CHRISTENSEN ASSOCIATES ENERGY CONSULTING

2013 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs Volume 1: *Ex-Post* and *Ex-Ante* Load Impacts

CALMAC Study ID PGE0341.01

Steven D. Braithwait
Daniel G. Hansen
David A. Armstrong

April 1, 2014

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 the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program Year 2013.

In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customer accounts, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Depending on their contractual arrangement with the IOU, aggregators can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, and PG&E's and SCE's Aggregator Managed Portfolio ("AMP") programs. The primary goals of this evaluation study are the following:

- Estimate *ex-post* load impacts for program year 2013;
- Estimate *ex-ante* load impacts for the programs for years 2014 through 2024; and
- Conduct baseline analyses for each aggregator program.[1]

Customer nominations in the day-of versions of all of the programs exceeded those in the day-ahead versions, and were generally higher in the AMP programs than for the CBP programs. Numbers of nominated customers ranged from less than 100 customer accounts for some product types, to more than 1,500 for SCE's AMP DO. Most program types were called from six to eight times in 2013.

Hourly *ex-post* load impacts were estimated for each program and event during the summer of 2013, using regression analysis of individual customer-level hourly load, weather, and event data. Estimated load impacts were reported for each event, for all programs and product types (*e.g.*, DA 1-4 hours and DO 2-6 hours). Load impacts for the average, or typical event were also reported by industry type and CAISO local capacity area where relevant.

Estimated CBP *ex-post* load impacts for PG&E, SCE and SDG&E were 4.7, 3, and 10.8 MW respectively, for the DA product type, and 13.7, 18.4 and 10.5 MW for the DO product type. AMP load impacts were 43.5 and 155.2 MW for PG&E's DA and DO product types, and 7.9 and 126.7 MW for SCE's DA and DO product types.

[1] The baseline analysis is included in Volume 2 of this report.

EXECUTIVE SUMMARY

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program-Year 2013. In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customers, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Aggregators, depending on their contractual arrangement with the IOU, can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU and customers.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, and PG&E's and SCE's Aggregator Managed Portfolio ("AMP") programs.

The primary goals of this evaluation study are the following:

- Estimate the *ex-post* load impacts for program year 2013;
- Estimate the *ex-ante* load impacts for 2014 through 2024; and
- Assess the accuracy and bias of various versions of the programs' 10-in-10 baseline.

The aggregator baseline analysis is documented in Volume 2 of this report.

ES.1 Program Resources

Capacity Bidding Program (CBP)

The statewide CBP program provides month-to-month *capacity* payments ($/kW) to aggregators based on their nominated kW load, the specific operating month, and the notice option (DA or DO). Additional *energy* payments ($/kWh) are made to bundled customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The monthly capacity payments can be adjusted by the actual kWh reductions during an event, and capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts. If no events are called, the aggregator receives the monthly capacity payment in accordance with their nomination, but no energy payments.

Participating aggregators may adjust their nomination each month, as well as their choice of available event type and event window options (*e.g.*, DA or DO events, and 1-

to-4, 2-to-6, or 4-to-8 hour maximum event durations). CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m., with a maximum of thirty event hours per month.[2]

Customers enrolled in CBP may participate in another DR program, so long as it is an energy-payment program and does not have the same advance notification (*i.e.*, day-ahead or day-of).

Aggregator Managed Portfolio (AMP)

Under AMP, third-party aggregators enter bilateral contracts with PG&E and/or SCE, and may create their own aggregated DR program by which participating customers achieve load reductions.

PG&E has contracts with five aggregators (accounting for one DA and four DO contracts), which include an nearly 1,800 nominated service accounts for the average event, representing nominated load reduction capacity of approximately 240 MW. Up to 80 hours of events may be called each year, including test events, during the hours of 11 a.m. and 7 p.m. AMP events may be triggered when Buyer expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or Buyer, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. Customers who participate in AMP with *day-ahead* notice are allowed to dually enroll in PG&E's Optional Binding Mandatory Curtailment program, while AMP customers who select *day-of* notification may also participate in DBP or Peak Day Pricing (PDP). The settlement baselines are based on the aggregate 10-in-10 method, with optional day-of adjustments.

