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

[2] "Similar days" exclude weekends, holidays, days when a customer was paid to reduce load, days when load reductions were requested, days when the customer was subject to a DR event, and days on which the customer experienced a rotating outage.

[3] Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement.

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. Enrollment in PG&E's DBP decreased slightly relative to PY2011, from 1,039 to 998 in 2012.[4] The sum of enrolled customers' coincident maximum demands[5] was 846 MW, or 0.85 MW for the average service account. The manufacturing and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment.

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	95	40.1	4.7%	0.42
2.Manufacturing	211	347.2	41.0%	1.65
3.Wholesale, Transportation, Utilities	139	69.2	8.2%	0.50
4.Retail	137	21.0	2.5%	0.15
5.Offices, Hotels, Health, Services	265	252.6	29.8%	0.95
6.Schools	30	19.6	2.3%	0.65
7.Entertainment, Other Services, Government.	120	96.5	11.4%	0.80
8.Other	1	0.2	0.0%	0.24
TOTAL	**998**	**846.4**		**0.85**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP averaged 1,369 service accounts across the PY2012 event days, which is a slight increase relative to the average of 1,354 enrolled service accounts across the PY2011 event days. These accounted for a total of 1,075 MW of maximum demand, or 0.79 MW per service account. Manufacturers continued to make up more than half of the enrolled load.

There are currently seven LCAs within PG&E's service area, 3 in SCE's service territory, and 1 representing SDG&E's entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA.

[4] "Enrollment" is defined as the average enrollment on event days during the 2012 program year. This differs from the previous 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).

[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 2.2: 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	22	24.0	2.2%	1.09
2.Manufacturing	319	557.5	51.9%	1.75
3.Wholesale, Transportation, Utilities	150	74.7	6.9%	0.50
4.Retail	102	117.7	11.0%	1.15
5.Offices, Hotels, Health, Services	213	52.3	4.9%	0.25
6.Schools	242	204.6	19.0%	0.84
7.Entertainment, Other Services, Government.	321	44.4	4.1%	0.14
TOTAL	**1,369**	**1,075.1**		**0.79**

Tables 2.3 and 2.4 show DBP enrollment by local capacity area for PG&E and SCE, respectively.

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	470	399.9	47.2%	0.85
Greater Fresno	52	36.7	4.3%	0.71
Humboldt	12	2.3	0.3%	0.19
Kern	51	22.9	2.7%	0.45
Northern Coast	71	33.0	3.9%	0.47
Not in any LCA	272	330.8	39.1%	1.22
Sierra	43	12.5	1.5%	0.29
Stockton	28	8.2	1.0%	0.29
TOTAL	**998**	**846.4**		**0.85**

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	1,072	728.3	67.7%	0.68
Outside LA Basin	66	128.8	12.0%	1.97
Ventura	232	218.0	20.3%	0.94
TOTAL	**1,369**	**1,075.1**		**0.79**

Tables 2.5 and 2.6 summarize 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.

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

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW[8]
1.Agriculture, Mining, Construction	3	1.4	3.5%
2.Manufacturing	25	29.9	8.6%
3.Wholesale, Transportation, Utilities	16	8.8	12.7%
4.Retail	14	0.7	3.3%
5.Offices, Hotels, Health, Services	23	5.3	2.1%
6.Schools	0	0.0	0.0%
7.Entertainment, Other Services, Government.	16	2.3	2.4%
TOTAL	**97**	**48.4**	**5.7%**

Table 2.6: DBP Bidding Behavior, *SCE*

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW
1.Agriculture, Mining, Construction	13	4.5	18.8%
2.Manufacturing	149	98.2	17.6%
3.Wholesale, Transportation, Utilities	63	16.6	22.2%
4.Retail	14	2.4	2.0%
5.Offices, Hotels, Health, Services	105	8.2	15.7%
6.Schools	22	0.9	0.4%
7.Entertainment, Other Services, Government.	29	3.4	7.7%
TOTAL	**395**	**134.3**	**12.5%**

SDG&E's DBP program consists of a single large customer. In the interest of customer confidentiality, we do not provide its LCA, industry group, or usage statistics.

2.3 Event Days

Table 2.7 lists DBP event days for the three utilities in 2012. PG&E called three events, each of which had an hour-ending 13 to 20 event window. SCE called eight events, all of which were eight-hour events from hours ending 13 through 20. SDG&E called three events. The first two events spanned hours ending 14 through 18, while the third event was from hours ending 15 through 18.

[8] "% of Enrolled Max MW" is calculated as "Avg. Hourly Bid MW" divided by the "Sum of Max MW" from Table 2.1.

Table 2.7: DBP Event Days

Date	Day of Week	SCE	PG&E	SDG&E
7/11/2012	Wednesday		1	
7/12/2012	Thursday	1		
8/8/2012	Wednesday	2		
8/9/2012	Thursday		2	
8/10/2012	Friday	3		
8/14/2012	Tuesday	4		1
8/16/2012	Thursday	5		
8/29/2012	Wednesday	6		
9/14/2012	Friday			2
10/1/2012	Monday	7	3	
10/2/2012	Tuesday			3
10/17/2012	Wednesday	8		

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 Section 7.

[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.

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.

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

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

Variable Name / Term	Variable / Term Description
Q_t	the demand in hour *t* for a customer enrolled in 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
$OtherEvt_t$	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

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

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 non-summer), in order to account for potential customer load changes in response to seasonal changes in rates.

The model specification shown above has the *level* of load in a particular hour as the dependent variable. As part of our model validation process (explained in Section 7), we tested models in which the dependent variable is the *difference* between the current hour's load and the load during the same hour on the previous day. We refer to these as models of "differences," in which these differences are calculated for all of the variables included in the model. Therefore, instead of estimating the equation using Q_t as the dependent variable (as in the levels model), the model is estimated using dQ_t, which is calculated from hourly data as follows:

$$dQ_t = Q_t - Q_{t-24}$$

Every explanatory variable in the estimating equation is transformed in the same fashion and the model is estimated using the differenced data.

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.

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.

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 utility. In this section we first summarize the estimated DBP load impacts for each of the utilities using a metric of estimated *average hourly load impacts* by event and for the average event. We also report average hourly load impacts for the average event by industry type and local capacity area. We then present tables of *hourly* load impacts for an *average event* (also referred to as a "typical event day") in the format required by the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in Decision (D.) 08-04-050 ("the Protocols"), including risk-adjusted load impacts at different probability levels, and figures that illustrate the reference loads, observed loads and estimated load impacts. The section concludes with an assessment of the effects of TA/TI and AutoDR.

On a summary level, the average event-hour load impact per enrolled customer was 37.9 kW for PG&E's program and 60.5 kW for SCE's program.

4.1 PG&E Load Impacts

4.1.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.1 summarizes average hourly reference loads and load impacts at the program level for each of PG&E's 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 was 37.8 MW, or an average of 4.6 percent of the total reference load. The load impacts were highest during the third event, at 44.1 MW (5.4 percent of the reference load). The vast majority of the load impacts came from customers who were dually enrolled in another DR program. These load impacts are low compared to the previous program year, in which customers averaged 57 MW of load impacts across two events.

Table 4.1: Average Hourly 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	7/11/2012	Wednesday	809.5	773.9	35.7	4.4%
	2	8/9/2012	Thursday	821.2	787.5	33.7	4.1%
	3	10/1/2012	Monday	821.1	777.0	44.1	5.4%
			Average	**817.3**	**779.5**	**37.8**	**4.6%**
			Std. Dev.			**5.6**	**0.7%**
Enrolled in DBP Only	1	7/11/2012	Wednesday	552.9	549.7	3.2	0.6%
	2	8/9/2012	Thursday	567.4	565.2	2.2	0.4%
	3	10/1/2012	Monday	575.3	572.5	2.7	0.5%
			Average	**565.2**	**562.5**	**2.7**	**0.5%**
			Std. Dev.			**0.5**	**0.1%**

Table 4.2 compares the bid quantities to the estimated load impacts for each event. Across the three events, the bid amount averaged approximately 39.8 MW, while the estimated average hourly load impact was 37.8 MW. The average bid realization rate (i.e., the estimated load impacts as a percentage of bid amounts) across all event hours

was 94.9 percent. The bid realization rate was somewhat lower for customers enrolled only in DBP, averaging 74.7 percent across the three event days.

Combining information from Tables 4.1 and 4.2, the reduction in program-level load impacts appears to be due to a reduction in bid amounts (57.6 MW last year versus 39.8 MW this year). The bid realization rate remained high, at 99 percent last year versus 95 percent this year.

Table 4.2: Average Hourly 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	7/11/2012	Wednesday	36.6	35.7	97.4%
	2	8/9/2012	Thursday	35.7	33.7	94.4%
	3	10/1/2012	Monday	47.3	44.1	93.4%
			Average	**39.8**	**37.8**	**94.9%**
Enrolled in DBP Only	1	7/11/2012	Wednesday	3.8	3.2	83.4%
	2	8/9/2012	Thursday	3.4	2.2	63.9%
	3	10/1/2012	Monday	3.6	2.7	75.7%
			Average	**3.6**	**2.7**	**74.7%**

Table 4.3 summarizes average hourly DBP load impacts at the program level (i.e., including both bidders and non-bidders) and by industry group for each of PG&E's event days. The Manufacturing industry group accounted for the largest share of the load impacts, with a 26.1 MW average event-hour load reduction.

Table 4.3: Average Hourly 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	95	37.5	36.8	0.7	1.8%
Manufacturing	211	334.6	308.5	26.1	7.8%
Wholesale, Transportation, & Other Utilities	139	73.0	65.5	7.5	10.2%
Retail Stores	137	22.3	22.2	0.1	0.2%
Offices, Hotels, Health, Services	265	241.5	238.9	2.6	1.1%
Schools	30	17.6	17.6	0.0	0.0%
Entertainment, Other Services, Government	120	90.7	89.8	0.9	1.0%
Other or Unknown	1	0.2	0.2	0.0	0.0%
Total	**998**	**817.3**	**779.5**	**37.8**	**4.6%**

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

Table 4.4: Average Hourly 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	470	388.5	383.9	4.6	1.2%
Greater Fresno	52	36.0	35.3	0.7	2.0%
Humboldt	12	2.1	1.8	0.3	14.7%
Kern	51	22.4	22.1	0.3	1.4%
Northern Coast	71	29.3	29.2	0.0	0.1%
Not in any LCA	272	319.9	288.0	31.8	10.0%
Sierra	43	11.8	11.8	0.0	0.0%
Stockton	28	7.3	7.3	0.0	0.6%
Total	**998**	**817.3**	**779.5**	**37.8**	**4.6%**

4.1.2 Hourly Load Impacts

Table 4.5 presents hourly PG&E DBP load impacts at the program level in the manner required by the Protocols. DBP load impacts were estimated from the individual customer regressions for customers enrolled at the time of either event. The average event-hour load impact ranges from 35.2 MW to 40.5 MW.

PG&E has two very different types of customers in DBP: those who are dually enrolled in Base Interruptible Program (BIP) and those who are not. The customers who are enrolled in both DBP and BIP tend to be larger and much more demand responsive than the customers who are only enrolled in DBP. On average, customers dually enrolled in BIP customers account for 34.6 MW of the 37.8 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/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	660.2	658.8	1.4	67	-4.2	-0.9	1.4	3.7	7.0
2	650.5	648.7	1.7	66	-3.8	-0.5	1.7	4.0	7.3
3	643.3	643.9	-0.6	65	-6.2	-2.9	-0.6	1.7	5.0
4	644.6	645.4	-0.9	64	-6.4	-3.1	-0.9	1.4	4.7
5	655.6	659.9	-4.2	62	-9.8	-6.5	-4.2	-2.0	1.3
6	687.7	690.7	-3.1	62	-8.7	-5.4	-3.1	-0.8	2.5
7	726.6	724.9	1.7	62	-3.9	-0.6	1.7	4.0	7.2
8	750.9	749.4	1.5	63	-4.1	-0.8	1.5	3.8	7.1
9	777.5	776.7	0.8	67	-4.8	-1.5	0.8	3.1	6.4
10	802.8	803.5	-0.7	72	-6.3	-3.0	-0.7	1.6	4.9
11	823.6	823.2	0.4	77	-5.2	-1.8	0.4	2.7	6.1
12	837.0	824.4	12.5	81	6.9	10.2	12.5	14.8	18.1
13	836.6	801.5	35.2	85	29.6	32.9	35.2	37.5	40.8
14	846.4	810.2	36.1	88	30.5	33.8	36.1	38.4	41.7
15	845.3	806.7	38.6	89	32.9	36.3	38.6	40.9	44.2
16	832.9	792.3	40.5	91	34.9	38.3	40.5	42.8	46.2
17	825.0	786.7	38.3	91	32.7	36.0	38.3	40.6	44.0
18	805.5	766.2	39.3	90	33.7	37.0	39.3	41.6	45.0
19	780.4	742.2	38.2	87	32.6	35.9	38.2	40.5	43.8
20	766.2	729.9	36.3	82	30.7	34.0	36.3	38.6	41.9
21	754.4	729.5	25.0	78	19.3	22.7	25.0	27.3	30.6
22	736.1	718.3	17.8	75	12.2	15.5	17.8	20.1	23.4
23	716.7	703.4	13.3	73	7.7	11.0	13.3	15.6	19.0
24	699.0	687.6	11.4	71	5.8	9.1	11.4	13.7	17.0
	Reference Energy Use (MWh)	**Observed Event-Day Energy Use (MWh)**	**Change in Energy Use (MWh)**	**Cooling Degree Hours (Base 75° F)**	**Uncertainty Adjusted Impact (MWh/hr) - Percentiles**				
					10th	**30th**	**50th**	**70th**	**90th**
Daily	18,105	17,724	381	113.0	n/a	n/a	n/a	n/a	n/a

