CHRISTENSEN ASSOCIATES ENERGY CONSULTING

# 2010 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report

**CALMAC Study ID SCE0298.01**


Steven D. Braithwait
Daniel G. Hansen
Jess D. Reaser


*March 29, 2011*


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

Voice 608.231.2266 Fax 608.231.2108

## Table of Contents

## Tables

## Figures

## Abstract

This report documents an ex post and ex ante load impact evaluation for the Demand Bidding Program ("DBP") administered by Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE"). The evaluation first reports on the estimation of DBP load impacts that occurred on the event days called during the 2010 program year at PG&E and SCE. Ex ante forecasts of load impacts are then reported based on enrollment forecasts provided by the utilities and the per-customer load impacts observed in 2010.

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 one four-hour test event on August 25$^{th}$. SCE called nine DBP events in 2010, all lasting from noon to 8 p.m.

Enrollment in PG&E's DBP was 1,052 service accounts in 2010. Total DBP load, represented by the sum of enrolled customers' individual maximum demands, amounted to 1,168 MW. Enrollment in SCE's DBP was 1,421 service accounts in 2010. Total DBP load was 1,461 MW.

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

The total program load impact for PG&E's test event averaged 68.2 MW, or 7.5 percent of enrolled load. For SCE, average hourly program load impacts averaged approximately 61.5 MW across nine events, or 5.9 percent of the total reference load. The load impacts showed some variation across event days, with a low of 41 MW and a high of 99 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, TA/TI service accounts provided 383 kW of load impacts and AutoDR service accounts provided 1,658 kW. For SCE, TA/TI service accounts provided 6,345 kW of load impacts and AutoDR service accounts provided 14,478 kW.

In the ex ante evaluation, SCE forecasts that DBP customer enrollment to increase substantially in 2013, decline slightly in 2014 and remain at that level through 2021. During this period, SCE's average event-hour load impact is approximately 87 MW. Because PG&E has proposed to end its DBP program at the end of 2012, we have only

forecast ex ante load impacts through that year. The forecast load impact for August 2011 is approximately 70 MW. 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 17.8 MW from 2014-2021. For PG&E, the 2011 portfolio-level load impact is 7.7 MW.

## 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") and Southern California Edison ("SCE") in 2010. (San Diego Gas and Electric Company discontinued its program in 2009.) The report first provides estimates of ex post load impacts that occurred during events called in 2010. The report then documents an ex ante forecast of load impacts for 2011 through 2021 (2011 only for PG&E) that is based on utility enrollment forecasts and the ex post load impacts estimated for 2010.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2010?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. What are the ex ante load impacts for 2011 through 2021?

### *ES.1 Resources covered*

#### DBP Program

DBP, which was created in 2001, is a voluntary Internet-based demand response bidding program that provides enrolled customers with the opportunity to receive financial incentives in payment for load reductions on event days. Credits are paid based on the difference between the customers' actual metered load during an event to a reference load, or baseline, which 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.

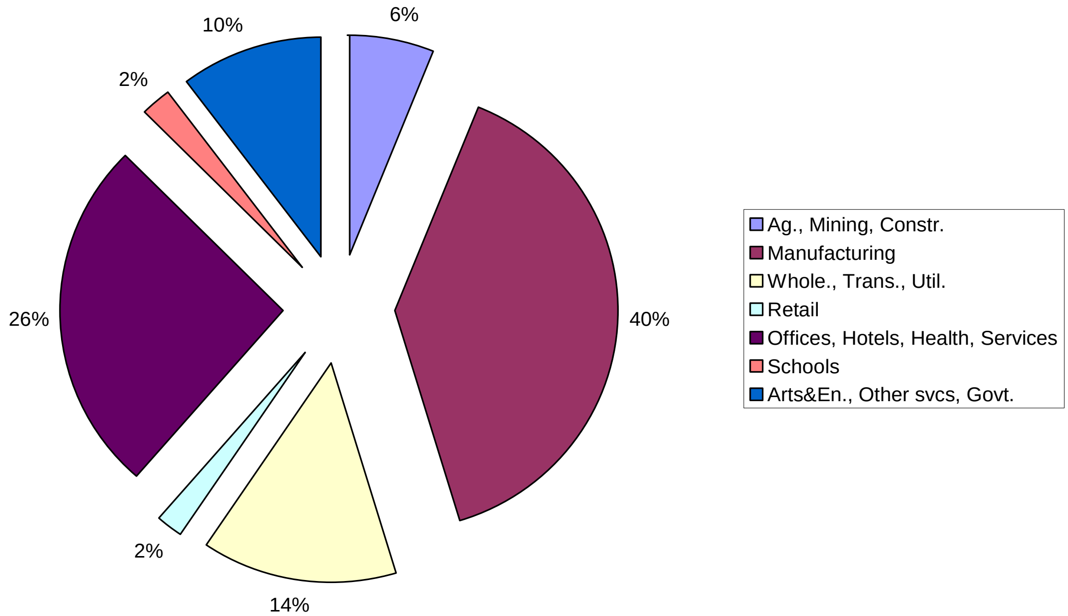
PG&E called one DBP event in 2010, a four-hour test event on August 25th that lasted from 2 p.m. to 6 p.m. SCE called nine DBP events in 2010, all lasting eight hours, from noon to 8 p.m.

#### Enrollment

Enrollment in PG&E's DBP declined slightly from 1,127 customer service accounts in 2009 to 1,052 in 2010. Total DBP load, represented by the sum of enrolled customers' individual maximum demands[1], amounted to 1,168 MW. 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.

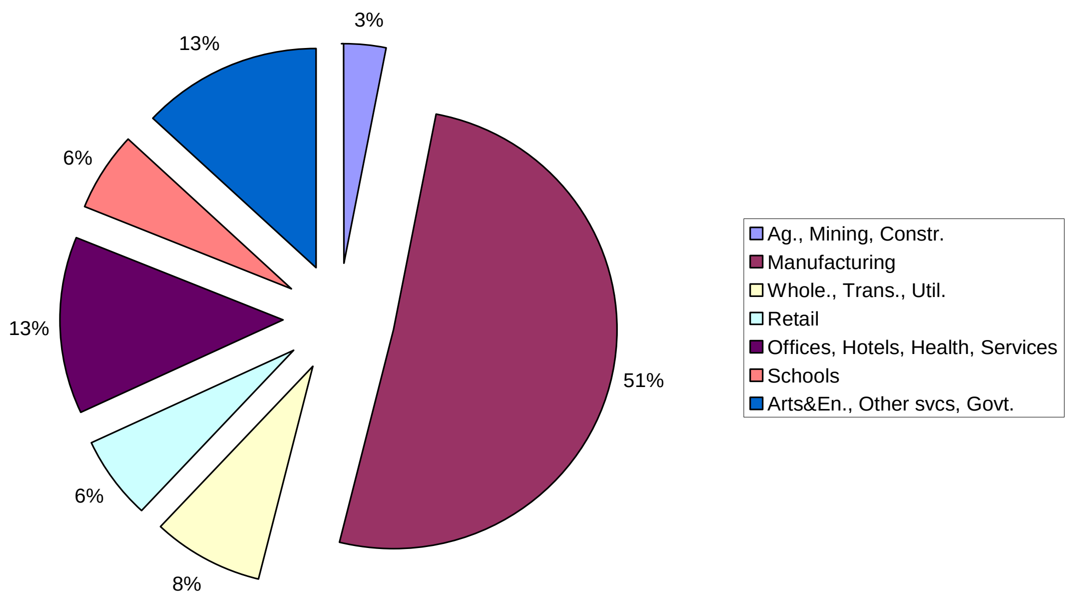
[1] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.

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




SCE's enrollment in DBP has expanded from 1,369 customer service accounts in 2009 to 1,421 in 2010. These accounted for 1,461 MW of maximum demand. Manufacturers continued to make up more than half of the enrolled load, as shown in Figure ES.2.

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




### Bidding Behavior

As in previous years, only a relatively small percentage of the customer accounts enrolled in DBP actually submitted bids for most events. Fewer than 200 PG&E customers, representing approximately 30 percent of the enrolled load, submitted a bid for the test event. At SCE, 470 customer accounts, representing 46 percent of the enrolled load, submitted at least one bid during 2010.

## *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.

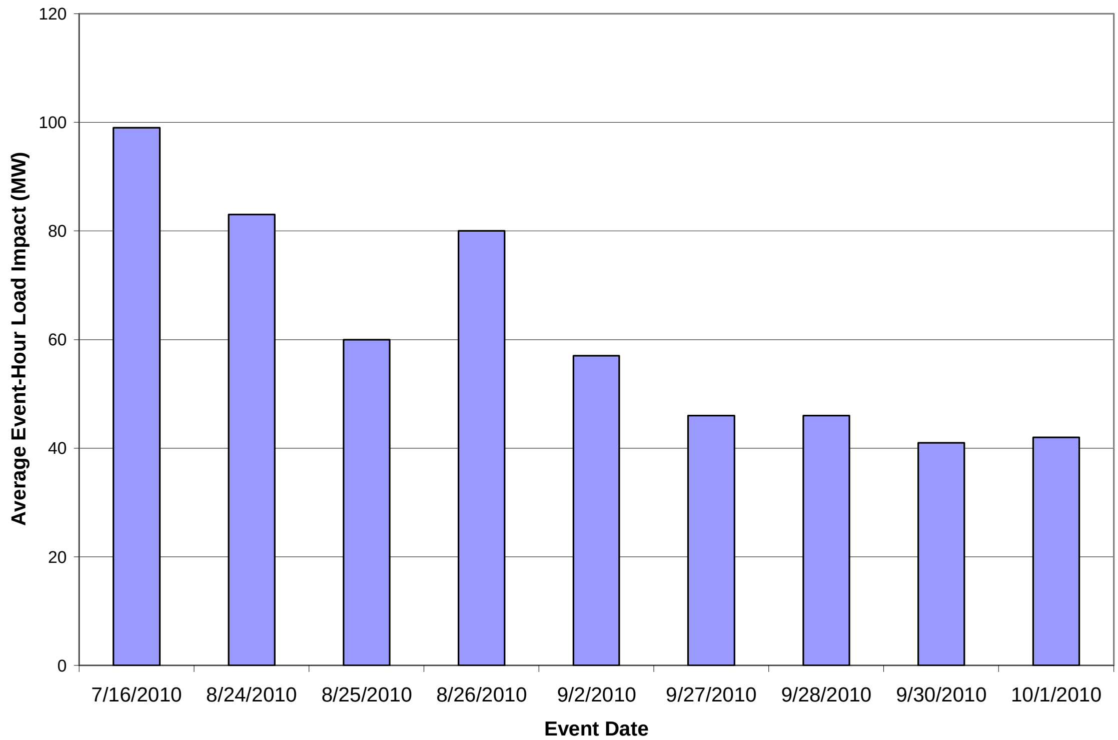
DBP load impacts for each event were obtained by summing the estimated hourly event coefficients for all customers who submitted a bid for that event. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, 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 test event averaged 68.2 MW, or 7.5 percent of enrolled load. Of this, 60 MW came from customers enrolled in both DBP and BIP. These dually enrolled customers averaged a 31 percent load reduction during event hours. In contrast, customers enrolled only in DBP reduced load by an average of 8 MW, or 1 percent of their load.

For SCE, average hourly program load impacts averaged approximately 61.5 MW across nine events. Figure ES.3 shows the average hourly load impacts for each event, and for the average event day. The load impacts showed some variation across event days, with a low of 41 MW and a high of 99 MW. On average, the load impacts were about 5.9 percent of the total reference load.

**Figure ES.3: Average Hourly DBP Load Impacts by Event – *SCE***




On a summary level, the average per-customer event-hour load impact was 65 kW for PG&E's program and 46 kW for SCE's program.

### *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. In addition, we attempted to estimate the *incremental* load impacts provided by customers participating in TA/TI and AutoDR. The incremental load impact is the observed load impact on TA/TI or AutoDR less the load impact that one would expect from the customer in the absence of the program. Because of data limitations, it can be quite difficult to accurately estimate incremental load impacts, as is reflected in the number of wrong-signed results that we estimated (indicating that TA/TI or AutoDR *reduced* demand responsiveness). Table ES.1 summarizes the total and incremental load impacts by utility and program. The large wrong-signed incremental load impact for SCE's TA/TI program is due to one industry group, in which the non-TA/TI service accounts consistently provide high percentage load impacts. The largest TA/TI service account is capable of providing a similarly high percentage load impact, but does so in only two events. The lack of response during the remaining events (in which the service account also submitted a bid) reduces the average percentage load impact significantly, creating the negative incremental load impact.

**Table ES.1: 2010 Total and Incremental Load Impacts from TA/TI and AutoDR**

| Utility | Program | Total Load Impact (kW) | % Total Load Impact | Incremental Load Impact (kW) |
|---|---|---|---|---|
| **PG&E** | TA/TI | 383 | 8.3% | 229 |
| | AutoDR | 1,658 | 3.1% | -336 |
| **SCE** | TA/TI | 6,345 | 13.9% | -12,832* |
| | AutoDR | 14,478 | 48.8% | 2,472 |

* This incremental impact is reduced to -690 kW when one very large industrial group is excluded from the comparison.

### *ES.5 Ex Ante Load Impacts*

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

Because PG&E is proposing to close its DBP program at the end of 2012, enrollments are only forecast through that year. The Brattle Group forecasts enrollments to be 1,066 customers in 2011 and 1,162 in 2012.

SCE anticipates enrollment in DBP of 1,456 customers in 2011 and 1,529 customers in 2012. SCE forecasts DBP enrollments to increase substantially to 4,069 customers in 2013 and then decline to 3,200 customers in 2014, where enrollment remains for the duration of the forecast period.

Figures ES.4 and ES.5 show the ex ante load impacts for SCE and PG&E, 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. SCE load impacts increase substantially in 2013 to match the increase in enrollments.

**Figure ES.4: Average 1-in-2 Weather Year Load Impacts by Year and Scenario, SCE**

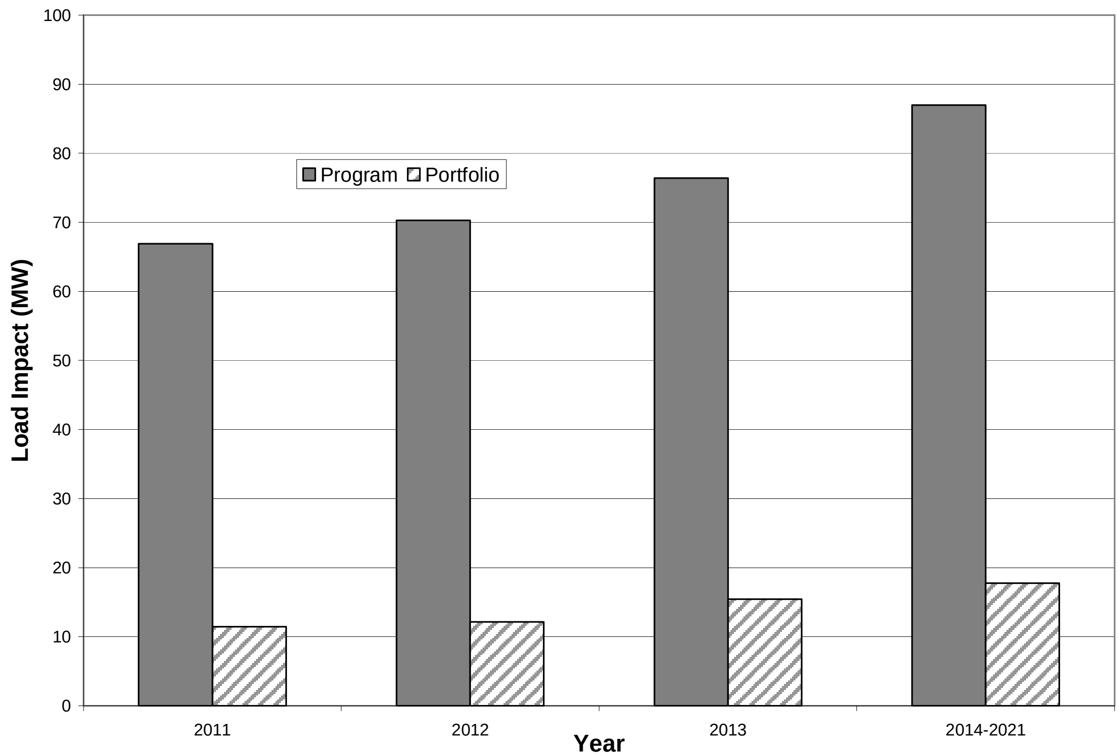
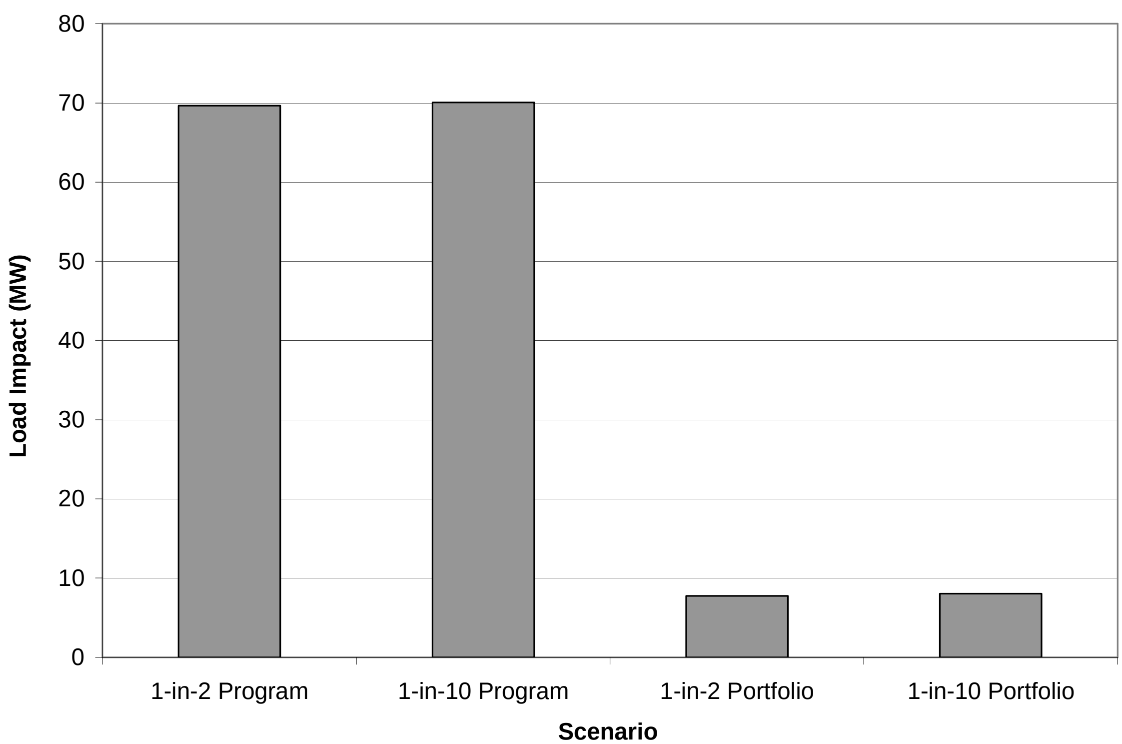



**Figure ES.5: Average PG&E 2011 DBP Hourly Load Impacts by Scenario**



### ES.6 Summary

In 2010, PG&E called one four-hour DBP test event and SCE called 9 events. PG&E's test event resulted in a 68 MW load reduction, of which 60 MW came from customers dually enrolled in DBP and the Base Interruptible Program (BIP). The remaining DBP customers provided 8 MW of load reduction, or just 1 percent of their reference load.