SCE has five AMP contracts, with one day-ahead contract and four day-of contracts, which in total include nearly 1,800 customer service accounts, with a DR resource capacity of nearly 300 MW. Customers participating in SCE's AMP may dually enroll in some other DR programs, depending on type of notification. DA customers may enroll in SCE's Optional Binding Mandatory Curtailment (OBMC) and Real-Time Pricing (RTP) programs, while DO customers may participate in OBMC, RTP, DBP, and Summer Advantage Incentive (Critical Peak Pricing). Settlement baselines are based on individual 10-in-10 baselines, with an optional day-of adjustment of up to 40 percent.

Program enrollment/nominations

Table ES–1 summarizes the numbers of customer accounts nominated for the DA and DO notice types across all aggregator programs at the three utilities in 2013, where the values represent the number of nominated customers for the average event, and thus do not necessarily equal the number nominated in any particular month. Generally, more customer accounts are nominated for DO product types than for DA product types.

[2] SCE may call CBP events on any non-holiday weekend throughout the year.

Table ES–1: Nominated Customer Accounts by Utility and Program Notice

Program	Utility	Nominated Accounts	
		DA	DO
CBP	PG&E	25	480
	SCE	20	420
	SDG&E	142	260
AMP	PG&E	425	1,344
	SCE	236	1,589

ES.2 Summary of Study Findings

Events called

Table ES–2 summarizes the numbers of aggregator events called in 2013, by utility, program and notice type. With the exception of SCE's CBP DA program, the various program types were called from four to nine times during 2013, although not all product types or aggregators were called for each event.[3] One of PG&E's CBP and AMP events was called only for one geographical area (Fresno).

Table ES–2: Aggregator Events Called in 2013

Program	Utility	Number of Events by Notice Type	
		DA	DO
CBP	PG&E	5	5
	SCE	29	4
	SDG&E	6	8
AMP	PG&E	7	6
	SCE	9	7

Estimated ex-post load impacts

Table ES–3 summarizes estimates of average event-hour *ex-post* load impacts for PY 2013, *for the average of the typical event* for each of the three utilities' aggregator programs and notice types (*e.g.*, *day-ahead* and *day-of* notice). Load impacts are shown in both per-customer (kW) and aggregate (MW) levels. Also shown are nominated resource capacity amounts.[4] Estimated load impacts for the *DO* product types are generally greater than for *DA* products, which is consistent with the greater DO enrollment and total nominated load.

[3] The last SCE CBP DA event, which occurred in December was not included in this study.

[4] Aggregators in the CBP program may change nominations on a monthly basis. The values shown are for the average of typical events. Nominated capacities for AMP and DRC are contractually based.

Table ES–3: Average Event-Hour Load Impacts for Average of Typical Events – *by Utility and Notice*

Program	Utility	Per-Customer (kW)		Aggregate (MW)		Nominated Capacity (MW)	
		DA	DO	DA	DO	DA	DO
CBP	PG&E	189.0	28.5	4.7	13.7	8.4	15.3
	SCE	145.4	43.9	3.0	18.4	2.3	19.9
	SDG&E	76.1	40.4	10.8	10.5	9.7	11.1
AMP	PG&E	102.4	115.5	43.5	155.2	72.3	169.3
	SCE	33.3	80.1	7.9	126.7	4.4	116.4

Comparison of ex-post and ex-ante nominations and load impacts

To illustrate the relationship between the *ex-post* estimated load impacts for 2013, and the *ex-ante* load impact forecasts, Table ES–4 shows *ex-post* values for the number of nominated customers and the aggregate load impacts for the typical event, along with *ex-ante* nominations and forecast aggregate load impacts for 2015, which for the most part are the same as those for 2014. For the PG&E and SDG&E CBP programs, the forecasts closely align with experience in 2013. SCE anticipates changes in its CBP and AMP programs, as one aggregator plans to switch its customers from AMP DA to CBP DA, and a number of customer accounts are expected to move from AMP DO to CBP DO. The forecast load impacts are adjusted accordingly. In addition, PG&E has modified its customer nomination forecast for AMP DA and DO to reflect larger numbers of relatively smaller customers, as aggregators attempt to achieve nominated load impact capacity.