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

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

Figure 4.1: DBP Load Impacts, *PG&E*

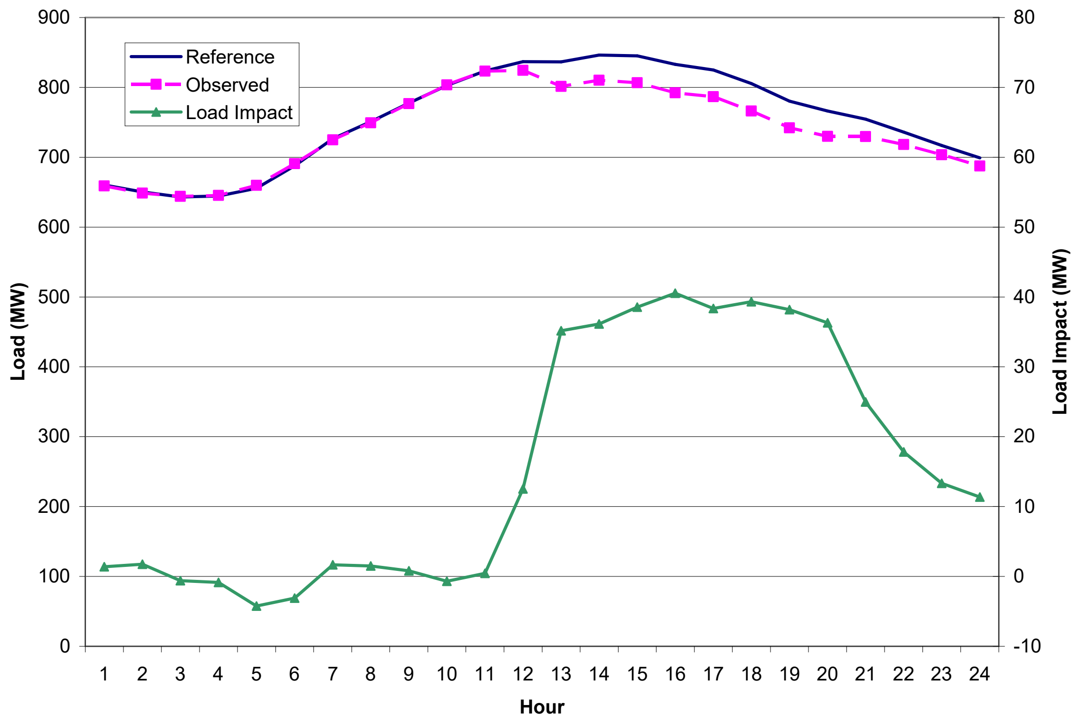
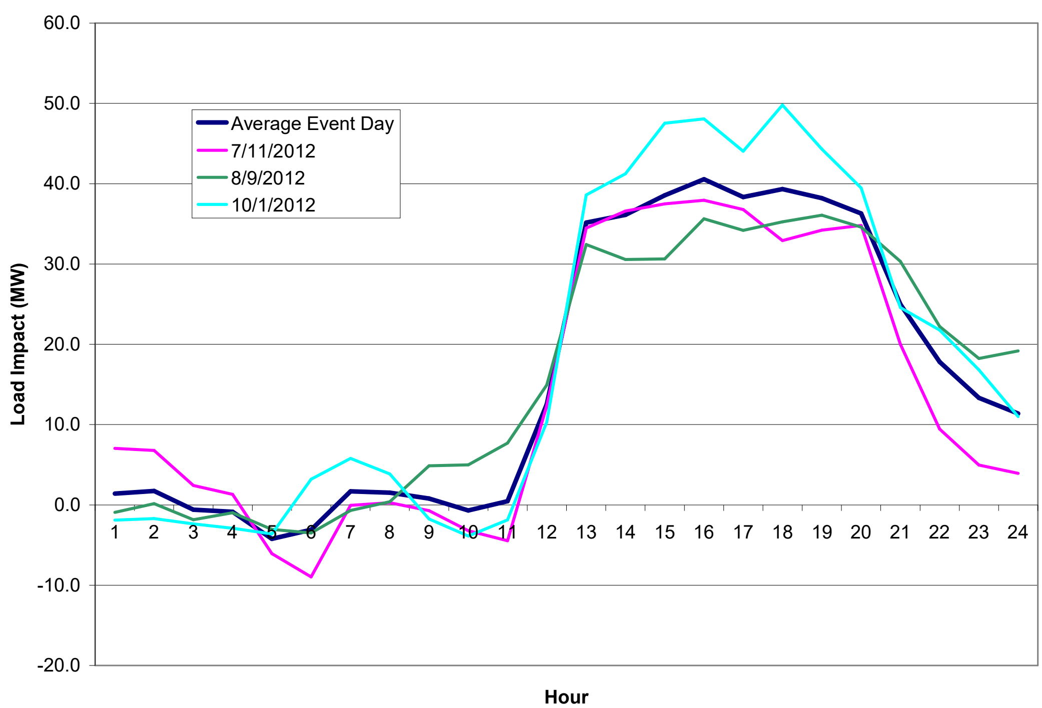


Figure 4.2: Hourly Load Impacts by Event, *PG&E DBP*



4.2 SCE Load Impacts

4.2.1 Average Hourly 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 eight DBP events. The top panel shows the results for all DBP 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 83 MW. The load impacts varied substantially across event days, with a low of 53.4 MW, a high of 102.2 MW, and a standard deviation of 18.1 MW. On average, the load impacts were 8.1 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 Hourly 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	7/12/2012	Thursday	993	894	98.8	9.9%
	2	8/8/2012	Wednesday	1,040	940	100.4	9.7%
	3	8/10/2012	Friday	1,019	916	102.2	10.0%
	4	8/14/2012	Tuesday	1,037	970	67.1	6.5%
	5	8/16/2012	Thursday	1,037	969	67.8	6.5%
	6	8/29/2012	Wednesday	1,053	1,000	53.4	5.1%
	7	10/1/2012	Monday	1,035	949	85.9	8.3%
	8	10/17/2012	Wednesday	1,004	917	86.7	8.6%
			Average	**1,027**	**945**	**82.8**	**8.1%**
			Std. Dev.			**18.1**	**1.8%**
Enrolled in DBP Only	1	7/12/2012	Thursday	548.6	542.2	6.4	1.2%
	2	8/8/2012	Wednesday	592.0	589.5	2.5	0.4%
	3	8/10/2012	Friday	582.8	579.9	2.9	0.5%
	4	8/14/2012	Tuesday	594.2	591.6	2.6	0.4%
	5	8/16/2012	Thursday	582.2	577.5	4.8	0.8%
	6	8/29/2012	Wednesday	609.9	604.3	5.5	0.9%
	7	10/1/2012	Monday	594.6	593.1	1.6	0.3%
	8	10/17/2012	Wednesday	566.2	564.6	1.6	0.3%
			Average	**583.8**	**580.3**	**3.5**	**0.6%**
			Std. Dev.			**1.8**	**0.3%**

Table 4.7 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 134 MW, while the estimated average hourly load impact was 83 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 61.7 percent. The sixth event, on August 29, had the lowest bid realization rate at 43.3 percent. An examination of the customer-specific load impacts indicates that some of the large

responders in previous events did not provide as much response during this event.[11] The bottom panel of Table 4.7 shows that the bid realization rate is quite low (17 percent) for the customers who were not enrolled in another DR program.

Table 4.7: Average Hourly 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	7/12/2012	Thursday	157.1	98.8	62.8%
	2	8/8/2012	Wednesday	142.1	100.4	70.6%
	3	8/10/2012	Friday	142.1	102.2	71.9%
	4	8/14/2012	Tuesday	123.1	67.1	54.5%
	5	8/16/2012	Thursday	119.2	67.8	56.9%
	6	8/29/2012	Wednesday	123.4	53.4	43.3%
	7	10/1/2012	Monday	130.8	85.9	65.7%
	8	10/17/2012	Wednesday	136.4	86.7	63.6%
			Average	**134.3**	**82.8**	**61.7%**
Enrolled in DBP Only	1	7/12/2012	Thursday	23.5	6.4	27.0%
	2	8/8/2012	Wednesday	18.3	2.5	13.7%
	3	8/10/2012	Friday	20.8	2.9	13.8%
	4	8/14/2012	Tuesday	19.5	2.6	13.3%
	5	8/16/2012	Thursday	19.9	4.8	23.9%
	6	8/29/2012	Wednesday	20.4	5.5	27.2%
	7	10/1/2012	Monday	21.3	1.6	7.4%
	8	10/17/2012	Wednesday	20.1	1.6	8.0%
			Average	**20.5**	**3.5**	**17.0%**

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.

[11] Measurement error may also play a role in the variations, as some of the large responders have somewhat unpredictable load patterns, making it difficult to estimate their load impacts with precision.

Table 4.8: Average Hourly 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	22	24	21	2.8	11.5%
Manufacturing	319	540	469	70.6	13.1%
Wholesale, Transportation, & Other Utilities	150	75	67	8.2	11.0%
Retail Stores	213	54	54	0.2	0.4%
Offices, Hotels, Health, Services	242	190	189	0.6	0.3%
Schools	321	31	31	0.1	0.2%
Entertainment, Other Services, Government	102	113	113	0.3	0.2%
Total	**1,369**	**1,027**	**945**	**82.8**	**8.1%**

Table 4.9: Average Hourly 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	1,072	691	635	56.2	8.1%
Outside LA Basin	66	128	108	20.2	15.8%
Ventura	232	208	202	6.4	3.1%
Total	**1,369**	**1,027**	**945**	**82.8**	**8.1%**
South Orange County	184	93.5	92.0	1.4	1.5%
South of Lugo	361	152.8	150.0	2.8	1.8%

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. Hourly load impacts for the average event range from 79.9 MW to 84.6 MW.

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

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	844.6	845.0	-0.4	75	-11.1	-4.8	-0.4	4.0	10.3
2	832.6	831.1	1.4	74	-9.3	-3.0	1.4	5.8	12.1
3	823.8	822.9	0.9	73	-9.8	-3.5	0.9	5.2	11.5
4	824.2	824.1	0.0	72	-10.7	-4.3	0.0	4.4	10.7
5	842.3	844.7	-2.4	71	-13.1	-6.8	-2.4	1.9	8.2
6	886.2	887.4	-1.2	71	-11.9	-5.6	-1.2	3.1	9.4
7	935.8	936.0	-0.2	70	-10.8	-4.5	-0.2	4.2	10.5
8	973.2	975.3	-2.0	70	-12.7	-6.4	-2.0	2.3	8.6
9	1,008.9	1,012.8	-3.9	71	-14.6	-8.3	-3.9	0.5	6.8
10	1,036.2	1,041.2	-5.0	75	-15.6	-9.3	-5.0	-0.6	5.7
11	1,057.3	1,060.5	-3.2	79	-13.9	-7.6	-3.2	1.1	7.5
12	1,065.5	1,040.0	25.5	83	14.9	21.2	25.5	29.9	36.2
13	1,066.3	986.4	79.9	86	69.2	75.5	79.9	84.3	90.6
14	1,075.1	993.1	82.0	88	71.4	77.7	82.0	86.4	92.7
15	1,073.2	989.4	83.9	89	73.2	79.5	83.9	88.2	94.5
16	1,054.5	970.7	83.8	89	73.1	79.5	83.8	88.2	94.5
17	1,030.5	945.9	84.6	89	73.9	80.2	84.6	89.0	95.3
18	1,002.5	918.9	83.6	89	72.9	79.2	83.6	88.0	94.3
19	966.0	882.1	83.9	88	73.3	79.6	83.9	88.3	94.6
20	950.0	869.5	80.6	85	69.9	76.2	80.6	85.0	91.3
21	938.5	883.2	55.3	82	44.6	51.0	55.3	59.7	66.0
22	918.3	879.0	39.3	80	28.6	34.9	39.3	43.7	50.0
23	888.5	858.9	29.6	78	18.9	25.2	29.6	34.0	40.3
24	868.8	843.7	25.2	77	14.5	20.8	25.2	29.5	35.8
	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	22,963	22,142	821	131.0	n/a	n/a	n/a	n/a	n/a

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. The load impacts varied somewhat substantially across events.

