2011 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post Report

CALMAC Study ID SDG0253

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

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

Voice 608.231.2266 Fax 608.231.2108

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Abstract
This report documents an ex post 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 2011 program year at PG&E and SCE.

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 two four-hour test events on September 8th and September 22nd. SCE called five DBP events in 2011, all lasting from noon to 8 p.m.

Enrollment in PG&E's DBP was 1,039 service accounts in 2011. The sum of enrolled customers' non-coincident maximum demands was 1,099 MW. Enrollment in SCE's DBP was 1,416 service accounts in 2011. The sum of enrolled customers' non-coincident maximum demands was 1,370 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 across the customer-level models.

The total program load impact for PG&E's test events averaged 57 MW, or 7.0 percent of enrolled load. The load impacts differed somewhat across the two event days, with a 67 MW load impact on the first test event and a 47 MW load impact for the second test event.

For SCE, average hourly program load impacts averaged approximately 78 MW across four events, or 7.6 percent of the total reference load. The event-specific load impacts ranged from a low of 70 MW to a high of 89.5 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, the TA/TI service account provided 122 kW of load impacts and AutoDR service accounts provided 16.8 MW. For SCE, TA/TI service accounts provided 6.4 MW of load impacts and AutoDR service accounts provided 13.2 MW.

Executive Summary

This report documents ex post 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 2011. (San Diego Gas and Electric Company discontinued its program in 2009.) The report provides estimates of ex post load impacts that occurred during events called in 2011. A follow-up report will include an ex ante forecast of load impacts for 2012 through 2022 (2012 only for PG&E) that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2009 through 2011.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2011?
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?

ES.1 Resources covered

DBP Program

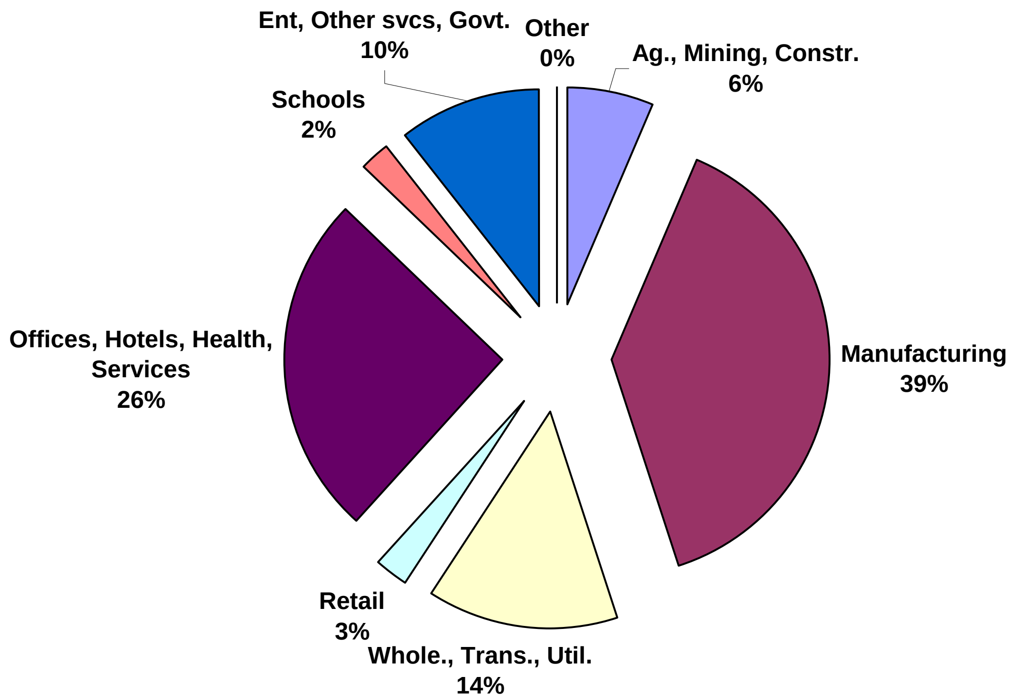
DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing power when a DBP event is triggered. First approved in CPUC D.01-07-025, modifications have been made to the program, including changes made for the 2006-2008 program cycle at the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

PG&E called two test events in 2011, on September 8th and 22nd. The event window for both events was hours ending 15 through 18. SCE called five events, all of which were eight-hour events from hours-ending 13 through 20.

Enrollment

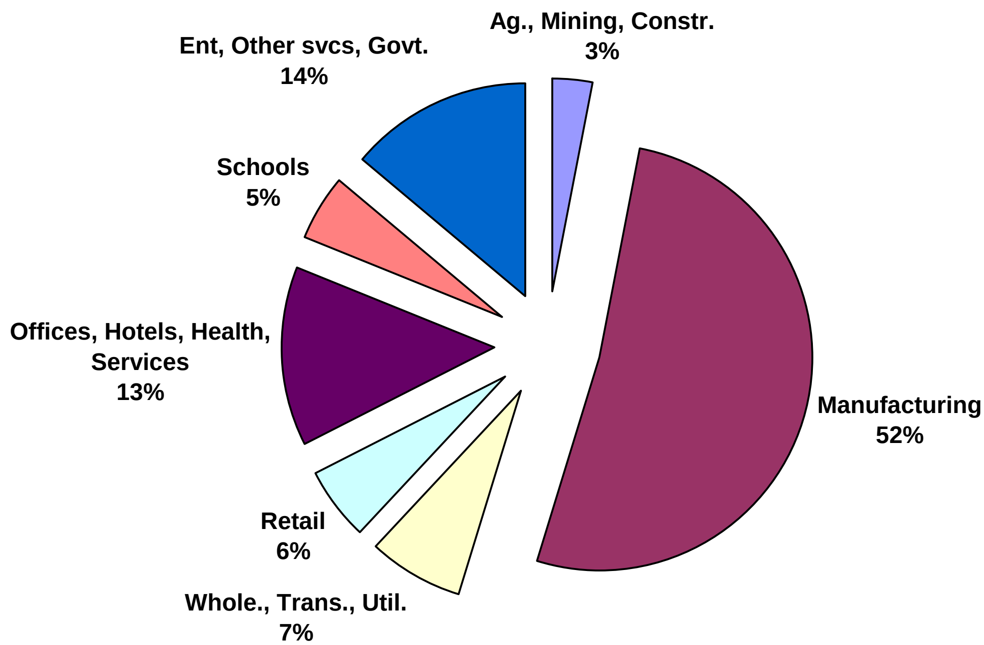
Enrollment in PG&E's DBP decreased slightly between the last two program years, from 1,052 in 2010 to 1,039 in 2011. The sum of enrolled customers' non-coincident maximum demands amounted to 1,099 MW, or 1.1 MW per service account. Average hourly usage for enrolled customers was 725 MW, or 698 kW per service account. The manufacturing; and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment. Figure ES.1 illustrates the distribution of DBP load across the indicated industry types.

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



SCE's enrollment in DBP decreased slightly from 1,421 service accounts in 2010 to 1,416 in 2011. These accounted for a total of 1,370 MW of maximum demand, or 1.0 MW per service account. Manufacturers continued to make up more than half of the enrolled load. Figure ES.2 illustrates the distribution of SCE's DBP load across the indicated industry types.

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



Bidding Behavior

As in previous years, a relatively small percentage of the customer accounts enrolled in DBP actually submitted bids for most events. For PG&E, 97 service accounts, representing approximately 22 percent of the enrolled load, submitted a bid for at least one of the test events. At SCE, 356 service accounts, representing 60 percent of the enrolled load, submitted at least one bid during 2011.

ES.2 Evaluation Methodology

We estimated ex post load impacts using regression analysis of customer-level hourly load data. Individual-customer regression equations modeled hourly load as a function of several variables designed to control for factors affecting consumers' hourly demand levels, including:

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

DBP load impacts for each event were obtained by summing the estimated hourly event coefficients from the customer-level regressions. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, by aggregating customer load impacts for the relevant industry group or local capacity area.

ES.3 Ex Post Load Impacts

The total program load impact for PG&E's test events averaged 57 MW, with a 67 MW load reduction (8.3 percent of enrolled load) for the first event, and 47 MW (5.6 percent of enrolled load) for the second event. Of the average 57 MW load impact across the two events, 45 MW came from customers enrolled in both DBP and BIP.

For SCE, average hourly program load impacts averaged approximately 78 MW across four events.[1] The load impacts across the four event days ranged from a low of 70 MW to a high of 89.5 MW. On average, the load impacts were approximately 7.6 percent of the total reference load.