Ex post load impacts for SCE's nine events averaged 61.5 MW, or 5.9 percent of the reference load.

In the ex ante evaluation, SCE forecasts that DBP customer enrollment to increase substantially in 2013, decline slightly in 2014 and remain at that level through 2021. During this period, SCE's average event-hour load impact is approximately 87 MW. Because PG&E has proposed to end its DBP program at the end of 2012, we have only forecast ex ante load impacts through that year. The forecast load impact for August 2011 is approximately 70 MW. 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 17.8 MW from 2014-2021. For PG&E, the 2011 portfolio-level load impact is 7.7 MW.

## 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") and Southern California Edison ("SCE") in 2010. (San Diego Gas and Electric Company discontinued its program in 2009.) The report first provides estimates of ex post load impacts that occurred during events called in 2010. The report then documents an ex ante forecast of load impacts for 2011 through 2021 (2011 only for PG&E) that is based on utility enrollment forecasts and the ex post load impacts estimated for 2010.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2010?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. What are the ex ante load impacts for 2011 through 2021?

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 the incremental effect of TA/TI and AutoDR on load impacts; Section 5 describes the ex ante load impact forecast; Section 6 contains an assessment of the validity of the study; and Section 7 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 2010.

### *2.1 Program Descriptions*

DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing usage when a DBP event is triggered on a day-ahead basis. 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 DPB 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. Restrictions exist for customers enrolled in multiple DR programs to avoid multiple payments for reduction during the same event period.

## PG&E's DBP 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 200kW 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.[2] Day-ahead 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 resources may not be adequate. Day-of events are triggered when the California ISO issues an energy warning. PG&E may also activate up to two DBP Day-Ahead test events per year in order to simulate an emergency event. When an event day is called, enrolled customers may choose to bid a load reduction for the event or not to participate for that event.

For events called a day ahead, 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 DBP 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 CPP, BIP, Day-of CBP, or OBMC.

---

[2] On June 24, 2010, PG&E filed Advice Letter 3560-E-B with the CPUC requesting the elimination of the DBP day-of program option. The Commission approved the advice letter on July 27, 2010 with a May 1, 2010 effective date.

However, the customer will not receive DBP incentive payments during overlapping event hours.

### SDG&E's DBP Program

SDG&E discontinued its DBP in 2009.

## *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:[3]

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).[4]

### 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 declined slightly from 1,127 in 2009 to 1,052 in 2010. Enrollments in previous years were 866 accounts in 2006; 1,063 in 2007; and 1,165 in 2008. Total DBP load, represented by the sum of enrolled customers' individual maximum demands[5], amounted to 1,168 MW, or 1.1 MW per service account. Average hourly usage for enrolled customers was 729 MW, or 693 kW

[3] SCE provided Standard Industrial Classification (SIC) codes in place of NAICS codes. The industry groups were therefore defined according the following SIC codes: 1 = under 2000; 2 = 2000 to 3999; 3 = 4000 to 5199; 4 = 5200 to 5999; 5 = 6000 to 8199; 6 = 8200 to 8299; 7 = 8300 and higher.

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

[5] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.

per service account.[6] 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 | Count | Sum of Max kW | Sum of Mean kWh | % of Max kW | Ave. Size (kW) |
|---|---|---|---|---|---|
| 1.Ag., Mining, Constr. | 113 | 71,506 | 33,244 | 6.1% | 633 |
| 2.Manufacturing | 251 | 456,667 | 307,675 | 39.1% | 1,819 |
| 3.Whole., Trans., Util. | 165 | 167,312 | 81,813 | 14.3% | 1,014 |
| 4.Retail | 84 | 20,009 | 11,379 | 1.7% | 238 |
| 5.Offices, Hotels, Health, Services | 281 | 304,519 | 206,300 | 26.1% | 1,084 |
| 6.Schools | 42 | 27,455 | 12,628 | 2.3% | 654 |
| 7.Ent, Other svcs, Govt. | 115 | 120,569 | 75,809 | 10.3% | 1,048 |
| 8.Other | 1 | 283 | 121 | 0.0% | 283 |
| **TOTAL** | **1,052** | **1,168,319** | **728,970** | | **1,111** |

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP has expanded slightly from 1,369 service accounts in 2009 to 1,421 in 2010. This is a continuation of a trend from recent years, which has seen enrollments increase from 1,079 customer service accounts in 2006 to 1,222 in 2007 and 1,244 in 2008. These accounted for a total of 1,461 MW of maximum demand, or 1 MW per service account. Manufacturers continued to make up more than half of the enrolled load.

**Table 2.2: DBP Enrollees by Industry group – *SCE***

| Industry Type | Count | Sum of Max kW | Sum of Mean kWh | % of Max kW | Ave. Size (kW) |
|---|---|---|---|---|---|
| 1.Ag., Mining, Constr. | 36 | 43,507 | 23,957 | 3% | 1,209 |
| 2.Manufacturing | 348 | 744,044 | 486,614 | 51% | 2,138 |
| 3.Whole., Trans., Util. | 186 | 113,706 | 67,655 | 8% | 611 |
| 4.Retail | 184 | 81,405 | 49,757 | 6% | 442 |
| 5.Offices, Hotels, Health, Services | 255 | 189,298 | 110,423 | 13% | 742 |
| 6.Schools | 294 | 92,759 | 25,027 | 6% | 316 |
| 7.Ent, Other svcs, Govt. | 118 | 196,415 | 122,281 | 13% | 1,665 |
| **TOTAL** | **1,421** | **1,461,133** | **885,714** | | **1,028** |

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

[6] Average hourly usage is calculated as the sum of usage during the program months divided by the number of hours during the program months.

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

| Local Capacity Area | Count | Sum of Max kW | Sum of Mean kWh | % of Max kW | Ave. Size (kW) |
|---|---|---|---|---|---|
| Greater Bay Area | 486 | 497,333 | 337,871 | 42.6% | 1,023 |
| Greater Fresno | 57 | 53,111 | 31,856 | 4.5% | 932 |
| Humboldt | 12 | 3,783 | 2,240 | 0.3% | 315 |
| Kern | 57 | 41,764 | 21,869 | 3.6% | 733 |
| Northern Coast | 74 | 47,264 | 25,091 | 4.0% | 639 |
| Not in any LCA | 292 | 496,503 | 296,783 | 42.5% | 1,700 |
| Sierra | 49 | 18,816 | 8,496 | 1.6% | 384 |
| Stockton | 25 | 9,744 | 4,764 | 0.8% | 390 |
| **TOTAL** | **1,052** | **1,168,319** | **728,970** | | **1,111** |

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

| Local Capacity Area | Count | Sum of Max kW | Sum of Mean kWh | % of Max kW | Ave. Size (kW) |
|---|---|---|---|---|---|
| LA Basin | 1,122 | 1,014,097 | 595,359 | 69% | 913 |
| Outside LA Basin | 68 | 188,743 | 124,104 | 13% | 2,839 |
| Ventura | 231 | 258,293 | 166,251 | 18% | 1,116 |
| **TOTAL** | **1,421** | **1,461,133** | **885,714** | | **1,038** |

Tables 2.5 and 2.6 summarize the characteristics of customer accounts that submitted a bid for at least one 2010 event for PG&E and SCE respectively. For both utilities, the manufacturing industry group had the highest share of enrolled load that submitted a bid.

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

| Industry Type | # Bidders | Sum of Max kW | % of Enrolled Max kW | Avg. Hourly Bid kW |
|---|---|---|---|---|
| 1.Ag., Mining, Constr. | 10 | 11,291 | 15.8% | 2,750 |
| 2.Manufacturing | 42 | 150,641 | 33.0% | 52,128 |
| 3.Whole., Trans., Util. | 26 | 57,736 | 34.5% | 6,772 |
| 4.Retail | 27 | 7,547 | 37.7% | 2,350 |
| 5.Offices, Hotels, Health, Services | 35 | 55,796 | 18.3% | 4,050 |
| 6.Schools | 0 | 0 | 0.0% | 0 |
| 7. Ent, Other svcs, Govt. | 57 | 64,940 | 53.9% | 2,133 |
| **TOTAL** | **197** | **347,952** | **29.8%** | **70,183** |

**Table 2.6: DBP Bidding Behavior – *SCE***

| Industry Type | # Bidders | Sum of Max kW | % of Enrolled Max kW | Avg. Hourly Bid kW |
|---|---|---|---|---|
| 1.Ag., Mining, Constr. | 21 | 22,377 | 51% | 6,797 |
| 2.Manufacturing | 174 | 350,439 | 47% | 99,083 |
| 3.Whole., Trans., Util. | 78 | 63,681 | 56% | 12,389 |
| 4.Retail | 34 | 37,721 | 46% | 5,574 |
| 5.Offices, Hotels, Health, Services | 97 | 83,538 | 44% | 9,313 |
| 6.Schools | 37 | 16,543 | 18% | 2,808 |
| 7. Ent, Other svcs, Govt. | 29 | 95,919 | 49% | 4,814 |
| **TOTAL** | **470** | **670,218** | **46%** | **140,778** |

## *2.3 Event Days*

Table 2.7 lists DBP event days for the two utilities in 2010. PG&E called only one event, a four-hour test event on August 25th that covered hours-ending 15 – 18. SCE called 9 events, all of which were eight-hour events from hours-ending 13 to 18.

**Table 2.7: DBP Events – 2010**

| Date | Day of Week | SCE | PG&E |
|---|---|---|---|
| 7/16/2010 | Friday | 1 | |
| 8/24/2010 | Tuesday | 2 | |
| 8/25/2010 | Wednesday | 3 | 1 (Test) |
| 8/26/2010 | Thursday | 4 | |
| 9/2/2010 | Thursday | 5 | |
| 9/27/2010 | Monday | 6 | |
| 9/28/2010 | Tuesday | 7 | |
| 9/30/2010 | Thursday | 8 | |
| 10/1/2010 | Friday | 9 | |

# 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 (*e.g.*, cooling degree hours, 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 14 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 14 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[7]

## *3.2 Description of methods*

### 3.2.1 Regression Model

The model shown below was separately estimated for each enrolled customer.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DBP} \times h_{i,t} \times DBP_t) + b^{MornLoad} \times MornLoad_t + \sum_{i=1}^{24} (b_i^{OTH} \times h_{i,t} \times OtherEvt_{i,t}) \\
&+ \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times CDH_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) \\
&+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + b_t^{Summer} \times Summer_t \\
&+ \sum_{i=1}^{24} (b_i^{CDH,S} \times h_{i,t} \times Summer_t \times CDH_t) + \sum_{i=2}^{24} (b_i^{MON,S} \times h_{i,t} \times Summer_t \times MON_t) \\
&+ \sum_{i=2}^{24} (b_i^{FRI,S} \times h_{i,t} \times Summer_t \times FRI_t) + \sum_{i=2}^{24} (b_i^{h,S} \times h_{i,t} \times Summer_t) + e_t
\end{aligned}
$$

In this equation, $Q_t$ represents the demand in hour $t$ for a customer enrolled in DBP prior to the last event date; the $b$'s are estimated parameters; $h_{i,t}$ is a dummy variable for hour $i$; $DBP_t$ is an indicator variable for program event days; $CDH_t$ is cooling degree hours;[8] $E$ is the number of event days that occurred during the program year; $MornLoad_t$ is a variable equal to the average of the day's load in hours 1 through 10; $OtherEvt_t$ is equal to one in the event hours of other demand response programs in which the customer is enrolled; $MON_t$ is a dummy variable for Monday; $FRI_t$ is a dummy variable for Friday; $DTYPE_{i,t}$ is a series of dummy variables for each day of the week; $MONTH_{i,t}$ is a series of dummy variables for each month; $Summer_t$ is a variable indicating summer months (defined as mid-June through mid-August)[9], which is interacted with the weather and

[7] 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.

[8] Cooling degree hours (CDH) was defined as MAX[0, Temperature – 50], where Temperature is the hourly temperature in degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

[9] This variable was initially designed to reflect the load changes that occur when schools are out of session. We have found the variables to a useful part of the base specification, as they do not appear to harm load impact estimates even in cases in which the customer does not change its usage level or profile during the summer months.

hourly profile variables; and $e_t$ is the error term. The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for the level of load on a particular day. Because of the autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

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). We add load impacts across only customers who submitted bids for a given event.

### 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 both 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 65 kW for PG&E's program and 44 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 DBP load impacts at the program level and by industry group for PG&E's test event, which occurred on August 25, 2010. While DBP load impacts were estimated from the individual customer regressions of only those enrolled customers who submitted a bid for the test event, the reference loads and observed loads shown in the table reflect all customers enrolled in DBP. Across the four event hours, the average hourly load impact was 68 MW, or 7.5 percent of enrolled load. The Manufacturing industry group accounted for the largest share of the load impacts.

Table 4.2 summarizes load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from outside of the seven LCAs.

**Table 4.1: 2010 Average Hourly Load Impacts – PG&E DBP, *by Industry Group***

| Industry Group | Count | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|
| Agriculture, Mining, & Construction | 113 | 39.8 | 37.2 | 2.6 | 6.6% |
| Manufacturing | 251 | 351.4 | 301.5 | 49.9 | 14.2% |
| Wholesale, Transportation, & Other Utilities | 165 | 83.9 | 77.5 | 6.4 | 7.6% |
| Retail Stores | 84 | 15.9 | 14.9 | 1.0 | 6.6% |
| Offices, Hotels, Health, Services | 280 | 288.1 | 283.5 | 4.6 | 1.6% |
| Schools | 42 | 23.3 | 23.3 | 0.0 | 0.0% |
| Entertainment, Other Services, Government | 115 | 101.7 | 98.1 | 3.6 | 3.6% |
| Other or Unknown | 1 | 0.2 | 0.2 | 0.0 | 0.0% |
| **Total** | **1,051** | **904.3** | **836.1** | **68.2** | **7.5%** |

**Table 4.2: 2010 Average Hourly Load Impacts – PG&E DBP, *by LCA***

| Local Capacity Area | Count | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|
| Greater Bay Area | 486 | 450.5 | 444.2 | 6.3 | 1.4% |
| Greater Fresno | 57 | 43.4 | 43.1 | 0.3 | 0.7% |
| Humboldt | 12 | 2.2 | 1.9 | 0.2 | 10.5% |
| Kern | 57 | 23.5 | 20.1 | 3.4 | 14.5% |
| Northern Coast | 74 | 35.5 | 34.6 | 0.9 | 2.5% |
| Sierra | 49 | 10.7 | 10.6 | 0.1 | 1.3% |
| Stockton | 25 | 6.2 | 6.1 | 0.1 | 1.2% |
| Not in any LCA | 291 | 332.3 | 275.4 | 56.9 | 17.1% |
| **Total** | **1,051** | **904.3** | **836.1** | **68.2** | **7.5%** |

### 4.1.2 Hourly Load Impacts

Table 4.3 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 of only those enrolled customers who submitted a bid for the test event. However, the reference loads and observed loads in the table reflect all customers enrolled in DBP. Hourly load impacts average 68 MW, which represents approximately 7.5 percent of the total DBP reference load for enrolled customers.

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. For example, 60 MW of the total 68 MW load impact comes from the DBP/BIP-overlap customers, which is a 31 percent load reduction for these dually enrolled customers. In contrast, the DBP-only customers account for only 8 MW of the total load impact and average a 1 percent load reduction during event hours.