Figure 4.3: DBP Load Impacts, *SCE*

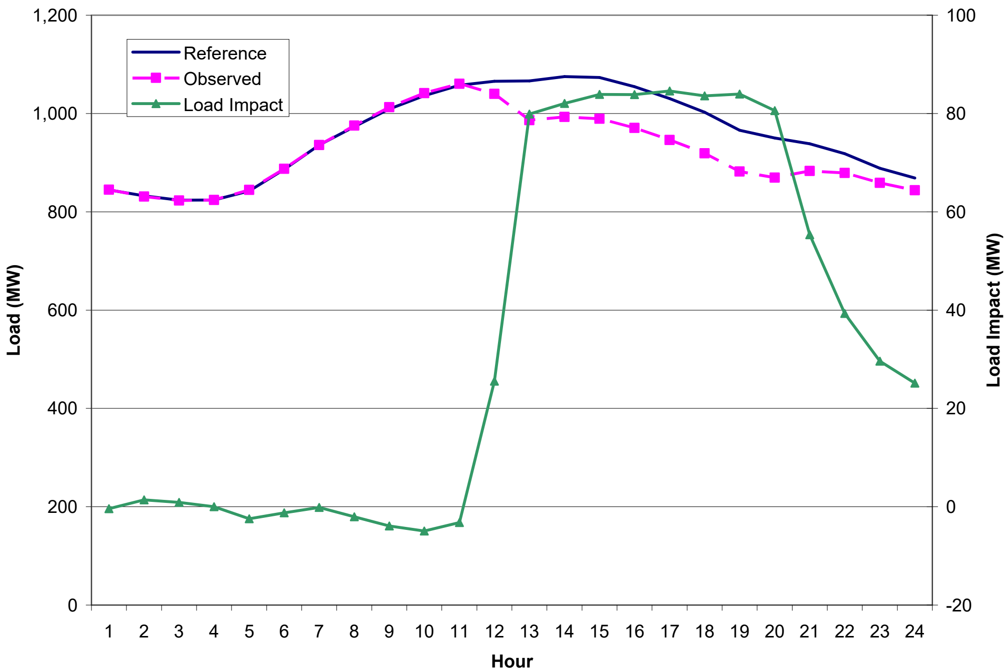
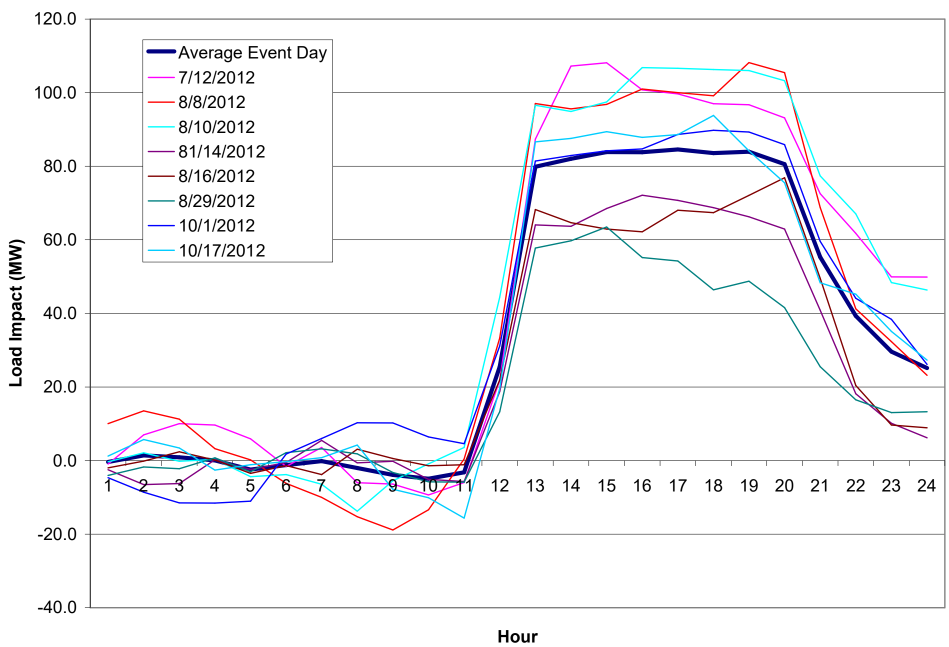


Figure 4.4: Hourly Load Impacts by Event, *SCE DBP*



4.3 SDG&E Load Impacts

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 Technical Assistance and Technology Incentives (TA/TI) program has two parts: technical assistance in the form of energy audits, and technology incentives. The objective of the TA portion of the program is to subsidize customer energy audits that have the objective of identifying ways in which customers can reduce load during demand response events. The TI portion of the program then provides incentive payments for the installation of equipment or control software supporting DR.

The Automated Demand Response (AutoDR) program helps customers to activate DR strategies, such as managing lighting or heating, ventilation and air conditioning (HVAC) systems, whereby electrical usage can be automatically reduced or eliminated during times of high electricity prices or electricity system emergencies.

In the sub-sections below, we summarize *total* load impacts for TA/TI and AutoDR. 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, ten DBP service accounts participated in the TA/TI program. However, no more than three of these service accounts submitted a bid during each event day.

Table 4.14 shows the event-specific load impact for the TA/TI participants. These customers averaged a 5.4 percent load impact across the three event days, with the highest response of 1.7 MW occurring on the third event day. The rightmost column ("Approved MW for bidders") shows the total MW approved following the TA/TI DR test.

Table 4.14: Average Hourly Load Impacts by Event, *PG&E 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
7/11/2012	10	3	15.2	14.2	0.9	6.3%	3.7
8/9/2012	10	1	19.8	19.8	0.1	0.3%	0.02
10/1/2012	10	3	14.8	13.1	1.7	11.3%	3.7
Average	**10**	**2**	**16.6**	**15.7**	**0.9**	**5.4%**	**2.5**

AutoDR

According to data provided by PG&E, an average of 35 DBP service accounts participated in the AutoDR program. During any one event, a maximum of 27 of these submitted a bid. Table 4.15 shows the average hourly load impact for the AutoDR participants, which was 18.5 MW, or 33.5 percent of the reference load.

Table 4.15: Average Hourly Load Impacts by Event, *PG&E 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
7/11/2012	35	27	54.4	38.7	15.6	28.8%	32.0
8/9/2012	35	22	55.5	35.3	20.2	36.4%	21.1
10/1/2012	35	24	55.3	35.7	19.5	35.4%	23.9
Average	**35**	**24**	**55.0**	**36.6**	**18.5**	**33.5%**	**25.7**

SCE

TA/TI

Table 4.16 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 90 of SCE's DBP service accounts participated in TA/TI, with an average of 20 participants submitting a bid during each event. DBP participants include both individual and load accounts, which can place a single bid for up to 25 service accounts. The load impacts for this group are quite variable across event days, with especially low load impacts in the fourth through sixth event days. The vast majority of the load impact is from a single service account, and this customer did not respond during those three events.

Table 4.16: Average Hourly 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
7/12/2012	90	27	63.4	45.5	17.9	28.3%	23.3
8/8/2012	89	19	68.7	50.3	18.4	26.8%	24.0
8/10/2012	89	18	67.9	45.6	22.3	32.8%	23.6
8/14/2012	89	19	68.2	67.4	0.7	1.1%	24.0
8/16/2012	89	19	68.2	67.8	0.4	0.6%	23.6
8/29/2012	90	19	51.9	49.6	2.3	4.4%	20.6
10/1/2012	90	19	71.9	52.3	19.6	27.2%	23.6
10/17/2012	90	18	68.7	49.4	19.2	28.0%	22.5
Average	**90**	**20**	**66.1**	**53.5**	**12.6**	**19.1%**	**23.2**

AutoDR

Table 4.17 shows the total DBP load impacts for SCE's AutoDR participants. Approximately 127 DBP service accounts participated in AutoDR, with an average of 40 participants bidding during each event. The percentage load impacts are uniformly high across events, averaging 28 percent, or 30 MW.

Table 4.17: Average Hourly 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
7/12/2012	124	37	104.1	77.6	26.5	25.4%	56.8
8/8/2012	125	41	108.3	73.5	34.8	32.1%	56.6
8/10/2012	126	41	107.9	72.1	35.8	33.2%	59.8
8/14/2012	127	38	111.9	79.8	32.1	28.7%	57.0
8/16/2012	127	38	112.2	76.0	36.2	32.2%	56.8
8/29/2012	128	40	105.5	83.1	22.4	21.2%	57.6
10/1/2012	130	44	106.3	79.1	27.1	25.5%	49.2
10/17/2012	129	41	104.9	81.1	23.8	22.7%	49.4
Average	**127**	**40**	**107.6**	**77.8**	**29.8**	**27.7%**	**55.4**

5. Baseline Analysis

5.1 Objectives

Decision 12-04-045 (pages 63-4) issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. Specifically, DBP uses a 10-in-10 baseline method, including an optional day-of adjustment based on the ratio of the current day's pre-event usage level to the usage level in the same period for the 10-in-10 baseline.[12] The tariff language currently limits this adjustment to +/- 20 percent. The Decision raises the cap for Capacity Bidding Program to 40% for the individual 10-in-10 baseline, but requires further study of the issue, which this section represents.

The alternative baseline methodologies that we examined include 10-in-10 unadjusted baselines, and day-of adjusted baselines with cap percentages of 20, 30, 40, and 50 percent, as well as an uncapped adjustment. Since there is no third party aggregation for DBP, the “aggregated” baseline is no different than the individual baseline and thus requires no additional analysis.

Two sets of days are examined: PY2012 event days; and a set of event-like non-event days.[13] For the event days, the baselines are compared to the estimated baseline load implied by the customer-specific regression models developed in the course of the DBP load impact evaluation. The baseline implied by the regression model for a particular customer was derived by adding the estimated hourly load impact coefficients from the regression equation to that customer’s *observed load* during the event hours. For

[12] The 10-in-10 baseline is calculated as the average energy usage for each hour across the ten most recent non-event weekdays. The day-of adjustment is calculated using average hourly consumption in the first three hours of the four hours prior to the event period.

[13] See Section 7.1.1 for a description of how these days were selected. A list of the event-like non-event days by utility is contained in Table 7.2.

example, if a customer's observed load during an event was 800 kW in each hour, and the estimated load impact coefficients were 200 kW in each hour of the event, then the implied reference, or baseline, load would be the sum of the two values, or 1,000 kW per hour. That reference load then becomes the "true" baseline load to which the alternative program baseline loads are compared.

For the event-like non-event days, the observed loads on those event-like days serve as "known" baselines, which may then be compared to all of the relevant alternative baseline methods.

5.2 Measures of baseline performance

Performance of the alternative baseline methods was measured primarily by two statistics measuring the baseline's *accuracy* and *bias*. The performance measures are calculated using the average across the event hours of each event day for each customer service account. That is, the observations used in constructing the performance statistics represent outcomes on a customer's event day.[14] The statistics combine information across customers of various types, and events.

Baseline **bias** was measured using the *median percentage error ("MPE")*, where the percentage error is defined as the *difference* between the baseline measure in question and the "true" baseline load (the regression-based baseline for event days or the observed load for event-like days), divided by the *level* of the true baseline. Therefore a positive MPE indicates an *upward* bias (or a tendency to overpay customers for load reductions) and a negative MPE is associated with a *downward* bias (or a tendency to underpay customers). Note that MPE is typically used to refer to "*mean* percentage error." In this study, we use the median in place of the mean because there are outliers (e.g., percentage errors in excess of 500 percent due to very low observed loads during the hours in question) that limit the usefulness of the mean values. The percentage error for each customer-event day is calculated as follows:

Percentage error = $(L^P_d - L^A_d) / L^A_d$,

where in this case

L^P_d is one of the alternative *predicted* (program) average baseline load on customer-event day *d*;

L^A_d is the "true" (based on regression results or observed loads) baseline load on customer-event day *d*; and

n is the total number of observations (e.g., the number of customer-event days).

[14] Baselines for customers that are part of an aggregation are calculated using the sum of the lead (or parent) and subordinate (or child) service accounts.

The MPE is the 50th percentile value of the percentage errors over the relevant observations (e.g., customers who selected the day-of adjustment on actual event days).

Baseline **accuracy** (relative to the true baseline) was measured using the *median absolute percentage error, or MAPE*.[15] This statistic measures the degree of difference, or error, *regardless of sign*, between two data series, which in this case are the alternative baselines and the true baseline. MAPE is calculated using the same formula as MPE, with one exception: MAPE uses the absolute value of the difference between the baseline and regression-based reference load or observed load.

5.3 Data

We examined only customers who submitted a bid for at least one event day during the 2012 program year. Results were calculated for each customer event day. That is, the hours of each customer's event were averaged to form a single value that was used to evaluate baseline bias and accuracy.

5.4 Results

5.4.1 PG&E DBP

Table 5.1 summarizes the *accuracy* results for the alternative baselines compared to the regression-based and observed baselines, with results reported by customer type (all customers or only those who selected the day-of adjustment) and event type (all studied events, only actual events, and only event-like days).

The results show that adjusted baselines tend to be more accurate than unadjusted baselines, but the presence or size of the cap does not have a substantial effect on accuracy. For example, the median unadjusted baseline error was 8.6 percent when examining all DBP customers on the three PY2012 event days. This error can be reduced to 4.9 to 5.1 percent using a day-of adjustment, with the best performance achieved for the 20 percent cap on the baseline adjustment. While improvement in baseline accuracy resulting from the day-of adjustment is similar whether one examines all DBP customers or only those who selected it during PY2012. The baseline accuracy results were also similar whether we examine actual event days or event-like non-event days.

[15] As with MPE, MAPE is typically used in reference to mean, rather than median absolute percentage errors. The existence of outliers affects the ability to usefully interpret mean values for both measures.