Table ES–4: *Ex-Post and Ex-Ante* Nominations and Load Impacts –2013

Program	Utility	*Ex-Post/ Ex-Ante*	Day Ahead		Day Of	
			Nom. Accnts.	Load Impact	Nom. Accnts.	Load Impact
CBP	PG&E	2013 ExP	25	4.7	480	13.7
		2015 ExA	25	4.2	472	14.3
	SCE	2013 ExP	20	3.0	420	18.4
		2015 ExA	261	12.2	859	45.4
	SDG&E	2013 ExP	142	10.8	260	10.5
		2015 ExA	145	9.5	275	10.2
AMP	PG&E	2013 ExP	425	43.5	1,344	155.2
		2015 ExA	1,142	68.0	1,514	162.5
	SCE	2013 ExP	236	7.9	1,531	122.6
		2015 ExA	0	0.0	1,125	88.4

ES.3 Evaluation Methodology

Estimates of total program-level load impacts for each program were developed from the estimated coefficients of individual customer-level regression equations. These equations were estimated using individual customer load data and associated weather data for the summer months for 2013, for each customer account nominated in a month containing an event.

The regression equations are based on models of hourly loads as functions of a list of variables designed to control for factors such as:

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours)
- Event indicators, which are invoked when a given nominated customer's product type was called, are interacted with hourly indicator variables to allow estimation of hourly load impacts for each event-day. Indicator variables for any other DR program in which a customer is enrolled are also included.

The resulting equations provide the capability of estimating hourly load impacts on every event day. In addition, the customer-specific equations provide the capability to summarize the distribution of load impacts by characteristics such as industry type and CAISO local capacity area, by adding across customers in any given category. Similarly, load impacts associated with TA/TI and AutoDR participation may be obtained by summing load impacts across those participants. Finally, uncertainty-adjusted load impacts are calculated to illustrate the degree of uncertainty that exists around the estimated load impacts.

1. INTRODUCTION AND OBJECTIVES OF THE STUDY

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program Year 2013. In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customers, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Aggregators, depending on their contractual arrangement with the IOU, can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU and customers.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, and PG&E's and SCE's Aggregator Managed Portfolio ("AMP") programs.

The primary goals of this evaluation study are the following:

- Estimate the *ex-post* load impacts for program year 2013;
- Estimate the *ex-ante* load impacts for 2014 through 2024; and
- Assess the accuracy and bias of various versions of the 10-in-10 baseline[5].

The first goal involves estimating *hourly load impacts* for each 2013 event for each of the utilities' aggregator programs, as well as the distribution of load impacts for a "typical" DR event across industry types and CAISO local capacity areas. Our primary approach involved estimating *individual customer regressions*, which provided a flexible basis for analyzing and reporting load impact results at various levels (*e.g.*, total program level) and by various subgroups (*e.g.*, by industry group and CAISO local capacity area), including those customers that also participated in the AutoDR and Technical Assistance and Technology Incentives (TA/TI) programs.

The second goal involves producing *forecasts of load impacts* for each of the programs through 2024, by combining the information on historical *ex-post* load impacts with utility projections of program enrollment or contracted load nominations.

The third goal involves analysis to assess the accuracy and bias of the current 10-in-10 program baseline method and several potential alternative baselines, including various same-day adjustments, for each of the aggregator programs. The baseline analysis

[5] The baseline results are presented in a separate volume of this report.

involves two types of load comparisons. One type involves comparing *estimated* reference loads from the *ex-post* evaluation (the "true baseline") to the alternative baseline loads on event days. The other compares the alternative baseline loads to *observed* loads on a set of event-like non-event days. In each case, we assess the performance of the alternative baseline methods in terms of accuracy (*i.e.*, degree of error, regardless of sign) and bias (*i.e.*, the tendency of a baseline method to under-state or over-state true baselines). Baseline analysis results are reported in Volume 2 of this report.