On a summary level, the average per-customer event-hour load impact was 55 kW for PG&E's program and 57 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.

Our goal was to estimate both *total* and *incremental* load impacts for TA/TI and AutoDR. Total load impacts are simply the sum of the estimated load impacts for the TA/TI and AutoDR customers, as estimated using the methods described in Section ES.2. *Incremental* load impacts are 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.

Given data limitations, we were unable to estimate reliable incremental load impacts. Specifically, we developed comparison groups according to industry classifications (SIC codes for SCE and NAICS codes for PG&E). Our findings revealed that the industry-level comparisons are based on too few customers to produce reliable results.

In addition, we lack sufficient information on the comparison and "treatment" (AutoDR or TA/TI) customers to ensure that the comparison is valid. Specifically, we do not know relevant information about the comparison group customers, such as details regarding their technological processes (and hence their ability to reduce load during event hours) or whether they possess enabling technology.

The total load estimated load impacts are summarized as follows. For PG&E, the TA/TI service account provided 122 kW of load impacts and AutoDR service accounts provided 16.8 MW. For SCE, TA/TI service accounts provided 6.4 MW of load impacts and AutoDR service accounts provided 13.2 MW.

[1] A fifth event was called for October 13th, but this date fell outside of our analysis timeframe.

1. Introduction and Purpose of the Study

This report documents ex post 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 2011. (San Diego Gas and Electric Company discontinued its program in 2009.) The report provides estimates of ex post load impacts that occurred during events called in 2011. A follow-up report will include an ex ante forecast of load impacts for 2012 through 2022 (2012 only for PG&E) that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2009 through 2011.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2011?
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?

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 contains an assessment of the validity of the study; and Section 6 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 2011.

2.1 Program Descriptions

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

PG&E'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 200 kW or greater for at least one or more of the past 12 billing months within each aggregated group that will be designated as the primary service agreement for the aggregated group.

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

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

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

SCE's 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 BIP or OBMC. 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:[2]

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

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

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows DBP enrollment by industry group for PG&E. Enrollment in PG&E's DBP decreased slightly between the last two program years, from 1,052 in 2010 to 1,039 in 2011.[4] The sum of enrolled customers' non-coincident maximum demands[5], amounted to 1,099 MW, or 1.1 MW for the average service account. Average hourly usage for enrolled customers was 725 MW, or 698 kW 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.

[2] 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.

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

[4] "Enrollment" is defined as having been enrolled at any time during the program year.

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

[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 2.1: DBP Enrollees by Industry group – *PG&E*

Industry Type	# of Service Accounts	Sum of Max MW[7]	Sum of Mean MWh[8]	% of Max MW	Ave. Max MW[9]
1.Ag., Mining, Constr.	106	70.8	35.6	6.4%	0.7
2.Manufacturing	216	423.1	304.6	38.5%	2.0
3.Whole., Trans., Util.	153	155.9	78.2	14.2%	1.0
4.Retail	133	28.7	16.3	2.6%	0.2
5.Offices, Hotels, Health, Services	270	281.3	201.5	25.6%	1.0
6.Schools	37	23.7	12.1	2.2%	0.6
7.Ent, Other svcs, Govt.	122	114.7	75.8	10.4%	0.9
8.Other	2	10	0.7	0.1%	0.5
TOTAL	**1,039**	**1,099.0**	**724.8**		**1.1**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP decreased slightly from 1,421 service accounts in 2010 to 1,416 in 2011. These accounted for a total of 1,370 MW of maximum demand, or 1.0 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	# of Service Accounts	Sum of Max MW	Sum of Mean MWh	% of Max MW	Ave. Max MW
1.Ag., Mining, Constr.	31	43.5	25.6	3.2%	1.4
2.Manufacturing	343	707.1	485.0	51.6%	2.1
3.Whole., Trans., Util.	161	99.6	57.3	7.3%	0.6
4.Retail	214	76.4	47.3	5.6%	0.4
5.Offices, Hotels, Health, Services	240	183.3	109.7	13.4%	0.8
6.Schools	321	69.7	20.5	5.1%	0.2
7.Ent, Other svcs, Govt.	106	190.3	120.3	13.9%	1.8
TOTAL	**1,416**	**1,369.8**	**865.8**		**1.0**

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

[7] "Sum of Max MW" is defined as the sum of the non-coincident peak demands across service accounts, where each service account's peak demand is calculated as the average of the five monthly peak demand values from May through September.
[8] "Sum of Avg. MWh" is defined as the sum of the average hourly usage values across service accounts. Each service account's average usage is calculated across all hours from May through September.
[9] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts".

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	Sum of Mean MWh	% of Max MW	Ave. Max MW
Greater Bay Area	483	465.6	335.0	42.4%	1.0
Greater Fresno	55	46.7	29.8	4.2%	0.8
Humboldt	13	3.8	2.1	0.3%	0.3
Kern	53	38.0	22.0	3.5%	0.7
Northern Coast	74	45.8	25.7	4.2%	0.6
Not in any LCA	287	471.6	295.8	42.9%	1.6
Sierra	48	19.8	10.2	1.8%	0.4
Stockton	26	7.8	4.2	0.7%	0.3
TOTAL	**1,039**	**1,099.0**	**724.8**		**1.1**

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	Sum of Mean MWh	% of Max MW	Ave. Max MW
LA Basin	1,110	906.1	562.5	66.1%	0.8
Outside LA Basin	67	184.2	120.5	13.4%	2.7
Ventura	239	279.5	182.8	20.4%	1.2
TOTAL	**1,416**	**1,369.8**	**865.8**		**1.0**

Tables 2.5 and 2.6 summarize the characteristics of customer accounts that submitted a bid for at least one 2011 event for PG&E and SCE respectively. For both utilities, the manufacturing industry group had the highest amount of load that submitted a bid.

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

Industry Type	# Bidders	Sum of Max MW	% of Enrolled Max MW[10]	Avg. Hourly Bid MW
1.Ag., Mining, Constr.	4	9.6	21.3%	0.6
2.Manufacturing	24	127.4	18.0%	49.5
3.Whole., Trans., Util.	25	54.6	50.6%	13.6
4.Retail	15	10.7	15.0%	3.1
5.Offices, Hotels, Health, Services	16	52.2	28.8%	1.9
6.Schools	2	2.9	4.1%	0.3
7. Ent, Other svcs, Govt.	11	48.9	25.7%	3.6
TOTAL	**97**	**306.3**	**22.3%**	**72.6**

[10] "% of Enrolled Max kW" is defined as the "Sum of Max kW" for bidders divided by the corresponding value for all enrolled customers, where the calculation is performed by industry group.

Table 2.6: DBP Bidding Behavior – *SCE*

Industry Type	# Bidders	Sum of Max MW	% of Enrolled Max MW	Avg. Hourly Bid MW
1.Ag., Mining, Constr.	14	24.3	55.9%	7.1
2.Manufacturing	139	450.3	63.7%	113.5
3.Whole., Trans., Util.	52	67.7	68.0%	10.6
4.Retail	24	43.7	57.2%	4.0
5.Offices, Hotels, Health, Services	84	97.3	53.1%	7.5
6.Schools	23	30.5	43.8%	1.7
7. Ent, Other svcs, Govt.	20	107.6	56.5%	2.5
TOTAL	**356**	**821.4**	**60.0%**	**146.9**

2.3 Event Days

Table 2.7 lists DBP event days for the two utilities in 2011. PG&E called two test events, on September 8th and 22nd. The event window for both events was hours ending 15 through 18. SCE called five events, all of which were eight-hour events from hours-ending 13 through 20.

Table 2.7: DBP Events – 2011

Date	Day of Week	SCE	PG&E
7/5/2011	Tuesday	1	
8/26/2011	Friday	2	
9/7/2011	Wednesday	3	
9/8/2011	Thursday	4	1 (Test)
9/22/2011	Thursday		2 (Test)
10/13/2011	Thursday	5	

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 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[11]

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;[12] 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)[13], which is interacted with the weather and hourly profile variables; and e_t is the error term. The "morning load" variable was used in

[11] 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.

[12] 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.

[13] 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 reflect changes in usage patterns and weather response that differ during the analysis timeframe for many customers, even those that are not schools.

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).

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 55 kW for PG&E's program and 53 kW for SCE's program.