Table 5.1: Accuracy of Alternative Baselines, *PG&E DBP*
(*Median Absolute Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	873	8.6%	4.9%	5.1%	5.1%	5.1%	5.1%
All	Selected Adj.	842	8.9%	4.9%	5.1%	5.1%	5.2%	5.2%
Actual	All	291	8.0%	4.7%	4.7%	4.7%	4.7%	5.1%
Actual	Selected Adj.	260	8.8%	4.7%	4.8%	5.0%	5.0%	5.3%
Event-like	All	582	9.0%	5.0%	5.1%	5.2%	5.2%	5.2%
Event-like	Selected Adj.	582	9.0%	5.0%	5.1%	5.2%	5.2%	5.2%

Table 5.2 presents results for the typical *bias* of the alternative baselines. In all cases, the MPE results indicate a tendency for baselines to be *understated* (i.e., the calculated baseline is less than the "true" baseline). The bias is somewhat large (-4.4 to -5.8 percent) for the unadjusted baseline, but less than one percent for all DBP customers on the three PY2012 event days. The bias is somewhat larger when examining the event-like days, with the 40 percent cap performing best (a -1.6 percent MPE across all DBP customers).

Table 5.2: Bias of Alternative Baselines, *PG&E DBP*
(*Median Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	873	-5.2%	-1.6%	-1.3%	-1.2%	-1.2%	-1.3%
All	Selected Adj.	842	-5.4%	-1.6%	-1.4%	-1.3%	-1.4%	-1.4%
Actual	All	291	-4.4%	-0.8%	-0.4%	-0.2%	-0.2%	-0.5%
Actual	Selected Adj.	260	-4.7%	-1.2%	-0.6%	-0.5%	-0.5%	-0.7%
Event-like	All	582	-5.8%	-2.0%	-1.7%	-1.6%	-1.6%	-1.7%
Event-like	Selected Adj.	582	-5.8%	-2.0%	-1.7%	-1.6%	-1.6%	-1.7%

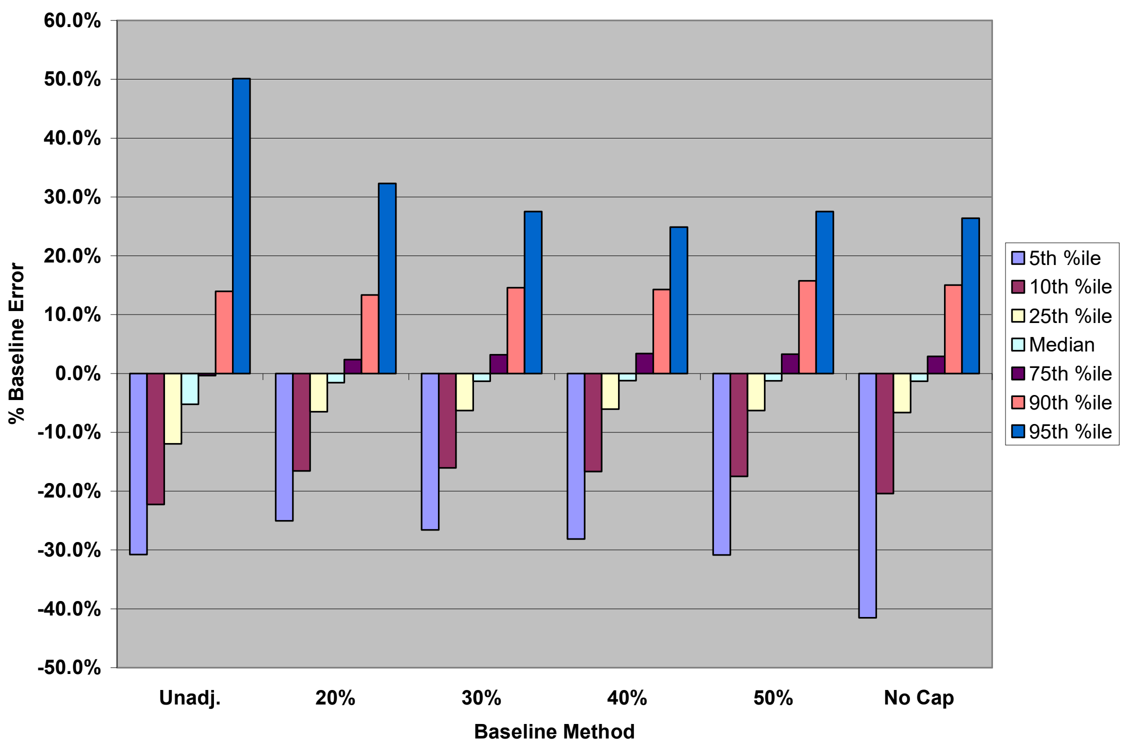
Table 5.3 provides information about the distribution of percentage baseline errors by customer group. All events (real and simulated) are included in the analysis. The results for all DBP customers (in the top panel) are also shown in Figure 5.1. The values for the 25th and 75th percentiles show the range within which half of the customer-event days fall. For the unadjusted baseline, half of all customer-event days have a baseline error between -12.0 and -0.4 percent. This highlights the negative bias in this baseline calculation, showing that approximately 75 percent of customer-event days result in an understated baseline when no day-of adjustment is applied.

The distribution is somewhat tighter and less negatively biased when the day-of adjustment is applied. For example, when the 40 percent cap is applied to the day-of adjustment, 50 percent of the customer-event days have a baseline percentage error between -6.1 and +3.4 percent. While the distribution of baseline errors does not vary too much across the different cap levels, the 5th percentile does show progressively higher error levels as the cap becomes less restrictive, with the 5th percentile error reaching -41.5 percent when the adjustment cap is removed entirely. This result indicates the potential benefits of implementing a more restrictive adjustment cap.

Table 5.3: Percentiles of Percentage Errors of Alternative Baselines, *PG&E DBP*

Customer Group	Count	Percentile	Unadj.	20%	30%	40%	50%	No Cap
All	873	5	-30.8%	-25.0%	-26.6%	-28.1%	-30.8%	-41.5%
		10	-22.3%	-16.5%	-16.1%	-16.7%	-17.5%	-20.4%
		25	-12.0%	-6.5%	-6.3%	-6.1%	-6.3%	-6.7%
		Median	-5.2%	-1.6%	-1.3%	-1.2%	-1.2%	-1.3%
		75	-0.4%	2.3%	3.2%	3.4%	3.3%	2.9%
		90	14.0%	13.3%	14.6%	14.3%	15.7%	15.0%
		95	50.1%	32.3%	27.5%	24.9%	27.5%	26.4%
Selected Adj.	842	5	-30.8%	-25.1%	-26.6%	-28.1%	-30.8%	-41.5%
		10	-22.4%	-16.7%	-16.3%	-17.0%	-17.7%	-20.6%
		25	-12.3%	-6.7%	-6.5%	-6.3%	-6.5%	-6.8%
		Median	-5.4%	-1.6%	-1.4%	-1.3%	-1.4%	-1.4%
		75	-0.4%	2.3%	3.0%	3.3%	3.0%	2.9%
		90	13.6%	12.9%	14.3%	13.9%	15.3%	14.7%
		95	50.1%	31.7%	26.7%	24.2%	25.9%	24.5%

Figure 5.1: Percentiles of Relative Errors of Alternative Baselines, *PG&E DBP*



5.4.2 SCE DBP

Table 5.4 summarizes SCE's the *accuracy* results for the alternative baselines compared to the regression-based and observed baselines, with results reported by customer type (all customers or only those who selected the day-of adjustment) and event type (all studied events, only actual events, and only event-like days).

As with PG&E's baseline study, the adjusted baselines perform better than the unadjusted baselines, though the improvement is smaller for SCE. The results for SCE are also similar to PG&E's in that the accuracy measures do not vary significantly with the level of the day-of adjustment cap.

Table 5.4: Accuracy of Alternative Baselines, *SCE DBP*
(*Median Absolute Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	8,149	8.0%	5.9%	5.9%	5.9%	5.9%	5.9%
All	Selected Adj.	1,279	6.4%	4.1%	4.2%	4.1%	4.1%	4.0%
Actual	All	3,104	7.7%	5.7%	5.8%	5.8%	5.8%	5.8%
Actual	Selected Adj.	487	6.4%	3.9%	4.0%	3.9%	3.9%	3.9%
Event-like	All	5,045	8.3%	6.0%	5.9%	6.1%	6.0%	6.0%
Event-like	Selected Adj.	792	6.3%	4.2%	4.2%	4.2%	4.1%	4.1%

Table 5.5 presents results for the typical *bias* of the alternative baselines. The majority of the results indicate a tendency for baselines to be *understated* (i.e., the calculated baseline is less than the "true" baseline). The bias is much larger for the unadjusted baselines than it is for the adjusted baselines. For example, the median bias for the unadjusted baseline is -4.0 percent across all customers and events, but only -0.9 to -0.3 percent across the various adjusted baselines.

Table 5.5: Bias of Alternative Baselines, *SCE DBP*
(*Median Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	8,149	-4.0%	-0.9%	-0.6%	-0.6%	-0.5%	-0.3%
All	Selected Adj.	1,279	-4.7%	-0.5%	-0.3%	-0.3%	-0.1%	0.1%
Actual	All	3,104	-4.7%	-0.6%	-0.4%	-0.2%	-0.1%	0.3%
Actual	Selected Adj.	487	-5.3%	0.5%	0.6%	0.7%	0.7%	0.9%
Event-like	All	5,045	-3.5%	-1.0%	-0.8%	-0.7%	-0.6%	-0.6%
Event-like	Selected Adj.	792	-4.4%	-1.0%	-0.8%	-0.8%	-0.7%	-0.5%

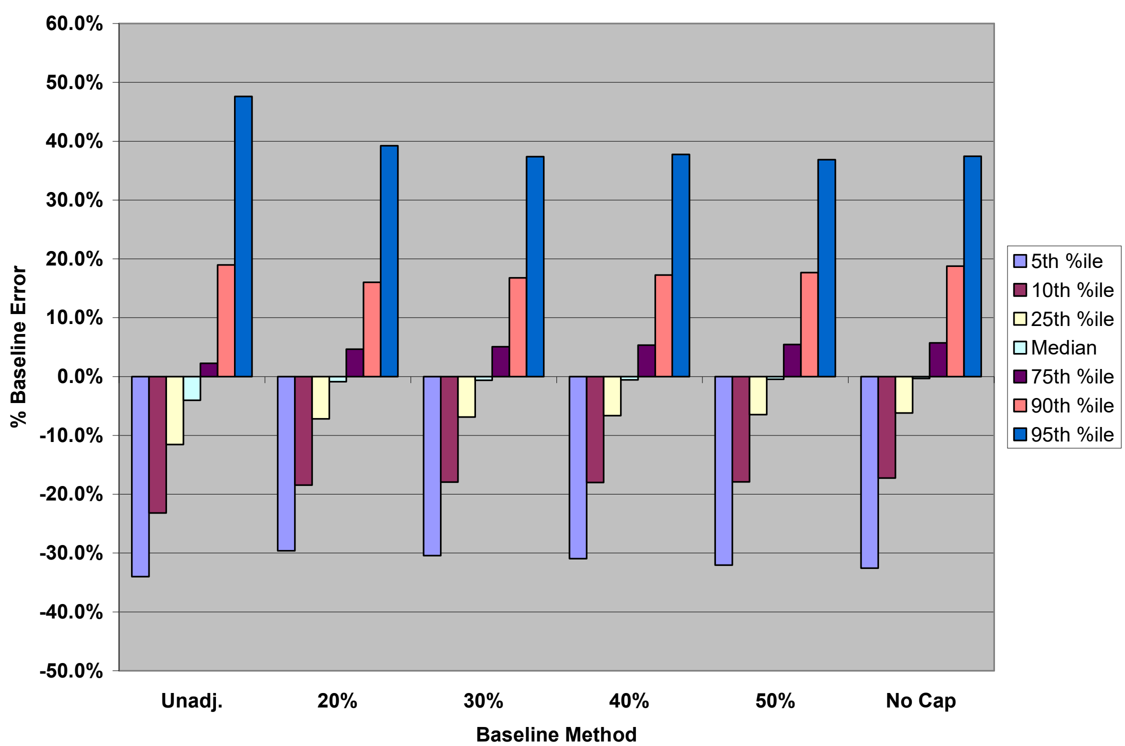
Table 5.6 provides information about the distribution of percentage baseline errors by customer group. All events (real and simulated) are included in the analysis. The results for all DBP customers (in the top panel) are also shown in Figure 5.2. For the unadjusted baseline, half of all customer-event days have a baseline error between -11.5 and +2.2 percent. This illustrates that the SCE program baselines are less skewed toward understating the true baseline than those of PG&E.

The distribution of SCE's baseline results differs from PG&E's in that the more extreme results (i.e., the 5th percentile) do not vary as much as the adjustment cap becomes less restrictive. In short, the results indicate that SCE baseline performance is not substantially affected by the presence of magnitude of the cap on the day-of adjustment (though the presence of a day-of adjustment, regardless of the cap level, produces improved performance relative to the unadjusted baselines).