2. AGGREGATOR DR PROGRAM RESOURCES

This section summarizes the aggregator programs covered in this evaluation, including the characteristics of the participants in the programs.

2.1 Capacity Bidding Program (CBP)

The statewide CBP program provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, and the program notice option (DA or DO).[6] Additional energy payments ($/kWh) are made to bundled[7] customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The monthly capacity payments can be adjusted by the actual kWh reductions during an event, and capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts. If no events are called, the aggregator receives the monthly capacity payment in accordance with their nomination, but no energy payments.

Participating aggregators may adjust their nominations each month, as well as their choice of available notice type and event window options (*e.g.*, DA or DO event notice, and 1-to-4, 2-to-6, or 4-to-8 hour maximum event durations). CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m., with a maximum of thirty event hours per month.[8]

Customers enrolled in CBP may participate in another DR program, so long as it is an energy-payment program and does not have the same advanced notification (*i.e.*, day-ahead or day-of).

Table 2–1 summarizes the characteristics of the customer accounts that were nominated for CBP at each utility in 2013, by type of notice and industry group. Since nominations vary by month, we use the convention of reporting the average number of nominated customer accounts for the average, or typical event, as reported in the Protocol tables and the summary tables in Section 4.[9]

[6] Participants may be individual customers or aggregators, but most all are aggregators.
[7] The program is also open to Direct Access and Community Choice Aggregation customers.
[8] SCE may call CBP events on any non-holiday weekend throughout the year.
[9] We report nominations because customers are not assigned to DA or DO product types until they are nominated in a particular month. The average number of nominated customer accounts may not equal

Retail stores make up a large share of CBP DO enrolled load at each of the utilities. The PG&E DA product type is dominated by customers in Agriculture, Mining, and Construction; Manufacturing; and Wholesale and other Utilities, while half of SDG&E's DA product consists of customers in Offices, Hotels, Health, and Services.

Table 2–1: CBP Nominated Customer Accounts by Utility and Industry Group (2013)

		Day-Ahead		Day-Of	
Utility	**Industry Type**	**Accounts**	**Summer Peak Demand (MW)**	**Accounts**	**Summer Peak Demand (MW)**
PG&E	1. Agriculture, Mining & Construction				
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities				
	4. Retail stores			429	80.78
	5. Offices, Hotels, Health, Services			30	12.75
	6. Schools				
	7. Entertainment, Other Services, Gov't				
	8. Other/Unknown				
	Total	**25**	**17.4**	**480**	**103.9**
SCE	1. Agriculture, Mining & Construction				
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities				
	4. Retail stores			387	79.8
	5. Offices, Hotels, Health, Services				
	6. Schools				
	7. Entertainment, Other Services, Gov't				
	8. Other/Unknown				
	Total	**24**	**24.2**	**417**	**115.6**
SDG&E	1. Agriculture, Mining & Construction	-	-	-	-
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities				
	4. Retail stores	32	6.90	217	48.4
	5. Offices, Hotels, Health, Services	77	21.8	28	9.85
	6. Schools				
	7. Entertainment, Other Services, Gov't				
	8. Other/Unknown				
	Total	**140**	**47.9**	**260**	**64.9**

the number called for any particular event. That number is shown for each event in the load impact tables.

Table 2–2 lists the definitions of the industry groups, which are defined as aggregations of the indicated North American Industry Classification System (NAICS) codes.

Table 2–2: Industry Type Definitions

Industry Types	NAICS Codes
1. Agriculture, Mining & 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. Institutional/Government	71, 81, 92
8. Other or unknown	

2.2 PG&E's Aggregator Managed Portfolio (AMP)

Under AMP, third-party aggregators enter bilateral contracts with PG&E and/or SCE, and may create their own aggregated DR program by which participating customers achieve load reductions. PG&E has contracts with five aggregators. Four offer DO contracts, one of which offers both DA and DO contracts, and one offers only a DA contract. Up to 80 hours of events may be called each year, including test events, during the hours of 11 a.m. and 7 p.m. AMP events may be triggered when Buyer expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or Buyer, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. Customers who participate in AMP with *day-ahead* notice are allowed to dually enroll in PG&E's Optional Binding Mandatory Curtailment program, while AMP customers who select *day-of* notification may also participate in DBP or Peak Day Pricing (PDP). The settlement baselines are based on the aggregate 10-in-10 method, with an optional day-of adjustment.