4.1 PG&E Load Impacts

4.1.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.1 summarizes average hourly reference loads and load impacts at the program level for each of PG&E's two DBP events. The average hourly load impact across both events was 57 MW. The average load impact on the first event day was 20 MW higher than the load impact on the second event day. On average, the load impacts were 7.0 percent of the total reference load.

Table 4.1: 2011 Average Hourly Load Impacts by Event, *PG&E*

Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1	9/8/2011	Thursday	810	742	67	8.3%
2	9/22/2011	Thursday	825	779	47	5.6%
		Average	**818**	**761**	**57**	**7.0%**
		Std. Dev.	**11**	**26**	**15**	**1.8%**

Table 4.2 compares the bid quantities to the estimated load impacts for each event. Across both events, the bid amount averaged approximately 57.6 MW, while the estimated average hourly load impact was 56.9 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 99 percent.

Table 4.2: 2011 Average Hourly Bid Realization Rates by Event*, PG&E*

Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
1	9/8/2011	Thursday	64.7	67.2	104%
2	9/22/2011	Thursday	50.5	46.5	92%
		Average	**57.6**	**56.9**	**99%**

Table 4.3 summarizes average hourly DBP load impacts at the program level (i.e., including both bidders and non-bidders) and by industry group for each of PG&E's event days. Across all event hours, the average hourly load impact was 57 MW, or 7.0 percent of enrolled load. The Manufacturing industry group accounted for the largest share of the load impacts.

Table 4.3: 2011 Average Hourly Load Impacts – PG&E DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	105.5	36.9	35.9	1.0	2.7%
Manufacturing	216	326.6	294.8	31.8	9.7%
Wholesale, Transportation, & Other Utilities	153	73.2	55.2	18.0	24.6%
Retail Stores	133	22.8	20.9	1.9	8.5%
Offices, Hotels, Health, Services	270	246.2	245.4	0.8	0.3%
Schools	37	18.8	19.4	-0.5	-2.7%
Entertainment, Other Services, Government	122	92.2	88.5	3.7	4.0%
Other or Unknown	2	0.8	0.7	0.1	8.6%
Total	**1,039**	**817.6**	**760.7**	**56.9**	**7.0%**

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

Table 4.4: 2011 Average Hourly Load Impacts – PG&E DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	483	395.2	390.1	5.1	1.3%
Greater Fresno	55	34.9	32.5	2.4	6.8%
Humboldt	13	2.1	1.3	0.8	39.3%
Kern	53	22.6	18.9	3.8	16.7%
Northern Coast	74	31.2	31.3	-0.2	-0.5%
Sierra	48	12.0	11.4	0.6	4.7%
Stockton	26	4.9	5.1	-0.2	-3.6%
Not in any LCA	287	314.7	270.1	44.6	14.2%
Total	**1,039**	**817.6**	**760.7**	**56.9**	**7.0%**

4.1.2 Hourly Load Impacts

Table 4.5 presents hourly PG&E DBP load impacts at the program level in the manner required by the Protocols. DBP load impacts were estimated from the individual customer regressions for customers enrolled at the time of either event. Hourly load impacts average 57 MW, which represents approximately 7.0 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. During the first event, approximately 49.5 of the 67 MW total load impact comes from the DBP/BIP-overlap customers. During the second event, approximately 40 of the 47 MW total load impact comes from the dually enrolled customers.

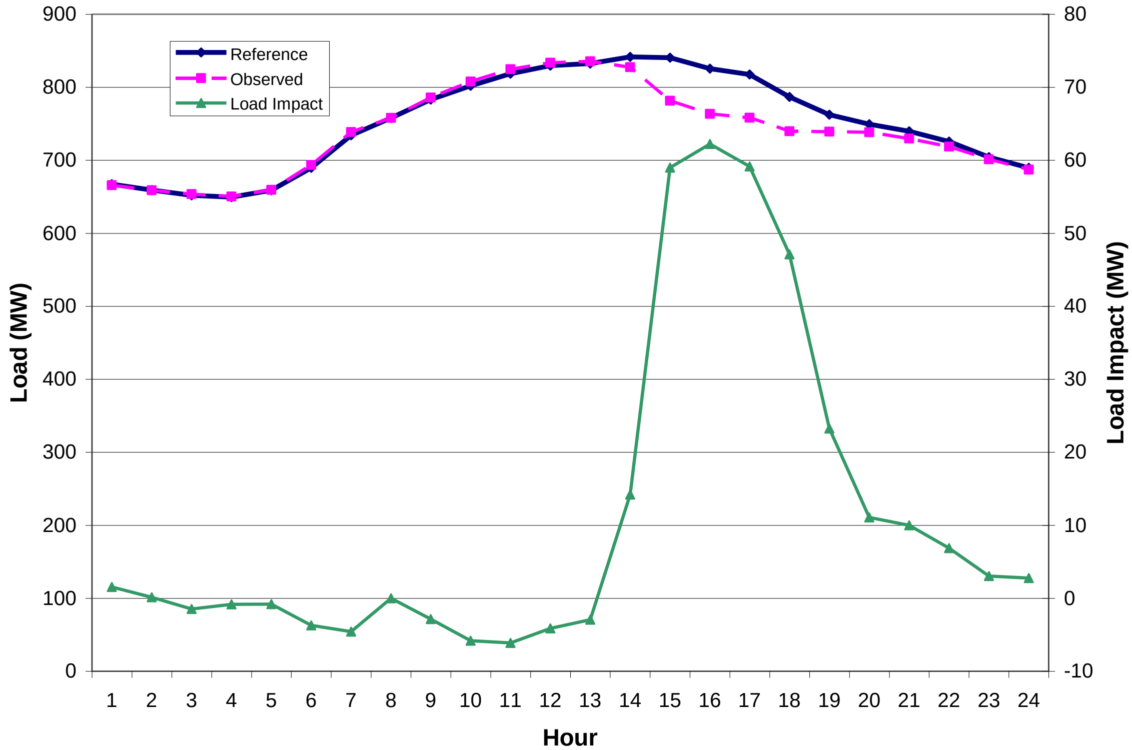
Table 4.5: DBP Hourly Load Impacts for the Average Event Day – *PG&E*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	667.2	665.7	1.5	66	-7.3	-2.1	1.5	5.2	10.4
2	659.1	658.9	0.1	65	-8.7	-3.5	0.1	3.7	9.0
3	652.0	653.5	-1.5	63	-10.3	-5.1	-1.5	2.1	7.3
4	649.6	650.4	-0.8	62	-9.7	-4.4	-0.8	2.8	8.0
5	658.7	659.6	-0.8	61	-9.6	-4.4	-0.8	2.8	8.0
6	689.7	693.4	-3.7	61	-12.5	-7.3	-3.7	-0.1	5.1
7	734.1	738.7	-4.6	60	-13.4	-8.2	-4.6	-1.0	4.2
8	758.0	758.0	0.0	60	-8.8	-3.6	0.0	3.6	8.8
9	783.1	786.0	-2.9	63	-11.7	-6.5	-2.9	0.7	5.9
10	802.1	807.9	-5.8	66	-14.6	-9.4	-5.8	-2.2	3.0
11	818.6	824.8	-6.1	70	-14.9	-9.7	-6.1	-2.5	2.7
12	829.6	833.7	-4.1	74	-12.9	-7.7	-4.1	-0.5	4.7
13	832.6	835.5	-2.9	77	-11.8	-6.5	-2.9	0.7	5.9
14	841.7	827.5	14.2	80	5.4	10.6	14.2	17.8	23.0
15	840.4	781.4	59.0	82	50.2	55.4	59.0	62.6	67.8
16	825.6	763.4	62.2	84	53.4	58.6	62.2	65.8	71.0
17	817.5	758.4	59.1	84	50.3	55.5	59.1	62.8	68.0
18	786.7	739.6	47.1	82	38.3	43.5	47.1	50.7	55.9
19	762.4	739.2	23.3	79	14.4	19.6	23.3	26.9	32.1
20	749.5	738.4	11.1	74	2.3	7.5	11.1	14.7	19.9
21	739.7	729.7	10.0	71	1.2	6.4	10.0	13.6	18.8
22	725.5	718.6	6.9	69	-2.0	3.3	6.9	10.5	15.7
23	704.3	701.2	3.1	68	-5.8	-0.6	3.1	6.7	11.9
24	689.7	687.0	2.8	67	-6.1	-0.9	2.8	6.4	11.6
	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	18,018	17,751	267	33.9	n/a	n/a	n/a	n/a	n/a

The top portion of Figure 4.1 illustrates the reference load 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: 2011 DBP Load Impacts – *PG&E*



4.2 SCE Load Impacts

4.2.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.6 summarizes average hourly reference loads and load impacts at the program level for each of SCE's four DBP events.[14] Across all events, the average hourly load impact was approximately 78 MW. The load impacts showed little variation across event days, with a low of 70 MW, a high of 89.5 MW, and a standard deviation of 8 MW. On average, the load impacts were 7.6 percent of the total reference load.