Table 5.6: Percentiles of Percentage Errors of Alternative Baselines, *SCE DBP*

Customer Group	Count	Percentile	Unadj.	20%	30%	40%	50%	No Cap
All		5	-34.0%	-29.6%	-30.4%	-31.0%	-32.1%	-32.6%
		10	-23.2%	-18.5%	-17.9%	-18.0%	-17.9%	-17.2%
		25	-11.5%	-7.2%	-6.9%	-6.7%	-6.5%	-6.2%
		Median	-4.0%	-0.9%	-0.6%	-0.6%	-0.5%	-0.3%
		75	2.2%	4.7%	5.1%	5.3%	5.4%	5.7%
		90	19.0%	16.0%	16.8%	17.3%	17.7%	18.8%
		95	47.6%	39.2%	37.4%	37.8%	36.8%	37.5%
Selected Adj.		5	-29.5%	-24.3%	-24.7%	-24.2%	-24.5%	-23.3%
		10	-20.0%	-15.2%	-13.0%	-12.3%	-12.0%	-11.4%
		25	-10.3%	-4.8%	-4.6%	-4.3%	-4.1%	-3.8%
		Median	-4.7%	-0.5%	-0.3%	-0.3%	-0.1%	0.1%
		75	-0.2%	3.5%	3.8%	3.9%	4.0%	4.2%
		90	5.5%	10.0%	10.6%	11.5%	11.8%	12.4%
		95	23.1%	21.5%	23.8%	22.0%	22.0%	22.0%

Figure 5.2: Percentiles of Relative Errors of Alternative Baselines, *SCE DBP*



5.4.3 SDG&E DBP

These results have been removed due to confidentiality concerns.

5.5 Summary of Results

The baseline analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment. There is some evidence from PG&E that more restrictive cap levels (e.g., 20 to 40 percent) prevent some of the larger baseline errors from occurring, with little apparent downside.

6. Ex Ante Load Impact Forecast

6.1 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-year conditions, and
- 1-in-10 weather-year conditions.

at both:

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

6.2 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.

6.2.1 Development of Customer Groups

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

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

The specific definition of "maximum demand" was based on the tariff on which the customer is served. For example, a tariff may require that a customer's monthly peak demand exceeds 20kW during any one of the previous twelve months. The total number of customer "cells" developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

For SCE, the analysis is complicated by an upcoming change to the program. In 2015, the program will begin enrolling customers with demands under 200 kW. In addition, SCE will begin removing "non-performing" customers from DBP during the 2014 program year. Based on current estimates, approximately 500 customers will be removed from DBP for this reason. In order to account for these changes, forecasts are developed for three groups of customers: the current program composition, for use until SCE begins removing non-performing customers; current customers with non-performing customers removed, to represent the over 200 kW customers for the remainder of the forecast period; and under 200 kW customers.

6.2.2 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.

Define data sources

For both PG&E and SCE, the reference loads are developed using data for customers enrolled in DBP during the 2012 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 (2010 through 2012).

For each service account, we determine the appropriate size group, LCA, and dual enrollment status. Service accounts that are dually enrolled in BIP or an aggregator program (e.g., the 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).

For SCE's under-200 kW customers, reference loads and percentage load impacts developed using the smaller customers from the current program year. Specifically, we use customers that have average event-hour reference loads (on a 1-in-2 typical event day) under 200 kW. To account for differences between these customers (e.g., which are likely to be significantly larger than typical under-200 kW customers) and the under-200 kW customers expected to be added to DBP, their reference loads and load impacts are scaled and weighted across industry groups using data provided by SCE, shown in Table 6.1.

Table 6.1: Forecast Characteristics of SCE's Under 200 kW DBP Customers

Industry Group	Share of Forecast Enrollment	Average per-SAID Hourly Usage (kW)
Agriculture, Mining, & Construction	3.2%	28.0
Manufacturing	27.2%	131.9
Wholesale, Transportation, & Other Utilities	15.2%	49.6
Retail Stores	12.0%	83.7
Offices, Hotels, Health, Services	19.2%	65.8
Schools	19.2%	82.4
Entertainment, Other Services, Government	4.0%	160.2
Total	**100.0%**	**89.2**

Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations for each enrolled customer account using data for the current program year. The resulting estimates were used to simulate reference loads for each service account under the various scenarios required by the Protocols (*e.g.*, the typical event day in a 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 THI variables used in the ex post regressions. The primary reason for this is that the historical data used in the ex ante scenarios do not contain complete data on relative humidity, such that we would need to fill in missing data in order to use THI in our simulations.

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 three ways: it includes HDH_t variables, where the summer model does not; the month dummies relate to a different set of months; and the event variables are removed (because no event days occurred during the regression timeframe). Table 6.2 describes the terms included in the equation.

$$Q_t = a + \sum_{i=1}^{24}(b_i^{CDH} \times h_{i,t} \times CDH_t) + \sum_{i=1}^{24}(b_i^{HDH} \times h_{i,t} \times HDH_t) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t)$$
$$+ \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24}(b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5}(b_i^{DTYPE} \times DTYPE_{i,t})$$
$$+ \sum_{i=2-5,10-12}(b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

Table 6.2: 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*
CDH_t	cooling degree hours
HDH_t	heating degree hours[16]
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. The definitions of the 1-in-2 and 1-in-10 weather years are the same as those used to develop ex ante load forecasts in the previous two studies (developed following PY2009).

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 2010 through 2012. Specifically, we examined only customers enrolled in PY2012, but included load impact estimates from the previous two program years for customers that were enrolled in those years. This method allowed us to base the ex ante load impacts on a larger sample of events, which should 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 PY10 through PY12. Within service account, we then calculate 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.

[16] 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.

These percentages are applied to the customer's ex ante (forecast) reference load for each required scenario.

From these customer-level forecasts of reference loads and load impacts, we form results for any given sub-group of customers (e.g., customers over 200 kW in size in the Greater Bay Area, 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 6.3.

Table 6.3: Method of Adapting the Ex Post Event Window to the Ex Ante Window

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 10^{th}, 30^{th}, 50^{th}, 70^{th}, and 90^{th} 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.

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.

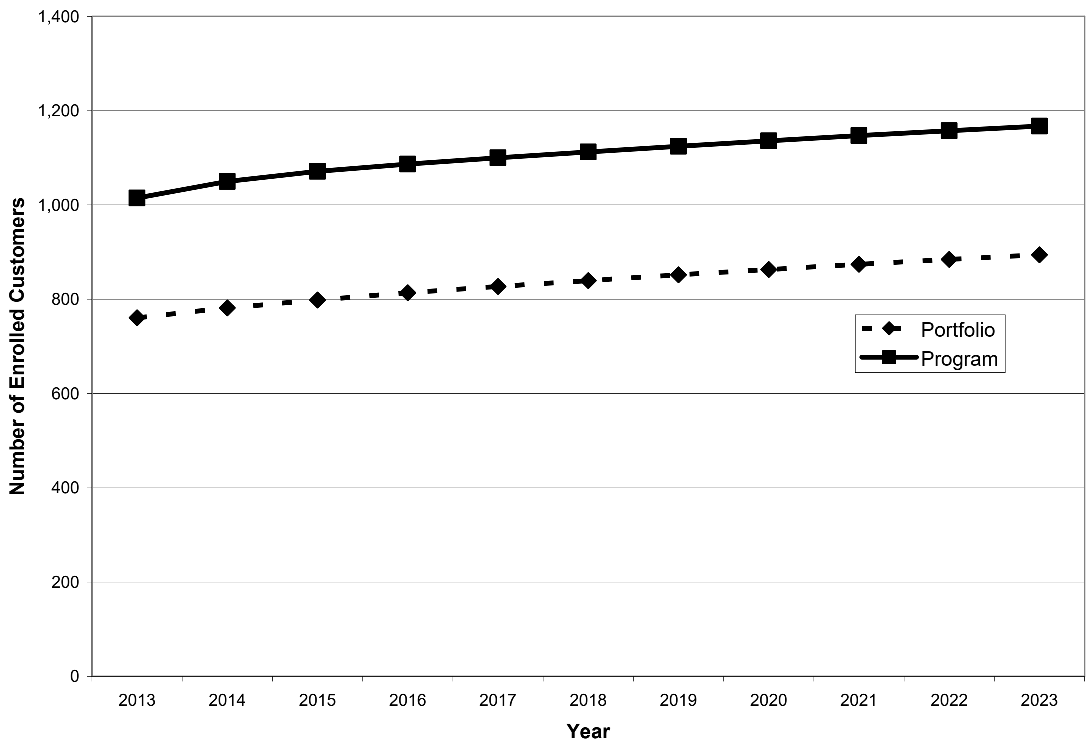
Apply forecast enrollments to produce program-level load impacts. The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2023, with separate enrollments provided at the program and portfolio level (the latter excludes dually enrolled customers) by LCA and size group. SCE provided monthly enrollments for 2013, 2014, 2015, 2016, and 2017 through 2023 (under the assumption that enrollments remain fixed during that time period). In addition, SCE provided the list of service accounts that they expect to exclude beginning in 2014 due to non-performance. The enrollments are then used to scale up the reference loads and load impacts for each required scenario and customer subgroup.

6.3 Enrollment Forecasts

PG&E

PG&E forecasts DBP enrollments to increase by approximately 3.5 percent in 2014. The rate of enrollment growth declines throughout the forecast period, to 0.8 percent by 2023. By 2023, 1,167 customers are expected to be enrolled in DBP. The portfolio-based enrollment forecast (which excludes dually enrolled customers) includes 254 to 273 fewer customers than the program-based enrollment forecast during the summer months. Figure 6.1 illustrates PG&E's forecast enrollments in August of each year.

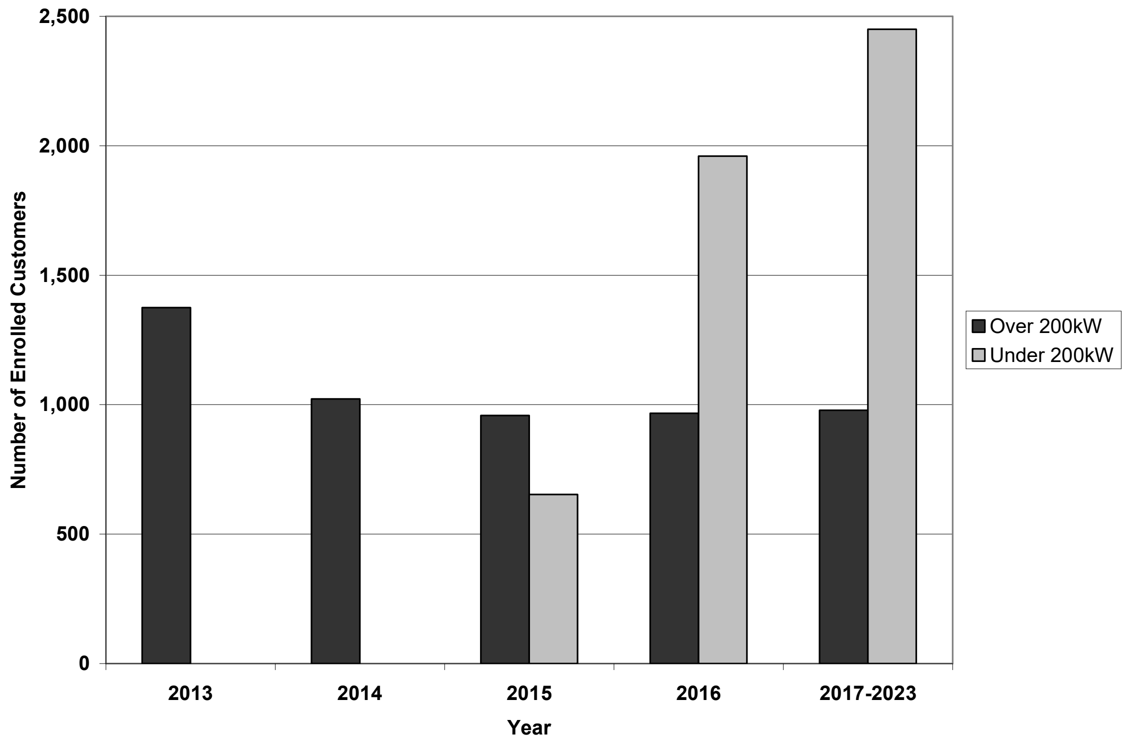
Figure 6.1: Number of Enrolled Customers in August of Each Forecast Year, *PG&E*



SCE

As described earlier, SCE is planning two changes to DBP that affect the enrollment forecast. During PY2014, SCE will begin removing non-performing customers from the program. Under-200 kW customers will begin joining the program in 2015, with their enrollment reaching 2,450 customers by the end of the forecast period. Figure 6.2 shows SCE's forecast of August enrollments by year.

Figure 6.2: Number of Enrolled Customers in August of Each Forecast Year, *SCE*



6.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information: the hourly profile of reference loads and load impacts for typical event days; the level of load impacts across years; and the distribution of load impacts by local capacity area. Outcomes for August 2015 are used throughout.

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.

6.4.1 PG&E

Figure 6.3 shows the program-level August 2015 forecast load impacts for a typical event day in a 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 56.2 MW, which represents 6.0 percent of the enrolled reference load. Figure 6.4 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 53.4 MW (relative to the program-level load impact) to 2.9 MW and the percentage load impact goes down to 0.5 percent. The large difference between program and portfolio load impacts is due to the contribution of customers dually enrolled in DBP and 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 DBP, dramatically reducing the load impact.