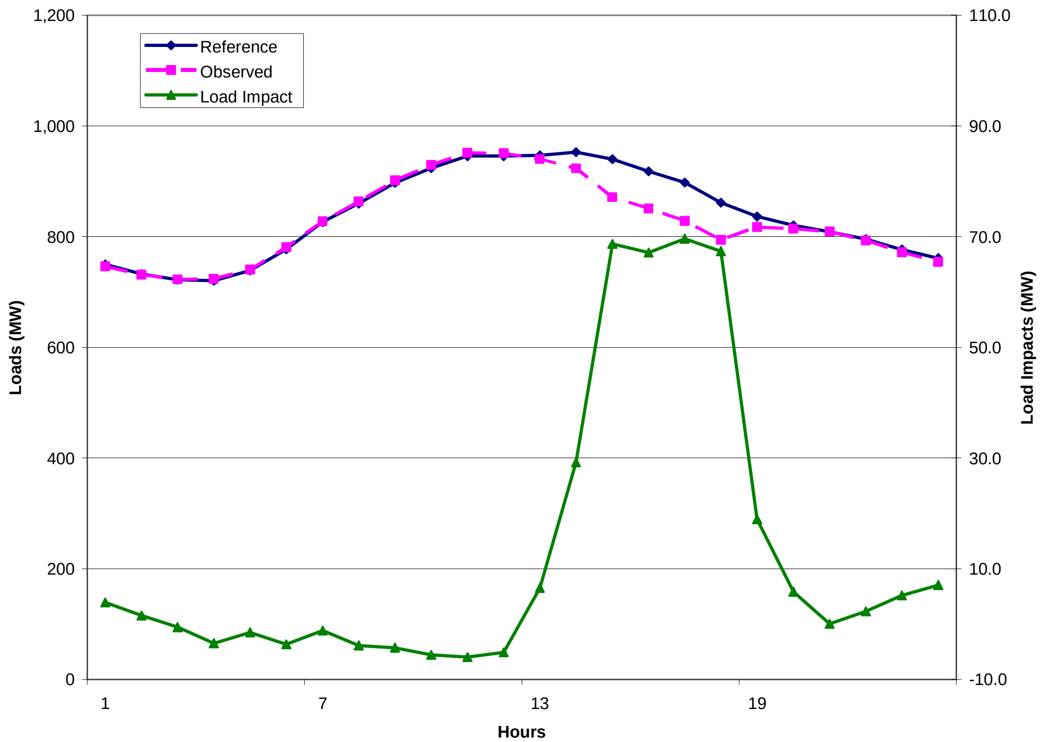
**Table 4.3: DBP Hourly Load Impacts for August 25, 2010 Event Day – *PG&E***

| Hour Ending | Estimated Reference Load (MWh/hour) | Observed Event Day Load (MWh/hour) | Estimated Load Impact (MWh/hour) | Weighted Average Temperature (°F) | Uncertainty Adjusted Impact (MWh/hr)- Percentiles | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | 10th%ile | 30th%ile | 50th%ile | 70th%ile | 90th%ile |
| **1** | 750 | 746 | 3.9 | 77 | -4 | 1 | 4 | 7 | 12 |
| **2** | 733 | 731 | 1.6 | 75 | -7 | -2 | 2 | 5 | 10 |
| **3** | 722 | 723 | -0.6 | 74 | -9 | -4 | -1 | 3 | 8 |
| **4** | 720 | 724 | -3.5 | 73 | -12 | -7 | -3 | 0 | 5 |
| **5** | 739 | 740 | -1.5 | 72 | -10 | -5 | -1 | 2 | 7 |
| **6** | 777 | 781 | -3.6 | 70 | -12 | -7 | -4 | 0 | 5 |
| **7** | 826 | 827 | -1.2 | 70 | -9 | -5 | -1 | 2 | 7 |
| **8** | 860 | 864 | -3.9 | 72 | -12 | -7 | -4 | 0 | 4 |
| **9** | 897 | 901 | -4.3 | 76 | -13 | -8 | -4 | -1 | 4 |
| **10** | 924 | 930 | -5.6 | 80 | -14 | -9 | -6 | -2 | 3 |
| **11** | 945 | 951 | -5.9 | 84 | -14 | -9 | -6 | -3 | 2 |
| **12** | 945 | 951 | -5.1 | 88 | -13 | -8 | -5 | -2 | 3 |
| **13** | 947 | 940 | 6.5 | 91 | -2 | 3 | 7 | 10 | 15 |
| **14** | 953 | 923 | 29.2 | 93 | 21 | 26 | 29 | 33 | 37 |
| **15** | 940 | 871 | 68.7 | 92 | 62 | 66 | 69 | 72 | 76 |
| **16** | 918 | 851 | 67.1 | 92 | 60 | 64 | 67 | 70 | 74 |
| **17** | 898 | 828 | 69.6 | 91 | 63 | 67 | 70 | 73 | 77 |
| **18** | 862 | 794 | 67.4 | 89 | 60 | 64 | 67 | 70 | 74 |
| **19** | 836 | 817 | 18.9 | 87 | 11 | 16 | 19 | 22 | 27 |
| **20** | 820 | 814 | 5.9 | 82 | -2 | 3 | 6 | 9 | 14 |
| **21** | 809 | 809 | 0.0 | 78 | -8 | -3 | 0 | 3 | 8 |
| **22** | 795 | 793 | 2.3 | 75 | -6 | -1 | 2 | 6 | 10 |
| **23** | 777 | 771 | 5.2 | 72 | -3 | 2 | 5 | 8 | 13 |
| **24** | 761 | 754 | 7.0 | 71 | -1 | 4 | 7 | 10 | 15 |
| | Reference Energy Use (MWh) | Estimated Event Day Energy Use (MWh) | Change in Energy Use (MWh) | Cooling Degree Hours (Base 75 oF) | Uncertainty Adjusted Impact (MWh/hour) - Percentiles | | | | |
| | | | | | 10th | 30th | 50th | 70th | 90th |
| **Daily** | 20,152 | 19,834 | 318 | 148.9 | n/a | n/a | n/a | n/a | n/a |

The top portion of Figure 4.1 illustrates the reference load (net of the BIP load reduction) and observed load for the DBP test event. The lower portion of the figure displays the estimated DBP load impacts (which are labeled on the right y-axis).

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: 2010 DBP Load Impacts – *PG&E***




#### 4.1.3 Comparison of PGE's Load Impacts to the 2009 Program Year

PGE's 2010 average hourly load reduction of 68.2 MW is 26 percent larger than the 54.1 MW reduction reported for 2009. The difference is due to a two-hour overlap of BIP and DBP events in 2009. For customers dually enrolled in BIP, measured load reductions were allocated to the BIP during the overlapping event hours. In 2009, customer responses appear to have extended through the two remaining DBP event hours after the end of the BIP event, with load reductions exceeding 100 MW in each hour (10 percent of program load).

In 2010, there was no overlap between DBP and BIP events. This helps address a question we had in the 2009 program year evaluation: how would the DBP/BIP customers respond to a stand-alone DBP event? The 2010 load impact is quite large (68.2 MW) compared to the load impact from the overlapping hours in 2009 (~5 MW), but lower than the load impact in the non-overlapping hours in 2009 (~100 MW). Thus it appears that customers dually enrolled in BIP provide more demand response to BIP events than DBP events.

## 4.2 SCE Load Impacts

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

Table 4.4 summarizes average hourly reference loads and load impacts at the program level for each of SCE's nine DBP events.[10] Across all events, the average hourly load impact was approximately 62 MW. The load impacts showed some variation across event days, with a low of 41 MW, a high of 99 MW, and a standard deviation of 21 MW. On average, the load impacts were 5.9 percent of the total reference load.

Table 4.5 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 110 MW, while the estimated average hourly load impact was 62 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 56 percent.

**Table 4.4: 2010 Average Hourly Load Impacts by Event, *SCE***

| Event | Date | Day of Week | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|---|
| 1 | 7/16/2010 | Friday | 1,028 | 928 | 99 | 9.6% |
| 2 | 8/24/2010 | Tuesday | 1,054 | 973 | 83 | 7.9% |
| 3 | 8/25/2010 | Wednesday | 1,062 | 1,007 | 60 | 5.7% |
| 4 | 8/26/2010 | Thursday | 1,046 | 973 | 80 | 7.6% |
| 5 | 9/2/2010 | Thursday | 1,005 | 948 | 57 | 5.6% |
| 6 | 9/27/2010 | Monday | 1,056 | 1,006 | 46 | 4.4% |
| 7 | 9/28/2010 | Tuesday | 1,049 | 1,004 | 46 | 4.4% |
| 8 | 9/30/2010 | Thursday | 1,028 | 990 | 41 | 4.0% |
| 9 | 10/1/2010 | Friday | 982 | 940 | 42 | 4.3% |
| | | **Average** | **1,034** | **974** | **62** | **5.9%** |
| | | **Std. Dev.** | **27** | **30** | **21** | **2.0%** |

[10] As for PG&E, the reference loads and observed loads represent all enrolled DBP customer accounts, while the estimated load reductions were estimated only for the accounts that submitted bids for a given event.

**Table 4.5: 2010 Average Hourly Bid Realization Rates by Event, *SCE***

| Event | Date | Day of Week | Average Bid Quantity (MW) | Estimated Load Impact (MW) | LI as % of Bid Amount |
|---|---|---|---|---|---|
| 1 | 7/16/2010 | Friday | 122 | 99 | 81% |
| 2 | 8/24/2010 | Tuesday | 112 | 83 | 74% |
| 3 | 8/25/2010 | Wednesday | 103 | 60 | 58% |
| 4 | 8/26/2010 | Thursday | 106 | 80 | 76% |
| 5 | 9/2/2010 | Thursday | 113 | 57 | 51% |
| 6 | 9/27/2010 | Monday | 105 | 46 | 44% |
| 7 | 9/28/2010 | Tuesday | 103 | 46 | 45% |
| 8 | 9/30/2010 | Thursday | 110 | 41 | 37% |
| 9 | 10/1/2010 | Friday | 119 | 42 | 35% |
| | | **Average** | **110** | **62** | **56%** |

Tables 4.6 and 4.7 summarize average hourly load impacts for the average event by industry group and LCA. Manufacturing service accounts accounted for the largest shares of the load impacts. By region, the highest share of the average load impact came from the LA Basin.

**Table 4.6: 2010 Average Hourly Load Impacts – SCE DBP, *by Industry Group***

| Industry Group | Count | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|
| Agriculture, Mining, & Construction | 35 | 26.0 | 25.1 | 0.9 | 3.3% |
| Manufacturing | 341 | 522.9 | 475.0 | 49.3 | 9.4% |
| Wholesale, Transportation, & Other Utilities | 185 | 72.4 | 66.8 | 5.6 | 7.7% |
| Retail Stores | 169 | 55.9 | 54.2 | 1.8 | 3.2% |
| Offices, Hotels, Health, Services | 254 | 146.1 | 144.0 | 2.1 | 1.5% |
| Schools | 289 | 51.4 | 51.8 | -0.4 | -0.7% |
| Entertainment, Other Services, Government | 110 | 159.6 | 157.4 | 2.2 | 1.4% |
| **Total** | **1,383** | **1,034.3** | **974.2** | **61.5** | **5.9%** |

**Table 4.7: 2010 Average Hourly Load Impacts – SCE DBP, *by LCA***

| Local Capacity Area | Count | Estimated Reference Load (MW) | Observed Load (MW) | Estimated Load Impact (MW) | % LI |
|---|---|---|---|---|---|
| LA Basin | 1,086 | 703.9 | 659.6 | 45.7 | 6.5% |
| Outside LA Basin | 67 | 125.6 | 115.9 | 9.7 | 7.7% |
| Ventura | 230 | 204.8 | 198.7 | 6.1 | 3.0% |
| **Total** | **1,383** | **1,034.3** | **974.2** | **61.5** | **5.9%** |

### 4.2.2 Hourly Load Impacts

Table 4.8 presents hourly load impacts at the program level for the average DBP event in the manner required by the Protocols. The reference loads and observed loads in the table reflect all customers enrolled in DBP. Load impacts reflect only customers that submitted bids. Hourly load impacts for the average event range from 54.4 MW to 66.0 MW. These load impacts represent 5.9 percent of the total enrolled DBP reference load.

**Table 4.8: 2010 DBP Hourly Load Impacts for Average Event Day, *SCE***

| Hour Ending | Estimated Reference Load (MWh/hour) | Observed Event Day Load (MWh/hour) | Estimated Load Impact (MWh/hour) | Weighted Average Temperature (°F) | Uncertainty Adjusted Impact (MWh/hr)- Percentiles | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | 10th%ile | 30th%ile | 50th%ile | 70th%ile | 90th%ile |
| **1** | 842 | 834 | 11.3 | 75 | 3 | 8 | 11 | 15 | 20 |
| **2** | 829 | 823 | 8.6 | 74 | 0 | 5 | 9 | 12 | 17 |
| **3** | 817 | 814 | 6.2 | 73 | -3 | 3 | 6 | 10 | 15 |
| **4** | 817 | 814 | 4.9 | 72 | -4 | 1 | 5 | 9 | 14 |
| **5** | 840 | 840 | 3.3 | 71 | -5 | 0 | 3 | 7 | 12 |
| **6** | 882 | 883 | 1.3 | 70 | -7 | -2 | 1 | 5 | 10 |
| **7** | 929 | 932 | -1.3 | 70 | -10 | -5 | -1 | 2 | 8 |
| **8** | 980 | 984 | -1.5 | 69 | -10 | -5 | -2 | 2 | 7 |
| **9** | 1,021 | 1,028 | -4.0 | 71 | -13 | -8 | -4 | 0 | 5 |
| **10** | 1,050 | 1,051 | 0.1 | 75 | -9 | -4 | 0 | 4 | 9 |
| **11** | 1,080 | 1,077 | 5.0 | 79 | -4 | 1 | 5 | 9 | 14 |
| **12** | 1,089 | 1,070 | 21.2 | 83 | 13 | 18 | 21 | 25 | 30 |
| **13** | 1,089 | 1,036 | 54.7 | 86 | 46 | 51 | 55 | 58 | 63 |
| **14** | 1,095 | 1,042 | 54.4 | 88 | 46 | 51 | 54 | 58 | 63 |
| **15** | 1,090 | 1,033 | 58.7 | 89 | 50 | 55 | 59 | 62 | 67 |
| **16** | 1,066 | 1,002 | 65.4 | 90 | 57 | 62 | 65 | 69 | 74 |
| **17** | 1,034 | 969 | 66.0 | 89 | 57 | 63 | 66 | 70 | 75 |
| **18** | 997 | 934 | 64.6 | 88 | 56 | 61 | 65 | 68 | 73 |
| **19** | 960 | 895 | 65.7 | 86 | 57 | 62 | 66 | 69 | 74 |
| **20** | 943 | 882 | 62.4 | 84 | 54 | 59 | 62 | 66 | 71 |
| **21** | 928 | 883 | 45.9 | 81 | 37 | 42 | 46 | 49 | 55 |
| **22** | 908 | 874 | 34.8 | 78 | 26 | 31 | 35 | 38 | 43 |
| **23** | 878 | 851 | 27.9 | 76 | 19 | 24 | 28 | 31 | 37 |
| **24** | 865 | 844 | 21.2 | 75 | 12 | 18 | 21 | 25 | 30 |
| | Reference Energy Use (MWh) | Estimated Event Day Energy Use (MWh) | Change in Energy Use (MWh) | Cooling Degree Hours (Base 75 oF) | Uncertainty Adjusted Impact (MWh/hour) - Percentiles | | | | |
| | | | | | 10th | 30th | 50th | 70th | 90th |
| **Daily** | 23,030 | 22,395 | 677 | 122.1 | n/a | n/a | n/a | n/a | n/a |

The top portion of Figure 4.2 illustrates the hourly reference load and observed load for the average DBP event. The bottom portion of Figure 4.2 displays the estimated hourly load impacts (scale is presented on the right y-axis) for the average DBP event. Figure 4.3 shows the variability of estimated load impacts across events.