Table 4.6: 2011 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	7/5/2011	Tuesday	939.0	865.0	74.0	7.9%
2	8/26/2011	Friday	1,036.0	965.7	70.3	6.8%
3	9/7/2011	Wednesday	1,069.0	992.3	76.8	7.2%
4	9/8/2011	Thursday	1,051.5	962.0	89.5	8.5%
		Average	**1,023.9**	**946.2**	**77.7**	**7.6%**
		Std. Dev.	**58.2**	**55.8**	**8.3**	**0.8%**

[14] A fifth event day was called on October 13, 2011, but this date falls outside of our analysis timeframe, which ends on September 30, 2011.

Table 4.7 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 129.1 MW, while the estimated average hourly load impact was 77.7 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 60 percent.

Table 4.7: 2011 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	7/5/2011	Tuesday	134.2	74.0	55%
2	8/26/2011	Friday	111.7	70.3	63%
3	9/7/2011	Wednesday	132.1	76.8	58%
4	9/8/2011	Thursday	138.5	89.5	65%
		Average	**129.1**	**77.7**	**60%**

Tables 4.8 and 4.9 summarize average hourly load impacts for the average event by industry group and LCA. Manufacturing service accounts accounted for the largest share of the load impacts. By region, the highest share of the average load impact came from the LA Basin.

Table 4.8: 2011 Average Hourly Load Impacts – SCE DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	29	27.2	24.4	2.9	10.5%
Manufacturing	333	532.9	472.1	60.8	11.4%
Wholesale, Transportation, & Other Utilities	155	59.5	51.5	8.0	13.5%
Retail Stores	202	60.1	58.1	2.0	3.4%
Offices, Hotels, Health, Services	231	145.5	144.4	1.1	0.7%
Schools	300	39.5	38.1	1.4	3.4%
Entertainment, Other Services, Government	104	159.2	157.7	1.5	1.0%
Total	**1,354**	**1,023.9**	**946.2**	**77.7**	**7.6%**

Table 4.9: 2011 Average Hourly Load Impacts – SCE DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin	1,059	673.0	620.5	52.5	7.8%
Outside LA Basin	64	137.3	122.9	14.4	10.5%
Ventura	230	213.5	202.8	10.7	5.0%
Total	**1,354**	**1,023.9**	**946.2**	**77.7**	**7.6%**

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts at the program level for the average DBP event in the manner required by the Protocols. Hourly load impacts for the average event range from 65 MW to 84 MW. These load impacts represent 7.6 percent of the total enrolled DBP reference load.

Table 4.10: 2011 DBP Hourly Load Impacts for the Average Event Day, *SCE*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (^oF)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	812.2	794.0	18.2	76	4.9	12.7	18.2	23.6	31.5
2	800.7	785.1	15.6	75	2.3	10.2	15.6	21.1	29.0
3	789.9	776.0	13.9	74	0.5	8.4	13.9	19.3	27.2
4	790.5	778.6	11.9	73	-1.4	6.4	11.9	17.4	25.3
5	810.0	800.0	10.0	72	-3.3	4.6	10.0	15.5	23.4
6	855.4	846.3	9.1	71	-4.3	3.6	9.1	14.6	22.5
7	905.2	900.1	5.1	70	-8.2	-0.3	5.1	10.6	18.5
8	951.6	957.0	-5.4	70	-18.7	-10.9	-5.4	0.1	8.0
9	999.9	1,013.9	-14.0	72	-27.4	-19.5	-14.0	-8.6	-0.7
10	1,034.0	1,042.4	-8.4	76	-21.8	-13.9	-8.4	-3.0	4.9
11	1,065.6	1,066.1	-0.5	80	-13.8	-5.9	-0.5	5.0	12.9
12	1,079.4	1,047.7	31.6	83	18.3	26.2	31.6	37.1	45.0
13	1,078.2	1,004.2	74.0	86	60.7	68.6	74.0	79.5	87.3
14	1,083.3	1,006.5	76.8	88	63.5	71.4	76.8	82.3	90.1
15	1,078.0	998.3	79.7	89	66.4	74.3	79.7	85.1	93.0
16	1,052.8	971.8	81.0	90	67.6	75.5	81.0	86.4	94.3
17	1,023.3	941.0	82.4	89	69.1	77.0	82.4	87.8	95.7
18	991.1	907.5	83.6	89	70.3	78.2	83.6	89.0	96.9
19	951.2	872.7	78.5	88	65.2	73.0	78.5	83.9	91.8
20	933.3	868.0	65.2	85	51.9	59.8	65.2	70.7	78.6
21	918.2	874.9	43.3	82	30.0	37.9	43.3	48.8	56.7
22	891.1	865.1	25.9	79	12.6	20.5	25.9	31.4	39.2
23	856.4	829.8	26.5	77	13.2	21.1	26.5	32.0	39.8
24	833.5	813.8	19.7	76	6.3	14.2	19.7	25.1	33.0
	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	22,585	21,761	824	132.2	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. The load impacts were quite consistent across events, particularly when compared to SCE's load impacts from the previous program year.

Figure 4.2: 2011 DBP Load Impacts – *SCE*

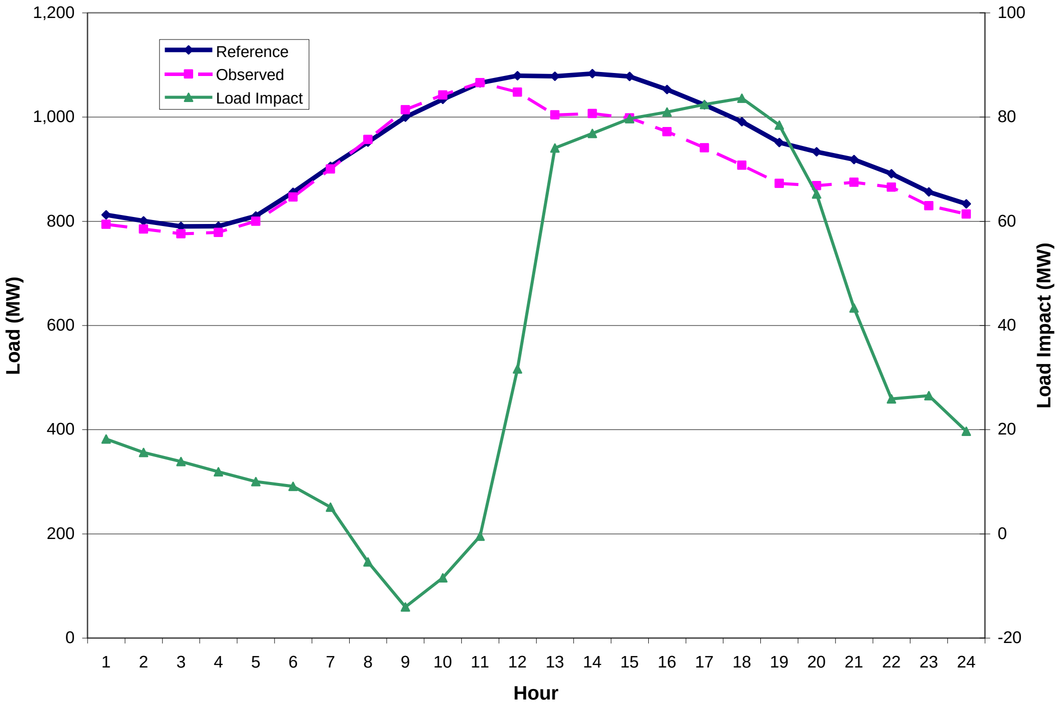
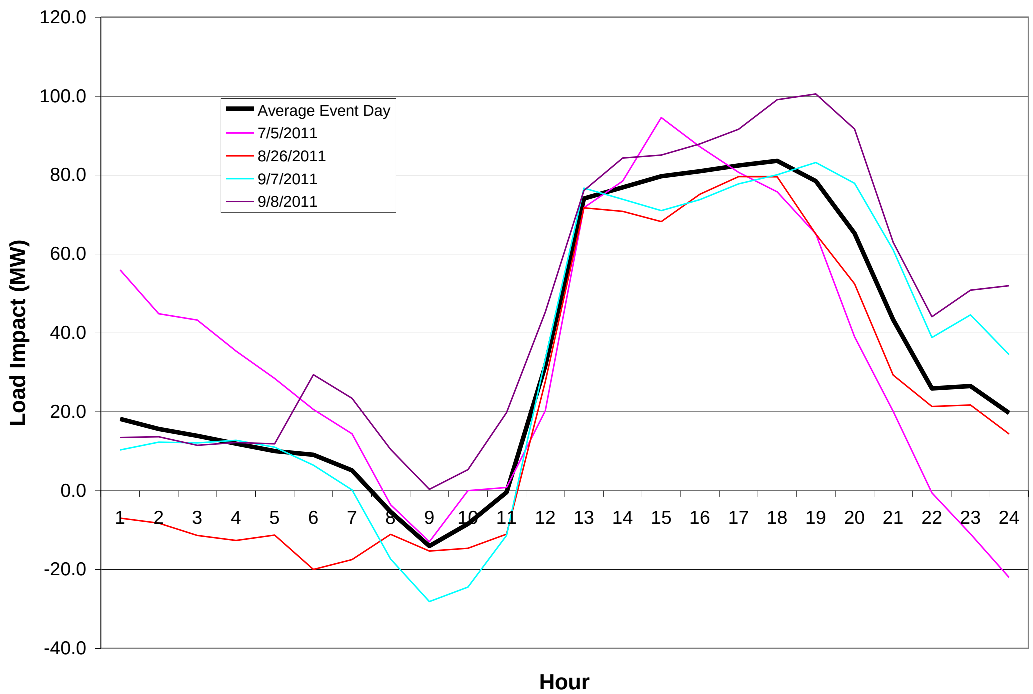