Figure 6.3: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Program Level

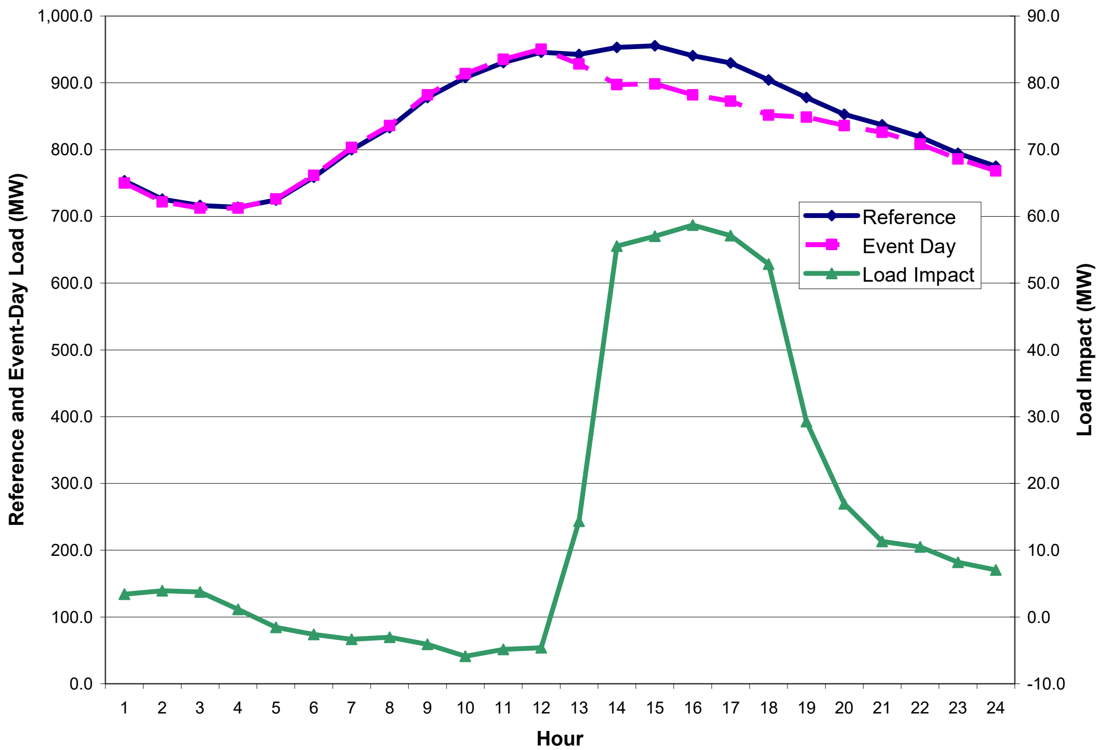


Figure 6.4: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Portfolio Level

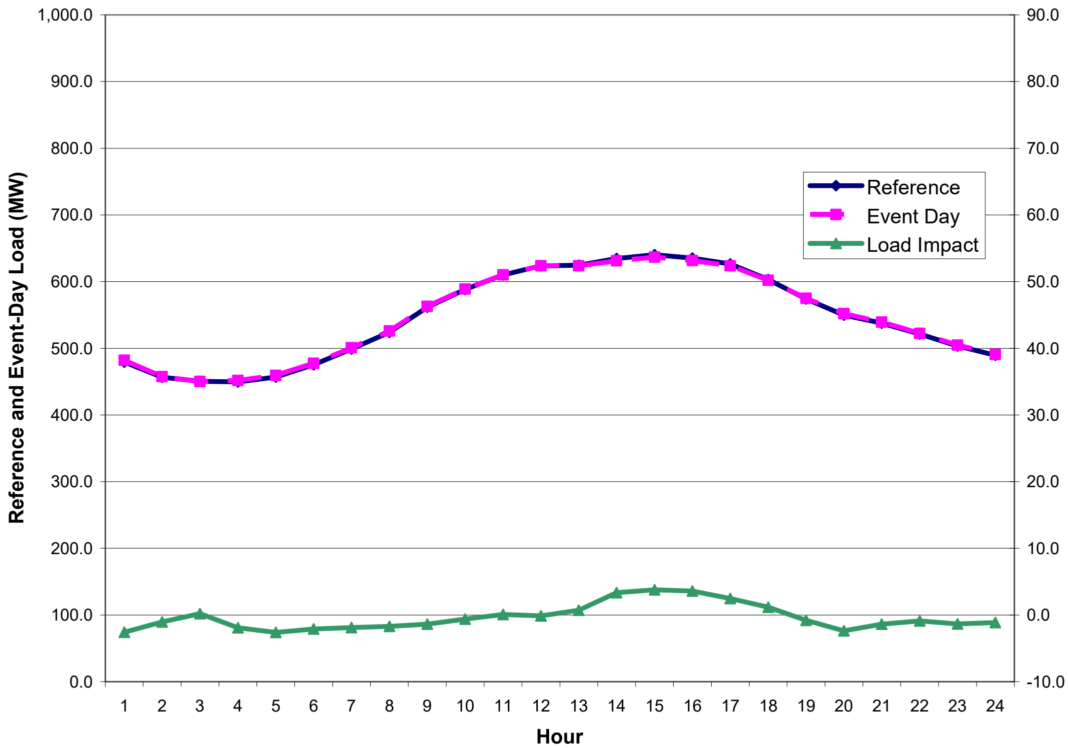


Figure 6.5 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2015 1-in-2 weather year. Customers not in any LCA account for the largest share, with 86 percent of the load impacts.

Figure 6.5: Share of Load Impacts by LCA for the August 2015 Typical Event Day in a 1-in-2 Weather Year

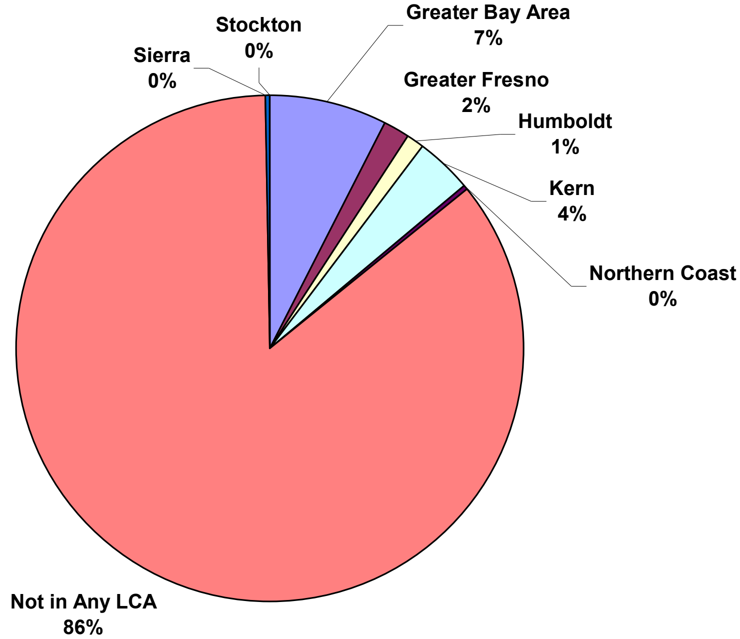
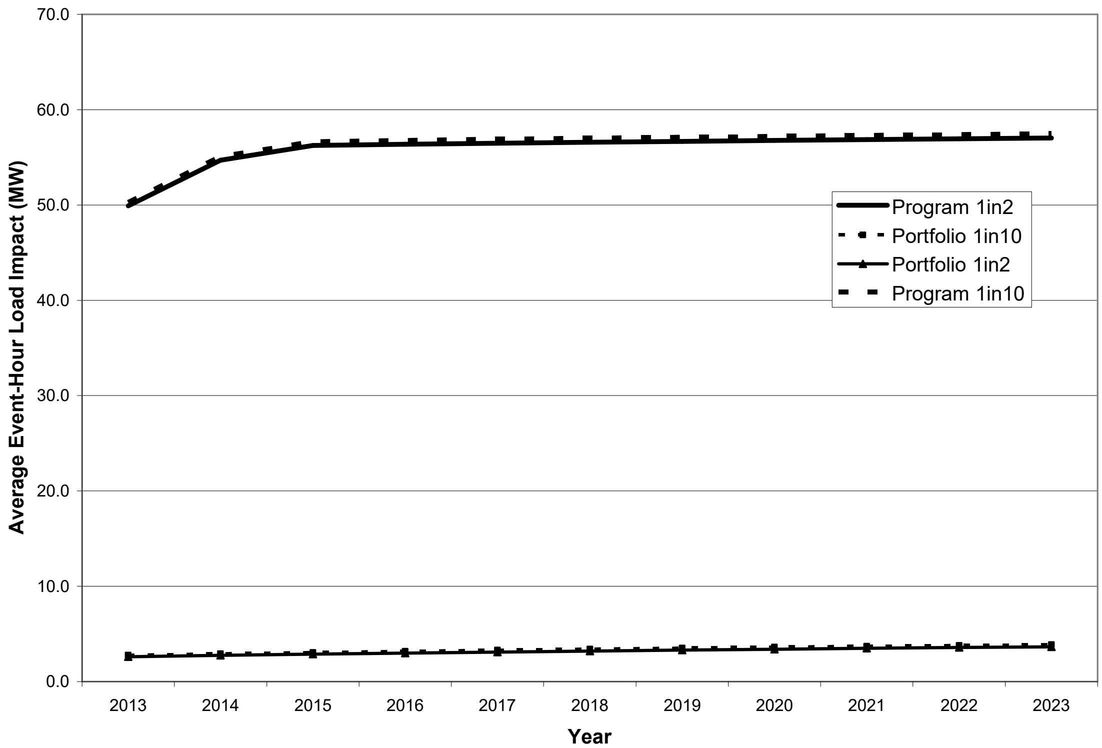


Figure 6.6 illustrates August load impact for each forecast year across four scenarios, differentiated by 1-in-2 versus 1-in-10 weather conditions, and portfolio- versus program-level load impacts. There is a very small difference in load impacts across weather scenarios, but the portfolio-level load impacts are much lower than the program-level load impacts (due to the removal of the customers dually enrolled in BIP or an aggregator program).

The pattern of forecast load impacts across years is quite different in this evaluation compared to the previous evaluation. The primary reason for this is that the previous evaluation used an enrollment forecast that included a declining share of customers dually enrolled in DBP and BIP over time. The share of dually enrolled customers in this year's forecast is much more stable over time, which explains the stability of the forecast load impacts from 2015 through 2023.

Figure 6.6: Average Hourly Ex Ante Load Impacts by Scenario and Year, *PG&E*



6.4.2 SCE

Figure 6.7 shows the program-level forecast reference loads and load impacts for the August 2015 peak day in a 1-in-2 weather year. The average program-level load impact is 78.3 MW, or 7.9 percent of the reference load.

Figure 6.8 shows the portfolio-level forecast for the August 2015 peak day in a 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 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 5.5 MW (a reduction of 72.6 MW relative to the program-level load impacts), or 1.1 percent of reference load.

Figure 6.7: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Program Level

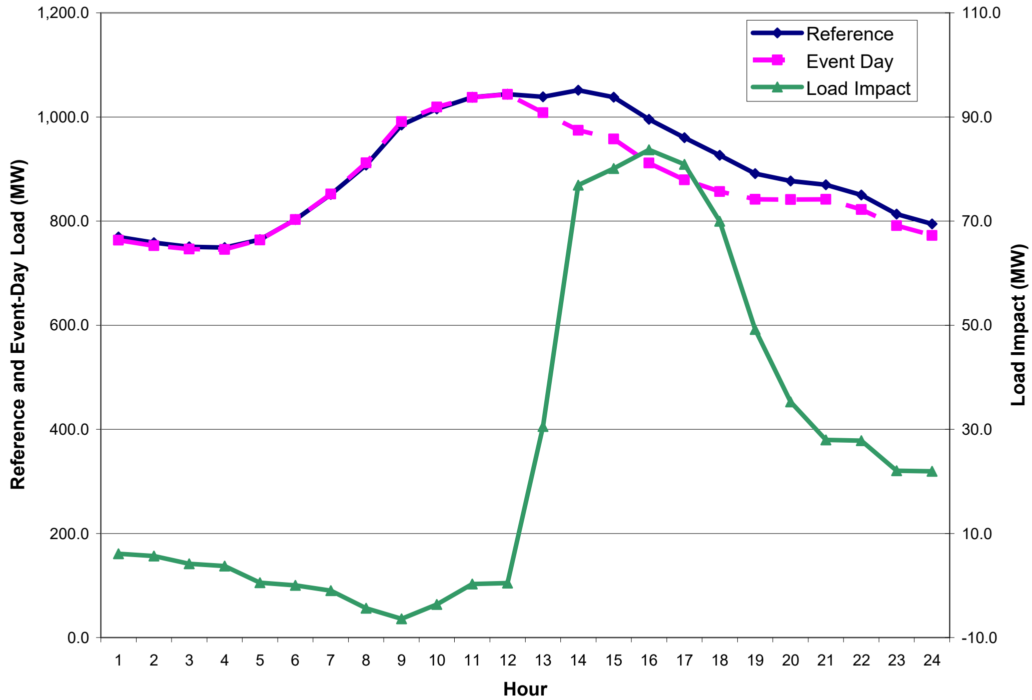


Figure 6.8: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Portfolio Level

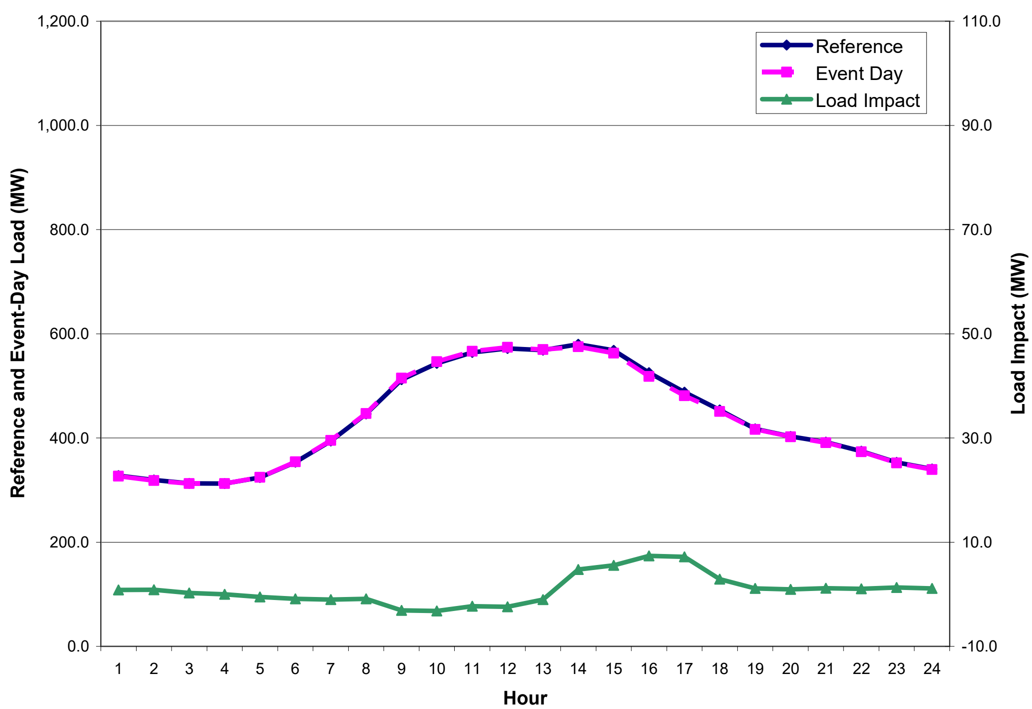


Figure 6.9 shows the distribution of program-level load impacts across local capacity areas. The LA Basin accounts for the largest share, with 70 percent of the total load impacts.