**Figure 4.2: 2010 DBP Load Impacts – *SCE***

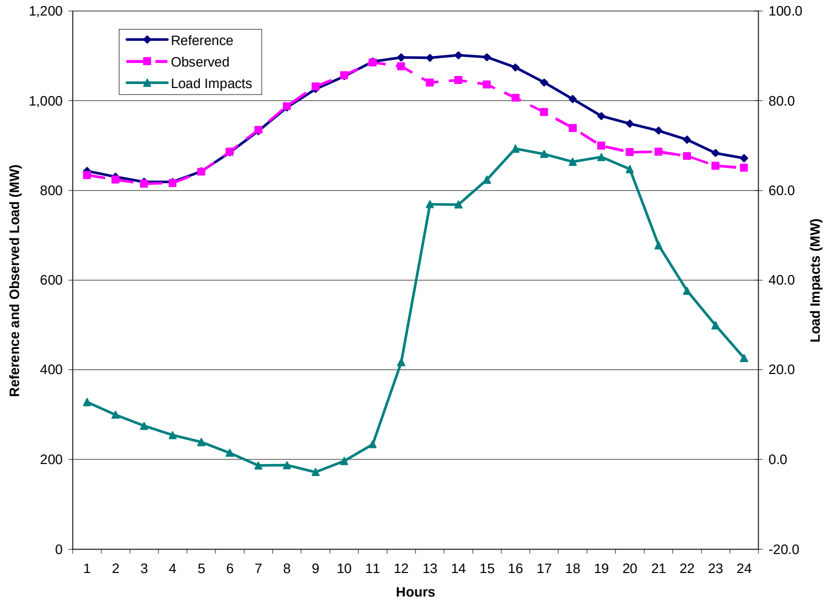
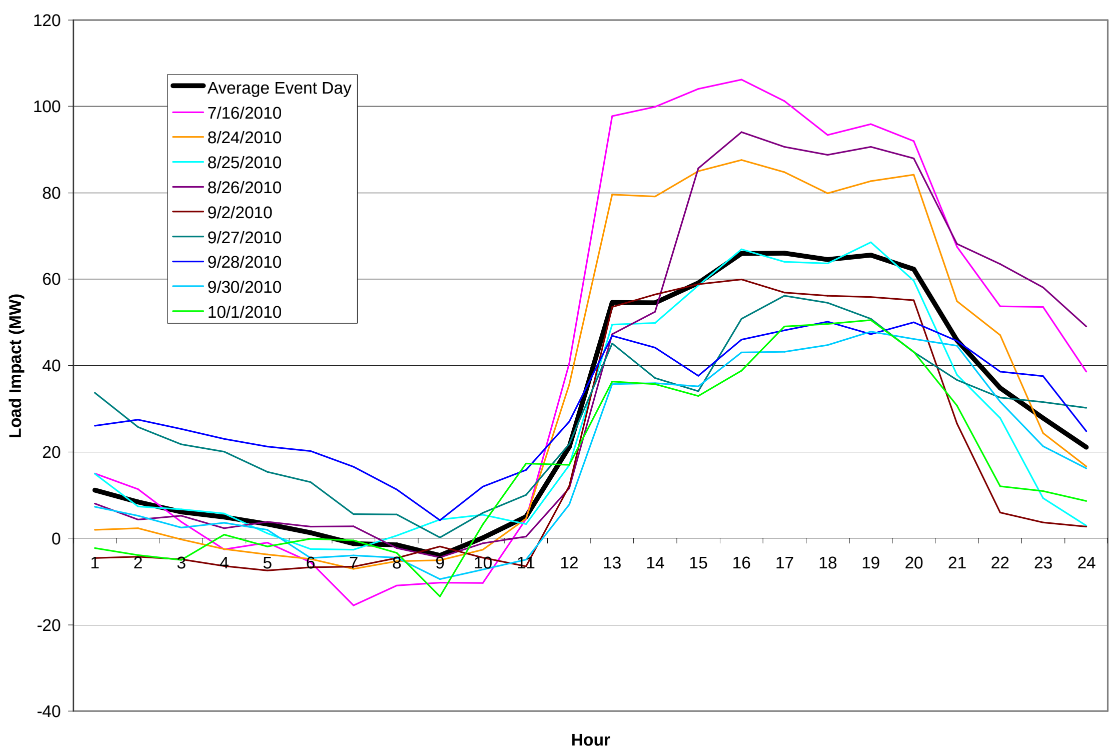



**Figure 4.3: 2010 Hourly Load Impacts by Event – *SCE DBP***




### 4.2.3 Comparison of SCE's Load Impacts to the 2009 Program Year

SCE’s 2010 average hourly load reduction of 61.5 MW is 51 percent larger than the average of 40.7 MW reported for 2009. For the nine events in 2010, percentage load impacts ranged from 4.0 percent to 9.6 percent, with an average of 5.9 percent. For the fifteen events during 2009, percentage load impacts ranged from 2.5 percent to 5.9 percent, with an average of 4.1 percent.

One reason for the increase in load impacts is that 2009 estimates do not include the response of all “aggregated load” customers. Aggregated load refers to groups of SAIDs that coordinate demand response. Aggregated load SAIDs are represented in bidding records by a lead SAID that submits a total bid for the entire group. In 2010, aggregated load customers provided and average of 1.5 MW of load response, representing 2.5 percent of the total average demand response. Assuming that aggregated customers would have responded similarly in 2009, their omission from the 2009 analysis would account for roughly 6 percent of the increase in measured response in 2010.

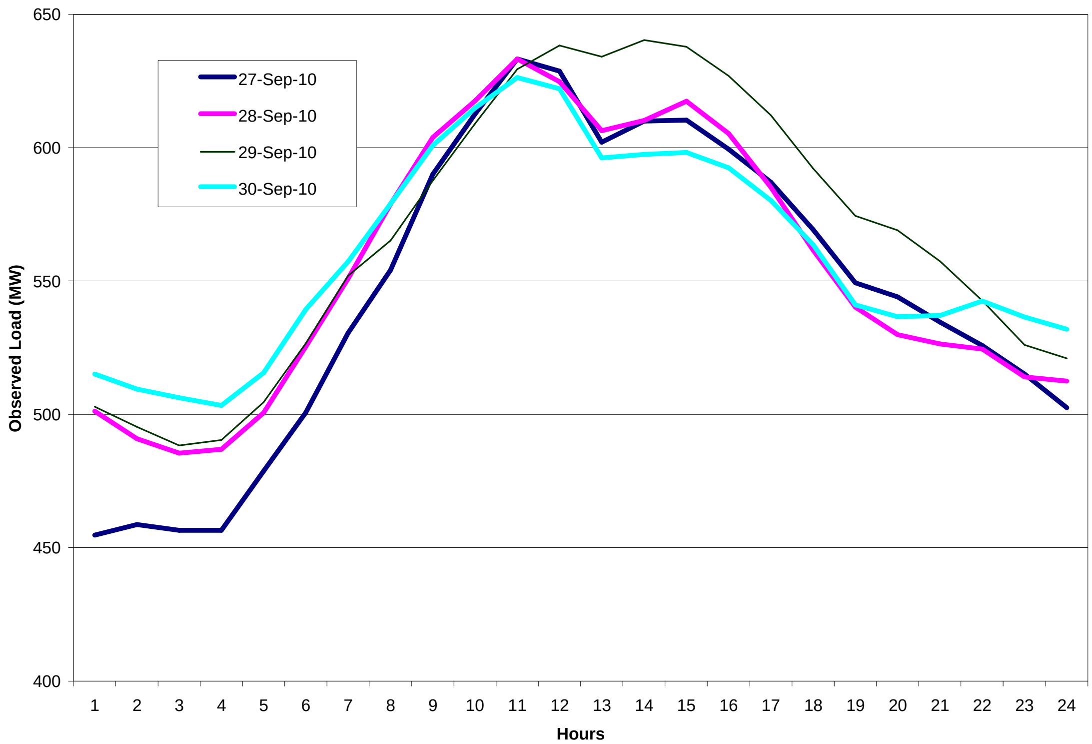
In addition, the composition of bidding customers changed between years. Some customers who bid in 2009 did not bid in 2010 because they left the program or chose not to participate. Similarly, some customers that did not participate in 2009 did participate in 2010. Entry into and exit from DBP, in addition to changes in the customers submitting bids, account for roughly 30 percent of the increase in measured response.

The remaining 64 percent of the increase in average DBP response is due to nearly 400 customers who bid at least once in both years. There are several potential explanations for the increase in response from customers who participated in events in both years: responding on a higher share of the event days; responding more consistently across event hours; or responding at a higher level during event hours.

One means of validating the estimated load impacts is to compare aggregate DBP loads on event and non-event days. Figure 4.4 shows observed aggregated loads for each day between September 27 and September 30. September 29 represents the only non-event day of that week. Temperatures on September 30 were similar to those on September 29 (averaging 83.0 and 83.9 degrees Fahrenheit during event hours, respectively). Using September 29 as a baseline would result in an average load reduction of 35 MW, or 85 percent of the 41 MW load impact measured in our ex post regression model and twice as large as the SCE program-based estimate.

While similar "day-matching"-based differences for September 27 and 28 versus September 29 are not as large, both of those event days were hotter than September 29 (with temperatures of 100.3 and 86.6 degrees Fahrenheit, respectively). These temperature differences would likely increase the implied reference load above the usage on September 29, resulting in impacts close to those estimated by the regression model.

**Figure 4.4: Observed Load and Temperature, Sep. 27 - Sep. 30 – SCE DBP**




### *4.3 Effect 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.

For each utility and incentive program, we present two types of information. The first type (e.g., Table 4.9) contains the overall average hourly load impacts provided by the service accounts that participated in TA/TI or AutoDR. The second set of tables (e.g., Tables 4.10 through 4.12) describes our attempt to estimate *incremental* TA/TI or AutoDR load impacts, or the load impacts achieved by these customers less the amount of the load impact one would expect in the absence of TA/TI or AutoDR. To do this, we develop comparison groups according to industry classifications (SIC codes for SCE and

NAICS codes for PG&E). Where possible, we conduct comparisons within a 6-digit NAICS code or 4-digit SIC code. Where a comparison at this level of disaggregation was not possible, we compared at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes.

We note that the above comparisons do not constitute a formal evaluation of the incremental effect of AutoDR or TA/TI on customers' demand response load impacts. This is the case largely due to lack of complete information. For example, we rarely observe "before and after" load responses for the same service account, because the TA/TI and AutoDR audits and installations typically took place prior to any events in 2009. In addition, enabling technology may be used by some SA IDs that did not participate in AutoDR or TA/TI. Therefore, we cannot be certain that when we compare TA/TI and non-TA/TI accounts we are actually measuring a "with and without" technology difference. However, given the available data, we believe that the comparisons made in this section are informative and the most relevant ones to provide.

The sub-sections below present the results for each of the utilities.

### PG&E

*TA/TI*

According to data provided by PG&E, 3 DBP service accounts participating in the TA/TI program submitted a bid for the August 25, 2010 event.

Table 4.9 shows the event-specific load impact for the TA/TI participants. TA/TI customers provided an average hourly load reduction of 383 kW, or 8.3 percent of their reference load.

**Table 4.9: Average Hourly Load Impacts by Event, *PG&E TA/TI***

| Event Date | Number of SAIDs | Estimated Reference Load (kW) | Observed Load (kW) | Estimated Load Impact (kW) | % Load Impact |
|---|---|---|---|---|---|
| 8/25/2010 | 3 | 4,638 | 4,255 | 383 | 8.3% |

All three TA/TI participants were in one 6-digit NAICS industry code. As shown in Table 4.10, the TA/TI SA IDs in this industry group had reference loads that were approximately twice the size of the non-TA/TI SA IDs.

**Table 4.10: Number of Service Accounts and Average Reference Load, *PG&E TA/TI***

| NAICS Code | NAICS Description | Basis of Comparison | Number of SAIDs | | Average Reference Load (kW) / SAID | |
|---|---|---|---|---|---|---|
| | | | No TA/TI | TA/TI | No TA/TI | TA/TI |
| 334419 | Other Electronic Component Manufacturing | 3-digit NAICS | 3 | 3 | 789 | 1,546 |

Table 4.11 shows that the TA/TI service accounts were more demand responsive, with an 8 percent average load impact versus the 3 percent load impact estimated for the non-

TA/TI service accounts. Table 4.12 uses this information to summarize the total incremental load impact, which is 229 kW.

**Table 4.11: Average Load Impacts in Levels and Percentages, *PG&E TA/TI***

| NAICS Code | NAICS Description | Basis of Comparison | Average Load Impact (kW) / SAID | | Average Percentage LI | |
|---|---|---|---|---|---|---|
| | | | No TA/TI | TA/TI | No TA/TI | TA/TI |
| 334419 | Other Electronic Component Manufacturing | 3-digit NAICS | 26 | 128 | 3% | 8% |

**Table 4.12: Incremental Load Impact Calculation, *PG&E TA/TI***

| NAICS Code | NAICS Description | Average % LI | | Reference Load (kW) | Incremental LI (kW) |
|---|---|---|---|---|---|
| | | No TA/TI | TA/TI | | |
| 334419 | Other Electronic Component Manufacturing | 3% | 8% | 4,638 | 229 |

*AutoDR*

According to data provided by PG&E, 71 DBP service accounts participating in the AutoDR program submitted a bid for the August 25th test event. (However, not all of these service accounts appeared to reduce load during event hours.) Table 4.13 shows the average hourly load impact for the AutoDR participants, which was 1,658 kW, or 3.1 percent of their reference load.

**Table 4.13: Average Hourly Load Impacts by Event, *PG&E AutoDR***

| Event Date | Number of SAIDs | Estimated Reference Load (kW) | Observed Load (kW) | Estimated Load Impact (kW) | % Load Impact |
|---|---|---|---|---|---|
| 8/25/2010 | 71 | 53,002 | 51,344 | 1,658 | 3.1% |

AutoDR participants were spread across 25 6-digit NAICS industry codes. In nine of these industry groups, non-AutoDR bidders are present to serve as a comparison group. For the remaining 16 industry groups with Auto-DR customers, comparisons are made at a more aggregated level. “Basis of Comparison” identifies the industry level used for the comparison group.

Tables 4.14 and 4.15 show the characteristics of the treatment and comparison groups. Notice that the average size (represented by the average reference loads shown in the two rightmost columns) can be quite different between the comparison group and the AutoDR DBP participants. AutoDR DBP customers are larger than the comparison group customers in 10 of the 25 comparisons.

Table 4.15 shows the load impacts in kW and percentage terms. A positive sign indicates load reductions during event hours. Notice that there are some wrong-signed results (indicating load increases during event hours) and a large share of counter-intuitive differences between the Auto-DR load impacts and those of the comparison group. (That is, we expect that Auto-DR customers will have a higher percentage load impact than the comparison group customers, but this is true in only 8 of the 25 comparisons.)

Table 4.16 combines the percentage load impact estimates with the reference loads to calculate the incremental load impacts.  In this case, the incremental load impact is -336 kW, indicating that the industry-group level calculations do not produce positive incremental Auto-DR load impacts.

**Table 4.14: Number of Service Accounts and Average Reference Load, *PG&E AutoDR***

| NAICS Code | NAICS Description | Basis of Comparison | Number of SAIDs | | Average Reference Load (kW) / SAID | |
|---|---|---|---|---|---|---|
| | | | No AutoDR | AutoDR | No AutoDR | AutoDR |
| 115114 | Postharvest Crop Activities (except Cotton Ginning) | Program | 153 | 3 | 938 | 989 |
| 221112 | Fossil Fuel Electric Power Generation | Program | 153 | 1 | 938 | 584 |
| 334112 | Computer Storage Device Manufacturing | 3-digit NAICS | 3 | 6 | 789 | 1246 |
| 424410 | General Line Grocery Merchant Wholesalers | 3-digit NAICS | 1 | 1 | 198 | 863 |
| 442110 | Furniture Stores | Program | 153 | 1 | 938 | 900 |
| 452111 | Department Stores (except Discount Department Stores) | Program | 153 | 23 | 938 | 114 |
| 452112 | Discount Department Stores | Program | 153 | 1 | 938 | 473 |
| 518210 | Data Processing, Hosting, and Related Services | 6-digit NAICS | 2 | 2 | 3000 | 1943 |
| 531123 | Lessors of Nonresidential Buildings (except Miniwarehouses) | 6-digit NAICS | 5 | 1 | 775 | 264 |
| 541710 | Research and Development in the Physical, Engineering, and Life Sciences | 6-digit NAICS | 1 | 3 | 4,874 | 618 |
| 551114 | Corporate, Subsidiary, and Regional Managing Offices | 6-digit NAICS | 4 | 3 | 2,125 | 2,329 |
| 621400 | Outpatient Care Centers | 3-digit NAICS | 1 | 1 | 155 | 462 |
| 621491 | HMO Medical Centers | 3-digit NAICS | 1 | 2 | 155 | 1,337 |
| 622112 | General Medical and Surgical Hospitals | Program | 153 | 1 | 938 | 1,063 |
| 624000 | Social Assistance | 3-digit NAICS | 1 | 1 | 196 | 136 |
| 624190 | Other Individual and Family Services | 3-digit NAICS | 1 | 1 | 196 | 184 |
| 624310 | Vocational Rehabilitation Services | 6-digit NAICS | 1 | 1 | 196 | 2,196 |
| 713940 | Fitness and Recreational Sports Centers | 6-digit NAICS | 20 | 4 | 101 | 175 |
| 812910 | Pet Care (except Veterinary) Services | Program | 153 | 1 | 938 | 228 |
| 921190 | Other General Government Support | 6-digit NAICS | 2 | 7 | 314 | 1,326 |
| 922120 | Police Protection | 3-digit NAICS | 11 | 1 | 3,405 | 2,386 |
| 922130 | Legal Counsel and Prosecution | 3-digit NAICS | 11 | 1 | 3,405 | 706 |
| 922140 | Correctional Institutions | 6-digit NAICS | 10 | 3 | 3,713 | 1,139 |
| 922160 | Fire Protection | 3-digit NAICS | 11 | 1 | 3,405 | 538 |
| 923130 | Administration of Human Resource Programs (except Education, Public Health, and Veterans' Affairs Programs) | 6-digit NAICS | 1 | 1 | 262 | 143 |