Figure 4.3: 2011 Hourly Load Impacts by Event – *SCE DBP*



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.

Our goal was to estimate both *total* and *incremental* load impacts for TA/TI and AutoDR. Total load impacts are simply the sum of the estimated load impacts for the TA/TI and AutoDR customers, as estimated using the methods described in Section 3.2.1. *Incremental* load impacts are 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.

Given data limitations, we were unable to estimate reliable incremental load impacts. Specifically, we developed comparison groups according to industry classifications (SIC codes for SCE and NAICS codes for PG&E). Where possible, we compared customers 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 using one of the eight industry groups described in Section 2.2.1. Our findings revealed that the industry-level comparisons are based on too few customers to produce reliable results. We considered aggregating AutoDR and TA/TI customers into larger industry groups as a solution to the sample-size issue, but this solution raises serious questions about the comparability of the results between the two groups. We have found that percentage load impacts can vary substantially across industry sub-groups, which calls into question the reasonableness of comparing customers within a higher-level industry group (e.g., all manufacturing customers).

In addition, we lack sufficient information on the comparison and "treatment" (AutoDR or TA/TI) customers to ensure that the comparison is valid. Specifically, we do not know relevant information about the comparison group customers, such as details regarding their technological processes (and hence their ability to reduce load during event hours) or whether they possess enabling technology.

For each utility and incentive program, we present two tables. The first table (e.g., Table 4.11) contains the overall average hourly load impacts provided by the service accounts that participated in TA/TI or AutoDR. The second table (e.g., Table 4.12) displays the number of service accounts by industry group for the comparison group customers and the AutoDR or TA/TI customers. This table format illustrates the small sample size issue described above.

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

PG&E

TA/TI

According to data provided by PG&E, one DBP service account participating in the TA/TI program submitted a bid for the September 8, 2011 event. No such service accounts submitted a bid for the September 22, 2011 event.

Table 4.11 shows the event-specific load impact for the TA/TI participant. The TA/TI customer provided an average hourly load reduction of 122 kW, or 3.1 percent of their reference load.

Table 4.11: 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
9/8/2011	1	4,062	3,940	122	3.1%

As shown in Table 4.12, only one service account is present in the comparison and treatment groups, raising questions about the reasonableness of a comparison of the responsiveness between them.

Table 4.12: Number of Service Accounts by Group , *PG&E TA/TI*

			Number of SAIDs	
NAICS Code	NAICS Description	Basis of Comparison	No TA/TI	TA/TI
541380	Testing Laboratories	6-digit NAICS	1	1

AutoDR

According to data provided by PG&E, an average of 65 DBP service accounts participating in the AutoDR program submitted a bid for the 2011 test events. Table 4.13 shows the average hourly load impact for the AutoDR participants, which was 16,835 kW, or 30 percent of their reference load. Note that the total and percentage load impacts are strongly influenced by one SAID that reduced its load by 100 percent, or 13.8 MW.

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
9/8/11	67	50,772	35,720	15,052	29.6%
9/22/11	62	61,341	42,722	18,618	30.4%
Average	**65**	**56,057**	**39,221**	**16,835**	**30.0%**

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. The “Basis of Comparison” column identifies the industry level used for the comparison group. Table 4.14 shows the sample size by industry group.

Twenty-two of the twenty-five industry groups contain a comparison in which at least one of the groups has only one service account.

Table 4.14: Number of Service Accounts by Group, *PG&E AutoDR*

NAICS Code	NAICS Description	Basis of Comparison	Number of SAIDs No AutoDR	Number of SAIDs AutoDR
115114	Postharvest Crop Activities (except Cotton Ginning)	6-Digit	1	3
221112	Fossil Fuel Electric Power Generation	Utilities, Wholesale	17	1
325120	Industrial Gas Manufacturing	Manufacturing	14	1
334112	Computer Storage Device Manufacturing	6-Digit	1	6
423930	Recyclable Material Merchant Wholesalers	Utilities, Wholesale	17	1
424410	General Line Grocery Merchant Wholesalers	Utilities, Wholesale	17	1
452111	Department Stores (except Discount Department Stores)	6-Digit	1	23
518210	Data Processing, Hosting, and Related Services	6-Digit	2	2
53112	Lessors of Nonresidential Buildings (except Miniwarehouses)	5-Digit	2	1
54171	Research and Development in the Physical, Engineering, and Life Sciences	5-Digit	1	2
551114	Corporate, Subsidiary, and Regional Managing Offices	6-Digit	1	2
6214	Outpatient Care Centers	Information	12	1
621491	HMO Medical Centers	Information	12	1
62211	General Medical and Surgical Hospitals	Information	12	1
624	Social Assistance	Information	12	1
624190	Other Individual and Family Services	Information	12	1
624310	Vocational Rehabilitation Services	Information	12	1
713940	Fitness and Recreational Sports Centers	6-Digit	10	4
812910	Pet Care (except Veterinary) Services	Arts, Entertainment	18	1
921190	Other General Government Support	6-Digit	2	7
922120	Police Protection	2-Digit	6	1
922130	Legal Counsel and Prosecution	2-Digit	6	1
922140	Correctional Institutions	6-Digit	1	3
922160	Fire Protection	2-Digit	6	1
923130	Administration of Human Resource Programs (except Education, Public Health, and Veterans' Affairs Programs)	6-Digit	1	1

SCE

TA/TI

Table 4.15 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 51 of SCE's DBP service accounts participated in TA/TI. The load impacts are much higher for the first event than the subsequent events. This is due to one service account that provided essentially no load impact for three events, but provided approximately 19 MW of load response for the first event. The load impacts in the absence of this customer average 1.7 MW, or 4.8 percent of the remaining reference load.

Table 4.15: 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
7/5/11	51	52,222	31,032	21,190	40.6%
8/26/11	51	55,108	53,248	1,859	3.4%
9/7/11	51	54,457	53,136	1,322	2.4%
9/8/11	51	54,328	53,253	1,074	2.0%
Average	**51**	**54,029**	**47,667**	**6,361**	**11.8%**

Table 4.16 shows the number of service accounts by industry group. Eight of the fourteen industry groups contain a comparison in which at least one of the groups has only one service account.