Figure 6.9: Share of SCE DBP Load Impacts by Local Capacity Area

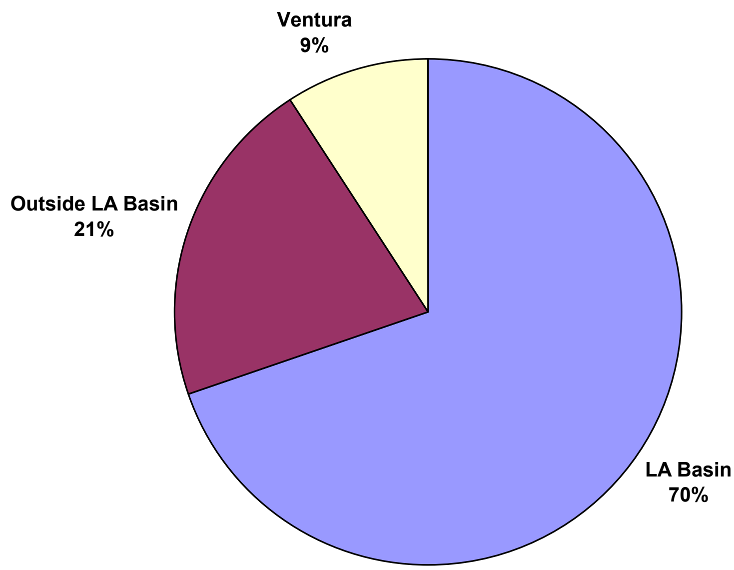
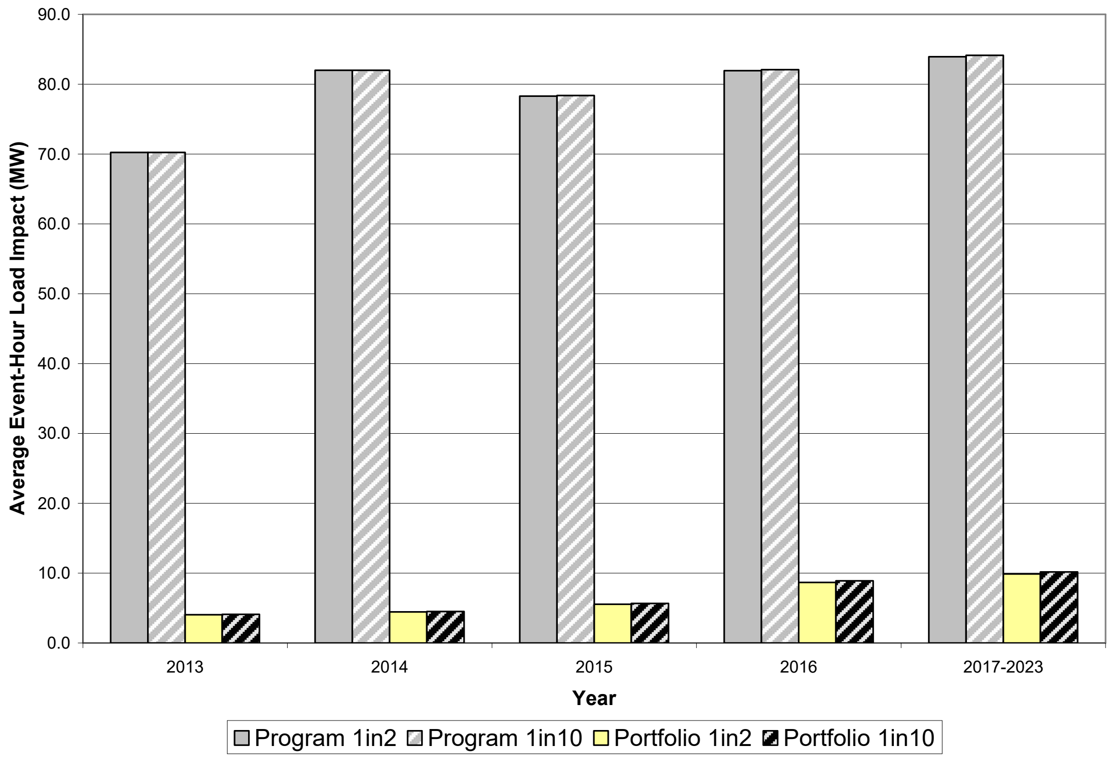


Figure 6.10 illustrates the average August hourly load impact across scenarios and year. The load impacts in 1-in-10 weather years are very similar to the corresponding 1-in-2 load impacts, but the program-level load impacts are much higher than the portfolio-level load impacts. By the 2017-2023 period, the program-level load impact reaches 84 MW in the 1-in-2 weather year.

Figure 6.10: Average Hourly Ex Ante Load Impacts by Scenario and Year, *SCE*



6.4.3 SDG&E

These results have been removed due to confidentiality concerns.

6.4.4 Comparison to Previous Ex Ante Forecast

Table 6.4 provides a comparison of the program-level ex ante forecasts from the current and previous studies. We compare August 1-in-2 forecasts for 2015 for SCE and 2013 for PG&E. No comparison is made for SDG&E because they did not have DBP in PY2011.

Table 6.4: Comparison of Current and Previous Ex Ante Forecasts, *Program-Level*

Result Type	Previous PG&E 2013	Current PG&E 2013	Previous SCE 2015	Current SCE 2015
# Enrolled	1,234	1,015	2,189	1,611
Reference Load (MW)	985 MW	876 MW	1,356 MW	994 MW
Load Impact (MW)	47.3 MW	49.9 MW	89.9 MW	78.3 MW
% Load Impact	4.8%	5.7%	6.6%	7.9%

For PG&E, the primary driver of the increase in percentage and MW load impacts between evaluations is a change in the forecast of the number of customers dually enrolled in DBP and BIP. That is, the previous enrollment forecast incorporated a declining number of DBP/BIP customers over time. This is not a feature of the current forecast. Specifically, the current forecast includes 143 customers who are dually enrolled in DBP and BIP in August 2013. The previous forecast had only 117 such customers. Because dually enrolled customers are the most responsive DBP customers, the decline in their number produces a reduction in program-level response despite the increase in the total number of customers.

For SCE, the forecast is affected by two factors. First, the current forecast includes fewer under-200 kW customers than the previous forecast did. Second, the under-200 kW customers that are included are not as responsive as they were in the previous forecast. In both cases, the percentage load impacts for the under-200 kW customers were based on the estimated ex post load impacts for the smaller customers currently enrolled in the program. In the previous program year, we estimated approximately 3 percent demand response from these customers. In this evaluation, the percentage load impact dropped to 1.5 percent. It is not clear why this is the case, though we note that the small customers tend to be less responsive, which could lead to imprecise (and therefore relatively less consistent) load impact estimates for those customers.

Table 6.5 conducts the same comparison, this time at the portfolio level (i.e., excluding the load impacts from customers dually enrolled in BIP or an aggregator program).

Table 6.5: Comparison of Current and Previous Ex Ante Forecasts, *Portfolio-Level*

Result Type	Previous PG&E 2013	Current PG&E 2013	Previous SCE 2015	Current SCE 2015
# Enrolled	942	761	2,090	1,224
Reference Load (MW)	703 MW	596 MW	1,001 MW	523 MW
Load Impact (MW)	13.9 MW	2.6 MW	11.9 MW	5.5 MW
% Load Impact	2.0%	0.4%	1.2%	1.1%

For PG&E, the percentage load impacts for DBP-only customers drop significantly, from 2.0 to 0.4 percent. Given that we modified our forecasting approach to build up from customer-level forecasts, the source of the change in percentage load impacts can be difficult to determine. One likely source is that this year's forecast excludes both dually enrolled aggregator customers and dually enrolled BIP customers, while the previous forecast excluded only dually enrolled BIP customers.

For SCE, the percentage load impact is approximately the same across program years, dropping from 1.2 percent to 1.1 percent. The larger change is in the amount of load that remains in the portfolio-level scenario, which is reduced almost by half relative to the previous evaluation.

7. Validity Assessment

7.1 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:

1. *Weather variables*. We tested 18 different combinations of weather variables. The weather variables include: temperature-humidity index (THI)[17]; the 24-hour moving average of THI; heat index (HI)[18]; the 24-hour moving average of HI; cooling degree hours (CDH)[19], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; the 24-hour moving average of CDH; the one-day lag of cooling degree days (CDD)[20]. A list of the 18 combinations of these variables that we tested in provided in Table 7.1.
2. *Level models versus difference models*. The dependent variable in the model presented in Section 3.2.1 is the level of customer usage in a particular hour. This has been the most common way of estimating load impact models in our previous evaluations. In our specification tests, we include models of *differences* in usage across days that attempt to explain day-to-day load changes, including those on event days. These models explain the difference in load for each hour relative to the same hour on the previous day as a function of the corresponding differences in weather conditions and day-types. The potential advantage of this approach is that each hour's load is evaluated relative only to loads on neighboring days, which may remove spurious effects across time (for which we are unable to control due to incomplete information).

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

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

[19] Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

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

Table 7.1: 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

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.

7.1.1 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 across customers, each of which is associated with a weather station. We "scored" each non-holiday weekday by comparing the dry-bulb temperature and relative humidity to the values for each event day. For example, we calculated the following statistic for each day relative to the first day: abs($Temp_t$ – $Temp_{Evt}$) / StdDev($Temp$). A similar score was calculated for the relative humidity, and the sum of the temperature and humidity scores was used to rank the days. We selected the five lowest-scoring days (low scores indicate greater similarity to the event day) for each event day. Days were excluded from the list as necessary (e.g., to exclude BIP event days).

Table 7.2: List of Event-Like Non-Event Days by Program

PG&E	SCE	SDG&E
6/11/2012	7/10/2012	8/10/2012
6/20/2012	7/13/2012	8/13/2012
7/10/2012	8/6/2012	8/17/2012
7/30/2012	8/7/2012	8/28/2012
8/13/2012	8/9/2012	8/31/2012
10/2/2012	8/13/2012	9/21/2012
	8/20/2012	
	8/27/2012	
	8/28/2012	
	9/4/2012	
	9/12/2012	
	9/20/2012	

7.1.2 Results from Tests of Alternative Weather Specifications

For each utility, we tested 36 specifications, which is 18 different sets of weather variables, each estimated in levels and differences. The aggregate load used in conducting these tests was constructed separately for each utility and included only customers who submitted a bid on at least one event day.

The tests are conducted by estimating one model for every utility (3), specification (36), and event-like day (6 for PG&E and SDG&E, 12 for SCE). Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Tables 7.3 through 7.5 show the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) for each specification, by utility. As a general rule, the level models perform better than the models of differences. For PG&E and SCE, the bias is quite small (the MPE is less than 0.25 percent for the selected model) and the models are quite accurate (the MAPE is less than 2 percent for the selected model). The SDG&E program consists of a single customer with a somewhat unpredictable load, so its model does not perform as well.