**Table 4.15: Average Load Impacts in Levels and Percentages, *PG&E AutoDR***

| NAICS Code | NAICS Description | Basis of Comparison | Average Load Impact (kW) / SAID | | Average Percentage LI | |
|---|---|---|---|---|---|---|
| | | | No AutoDR | AutoDR | No AutoDR | AutoDR |
| 115114 | Postharvest Crop Activities (except Cotton Ginning) | Program | 54 | -80 | 6% | -8% |
| 221112 | Fossil Fuel Electric Power Generation | Program | 54 | -48 | 6% | -8% |
| 334112 | Computer Storage Device Manufacturing | 3-digit NAICS | 26 | 28 | 3% | 2% |
| 424410 | General Line Grocery Merchant Wholesalers | 3-digit NAICS | 11 | -8 | 6% | -1% |
| 442110 | Furniture Stores | Program | 54 | -100 | 6% | -11% |
| 452111 | Department Stores (except Discount Department Stores) | Program | 54 | 39 | 6% | 34% |
| 452112 | Discount Department Stores | Program | 54 | -9 | 6% | -2% |
| 518210 | Data Processing, Hosting, and Related Services | 6-digit NAICS | -82 | 102 | -3% | 5% |
| 531123 | Lessors of Nonresidential Buildings (except Miniwarehouses) | 6-digit NAICS | 40 | 37 | 5% | 14% |
| 541710 | Research and Development in the Physical, Engineering, and Life Sciences | 6-digit NAICS | 94 | 9 | 2% | 1% |
| 551114 | Corporate, Subsidiary, and Regional Managing Offices | 6-digit NAICS | 175 | 28 | 8% | 1% |
| 621400 | Outpatient Care Centers | 3-digit NAICS | -12 | -27 | -7% | -6% |
| 621491 | HMO Medical Centers | 3-digit NAICS | -12 | 92 | -7% | 7% |
| 622112 | General Medical and Surgical Hospitals | Program | 54 | 126 | 6% | 12% |
| 624000 | Social Assistance | 3-digit NAICS | 13 | -6 | 7% | -5% |
| 624190 | Other Individual and Family Services | 3-digit NAICS | 13 | -16 | 7% | -9% |
| 624310 | Vocational Rehabilitation Services | 6-digit NAICS | 13 | 101 | 7% | 5% |
| 713940 | Fitness and Recreational Sports Centers | 6-digit NAICS | 4 | 19 | 4% | 11% |
| 812910 | Pet Care (except Veterinary) Services | Program | 54 | 4 | 6% | 2% |
| 921190 | Other General Government Support | 6-digit NAICS | -2 | 43 | 0% | 3% |
| 922120 | Police Protection | 3-digit NAICS | 271 | 60 | 8% | 2% |
| 922130 | Legal Counsel and Prosecution | 3-digit NAICS | 271 | 1 | 8% | 0% |
| 922140 | Correctional Institutions | 6-digit NAICS | 301 | 32 | 8% | 3% |
| 922160 | Fire Protection | 3-digit NAICS | 271 | -267 | 8% | -50% |
| 923130 | Administration of Human Resource Programs (except Education, Public Health, and Veterans' Affairs Programs) | 6-digit NAICS | 28 | 14 | 11% | 10% |

### Table 4.16: Incremental Load Impact Calculation, *PG&E AutoDR*

| NAICS Code | NAICS Description | Average % LI | | Reference Load (kW) | Incremental LI (kW) |
|---|---|---|---|---|---|
| | | No AutoDR | AutoDR | | |
| 115114 | Postharvest Crop Activities (except Cotton Ginning) | 8% | -8% | 2,966 | -468 |
| 221112 | Fossil Fuel Electric Power Generation | 8% | -8% | 584 | -92 |
| 334112 | Computer Storage Device Manufacturing | 3% | 2% | 7,479 | -78 |
| 424410 | General Line Grocery Merchant Wholesalers | 6% | -1% | 863 | -56 |
| 442110 | Furniture Stores | 8% | -11% | 900 | -169 |
| **452111** | **Department Stores (except Discount Department Stores)** | **8%** | **34%** | **2,630** | **696** |
| 452112 | Discount Department Stores | 8% | -2% | 473 | -45 |
| **518210** | **Data Processing, Hosting, and Related Services** | **-3%** | **5%** | **3,885** | **309** |
| **531123** | **Lessors of Nonresidential Buildings (except Miniwarehouses)** | **5%** | **14%** | **264** | **23** |
| 541710 | Research and Development in the Physical, Engineering, and Life Sciences | 2% | 1% | 1,853 | -9 |
| 551114 | Corporate, Subsidiary, and Regional Managing Offices | 8% | 1% | 6,986 | -491 |
| **621400** | **Outpatient Care Centers** | **-7%** | **-6%** | **462** | **7** |
| **621491** | **HMO Medical Centers** | **-7%** | **7%** | **2,674** | **386** |
| **622112** | **General Medical and Surgical Hospitals** | **8%** | **12%** | **1,063** | **45** |
| 624000 | Social Assistance | 7% | -5% | 136 | -15 |
| 624190 | Other Individual and Family Services | 7% | -9% | 184 | -28 |
| 624310 | Vocational Rehabilitation Services | 7% | 5% | 2,196 | -47 |
| **713940** | **Fitness and Recreational Sports Centers** | **4%** | **11%** | **701** | **44** |
| 812910 | Pet Care (except Veterinary) Services | 8% | 2% | 228 | -13 |
| **921190** | **Other General Government Support** | **0%** | **3%** | **9,285** | **346** |
| 922120 | Police Protection | 8% | 2% | 2,386 | -131 |
| 922130 | Legal Counsel and Prosecution | 8% | 0% | 706 | -55 |
| 922140 | Correctional Institutions | 8% | 3% | 3,416 | -182 |
| 922160 | Fire Protection | 8% | -50% | 538 | -310 |
| 923130 | Administration of Human Resource Programs (except Education, Public Health, and Veterans' Affairs Programs) | 11% | 10% | 143 | -2 |
| **Total** | | | | | **-336** |

## SCE

*TA/TI*

Table 4.17 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 55 of SCE's DBP service accounts participated in TA/TI. The load impacts vary dramatically across events. The variability is largely due to one service account that sometimes provides essentially zero load impacts, but for other events provides 15 to 19 MW of load response. The load impacts in the absence of this customer average 1.9 MW, or 12.7 percent of the remaining reference load.

**Table 4.17: Average Hourly TA/TI Load Impacts by Event, *SCE TA/TI***

| Event Date | Number of SAIDs | Estimated Reference Load (kW) | Observed Load (kW) | Estimated Load Impact (kW) | % Load Impact |
|---|---|---|---|---|---|
| 7/16/2010 | 56 | 48,277 | 27,145 | 21,132 | 43.8% |
| 8/24/2010 | 53 | 42,975 | 22,295 | 20,680 | 48.1% |
| 8/25/2010 | 53 | 44,571 | 42,819 | 1,752 | 3.9% |
| 8/26/2010 | 53 | 43,925 | 42,996 | 929 | 2.1% |
| 9/2/2010 | 53 | 41,949 | 39,921 | 2,028 | 4.8% |
| 9/27/2010 | 56 | 48,764 | 46,828 | 1,936 | 4.0% |
| 9/28/2010 | 56 | 47,625 | 46,022 | 1,603 | 3.4% |
| 9/30/2010 | 56 | 46,896 | 46,199 | 696 | 1.5% |
| **Average** | **55** | **45,623** | **39,278** | **6,345** | **13.9%** |

Table 4.18 shows load impact comparisons by industry group. The load impact differences between TA/TI participants and non-participants vary dramatically across industry groups. TA/TI load impacts are higher than non-TA/TI impacts in only 7 of 16 industries (the seven instances are shown in bold). The most remarkable difference is for Industrial Gases SIC (2813), where the percentage load impacts for TA/TI accounts are 66 percentage points *lower* than those of non-TA/TI service accounts. In this case, there is one TA/TI service account that can provide a comparable percentage demand response to the non-TA/TI service accounts, but it does so during only two events (but the customer submitted a bid for all of the events). Therefore, the average percentage load impact across all events is quite low compared to the non-TA/TI service accounts, which provided much more consistent demand response. Due to the large average reference load in this industry, this large percentage difference results in a negative incremental load impact for SCE's TA/TI customers. In the absence of this customer, the total incremental TA/TI load impact is substantially closer to zero (-690 kW).

**Table 4.18: Incremental TA/TI Load Impacts by Industry Group, *SCE TA/TI***

| SIC Code | SIC Description | Average Percentage LI | | Reference Load (kW) | Incremental LI (kW) |
|---|---|---|---|---|---|
| | | No TA/TI | TA/TI | | |
| 2026 | Fluid Milk | 2.5% | 0.4% | 954 | -20 |
| 2041 | Flour and Other Grain Mill Products | 1.0% | -7.1% | 1,746 | -140 |
| 2813 | Industrial Gases | 89.3% | 23.5% | 20,539 | -13,522 |
| 2834 | Pharmaceutical Preparations | 4.8% | 2.5% | 2,135 | -51 |
| 4941 | Water Supply | 29.3% | 22.5% | 17 | -1 |
| **5072** | **Hardware** | **0.9%** | **21.9%** | **1,174** | **246** |
| 5311 | Department Stores | 2.5% | 0.9% | 2,009 | -33 |
| 5318 | Retail stores | 1.2% | -0.3% | 5,197 | -80 |
| **5411** | **Grocery Stores** | **5.8%** | **6.7%** | **3,517** | **32** |
| 5651 | Family Clothing Stores | 7.8% | 7.4% | 1,021 | -4 |
| **5912** | **Drug Stores and Proprietary Stores** | **-3.5%** | **0.2%** | **1,448** | **54** |
| **6512** | **Operators of Nonresidential Buildings** | **1.4%** | **7.7%** | **10,871** | **682** |
| 6514 | Operators of Dwellings Other Than Apartment Buildings | 20.8% | 10.6% | 533 | -54 |
| **8011** | **Kidney dialysis centers** | **0.01%** | **10.6%** | **507** | **54** |
| **9111** | **Executive Offices** | **0.1%** | **4.8%** | **104** | **5** |
| **9229** | **Public Order and Safety, Not Elsewhere Classified** | **3.1%** | **25.2%** | **1** | **0.2** |
| **TOTAL** | | | | | **-12,832** |
| **TOTAL Excluding SIC 2813** | | | | | **-690** |

*AutoDR*

Table 4.19 shows the total DBP load impacts for SCE's AutoDR participants. The percentage load impacts are uniformly high across events, averaging 49 percent, or around 14.5 MW of load impact. This result is driven by the participation of one SAID from the Industrial Gases SIC (2813), who consistently reduced load by 13 MW.

**Table 4.19: Average Hourly AutoDR Load Impacts by Event, *SCE AutoDR***

| Event Date | Number of SAIDs | Estimated Reference Load (kW) | Observed Load (kW) | Estimated Load Impact (kW) | % Load Impact |
|---|---|---|---|---|---|
| 7/16/2010 | 58 | 36,471 | 19,136 | 17,336 | 47.5% |
| 8/24/2010 | 65 | 27,724 | 12,586 | 15,138 | 54.6% |
| 8/25/2010 | 65 | 27,658 | 14,725 | 12,933 | 46.8% |
| 8/26/2010 | 65 | 27,312 | 14,197 | 13,115 | 48.0% |
| 9/2/2010 | 65 | 26,878 | 12,372 | 14,506 | 54.0% |
| 9/27/2010 | 66 | 34,403 | 18,568 | 15,835 | 46.0% |
| 9/28/2010 | 65 | 28,605 | 14,629 | 13,976 | 48.9% |
| 9/30/2010 | 65 | 28,131 | 15,142 | 12,989 | 46.2% |
| **Average** | **64** | **29,648** | **15,169** | **14,478** | **48.8%** |

Table 4.20 describes the comparison groups, including the number of SAIDs and average reference load for each group. Table 4.21 shows the load impact comparisons by industry group. AutoDR participants showed higher load impacts in six of the eight industry groups, with several industry groups showing much higher percentage load impact. SICs 723 (Crop Preparation Services for Market, Except Cotton Ginning) and 2653 (Corrugated and Solid Fiber Boxes) provided the opposite outcome, with AutoDR participants providing substantially lower responses than non-participants.

**Table 4.20: Number of Service Accounts and Average Reference Load, *SCE AutoDR***

| SIC Code | SIC Description | Basis of Comparison | Number of SAIDs | | Average Reference Load (kW) / SAID | |
|---|---|---|---|---|---|---|
| | | | No AutoDR | AutoDR | No AutoDR | AutoDR |
| 723 | Crop Preparation Services for Market, Except Cotton Ginning | 4 Dig. SIC | 1 | 2 | 387 | 296 |
| 2026 | Fluid Milk | 4 Dig. SIC | 5 | 1 | 1,433 | 5,828 |
| 2653 | Corrugated and Solid Fiber Boxes | 4 Dig. SIC | 4 | 2 | 913 | 979 |
| 2813 | Industrial Gases | 4 Dig. SIC | 4 | 1 | 4,731 | 13,291 |
| 3691 | Storage Batteries | 2 Dig. SIC | 24 | 2 | 3,152 | 1,004 |
| 5311 | Department Stores | 4 Dig. SIC | 1 | 47 | 158 | 161 |
| 5712 | Furniture Stores | 4 Dig. SIC | 1 | 3 | 90 | 834 |
| 5941 | Sporting Goods Stores and Bicycle Shops | 2 Dig. SIC | 25 | 9 | 621 | 147 |

**Table 4.21: Average Load Impacts in Levels and Percentages, *SCE AutoDR***

| SIC Code | SIC Description | Basis of Comparison | Average Load Impact (kW) / SAID | | Average Percentage LI | |
|---|---|---|---|---|---|---|
| | | | No AutoDR | AutoDR | No AutoDR | AutoDR |
| 723 | Crop Preparation Services for Market, Except Cotton Ginning | 4 Dig. SIC | 60 | -5 | 15.5% | -1.6% |
| 2026 | Fluid Milk | 4 Dig. SIC | 36 | 516 | 2.5% | 8.9% |
| 2653 | Corrugated and Solid Fiber Boxes | 4 Dig. SIC | 66 | -74 | 7.3% | -7.5% |
| 2813 | Industrial Gases | 4 Dig. SIC | 4,226 | 13,026 | 89.3% | 98.0% |
| 3691 | Storage Batteries | 2 Dig. SIC | 24 | 221 | 0.8% | 22.0% |
| 5311 | Department Stores | 4 Dig. SIC | 4 | 21 | 2.5% | 12.8% |
| 5712 | Furniture Stores | 4 Dig. SIC | 5 | 57 | 5.1% | 6.9% |
| 5941 | Sporting Goods Stores and Bicycle Shops | 2 Dig. SIC | 5 | 12 | 0.8% | 8.1% |

Table 4.22 shows an incremental load impact for SCE's AutoDR participants of 2.5 MW. The six industry groups that show positive incremental load impacts from AutoDR are shown in bold. Nearly half of the 2.5 MW incremental load impact comes from the customer in the Industrial Gases SIC (2813). Notably in that industry, both the AutoDR and non-AutoDR groups show high percentage responses, of 98 and 89 percent, respectively. However, even when excluding that industry, the incremental impact for AutoDR customers is approximately 1.3 MW, or 6.1 percent of remaining reference load.

**Table 4.22: Incremental Load Impact Calculation, *SCE AutoDR***

| SIC Code | SIC Description | Average Percentage LI | | Reference Load (kW) | Incremental LI (kW) |
|---|---|---|---|---|---|
| | | No AutoDR | AutoDR | | |
| 723 | Crop Preparation Services for Market, Except Cotton Ginning | 15.5% | -1.6% | 591 | -101 |
| **2026** | **Fluid Milk** | **2.5%** | **8.9%** | **5,828** | **370** |
| 2653 | Corrugated and Solid Fiber Boxes | 7.3% | -7.5% | 1,959 | -289 |
| **2813** | **Industrial Gases** | **89.3%** | **98.0%** | **13,291** | **1,152** |
| **3691** | **Storage Batteries** | **0.8%** | **22.0%** | **2,008** | **427** |
| **5311** | **Department Stores** | **2.5%** | **12.8%** | **7,560** | **772** |
| **5712** | **Furniture Stores** | **5.1%** | **6.9%** | **2,502** | **44** |
| **5941** | **Sporting Goods Stores and Bicycle Shops** | **0.8%** | **8.1%** | **1,325** | **97** |
| **Total** | | | | | **2,472** |

# 5. Ex Ante Load Impact Forecast

## *5.1 Ex Ante Load Impact Requirements*

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

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

under both:

- 1-in-2 weather-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).

## *5.2 Description of Methods*

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

### 5.2.1 Development of Customer Groups

For PG&E'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 for three out 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 was simplified because the enrollment assumes a continuation of the status quo with respect to shares of customers by size group and LCA. Therefore, we only simulated sets of reference loads for each of the three local capacity areas.

### 5.2.2 Development of Reference Loads and Load Impacts

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

1. Define data sources
2. Estimate ex ante regressions and simulate reference loads by cell and scenario
3. Calculate percentage load impacts by cell
4. Apply percentage load impacts to the reference loads
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 2010 program year. In addition, the percentage load impacts that are applied to the reference loads to create hourly load impacts are based upon the ex post load impacts from the 2010 program year.

For PG&E, we divided the DBP customers into two groups according to whether they are dually enrolled in the Base Interruptible Program (BIP). BIP customers tend to be larger and more demand responsive (even during DBP events) than other DBP customers. Therefore, separating the dually enrolled customers helped ensure that The Brattle Group was able to properly match enrollments to load impacts.

*Simulate reference loads*
In order to develop reference loads, we first re-estimated regression equations for each enrolled customer account, using data for 2010. These equations were then used to simulate reference loads by customer type 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 four ways. First, the ex ante models excluded the morning-usage variable. While this variable is useful for improving accuracy in estimating ex post load impacts for particular events, it complicates the use of the equations in ex ante simulation. That is, it would require a separate simulation of the level of the morning load. Second, the ex ante models excluded the summer variables (e.g., the summer variable interacted with the hourly profile). Third, for SCE the event variables were modified from the version that produces estimates of 24 hourly load impact values for *each* event, to a version that produces estimates of *average hourly event-period* load impacts across all events. (PG&E only had one test event, so this modification was not required.) The fourth difference between the ex post and ex ante models is that the ex ante model uses cooling degree days instead of cooling degree hours.[11]

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.