Table 2–3 shows the number of customers nominated for the average AMP DA and DO event, by industry type. The aggregators nominated nearly 1,800 service accounts. More than half of those nominated for DA are in the Manufacturing or Retail store industry types, while DO nominations are spread over several industry types.

Table 2–3: PG&E AMP Nominated Customer Accounts by Industry Group

Industry Type	Day-Ahead		Day-Of	
	Accounts	Summer Peak Demand (MW)	Accounts	Summer Peak Demand (MW)
1. Agriculture, Mining & Construction	38	6.3	487	91.6
2. Manufacturing	120	134.2	126	139.8
3. Wholesale, Transport, other Utilities	38	13.4	195	92.6
4. Retail stores	131	39.1	225	60.0
5. Offices, Hotels, Health, Services	38	25.6	177	110.3
6. Schools	32	12.0	21	20.8
7. Entertainment, Other Services, Gov't	21	8.8	56	42.5
8. Other/Unknown			57	15.1
Total	425	241.3	1,344	572.8

2.3 SCE's Aggregator Managed Portfolio (AMP)

SCE has five AMP aggregator contracts, including one day-ahead contract and four day-of contracts. The contracts include about 1,750 nominated customer service accounts across the two notice types. Customers participating in SCE's AMP may dually enroll in some other DR programs, depending on type of notification. DA customers may enroll in SCE's Optional Binding Mandatory Curtailment (OBMC) and Real-Time Pricing (RTP) programs, while DO customers may participate in OBMC, RTP, DBP, and Summer Advantage Incentive (Critical Peak Pricing). Settlement baselines are based on individual 10-in-10 baselines, with an optional day-of adjustment of up to 40 percent.

Table 2–4 shows customer nominations by industry type for the average DA and DO event. The majority of DA contracts are with customers in the Retail stores industry type. Nominations for DRC DO are spread over several industry types.

Table 2–4: SCE AMP Nominations by Industry Group

Industry Type	Day-Ahead		Day-Of	
	Accounts	Summer Peak Demand (MW)	Accounts	Summer Peak Demand (MW)
1. Agriculture, Mining & Construction	7	1.0	208	38.7
2. Manufacturing	66	63.7	107	84.9
3. Wholesale, Transport, other Utilities	24	8.4	502	98.7
4. Retail stores	126	51.4	568	193.0
5. Offices, Hotels, Health, Services	3	2.8	109	57.3
6. Schools	4	2.8	17	41.0
7. Entertainment, Other Services, Gov't	5	2.2	12	7.2
8. Other/Unknown				
Total	235	132.3	1,523	520.8

3. STUDY METHODS

3.1 Overview

The primary evaluation method used in the *ex-post* portion of this study involved customer-level regression analysis applied to hourly load data to estimate hourly load impacts for each customer account that was nominated and called for an event. The regression equations model hourly load as a function of a set of variables designed to control for factors affecting consumers' hourly demand levels, such as:

- *Seasonal and hourly time patterns* (*e.g.*, year, month, day-of-week, and hour, plus various hour/day-type interactions);
- *Weather*, including hour-specific weather coefficients;
- *Event variables*. Indicator variables are included to account for each hour of each event day, which allows us to estimate load impacts for all hours across each event day, for each customer.

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each customer that is nominated and called for at least one event. As a result, the estimated coefficients on the event day/hour variables are direct estimates of the *ex-post* load impacts, and their standard errors indicate the precision of the estimates. For example, an hour-15 event coefficient of -100 on a particular event day implies 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 because aggregator events may be called only on weekdays.