Table 4.16: Number of Service Accounts by Group, *SCE TA/TI*

SIC Code	SIC Description	Basis of Comparison	Number of SAIDs	
			No TA/TI	TA/TI
2026	Fluid Milk	2 Dig. SIC	2	1
2041	Flour and Other Grain Mill Products	4 Dig. SIC	2	1
2813	Industrial Gases	4 Dig. SIC	4	2
2834	Pharmaceutical Preparations	4 Dig. SIC	2	1
3728	Aircraft Parts and Equipment, NEC	4 Dig. SIC	2	1
5072	Hardware	1 Dig. SIC	11	2
5318	Shopping Centers-Retail Sales	4 Dig. SIC	1	1
5411	Grocery Stores	4 Dig. SIC	8	13
5651	Family Clothing Stores	4 Dig. SIC	1	2
5912	Drug Stores and Proprietary Stores	1 Dig. SIC	11	1
6512	Nonresidential Building Operators	4 Dig. SIC	18	21
6514	Dwelling Operators, Exc. Apartments	4 Dig. SIC	6	4
7011	Hotels and Motels	4 Dig. SIC	21	1
8011	Offices & Clinics of Medical Doctors	4 Dig. SIC	6	1

AutoDR

Table 4.17 shows the total DBP load impacts for SCE's AutoDR participants. The percentage load impacts are uniformly high across events, averaging 32 percent, or a 13.2 MW load impact. This result is driven by the participation of one SAID from the Industrial Gases SIC (2813), which consistently reduced load by approximately 11 MW.

Table 4.17: 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
7/5/11	82	29,493	16,461	13,031	44.2%
8/26/11	90	49,182	36,088	13,095	26.6%
9/7/11	94	48,646	34,625	14,021	28.8%
9/8/11	77	38,416	25,950	12,467	32.5%
Average	**86**	**41,434**	**28,281**	**13,154**	**31.7%**

Table 4.18 shows the number of service accounts by industry group. Nine of the eleven industry groups contain a comparison in which at least one of the groups has two or fewer service accounts.

Table 4.18: Number of Service Accounts by Group, *SCE AutoDR*

SIC Code	SIC Description	Basis of Comparison	Number of SAIDs	
			No AutoDR	AutoDR
2026	Fluid Milk	4 Dig. SIC	2	2
2653	Corrugated And Solid Fiber Boxes	4 Dig. SIC	1	1
2656	Sanitary Food Containers	4 Dig. SIC	2	2
2813	Industrial Gases	4 Dig. SIC	4	1
3089	Plastics Products, NEC	4 Dig. SIC	20	2
3691	Storage Batteries	2 Dig. SIC	68	1
5311	Department Stores	4 Dig. SIC	2	45
5712	Furniture Stores	4 Dig. SIC	1	2
5731	Radio, TV, & Electronic Stores	4 Dig. SIC	11	9
5941	Sporting Goods and Bicycle Shops	2 Dig. SIC	33	21
6531	Real Estate Agents And Managers	1 Dig. SIC	30	2

5. Validity Assessment

5.1 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the ex post load impact analysis. Model variations included the following:

- The use of cooling degree days (CDD) versus cooling degree hours (CDH);[15]
- A range of temperature thresholds used in the CDD and CDH calculations, from 50 through 70 degrees Fahrenheit in 5 degree increments;
- Whether to include the square of CDD or CDH for each hour; and
- The inclusion of the morning load variable[16] versus excluding the variable and controlling for serial correlation using the Prais-Winsten estimation method.

[15] CDD = MAX{Average(Maximum Temperature for the Day, Minimum Temperature for the Day) – Temperature Threshold,0}. CDD is the same in each hour of a given day. CDH = MAX{Temperature in that Hour – Temperature Threshold),0}. CDH can vary across the hours of a given day.
[16] The morning load variable equals the customer's average daily load from hours ending 1 through 10. It is intended to work in a similar fashion as the day-of adjustment to the 10-in-10 baseline calculation method.

The primary criterion used to compare the alternative specifications was the model's accuracy on a set of event-like non-event days. Testing was conducted on the aggregated DBP load for each utility. For each utility, we selected five non-event days that most resembled the actual event days to serve as proxies for event days.[17] That is, the ability of the model to accurately predict the DBP load on these days may be indicative of its ability to perform well on event days (for which we do not have the "true" answer).

For each utility and specification, we estimate five models. In each of these models, one of the five "test" days is withheld from the sample, and the estimated model parameters are used to predict the usage difference (i.e., the dependent variable) for that day. The difference between the observed value and the predicted value for the test days provides a means of assessing the model's accuracy.

Figures 5.1 and 5.2 provide an initial examination of the appropriate temperature threshold to be used in the CDD and CDH calculations. These figures contain scatter plots of average DBP loads and temperatures for each utility, during hours ending 15 through 18 for PG&E and 13 through 20 for SCE (which encompasses all of the event hours that were called in 2011) for non-holiday and non-event weekdays in the summer of 2011. The figures appear to imply a linear relationship between temperature and load, which would lead us to suspect that the squared weather variables would have little effect on the estimates. With the exception of a couple of low-temperature days in Figure 5.1, the linear relationship holds to the lowest observed temperature levels, leading us to conclude that lower threshold temperatures are more appropriate than higher threshold temperatures. With so few observations below 60 degrees Fahrenheit, we would expect that thresholds at or below this level would produce similar results.

[17] For PG&E, the selected days are: August 25, September 9, September 13, September 21, and September 23. For SCE, the selected days are: July 6, August 2, August 24, August 25, and September 6.

Figure 5.1: Average Temperatures versus Aggregate DBP Loads, *PG&E*

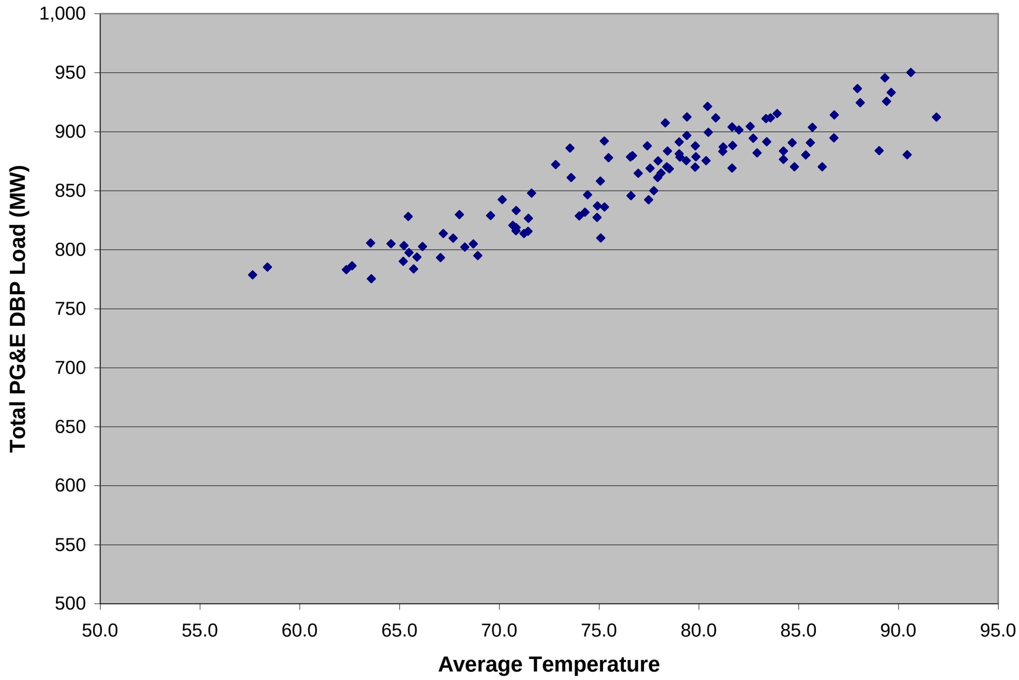
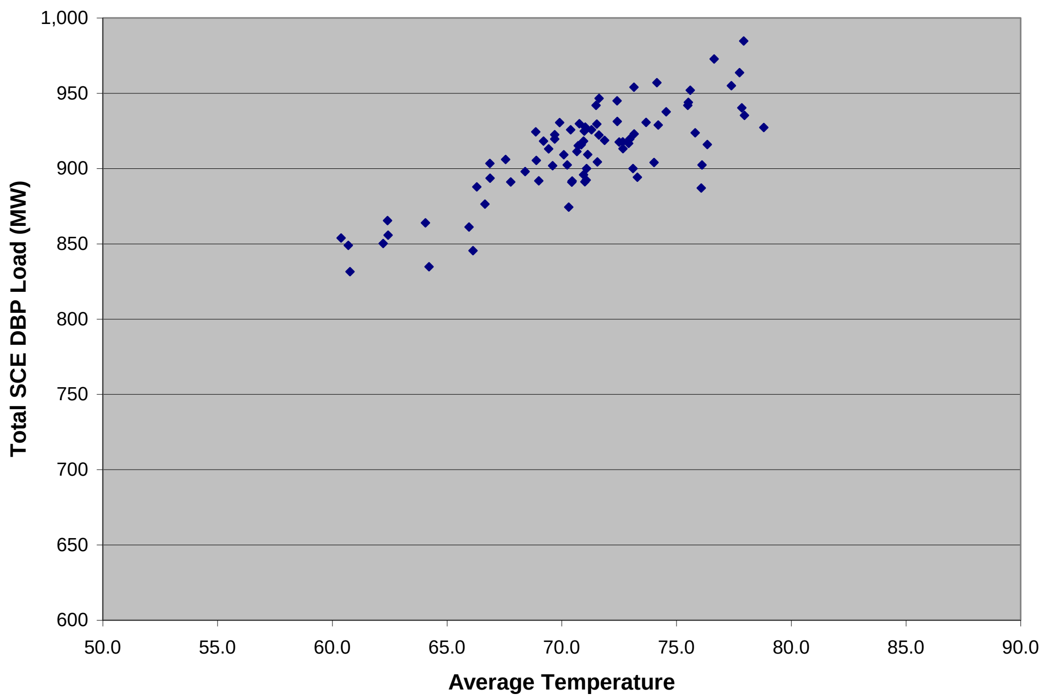