[11] Cooling degree days (CDD) was defined as MAX[0, (MaxT + MinT) / 2 – 50], where MaxT is the daily maximum temperature and MinT is the daily minimum temperature, both expressed in degrees Fahrenheit. Customer-specific CDD values are calculated using data from the most appropriate weather station.

$$Q_t = a + \sum_{i=1}^{24}(b_i^{DBP} \times h_{i,t} \times DBP_t) + \sum_{i=1}^{24}(b_i^{OTH} \times h_{i,t} \times OtherEvt_{i,t}) + \sum_{i=1}^{24}(b_i^{CDD} \times h_{i,t} \times CDD_t)$$
$$+ \sum_{i=1}^{24}(b_i^{HDD} \times h_{i,t} \times HDD_t) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24}(b_i^{h} \times h_{i,t})$$
$$+ \sum_{i=2}^{5}(b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=2-5,10-12}(b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

In this equation, $Q_t$ represents the demand in hour *t* for a customer enrolled in DBP prior to the last event date; the *b*'s are estimated parameters; $h_{i,t}$ is a dummy variable for hour *i*; $DBP_t$ is an indicator variable for program event days; $CDD_t$ is cooling degree days; $HDD_t$ is heating degree days;[12] $OtherEvt_t$ is equal to one in the event hours of other demand response programs in which the customer is enrolled; $MON_t$ is a dummy variable for Monday; $FRI_t$ is a dummy variable for Friday; $DTYPE_{i,t}$ is a series of dummy variables for each day of the week; $MONTH_{i,t}$ is a series of dummy variables for each month; and $e_t$ is the error term.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. Each of the profiles was simulated as an average of Tuesday, Wednesday, and Thursday profiles. 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 study (following the 2009 program year).

*Calculate forecast percentage load impacts*

For PG&E, hourly percentage load impacts were developed by LCA and whether the customer was dually enrolled with BIP. Because the forecast event window (1:00 to 6:00 p.m. in summer months; and 4:00 to 9:00 p.m. in non-summer months) differs from the historical event window (2:00 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 replaced the 12:00 to 2:00 p.m. percentage load impacts with the values from 1:00 to 3:00 p.m. This ensured that the additional ex ante event hour included event-based load impacts and also ensured that the hour preceding the event included any historical effects observed in that hour (e.g., pre-event increases in load).

For the non-summer months, we replaced the values in 2:00 to 11:00 p.m. (including the non-summer event window and the two surrounding hours on each side) with the historical values from 12:00 to 8:00 p.m. In addition, the values in the hours from 12:00 to 2:00 p.m. were replaced with the values from 11:00 a.m. to 12:00 p.m.

[12] Heating degree days (HDD) was defined as MAX[0, 50 – (MaxT + MinT) / 2], where MaxT is the daily maximum temperature and MinT is the daily minimum temperature, both expressed in degrees Fahrenheit. Customer-specific HDD values are calculated using data from the most appropriate weather station.

For the customers dually enrolled in BIP, we combined the load impacts across the Greater Fresno, Northern Coast, Sierra, and Stockton LCAs because these LCAs had relatively few customers (who were also not very demand responsive).

The uncertainty-adjusted load impacts (i.e., the 10th, 30th, 50th, 70th, and 90th percentile scenarios of load impacts) were calculated under the assumption that the load impacts are normally distributed with a mean equal to the total estimated load impact and a variance equal to the sum of the variances (the squares of the standard errors) associated with the load impact estimates.

Tables 5.1 through 5.4 show the resulting hourly load impacts by LCA, according to season and whether the customers are dually enrolled in BIP.

**Table 5.1: Hourly Percentage Load Impacts, PG&E Customers not dually enrolled in BIP, Summer Months**

| Hour | Greater Bay Area | Greater Fresno | Humboldt | Kern | Northern Coast | Not in Any LCA | Sierra | Stockton |
|---|---|---|---|---|---|---|---|---|
| 1 | -0.1% | 0.3% | 0.0% | 0.1% | -0.2% | 0.7% | 0.1% | -0.3% |
| 2 | -0.1% | 0.6% | 0.0% | -0.6% | -0.2% | 0.7% | 0.1% | -0.3% |
| 3 | -0.1% | 0.0% | 0.0% | -0.3% | -0.9% | 0.6% | 0.1% | 0.0% |
| 4 | -0.2% | -0.5% | 0.0% | 0.5% | -1.0% | 0.3% | 0.1% | 0.1% |
| 5 | -0.1% | -0.2% | 0.0% | 0.1% | -0.9% | 0.3% | 0.1% | 0.2% |
| 6 | -0.2% | -0.1% | 0.0% | 0.1% | 0.0% | -0.1% | -0.3% | 0.3% |
| 7 | -0.4% | -0.1% | 0.0% | -0.3% | 1.0% | -0.4% | -0.1% | -0.1% |
| 8 | -0.3% | 0.5% | 0.0% | 0.0% | 0.0% | -0.9% | -0.1% | 0.2% |
| 9 | -0.2% | 0.7% | 0.0% | -0.7% | -0.6% | -0.5% | -0.3% | -1.5% |
| 10 | 0.2% | -0.5% | 0.0% | -1.2% | 0.3% | -0.3% | -0.1% | -0.3% |
| 11 | 0.3% | -0.2% | 0.0% | -1.4% | 0.6% | 0.1% | 0.0% | 0.5% |
| 12 | 0.4% | -0.2% | 0.0% | -1.6% | 0.5% | 0.3% | 0.2% | 1.3% |
| 13 | 0.3% | 0.0% | 0.0% | 2.9% | 1.5% | 0.5% | 0.1% | 0.6% |
| **14** | **0.5%** | **-0.8%** | **0.0%** | **2.6%** | **1.9%** | **3.2%** | **-0.9%** | **0.5%** |
| **15** | **0.5%** | **-0.8%** | **0.0%** | **2.6%** | **1.9%** | **3.2%** | **-0.9%** | **0.5%** |
| **16** | **0.8%** | **-0.3%** | **0.0%** | **2.7%** | **3.0%** | **1.4%** | **-0.9%** | **-0.2%** |
| **17** | **0.9%** | **1.8%** | **0.0%** | **3.4%** | **2.5%** | **1.4%** | **-0.1%** | **1.7%** |
| **18** | **0.8%** | **2.7%** | **0.0%** | **1.3%** | **2.8%** | **1.6%** | **1.0%** | **5.2%** |
| 19 | 0.4% | 1.7% | 0.0% | -0.9% | 1.4% | 0.8% | -0.2% | -0.2% |
| 20 | 0.7% | 0.9% | 0.0% | 0.0% | 1.3% | 1.1% | -0.4% | -1.1% |
| 21 | 0.8% | 0.7% | 0.0% | -0.9% | 1.5% | 0.9% | -0.5% | -0.3% |
| 22 | 0.9% | 0.7% | 0.0% | -0.3% | 2.5% | 1.4% | -0.4% | 0.7% |
| 23 | 1.1% | 0.8% | 0.0% | 0.3% | 3.1% | 1.6% | 0.1% | 1.0% |
| 24 | 1.0% | 0.8% | 0.0% | -1.7% | 3.1% | 1.6% | -0.5% | -0.8% |

**Table 5.2: Hourly Percentage Load Impacts, PG&E Customers not dually enrolled in BIP, Non-summer Months**

| Hour | Greater Bay Area | Greater Fresno | Humboldt | Kern | Northern Coast | Not in Any LCA | Sierra | Stockton |
|---|---|---|---|---|---|---|---|---|
| 1 | -0.1% | 0.3% | 0.0% | 0.1% | -0.2% | 0.7% | 0.1% | -0.3% |
| 2 | -0.1% | 0.6% | 0.0% | -0.6% | -0.2% | 0.7% | 0.1% | -0.3% |
| 3 | -0.1% | 0.0% | 0.0% | -0.3% | -0.9% | 0.6% | 0.1% | 0.0% |
| 4 | -0.2% | -0.5% | 0.0% | 0.5% | -1.0% | 0.3% | 0.1% | 0.1% |
| 5 | -0.1% | -0.2% | 0.0% | 0.1% | -0.9% | 0.3% | 0.1% | 0.2% |
| 6 | -0.2% | -0.1% | 0.0% | 0.1% | 0.0% | -0.1% | -0.3% | 0.3% |
| 7 | -0.4% | -0.1% | 0.0% | -0.3% | 1.0% | -0.4% | -0.1% | -0.1% |
| 8 | -0.3% | 0.5% | 0.0% | 0.0% | 0.0% | -0.9% | -0.1% | 0.2% |
| 9 | -0.2% | 0.7% | 0.0% | -0.7% | -0.6% | -0.5% | -0.3% | -1.5% |
| 10 | 0.2% | -0.5% | 0.0% | -1.2% | 0.3% | -0.3% | -0.1% | -0.3% |
| 11 | 0.3% | -0.2% | 0.0% | -1.4% | 0.6% | 0.1% | 0.0% | 0.5% |
| 12 | 0.4% | -0.2% | 0.0% | -1.6% | 0.5% | 0.3% | 0.2% | 1.3% |
| 13 | 0.4% | -0.2% | 0.0% | -1.6% | 0.5% | 0.3% | 0.2% | 1.3% |
| 14 | 0.4% | -0.2% | 0.0% | -1.6% | 0.5% | 0.3% | 0.2% | 1.3% |
| 15 | 0.3% | -0.1% | 0.0% | -0.7% | 1.6% | 0.7% | 0.2% | 1.1% |
| 16 | 0.3% | 0.0% | 0.0% | 2.9% | 1.5% | 0.5% | 0.1% | 0.6% |
| **17** | **0.5%** | **-0.8%** | **0.0%** | **2.6%** | **1.9%** | **3.2%** | **-0.9%** | **0.5%** |
| **18** | **0.8%** | **-0.3%** | **0.0%** | **2.7%** | **3.0%** | **1.4%** | **-0.9%** | **-0.2%** |
| **19** | **0.9%** | **1.8%** | **0.0%** | **3.4%** | **2.5%** | **1.4%** | **-0.1%** | **1.7%** |
| **20** | **0.8%** | **2.7%** | **0.0%** | **1.3%** | **2.8%** | **1.6%** | **1.0%** | **5.2%** |
| **21** | **0.4%** | **1.7%** | **0.0%** | **-0.9%** | **1.4%** | **0.8%** | **-0.2%** | **-0.2%** |
| 22 | 0.7% | 0.9% | 0.0% | 0.0% | 1.3% | 1.1% | -0.4% | -1.1% |
| 23 | 1.1% | 0.8% | 0.0% | 0.3% | 3.1% | 1.6% | 0.1% | 1.0% |
| 24 | 1.0% | 0.8% | 0.0% | -1.7% | 3.1% | 1.6% | -0.5% | -0.8% |

**Table 5.3: Hourly Percentage Load Impacts, PG&E Customers dually enrolled in BIP, Summer Months**

| Hour | Greater Bay Area | Humboldt | Kern | All Others | Not in Any LCA |
|---|---|---|---|---|---|
| 1 | -5.5% | -0.1% | 1.1% | -0.5% | 3.5% |
| 2 | -3.9% | 4.1% | 3.5% | 1.7% | 1.1% |
| 3 | -4.6% | 3.3% | 2.0% | 1.2% | -0.4% |
| 4 | 0.1% | 4.6% | 7.3% | 0.9% | 0.4% |
| 5 | 1.5% | 3.5% | 14.9% | 0.7% | 1.3% |
| 6 | 0.1% | 4.0% | 13.8% | 1.7% | 0.5% |
| 7 | 0.7% | -1.1% | -7.3% | 1.4% | 3.9% |
| 8 | 0.2% | -2.2% | -0.8% | -0.8% | 1.6% |
| 9 | -1.2% | -1.1% | -1.1% | -1.9% | 1.1% |
| 10 | -2.2% | -0.8% | 0.9% | -0.1% | -0.8% |
| 11 | -3.1% | -0.7% | -1.6% | 0.2% | -2.3% |
| 12 | -4.7% | -0.9% | -2.3% | 5.5% | -3.0% |
| 13 | 0.6% | 5.1% | -0.3% | 5.8% | 15.4% |
| **14** | **11.0%** | **11.4%** | **19.1%** | **3.7%** | **39.1%** |
| **15** | **11.0%** | **11.4%** | **19.1%** | **3.7%** | **39.1%** |
| **16** | **11.8%** | **11.8%** | **29.4%** | **1.8%** | **39.3%** |
| **17** | **11.1%** | **9.7%** | **29.4%** | **1.1%** | **40.8%** |
| **18** | **11.3%** | **10.7%** | **27.4%** | **2.0%** | **39.6%** |
| 19 | 1.3% | 1.7% | 13.4% | 0.0% | 14.8% |
| 20 | -2.7% | -0.6% | -0.5% | -2.1% | 8.0% |
| 21 | 8.5% | -0.4% | -4.5% | -3.7% | 3.0% |
| 22 | 3.8% | -1.7% | -0.1% | -3.4% | 3.8% |
| 23 | 3.1% | -2.0% | -1.2% | -1.6% | 5.0% |
| 24 | 2.7% | -2.9% | -6.5% | 0.4% | 6.4% |

**Table 5.4: Hourly Percentage Load Impacts, PG&E Customers dually enrolled in BIP, Non-summer Months**

| Hour | Greater Bay Area | Humboldt | Kern | All Other | Not in Any LCA |
|---|---|---|---|---|---|
| 1 | -5.5% | -0.1% | 1.1% | -0.5% | 3.5% |
| 2 | -3.9% | 4.1% | 3.5% | 1.7% | 1.1% |
| 3 | -4.6% | 3.3% | 2.0% | 1.2% | -0.4% |
| 4 | 0.1% | 4.6% | 7.3% | 0.9% | 0.4% |
| 5 | 1.5% | 3.5% | 14.9% | 0.7% | 1.3% |
| 6 | 0.1% | 4.0% | 13.8% | 1.7% | 0.5% |
| 7 | 0.7% | -1.1% | -7.3% | 1.4% | 3.9% |
| 8 | 0.2% | -2.2% | -0.8% | -0.8% | 1.6% |
| 9 | -1.2% | -1.1% | -1.1% | -1.9% | 1.1% |
| 10 | -2.2% | -0.8% | 0.9% | -0.1% | -0.8% |
| 11 | -3.1% | -0.7% | -1.6% | 0.2% | -2.3% |
| 12 | -4.7% | -0.9% | -2.3% | 5.5% | -3.0% |
| 13 | -4.7% | -0.9% | -2.3% | 5.5% | -3.0% |
| 14 | -4.7% | -0.9% | -2.3% | 5.5% | -3.0% |
| 15 | -1.6% | -2.5% | -1.7% | 6.6% | 0.0% |
| 16 | 0.6% | 5.1% | -0.3% | 5.8% | 15.4% |
| **17** | **11.0%** | **11.4%** | **19.1%** | **3.7%** | **39.1%** |
| **18** | **11.8%** | **11.8%** | **29.4%** | **1.8%** | **39.3%** |
| **19** | **11.1%** | **9.7%** | **29.4%** | **1.1%** | **40.8%** |
| **20** | **11.3%** | **10.7%** | **27.4%** | **2.0%** | **39.6%** |
| **21** | **1.3%** | **1.7%** | **13.4%** | **0.0%** | **14.8%** |
| 22 | -2.7% | -0.6% | -0.5% | -2.1% | 8.0% |
| 23 | 3.1% | -2.0% | -1.2% | -1.6% | 5.0% |
| 24 | 2.7% | -2.9% | -6.5% | 0.4% | 6.4% |

The process was somewhat different for SCE, for two reasons. First, SCE had eight DBP events (to PG&E's one). Therefore, we based the uncertainty-adjusted load impacts on the variation in load impacts across events (as opposed to the standard error of the estimates, as was done for PG&E). Second, SCE's events lasted from 12:00 to 8:00 p.m., so in transitioning from ex post to ex ante event windows, we needed to reduce the size of the event window (as opposed to expanding it for PG&E).

We collapsed the event hour percentage load impacts from eight hours to five hours as follows: the first and last hours of the ex post window were applied in the ex ante window. The second ex ante hour was set to the average of the second and third ex post hours; the third ex ante hour was set to the average of the fourth and fifth ex post hours; and the fourth ex ante hour was set to the average of the sixth and seventh ex post hours. We then adjusted the non-event hours load impacts to fit around the newly formed event windows.

Tables 5.5 through 5.8 show the hourly percentage load impacts by LCA for each season, with the first two tables containing results for the entire program (used in the program-level scenarios) and the final two tables containing results only for customers not dually enrolled in BIP (used in the portfolio-level scenarios).