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. This process and its results are explained in Appendix A. The methods used to develop the *ex-ante* load impact forecasts are described in Section 6.

3.2 Description of methods

3.2.1 Regression Model

The model shown below characterizes the nature of the regressions equations that were separately estimated for each customer. Table 3–1 describes the terms included in the equation.

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

Table 3–1: Descriptions of Terms included in the *Ex-Post* Regression Equation

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

The OtherEvt variables help the model explain load changes that occur on event days in cases in which aggregator customers are dually enrolled. (In the absence of these variables, any load reductions that occur on such days may be falsely attributed to other included variables, such as weather condition or day type variables.) The "morning load" variables are included in the same spirit as the day-of adjustment to the 10-in-10 baseline settlement method. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of an event) for factors that affect pre-event usage, but are not accounted for by the other included variables.

The model allows for the hourly load profile to differ by: day of week, with separate profiles for Monday, Tuesday through Thursday, and Friday; and by pricing season (*i.e.*, summer versus non-summer), in order to account for customer load changes in response to seasonal differences in peak energy prices and/or demand charges.

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).

[10] The summer pricing season is July through September for SCE, May through September for SDG&E, and May through October for PG&E. This variable is designed to account for the effect of the strong summer peak TOU prices that are in effect during this period for most customers at each of the three utilities.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

In addition to producing point estimates of the ex-post load impacts, we will produce *uncertainty-adjusted* program impacts for each event, which show the uncertainty around the estimated impacts, as required by the Protocols. These methods use the estimated load-impact parameter values and the associated variances to derive scenarios of hourly load impacts.

4. STUDY RESULTS – CBP *EX-POST* LOAD IMPACTS

This section describes the estimated *ex-post* load impacts for each utility's CBP program and product type. For each program and product type (*e.g.*, DA 1-4 Hours and DO 1-4 Hours), we show the following information:

- Events that were called in 2013;
- For each event, the number of customer accounts called, average event-hour reference load, estimated load impact, and percentage load impact, for both the aggregate and per-customer level;
- For the average of typical events, the average event-hour reference load, estimated load impact, and percentage load impact, by industry type and LCA;
- For selected events, the hourly profile of the estimated reference load and load impacts; and
- Estimates of TA/TI and AutoDR impacts.

4.1 Capacity Bidding Program (CBP) – PG&E

4.1.1 Events for PG&E CBP

Table 4–1 lists the features of PG&E's CBP DA and DO events in 2013, including event type, event hours, number of aggregators called, and monthly nominated capacity. All DA and DO product types were called for four of the events, in July and September. Only the DA product type was called for one event, on July 3. In addition, two localized events were called, on June 7 and September 10, in which only customers in some sub-laps were called. The last event in particular was called only for the Fresno area.

Table 4–1: Event Summary for 2013 – *PG&E CBP*

Date	Day of Week	Event Type	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
06/07/13	Friday	Event (Local)	DO	1-4 Hour	16 - 18	3	10.9
				2-6 Hour	16 - 18	1	4.2
07/01/13	Monday	Event	DA	1-4 Hour	16 - 19	2	8.7
			DO	1-4 Hour	16 - 19	5	11.0
				2-6 Hour	16 - 19	1	4.2
07/02/13	Tuesday	Event	DA	1-4 Hour	15 - 18	2	8.7
			DO	1-4 Hour	16 - 19	5	11.0
				2-6 Hour	16 - 19	1	4.2
07/03/13	Wednesday	Event	DA	1-4 Hour	16 - 19	2	8.7
09/09/13	Monday	Event	DA	1-4 Hour	16 - 19	3	7.3
			DO	1-4 Hour	16 - 19	6	11.3
				2-6 Hour	16 - 19	2	4.4
09/10/13	Tuesday	Event (Local)	DA	1-4 Hour	16 - 19	1	1.7
			DO	1-4 Hour	16 - 19	4	1.2
				2-6 Hour	13 - 19	2	1.2

4.1.2 Summary load impacts

Table 4–2 shows average event-hour estimated *reference loads*, *load impacts*, at both an average customer and aggregate level, as well as *percentage load impacts*, for the DA and DO notice and associated product types, for each of PG&E's CBP events, and for averages across each of the respective events. Also shown are average event-hour temperatures, and nominated capacity. The average event-hour DA load impact for the typical event was 4.7 MW, while DO load impacts averaged 8.5 MW for the 1-4 Hour product, and 5.2 MW for the 2-6 Hour product. Average percentage load impacts ranged from 12 to 31 percent across the three product types.