Figure 5.2: Average Temperatures versus Aggregate DBP Loads, *SCE*



The most important conclusion we reached from the specification tests is that the load impact estimates are very robust to alternative specifications. That is, the load impacts did not vary substantially as we varied the temperature threshold or included the squared weather terms. General conclusions are as follows:

- CDH models fit better than CDD models;
- The inclusion of the morning load variable produces more accurate load shapes than the Prais-Winsten models without the morning load variable; and
- The squared weather variables have little to no effect on model accuracy.

Figures 5.3 and 5.4 illustrate, for each utility, the accuracy of the model predictions by comparing the average observed load for the five event-like days to the predicted loads for those same days across a variety of the specifications. In the figures, "ML" indicates models using the morning load variable, while "P-W" indicates models using the Prais-Winsten estimation method. As the figure shows, the results across model specifications almost completely overlap one another. That is, all of the specifications shown are quite accurate.

Figure 5.3: Predicted versus Observed Loads on Event-Like Non-Event Days, *PG&E*

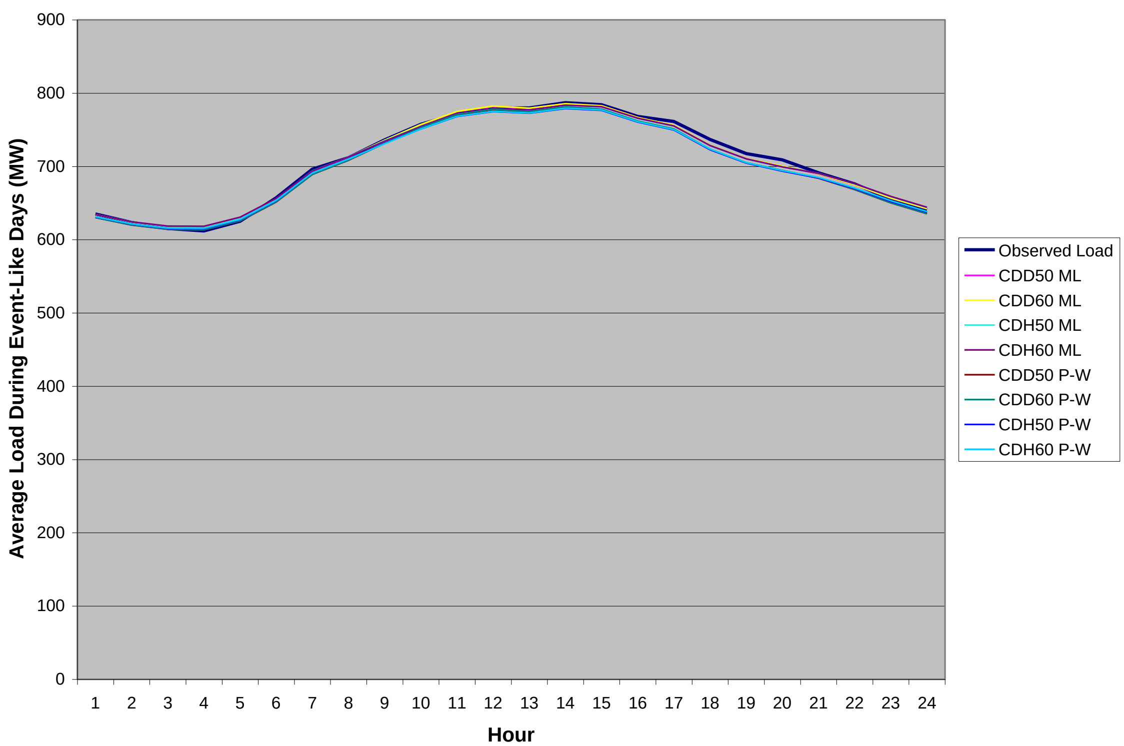
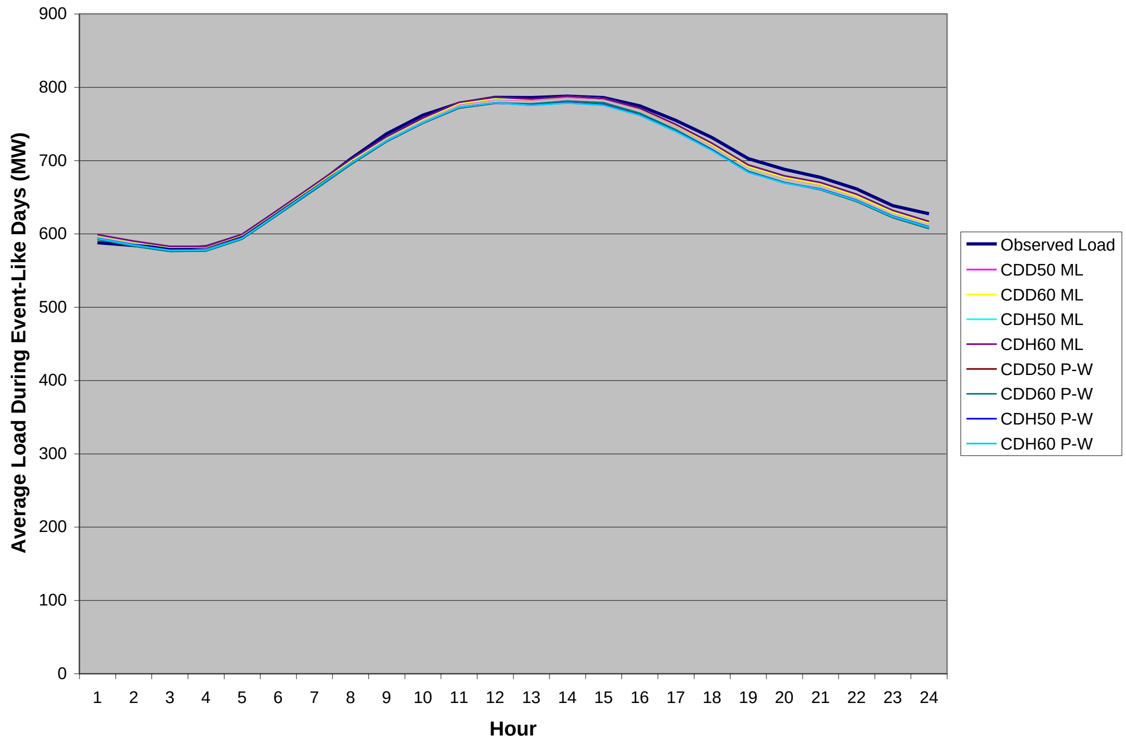


Figure 5.4: Predicted versus Observed Loads on Event-Like Non-Event Days, *SCE*



Tables 5.1 and 5.2 provide detailed results from the specification tests. Model variations shown in the table include the morning load versus Prais-Winsten models; the use of CDD or CDH weather variables; and temperature thresholds of 50, 55, 60, and 65 degrees Fahrenheit. The types of results shown are the R-squared for the model as a whole; and the root mean squared error (RMSE) for all hours and the "event" hours of the event-like non-event days. The "best" value in each column is highlighted in bold.

Notice that the most accurate models are nearly all in the morning load, CDH results section. Based on these results, we proceeded with the model that uses the 50 degree threshold, which produced the best fit across all hours for both utilities.