**Table 5.5: Hourly Percentage Load Impacts, All SCE DBP Customers, Summer Months**

| Hour | LA Basin | Outside LA Basin | Ventura |
|---|---|---|---|
| 1 | 1.5% | 2.3% | 1.6% |
| 2 | 1.5% | 2.3% | 1.6% |
| 3 | 1.3% | 1.4% | 0.9% |
| 4 | 1.1% | 0.8% | 0.6% |
| 5 | 0.9% | 0.0% | 0.4% |
| 6 | 0.7% | -0.6% | 0.4% |
| 7 | 0.5% | -1.7% | 0.1% |
| 8 | 0.5% | -2.2% | -1.0% |
| 9 | 0.6% | -2.3% | -1.6% |
| 10 | 0.3% | -2.0% | -1.4% |
| 11 | 0.4% | -1.2% | -1.0% |
| 12 | 0.8% | -1.2% | -0.5% |
| 13 | 2.5% | 1.0% | 0.6% |
| **14** | **6.3%** | **4.0%** | **2.1%** |
| **15** | **6.1%** | **5.8%** | **2.8%** |
| **16** | **7.0%** | **8.3%** | **3.3%** |
| **17** | **7.4%** | **8.9%** | **3.3%** |
| **18** | **7.5%** | **8.3%** | **3.2%** |
| 19 | 5.7% | 5.7% | 2.5% |
| 20 | 4.6% | 4.5% | 2.0% |
| 21 | 4.0% | 2.6% | 1.9% |
| 22 | 3.2% | 2.1% | 1.0% |
| 23 | 1.5% | 2.3% | 1.6% |
| 24 | 1.3% | 1.4% | 0.9% |

**Table 5.6: Hourly Percentage Load Impacts, All SCE DBP Customers, Non-summer Months**

| Hour | LA Basin | Outside LA Basin | Ventura |
|---|---|---|---|
| 1 | 1.5% | 2.3% | 1.6% |
| 2 | 1.5% | 2.3% | 1.6% |
| 3 | 1.5% | 2.3% | 1.6% |
| 4 | 1.5% | 2.3% | 1.6% |
| 5 | 1.5% | 2.3% | 1.6% |
| 6 | 1.3% | 1.4% | 0.9% |
| 7 | 1.1% | 0.8% | 0.6% |
| 8 | 0.9% | 0.0% | 0.4% |
| 9 | 0.7% | -0.6% | 0.4% |
| 10 | 0.5% | -1.7% | 0.1% |
| 11 | 0.5% | -2.2% | -1.0% |
| 12 | 0.6% | -2.3% | -1.6% |
| 13 | 0.3% | -2.0% | -1.4% |
| 14 | 0.4% | -1.2% | -1.0% |
| 15 | 0.8% | -1.2% | -0.5% |
| 16 | 2.5% | 1.0% | 0.6% |
| **17** | **6.3%** | **4.0%** | **2.1%** |
| **18** | **6.1%** | **5.8%** | **2.8%** |
| **19** | **7.0%** | **8.3%** | **3.3%** |
| **20** | **7.4%** | **8.9%** | **3.3%** |
| **21** | **7.5%** | **8.3%** | **3.2%** |
| 22 | 5.7% | 5.7% | 2.5% |
| 23 | 4.6% | 4.5% | 2.0% |
| 24 | 4.0% | 2.6% | 1.9% |

**Table 5.7: Hourly Percentage Load Impacts, SCE DBP Customers not in BIP, Summer Months**

| Hour | LA Basin | Outside LA Basin | Ventura |
|---|---|---|---|
| 1 | 0.7% | 1.7% | 1.0% |
| 2 | 0.7% | 1.7% | 1.0% |
| 3 | 0.7% | 1.6% | 1.0% |
| 4 | 0.5% | 1.1% | 0.8% |
| 5 | 0.3% | 0.6% | 0.9% |
| 6 | 0.1% | 0.0% | 0.9% |
| 7 | 0.1% | -1.0% | 0.5% |
| 8 | -0.1% | -1.5% | -0.2% |
| 9 | 0.0% | -0.7% | -0.5% |
| 10 | -0.5% | -1.0% | -1.1% |
| 11 | -0.6% | -0.7% | -1.2% |
| 12 | -0.3% | -0.5% | -1.2% |
| 13 | 0.1% | -0.1% | -1.2% |
| **14** | **1.4%** | **1.3%** | **-0.5%** |
| **15** | **1.3%** | **2.6%** | **0.0%** |
| **16** | **1.9%** | **4.1%** | **0.8%** |
| **17** | **2.0%** | **4.6%** | **0.5%** |
| **18** | **1.9%** | **3.8%** | **0.3%** |
| 19 | 1.0% | 3.0% | 0.1% |
| 20 | 0.8% | 2.8% | 0.1% |
| 21 | 1.2% | 3.0% | 0.4% |
| 22 | 1.0% | 2.4% | 0.3% |
| 23 | 0.7% | 1.7% | 1.0% |
| 24 | 0.7% | 1.6% | 1.0% |

**Table 5.8: Hourly Percentage Load Impacts, SCE DBP Customers not in BIP, Non-summer Months**

| Hour | LA Basin | Outside LA Basin | Ventura |
|---|---|---|---|
| 1 | 0.7% | 1.7% | 1.0% |
| 2 | 0.7% | 1.7% | 1.0% |
| 3 | 0.7% | 1.7% | 1.0% |
| 4 | 0.7% | 1.7% | 1.0% |
| 5 | 0.7% | 1.7% | 1.0% |
| 6 | 0.7% | 1.6% | 1.0% |
| 7 | 0.5% | 1.1% | 0.8% |
| 8 | 0.3% | 0.6% | 0.9% |
| 9 | 0.1% | 0.0% | 0.9% |
| 10 | 0.1% | -1.0% | 0.5% |
| 11 | -0.1% | -1.5% | -0.2% |
| 12 | 0.0% | -0.7% | -0.5% |
| 13 | -0.5% | -1.0% | -1.1% |
| 14 | -0.6% | -0.7% | -1.2% |
| 15 | -0.3% | -0.5% | -1.2% |
| 16 | 0.1% | -0.1% | -1.2% |
| **17** | **1.4%** | **1.3%** | **-0.5%** |
| **18** | **1.3%** | **2.6%** | **0.0%** |
| **19** | **1.9%** | **4.1%** | **0.8%** |
| **20** | **2.0%** | **4.6%** | **0.5%** |
| **21** | **1.9%** | **3.8%** | **0.3%** |
| 22 | 1.0% | 3.0% | 0.1% |
| 23 | 0.8% | 2.8% | 0.1% |
| 24 | 1.2% | 3.0% | 0.4% |

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

*Apply forecast enrollments to produce program-level load impacts*. For PG&E, The Brattle Group produced load impacts at the program level, portfolio level, and by LCA by applying the database of per-customer load impacts created in the previous step to their enrollment forecasts. The per-customer reference loads and load impacts were first scaled to match the expected *size* of customers (measured as annual average usage) in the enrollment forecast and then multiplied by the number of enrolled customers to obtain cell-level results. Program-level results were obtained by aggregating results across cells. SCE provided with its own enrollment forecast, which is summarized in the next section.

### 5.3 Enrollment Forecasts

This section summarizes the enrollment forecasts, and resulting reference loads and ex ante load impact forecasts. Detailed tables of all results required by the Protocols are provided in associated appendices.

Because PG&E is proposing to close its DBP program at the end of 2012, enrollments are forecast through the end of that year. The Brattle Group forecasts enrollments to be 1,066 customers in 2011 and 1,162 in 2012.

SCE anticipates enrollment in DBP of 1,456 customers in 2011 and 1,529 customers in 2012. SCE forecasts DBP enrollments to increase substantially to 4,069 customers in 2013 and then decline to 3,200 customers in 2014, where enrollment remains for the duration of the forecast period. Two major changes in SCE's DBP enrollment occur in 2013. First, DBP is extended to include smaller customers (under 200 kW), which leads to the addition of 2,463 service accounts in 2013 and 2,586 service accounts in 2014. The reference loads and percentage load impacts for these customers are developed using information from the over 200 kW customers who are not dually enrolled in BIP, scaled to the appropriate load level. The DBP/BIP customers are excluded because they tend to be large and very demand responsive, which is a type of customer we do not expect to be present in the smaller customer groups.

The second change that occurs in 2013 is that service accounts will be removed from the program at the end of the program year if they did not receive a credit during any of the events. As a result, 912 service accounts are removed from the program at the end of the 2013 program year. The 2014 program year therefore includes 614 large service accounts, which includes the "participants" (i.e., service accounts who received a credit in the previous program year) and 80 new service accounts (5 percent of the previous year's total), which are assumed to have the same characteristics as the participants.

Enrollments for the portfolio-level analyses removed a fixed number of customers dually enrolled in BIP each year (because BIP enrollments are not forecast to change in the 2011-2021 period). The number of customers we removed from the DBP enrollment forecast was equal to the number of overlapping customers in the 2010 program year (i.e., we did not remove all of the forecast BIP customers because they are not all dually enrolled in DBP, and dual enrollments were not explicitly forecast).

## *5.4 Reference Loads and Load Impacts*

For each utility and program type, we provide the following summary information regarding the load impact forecasts, including the hourly profile of reference loads and load impacts for typical event days; the level of load impacts across years; and the distribution of load impacts by local capacity area.

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

### 5.4.1 PG&E

Figure 5.1 shows the program-level August 2011 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 70 MW, which represents approximately 8.1 percent of the enrolled reference load. Figure 5.2 shows the same load impacts at the portfolio (i.e., when all DR programs are simultaneously called). On average, the load impacts are reduced by 62 MW (relative to the program-level load impact) to 7.7 MW. The percentage load impact goes down to 1.2 percent. The large difference between program and portfolio load impacts is due to the contribution of customers dually enrolled in DBP and BIP. In the portfolio analysis (when a BIP event is 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 5.1: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2011, Program Level**

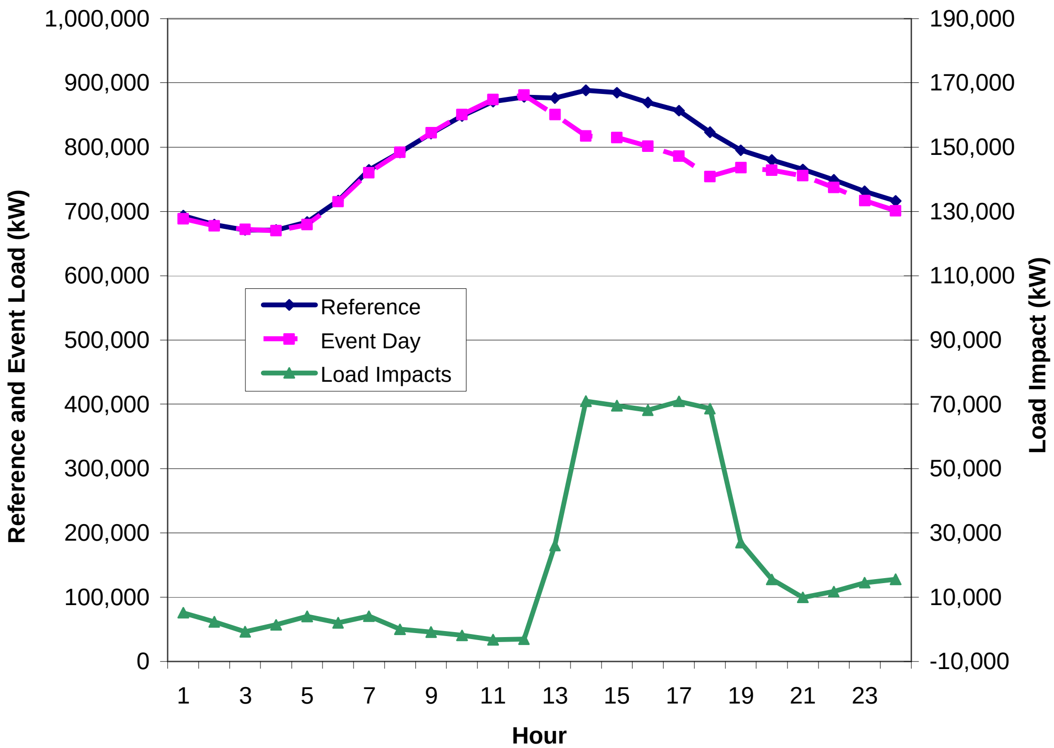


**Figure 5.2: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2011, Portfolio Level**

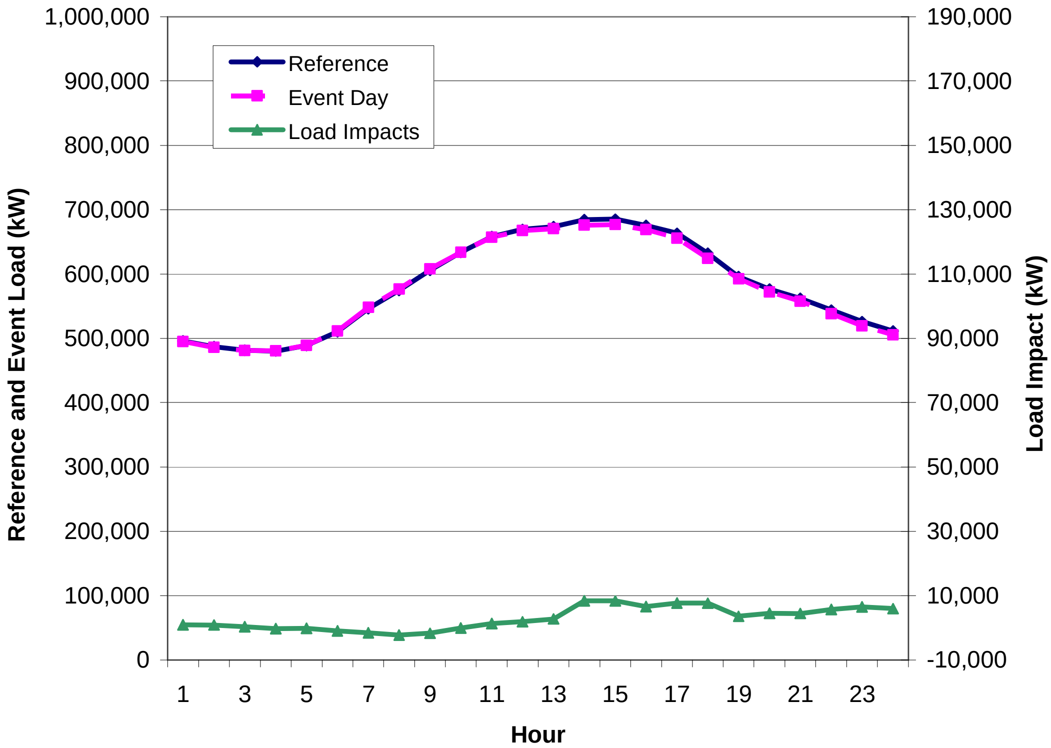



Figure 5.3 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2011 1-in-2 weather year. Customers not in any LCA account for the largest share, with 86 percent of the load impacts.

**Figure 5.3: Share of Load Impacts by LCA for the August 2012 Typical Event Day in a 1-in-2 Weather Year**

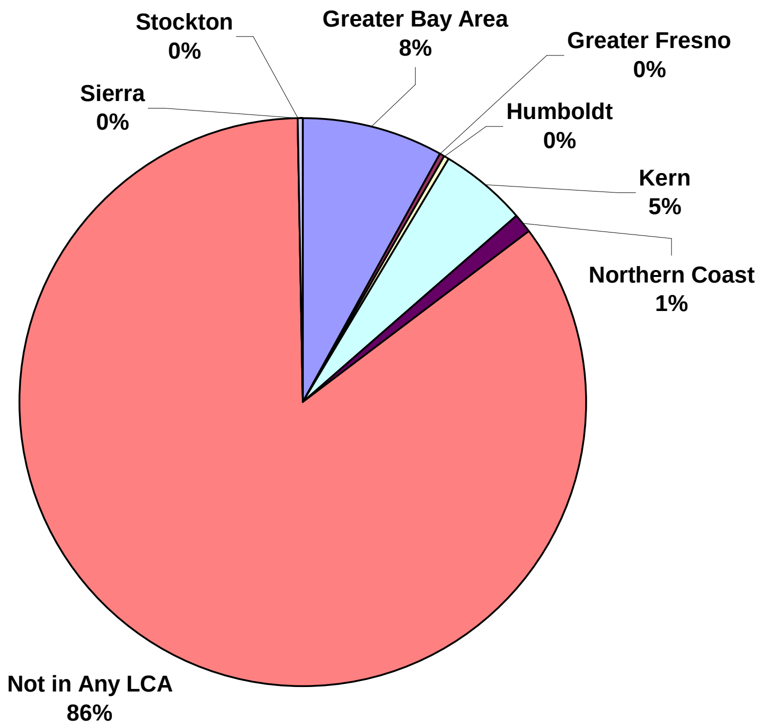
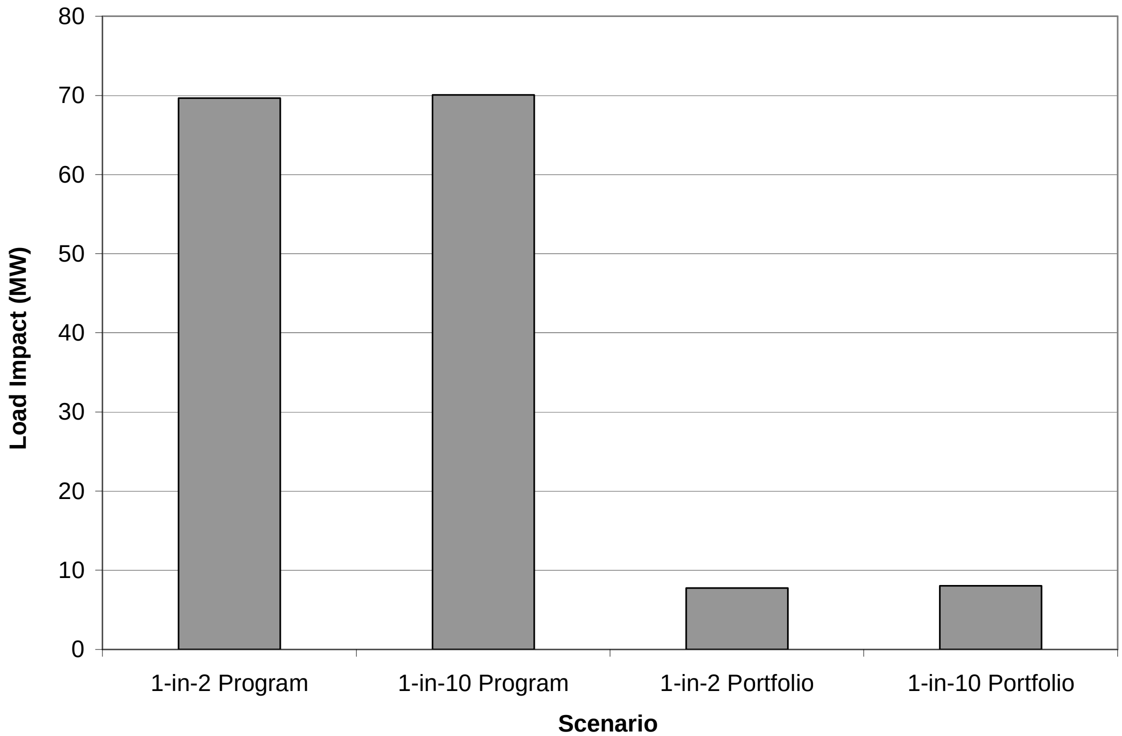



Figure 5.4 illustrates level of load impacts across the four key scenarios, differentiated by 1-in-2 versus 1-in-10 weather conditions, and portfolio- versus program-level load impacts. There is a very small difference in load impacts across weather scenarios, but the portfolio-level load impacts are much lower than the program-level load impacts (due to the removal of the customers dually enrolled in BIP).