Table 7.3: Specification Test Results, *PG&E*

Specification Number	Level or Differences	Adjusted R^2	MPE	MAPE
1	Level	0.927	0.12%	1.92%
2		0.925	0.10%	2.01%
3		0.926	0.51%	2.03%
4		0.924	0.49%	2.02%
5		0.927	0.56%	2.04%
6		0.925	0.60%	2.02%
7		0.926	0.14%	1.89%
8		0.926	0.12%	2.01%
9		0.926	0.48%	2.01%
10		0.926	0.46%	2.04%
11		0.927	0.52%	1.94%
12		0.926	0.48%	1.91%
13		0.926	0.17%	1.85%
14		0.925	0.13%	1.96%
15		0.926	0.56%	1.98%
16		0.924	0.54%	1.97%
17		0.927	0.66%	1.99%
18		0.925	0.69%	1.98%
1	Differences	0.753	0.66%	5.95%
2		0.752	0.66%	5.87%
3		0.751	0.62%	5.87%
4		0.749	0.57%	5.85%
5		0.750	0.69%	5.90%
6		0.748	0.66%	5.88%
7		0.753	0.50%	5.95%
8		0.751	0.66%	5.90%
9		0.751	0.69%	5.92%
10		0.750	0.75%	5.92%
11		0.750	0.63%	5.94%
12		0.749	0.70%	5.93%
13		0.753	0.71%	5.97%
14		0.752	0.71%	5.89%
15		0.750	0.70%	5.90%
16		0.749	0.65%	5.88%
17		0.750	0.73%	5.91%
18		0.748	0.71%	5.90%

Table 7.4: Specification Test Results, *SCE*

Specification Number	Level or Differences	Adjusted R^2	MPE	MAPE
1	Level	0.956	0.23%	1.82%
2		0.955	0.22%	1.86%
3		0.957	0.38%	1.69%
4		0.956	0.40%	1.69%
5		0.955	0.39%	1.75%
6		0.954	0.43%	1.76%
7		0.957	0.22%	1.78%
8		0.955	0.21%	1.86%
9		0.957	0.36%	1.68%
10		0.956	0.36%	1.69%
11		0.956	0.33%	1.67%
12		0.955	0.33%	1.68%
13		0.957	0.23%	1.85%
14		0.955	0.21%	1.87%
15		0.957	0.37%	1.68%
16		0.956	0.39%	1.69%
17		0.956	0.39%	1.71%
18		0.955	0.43%	1.74%
1	Differences	0.834	3.66%	5.54%
2		0.832	3.58%	5.51%
3		0.835	3.59%	5.47%
4		0.834	3.57%	5.47%
5		0.834	3.62%	5.61%
6		0.833	3.63%	5.64%
7		0.834	3.69%	5.56%
8		0.832	3.67%	5.59%
9		0.835	3.69%	5.57%
10		0.834	3.69%	5.60%
11		0.834	3.68%	5.64%
12		0.833	3.67%	5.66%
13		0.834	3.68%	5.58%
14		0.831	3.62%	5.56%
15		0.834	3.63%	5.53%
16		0.834	3.62%	5.54%
17		0.833	3.67%	5.63%
18		0.833	3.67%	5.66%

Table 7.5: Specification Test Results, *SDG&E*

Specification Number	Level or Differences	Adjusted R^2	MPE	MAPE
1	Level	0.710	-6.01%	9.60%
2		0.709	-8.05%	10.52%
3		0.707	-6.57%	9.90%
4		0.703	-5.90%	10.00%
5		0.709	-6.16%	9.77%
6		0.705	-5.21%	9.71%
7		0.709	-6.53%	9.87%
8		0.708	-7.55%	10.21%
9		0.707	-6.37%	9.89%
10		0.705	-5.41%	9.79%
11		0.708	-7.39%	10.33%
12		0.706	-6.87%	10.44%
13		0.710	-7.42%	10.40%
14		0.708	-9.11%	11.15%
15		0.707	-7.43%	10.27%
16		0.704	-6.41%	10.12%
17		0.709	-7.36%	10.31%
18		0.706	-6.13%	10.05%
1	Differences	0.433	-6.96%	15.47%
2		0.431	-7.70%	15.44%
3		0.432	-7.67%	15.26%
4		0.432	-7.58%	15.13%
5		0.436	-6.99%	14.37%
6		0.436	-6.73%	14.16%
7		0.439	-3.57%	13.67%
8		0.442	-2.52%	12.59%
9		0.443	-1.88%	12.77%
10		0.447	0.48%	12.25%
11		0.442	-1.54%	12.78%
12		0.446	1.08%	12.27%
13		0.432	-4.80%	15.51%
14		0.429	-5.25%	15.57%
15		0.431	-4.99%	15.34%
16		0.431	-4.80%	15.19%
17		0.435	-4.08%	14.38%
18		0.435	-3.62%	14.21%

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). 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.

Figures 7.1 through 7.3 show the estimated hourly load impacts for each of the 18 level models by utility. There were differences between the load impacts for the level versus differences models, but given the performance of the differences models, we show only the results for the levels models here. Based on the tests, we selected the first specification, which uses current-hour THI interacted with each hour of the day as the weather variables. While it is not the best performer for every utility, it is among the better models for all of them and allows us to apply a consistent model across utilities.

The load impacts for the THI-based specification are highlighted in bold in each of the figures. As the figures show, the load impacts would not change substantially if we were to alter the weather specification.

Figure 7.1: Average Event-Hour Load Impacts by Specification, *PG&E Level Models*

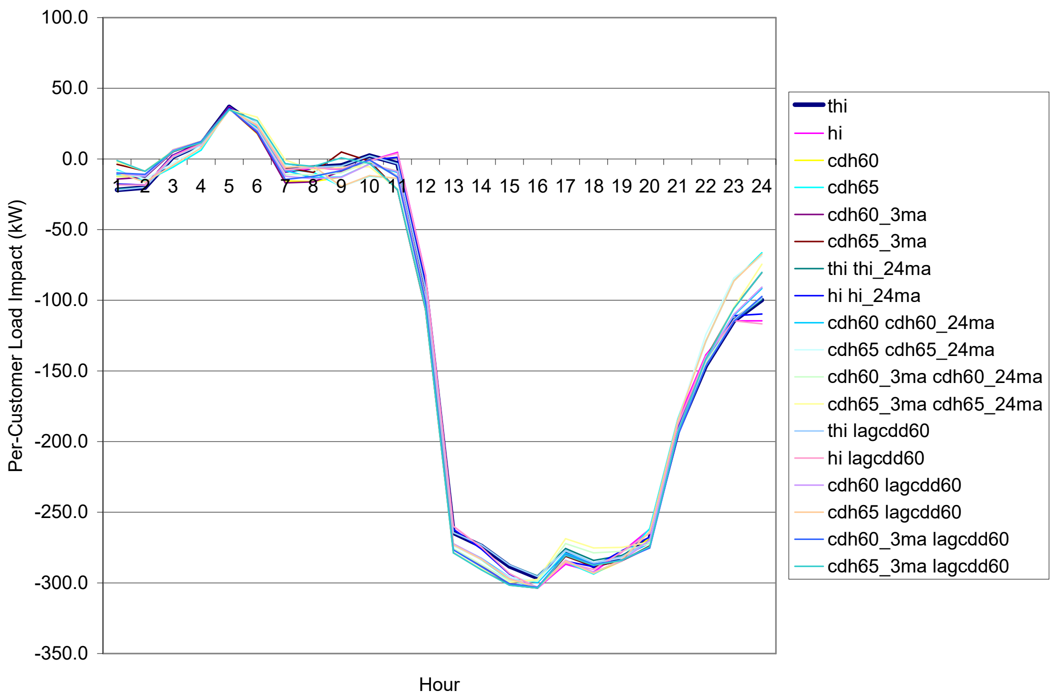


Figure 7.2: Average Event-Hour Load Impacts by Specification, *SCE Level Models*

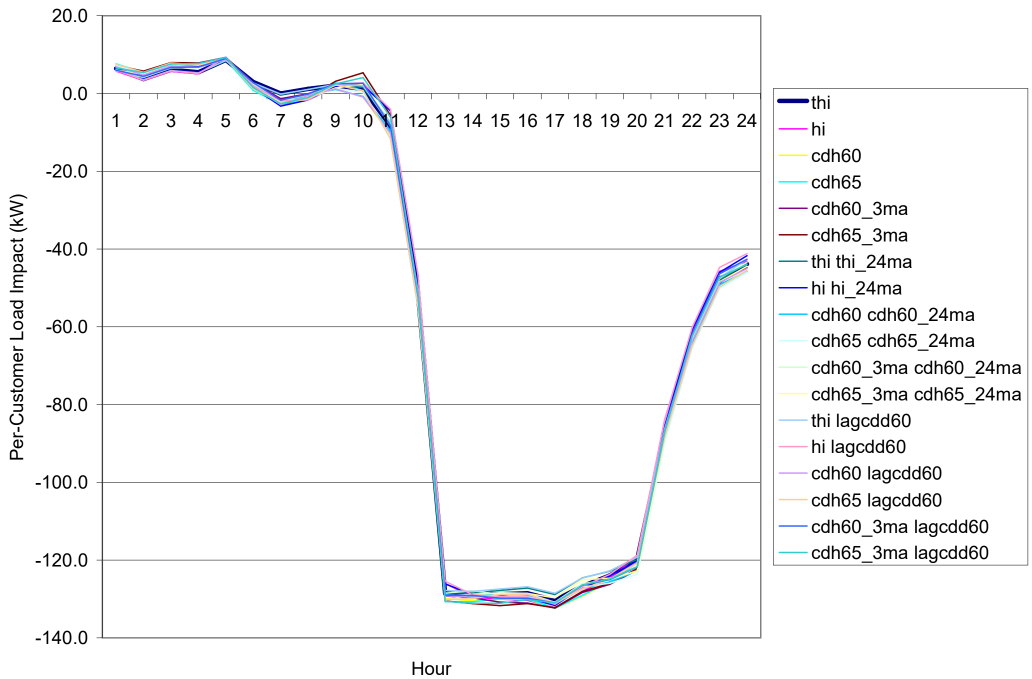


Figure 7.3: Average Event-Hour Load Impacts by Specification, *SDG&E Level Models*
Figure removed due to confidentiality concerns.

7.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section 7.1.2, 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 7.2, 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 7.6 presents the results of this test for each utility, showing only the coefficients during the event window (hours-ending 13 through 20). 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 p-values in Table 7.6 are uniformly higher than this standard, indicating that each model "passes" this test.

Table 7.6: Synthetic Event-Day Tests by Program

Hour	PG&E	SCE	SDG&E
13	-2.7 (0.866)	1.7 (0.764)	483.8 (0.637)
14	2.1 (0.897)	-7.5 (0.176)	987.3 (0.338)
15	6.4 (0.691)	-5.8 (0.291)	806.8 (0.433)
16	-2.7 (0.865)	-1.8 (0.750)	748.2 (0.468)
17	-0.6 (0.972)	-8.2 (0.136)	814.1 (0.428)
18	2.6 (0.873)	-9.2 (0.094)	918.3 (0.372)
19	0.1 (0.995)	-7.5 (0.171)	748.7 (0.467)
20	-13.7 (0.395)	-6.5 (0.236)	353.6 (0.732)

7.2 Refinement of Customer-Level Models

While the specification tests described in Section 7.1 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 elected not to modify any of the estimated load impacts as a result of these inspections.

7.3 Comparison of Load Impacts to Program Year 2011

It may be instructive to compare the ex post load impacts estimated for PY 2012 to those of the previous program year.[21] Tables 7.7 and 7.8 present load impacts for each utility and program year, with customers separated into three groups:

- Customers who were present in the program in both program years 2011 and 2012;
- Customers who were present in the program in PY 2012 only (new additions); and
- Customers who were present in the program in PY 2011 only (attrition).

Table 7.7 shows that for PG&E the largest source of the change in load impact estimates across years is a change in estimated load impacts for customers present in both program years. As shown in Table 4.2, the bid realization rate for PG&E remained high. The majority of the difference in load impacts across years is due to the fact that a large

[21] SDG&E did not have DBP during PY2011, so no comparison across years can be made for that program.

responder in PY2011 did not submit any bids in PY2012. This alone accounts for approximately 11 MW of the difference between years.

Table 7.7: Comparison of Load Impacts (in MW) in PY 2011 and PY 2012, *PG&E*

Program Year	LI in PY 2012	LI in PY 2011	Change
In both years	57.7	36.7	-21.1
In PY 2012 only	-0.8	n/a	0.8
In PY 2011 only	n/a	1.2	1.2
TOTAL	**56.9**	**37.8**	**-19.1**

Table 7.8 shows that SCE's load impacts did not change substantially across program years. The largest source of the change in load impact estimates across years is from customers who were enrolled in both years, who increased their average load impact by 2.9 MW.

Table 7.8: Comparison of Load Impacts (in MW) in PY 2011 and PY 2012, *SCE*

Program Year	LI in PY 2012	LI in PY 2011	Change
In both years	81.5	78.6	2.9
In PY 2012 only	1.3	n/a	1.3
In PY 2011 only	n/a	-0.9	0.9
TOTAL	**82.8**	**77.7**	**5.1**

8. 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.

In addition, the day-of adjustments to the 10-in-10 baselines appear to significantly improve the accuracy of, and reduce the bias in, program baseline performance. The improvements are not very sensitive to the level of the day-of adjustment cap, though there is some evidence that a cap of 20 to 40 percent would strike a reasonable balance between improved performance and limited risk (i.e., preventing extreme adjustments).

Appendices

The following Appendices accompany this report. Each is an Excel file that can produce the tables required by the Protocols.[22]

DBP Study Appendix A	PG&E Ex-Post Load Impact Tables
DBP Study Appendix B	SCE Ex-Post Load Impact Tables

[22] Note that Appendices C and F are excluded from public versions of this report due to confidentiality.

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