Table 5.1: Specification Test Results, *PG&E*

Model Type	Weather Type	Temperature Threshold	R^2	Event-like Day RMSE All Hours	Event-like Day RMSE Event Hours
Morning Load	CDD	50	0.974	7,743	8,257
		55	0.974	7,730	8,225
		60	0.973	7,694	8,166
		65	0.970	7,687	8,278
	CDH	50	**0.977**	7,082	8,299
		55	0.977	7,070	8,278
		60	0.977	**7,032**	8,146
		65	0.975	7,060	**7,986**
Prais-Winsten	CDD	50	0.947	9,908	11,652
		55	0.947	9,880	11,594
		60	0.946	9,769	11,442
		65	0.944	9,743	11,806
	CDH	50	0.949	10,009	12,836
		55	0.950	9,861	12,704
		60	0.949	9,793	12,485
		65	0.947	10,261	13,020

Table 5.2: Specification Test Results, *SCE*

Model Type	Weather Type	Temperature Threshold	R^2	Event-like Day RMSE All Hours	Event-like Day RMSE Event Hours
Morning Load	CDD	50	0.974	15,695	16,763
		55	0.974	15,694	16,756
		60	0.974	15,684	16,713
		65	0.974	15,703	16,752
	CDH	50	**0.976**	**15,382**	16,751
		55	0.976	15,385	16,738
		60	0.976	15,394	16,744
		65	0.975	15,490	16,882
Prais-Winsten	CDD	50	0.953	19,946	16,747
		55	0.953	19,808	16,491
		60	0.953	19,694	16,234
		65	0.953	19,574	**16,030**
	CDH	50	0.954	20,271	18,122
		55	0.954	20,261	18,153
		60	0.954	20,532	18,525
		65	0.952	21,440	20,235

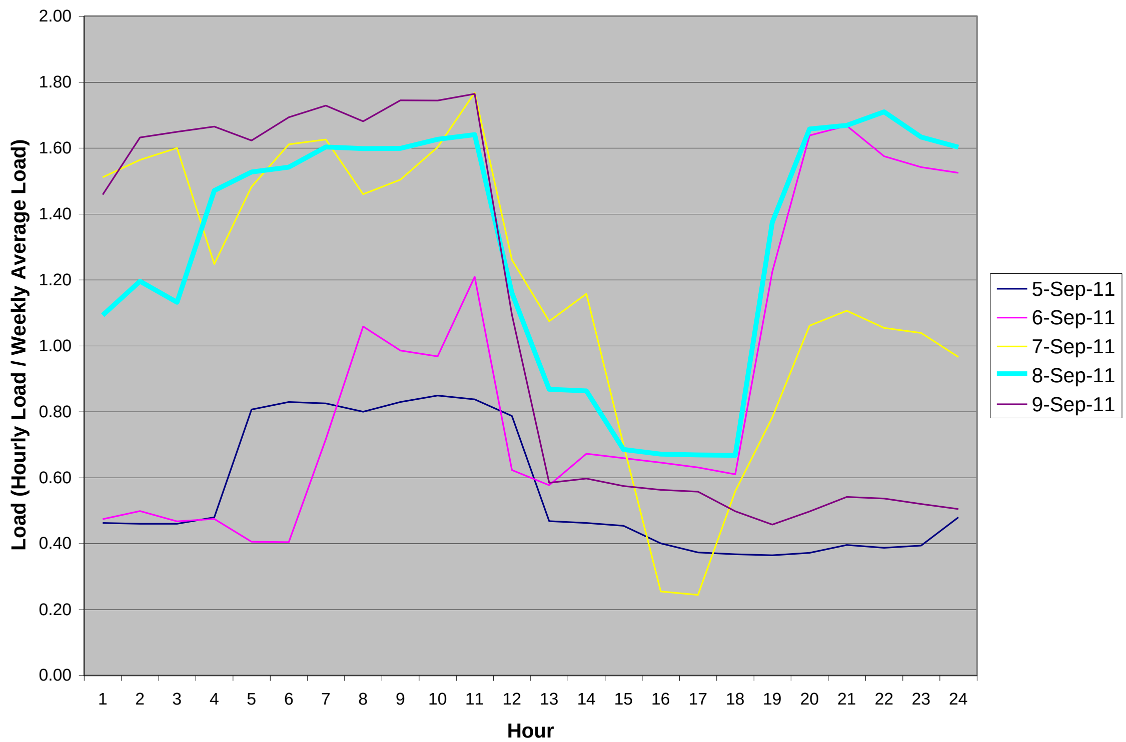
5.2 Refinement of Customer-Level Models

While the specification tests described in Section 5.1 were conducted on aggregated load profiles for each utility, the ex post load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a "day matching" load impact that may be compared to the estimated load impacts.

This examination resulted in revisions to the load impacts for six SCE service accounts and eleven PG&E service accounts. In each case, the regression model estimated sizeable load impacts (both positive and negative), whereas the findings from the informal day-matching method indicated no response to the event day.

Figure 5.5 illustrates an example of a load impact estimate that was revised to zero using our examination of the load data.[18] For this PG&E customer, the model estimated a 46 percent load reduction during the September 8th event. An examination of the raw usage data indicated that the load reduction during the event hours was something that happened regularly, even on non-event days. However, the pattern of the reductions was such that the regression model was unable to identify it. Based on this, we determined that the load reductions were not a response to DBP incentives and set the load impact for that customer's event to zero.

Figure 5.5: Example of an Edited Customer Load Impact Estimate



5.3 Comparison of Load Impacts to Program Year 2010

It may be instructive to compare the ex post load impacts estimated for PY 2011 to those of the previous program year. Tables 5.3 and 5.4 present load impacts for each utility and program year, with customers separated into three groups:

- Customers who were present in the program in both program years 2010 and 2011;

[18] For confidentiality purposes, the "loads" shown in Figure 5.5 are equal to each hour's load divided by the average hourly load for the week's observations.

- Customers who were present in the program in PY 2011 only (new additions); and
- Customers who were present in the program in PY 2010 only (attrition).

Table 5.3 shows that for PG&E the largest source of the change in load impact estimates across years is a change in estimated load impacts for customers present in both program years. However, we estimated 67.2 MW of load impacts for the first event in PY 2011, which is quite close to the value for the single test event in PY 2010. Therefore, the difference in average load impacts across years may simply reflect variability in load impacts across the two PG&E test events.

Table 5.3: Comparison of Load Impacts (in MW) in PY 2010 and PY 2011, PG&E

Program Year	LI in PY 2011	LI in PY 2010	Change
In both years	55.6	66.1	-10.5
In PY 2011 only	1.3	n/a	1.3
In PY 2010 only	n/a	2.1	-2.1
TOTAL	**56.9**	**68.2**	**-11.3**

Table 5.4 shows that for SCE the largest source of the change in load impact estimates across years is 16.3 MW in load impacts from newly enrolled customers. Therefore, the increase in program-level load impacts appears to be largely due to changes in program participation.

Table 5.4: Comparison of Load Impacts (in MW) in PY 2010 and PY 2011, SCE

Program Year	LI in PY 2011	LI in PY 2010	Change
In both years	61.5	59.6	1.9
In PY 2011 only	16.3	n/a	16.3
In PY 2010 only	n/a	2.5	-2.5
TOTAL	**77.8**	**62.1**	**15.6**

6. Recommendations

We recommend an investigation of alternative methods for estimating the incremental load impacts from the AutoDR and TA/TI programs. As described in Section 4.3, data limitations prevented us from estimating reliable incremental load impacts for this evaluation.

In the future, utilities may want to investigate the feasibility of basing the incremental load impacts on information gathered from data loggers applied to the equipment affected by AutoDR or TA/TI. (This may not be possible, depending on the program or specific application of the technology.) A simulated event test could be conducted before and after the technology is installed at the customer's site. A comparison of the test results before and after the installation of the technology would provide the estimate of incremental load impacts of the technology for that customer.

In addition, the utilities may want to consider whether the analysis of AutoDR and TA/TI load impacts should be conducted under a separate contract from the current load impact evaluations, such that all AutoDR and TA/TI customers would be evaluated by the same contractor using a uniform methodology. This may more easily allow the contractor to employ methods that fundamentally differ from the methods used to estimate program load impacts. One potential problem with this approach is that it may require the contractor to be familiar with the details of a variety of DR programs.

Appendices

The following Appendices accompany this report. Each is an Excel file that can produce the ex post 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