**Figure 5.4: Average PG&E 2011 DBP Hourly Load Impacts by Scenario**




### 5.4.2 SCE

Figures 5.5 and 5.6 show the program-level forecast reference load and load impacts for a typical event day in a 1-in-2 and 1-in-10 weather years from 2014 through 2021 (the enrollment forecast is assumed to remain constant during this period of time).

The 1-in-2 typical event day load impacts average 86.9 MW across the event hours, or 8.7 percent of the reference load. The figures show only small differences across the two weather years, with load impacts increasing to an average of 89.2 MW in the 1-in-10 weather year.

Figure 5.7 shows the portfolio-level forecast for a typical event day in a 1-in-2 weather year from 2014 through 2021. This forecast differs from the program-level forecast by excluding customers who are dually enrolled in DBP and BIP. Because the dually enrolled customers are much more demand responsive than the non-BIP customers, the load impacts are much lower in the portfolio-based scenario. Event-hour load impacts average 17.8 MW (down from 86.9 MW in the corresponding program-level scenario), or 2.4 percent of reference load.

**Figure 5.5: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2014-2021, Program Level**

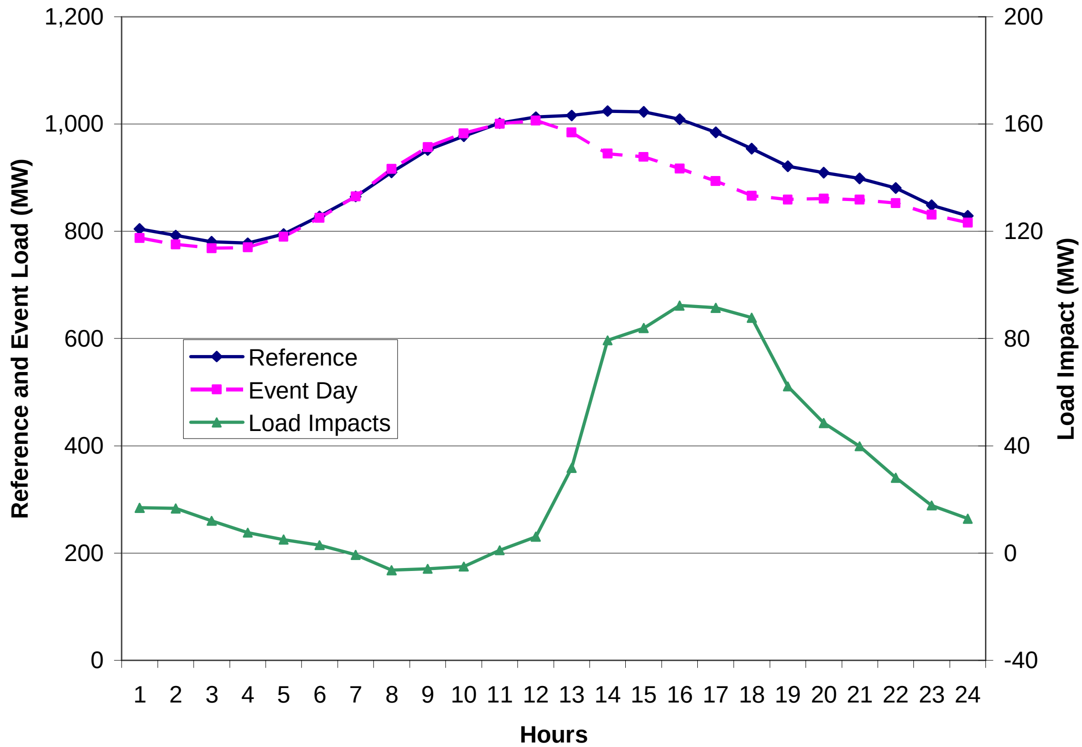



**Figure 5.6: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-10 Weather Year for August 2014-2021, Program Level**

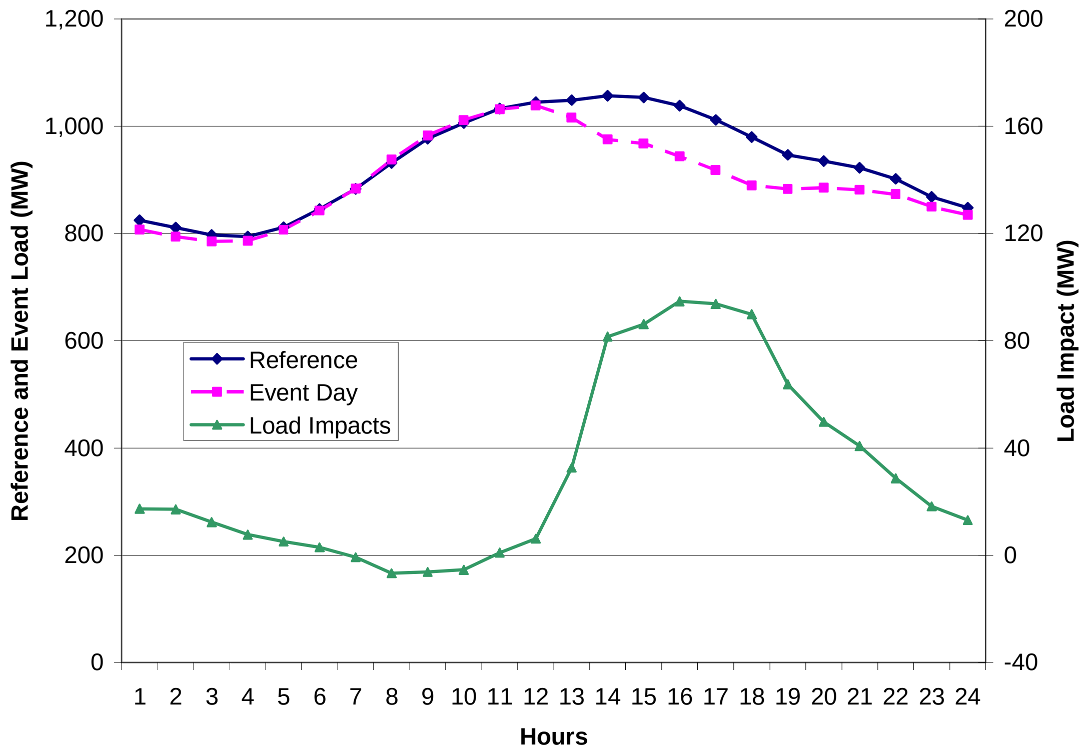


**Figure 5.7: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2014-2021, Portfolio Level**

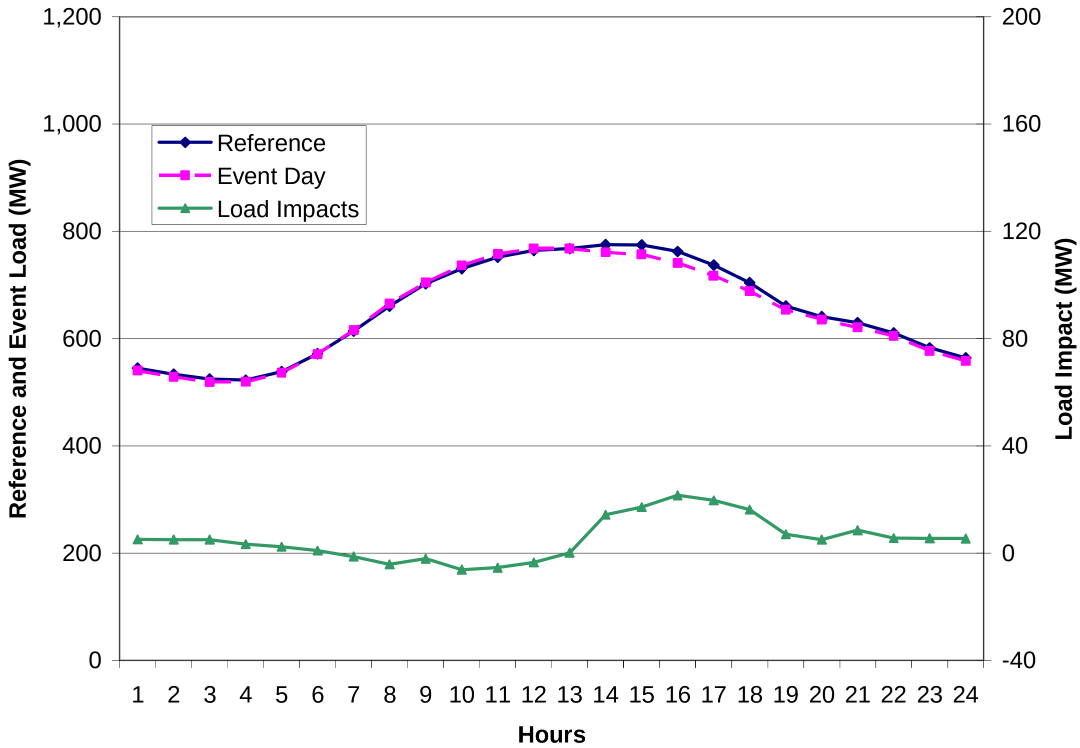



**Figure 5.8: Share of SCE DBP Load Impacts by Local Capacity Area**

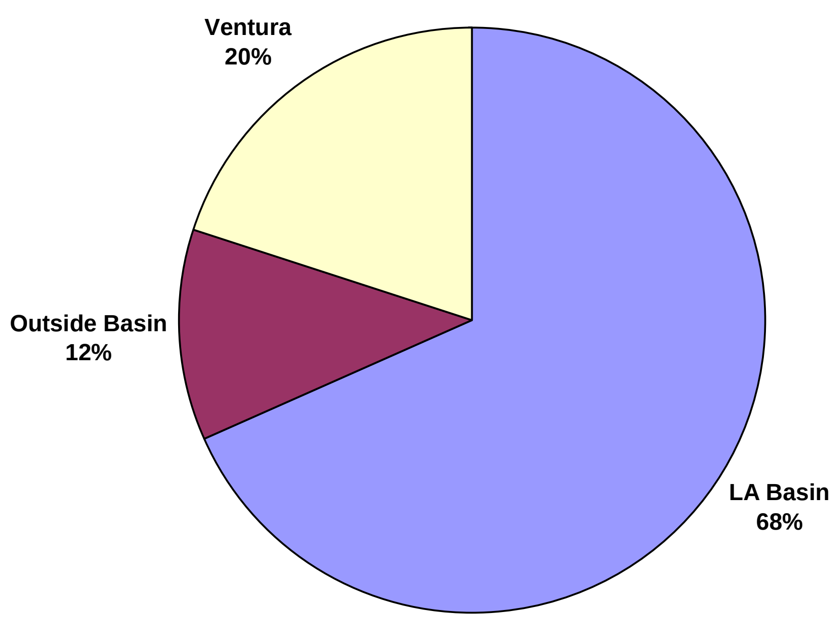
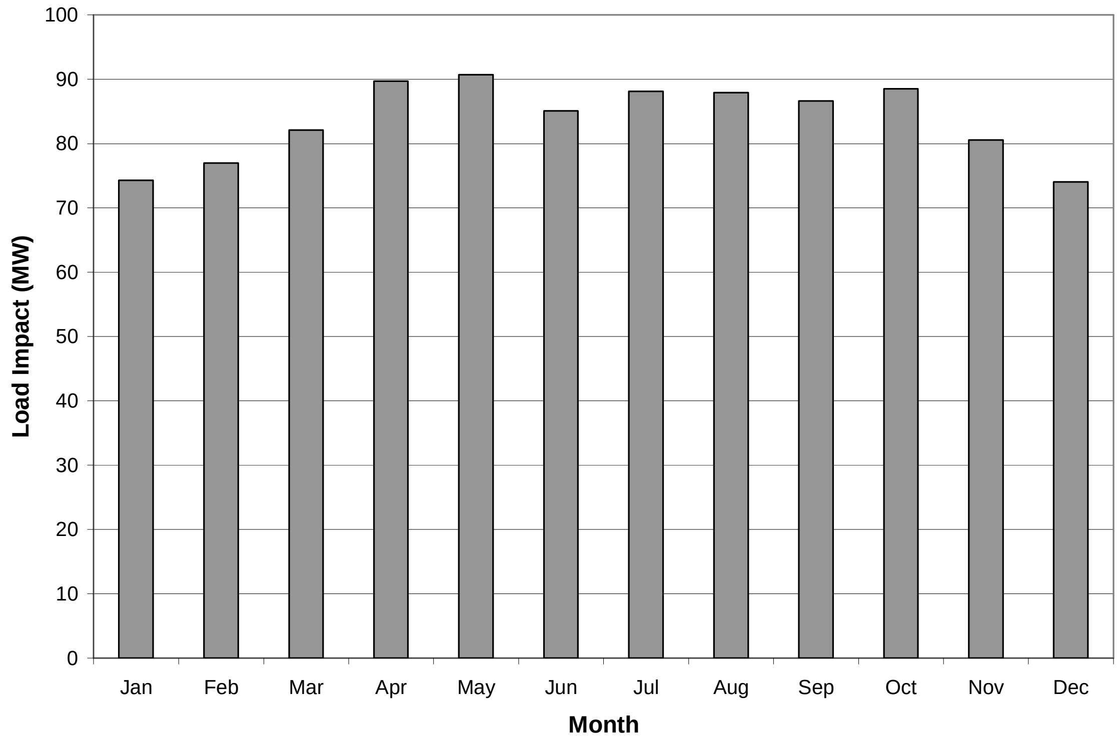



Figure 5.8 shows the distribution of program-level load impacts across local capacity areas. The LA Basin accounts for the largest share, with 68 percent of the total load impacts.

Figure 5.9 illustrates the average hourly program-level load impact across monthly system peak days of a 1-in-2 weather year, 2014-2021. Because we have not observed DBP event days in non-summer months, the percentage load impacts are constant across months. The level of the load impacts varies with the size of the reference loads.

**Figure 5.9: SCE Average Event-.Hour Load Impacts by Monthly System Peak Day in a 1-in-2 Weather Year from 2014-2021**




## 6. Validity Assessment

We estimated load impacts using service account-specific regression models. This method has some advantages relative to the aggregated models (*e.g.*, properly accounting for when each SAID submitted bids, and allowing the results to be summarized according to any observed customer characteristic without requiring the estimation of a new model). However, it does require estimation of many models and it is important to use a uniform model structure across all of the service accounts in a program.

Our primary concern with respect to the validity of the findings is regarding the appropriateness of the model specification that is used. We believe that the most significant issue in an ex post analysis of load impacts is the risk of omitted variable bias. That is, loads levels may change for reasons that cannot be easily known to the analyst, and consequentially those reasons cannot be captured in the econometric models. For example, it is not uncommon for manufacturing customers to shut down operations for one to two weeks. Such activity can bias the estimates for the other included variables if variables are not included to explicitly account for such a "shut down".

In order to minimize the potential for omitted variable bias, we screen the SAID-level models to determine whether the load impacts appear to be “real”. Because of time and resource constraints, we limit the screening to the models containing the largest estimated load impacts (positive and negative). For these service accounts, we extract the observed loads for each week in which an event day occurred. We then graph the daily loads for each event week. This provides an informal day-matching method for confirming the estimated customer load impacts. For cases in which this visual examination provides a clear confirmation that the estimation model does not properly capture the SAID’s regular usage patterns and that the customer does not appear to change its behavior because of DBP event days, we zero out the estimated load impact. In a couple of cases, we found that load impacts using PG&E's 10-in-10 program baseline values better reflected the load impacts we observe from the day-matching method, so we used those values. Otherwise, we retain the estimates for the higher level summaries of load impacts.

## 7. Recommendations

In its 2012-2014 DR Portfolio Application, PG&E proposes to transition DBP customers to the Best Efforts, Day Ahead portion of its PeakChoice Program beginning in 2012, and close DBP by December 31, 2012. As the ex post load impacts in this study have shown, the percentage load impacts from PG&E's DBP customers are high (~30 percent) for those dually enrolled in the Base Interruptible Program (BIP) and low (~1 percent) for those who are not. PG&E plans to modify its PeakChoice program to allow for dual enrollment in the Best Efforts program and BIP. We recommend that PG&E remain aware that future load impacts on PeakChoice may substantially increase in size and variability depending upon which DBP customers choose to migrate.

## Appendices

The following Appendices accompany this report. Each is an Excel file that can produce the ex post and ex ante tables required by the Protocols.

| | |
|---|---|
| DBP Study Appendix A PG&E | Ex-Post Load Impact Tables |
| DBP Study Appendix B SCE | Ex-Post Load Impact Tables |
| DBP Study Appendix C PG&E | Ex-Ante Load Impact Tables |
| DBP Study Appendix D SCE | Ex-Ante Load Impact Tables |