Table 4–2: Average Event-Hour Load Impacts by Event – *PG&E CBP*[11]

Date	Notice	Product	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
06/07/13	DO	1-4 Hour	27	140.7	8.0	3.8	0.2	6%	98.6	0.4
		2-6 Hour								
07/01/13	DA	1-4 Hour	25	581.8	211.7	14.5	5.3	36%	85.9	8.7
	DO	1-4 Hour	379	192.7	21.7	73.0	8.2	11%	90.5	11.0
		2-6 Hour	91	284.3	56.1	25.9	5.1	20%	93.5	4.2
07/02/13	DA	1-4 Hour	25	606.4	238.3	15.2	6.0	39%	88.9	8.7
	DO	1-4 Hour	379	192.3	20.4	72.9	7.7	11%	89.0	11.0
		2-6 Hour	91	284.3	57.6	25.9	5.2	20%	91.6	4.2
07/03/13	DA	1-4 Hour	25	590.2	98.3	14.8	2.5	17%	90.5	8.7
09/09/13	DA	1-4 Hour	24	667.6	208.5	16.0	5.0	31%	77.9	7.3
	DO	1-4 Hour	402	151.1	23.7	60.7	9.5	16%	87.4	11.3
		2-6 Hour	97	272.6	55.3	26.4	5.4	20%	89.2	4.4
09/10/13	DA	1-4 Hour								
	DO	1-4 Hour	55	141.0	23.3	7.8	1.3	17%	97.1	1.2
		2-6 Hour								
Average of Typical Events	DA	1-4 Hour	25	610.9	189.0	15.1	4.7	31%	85.8	8.4
	DO	1-4 Hour	387	178.1	22.0	68.9	8.5	12%	89.1	11.1
		2-6 Hour	93	280.2	56.3	26.1	5.2	20%	91.4	4.2

Table 4–3 shows the distribution of average event-hour load impacts for the typical DA and DO event by industry type. DA load impacts are concentrated in the Offices, Hotels, Finance and Services industry type, while DO load impacts are spread across several industry types.

[11] Blank rows indicate results not shown for confidentiality reasons due to small numbers of customers for the localized events.

Table 4–3: Distribution of Average Event-Hour Load Impacts by Industry Type – *PG&E CBP*

Notice	Industry	Accounts Called	Average Customer: Reference Load (kW)	Average Customer: Load Impact (kW)	Aggregate: Reference Load (MW)	Aggregate: Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction							
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores							
	Offices, Hotels, Finance, Services							
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DA	**25**	**610.9**	**189.0**	**15.12**	**4.68**	**31%**	**85.8**
DO	Agriculture, Mining & Construction							
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores	429	175.9	19.9	75.52	8.53	11%	90.8
	Offices, Hotels, Finance, Services	30	358.4	5.8	10.87	0.17	2%	80.5
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DO	**480**	**197.9**	**28.6**	**94.94**	**13.72**	**14%**	**89.7**

Table 4–4 shows the distribution of average event-hour load impacts by LCA.[12] Most of the DA load impacts were located outside of any LCA. DO load impacts were more widely spread, with the greatest amount in the Greater Bay Area.

Table 4–4: Distribution of Average Event-Hour Load Impacts by LCA – *PG&E CBP*

[Table removed for confidentiality reasons.]

4.1.3 Hourly load impacts

Figures 4–1 and 4–2 illustrate the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) for the PG&E CBP DO 1-4 and DO 2-6 product types for the four-hour July 2 event, which was called for hours-ending 16 to 19. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

[12] PG&E has been ordered by the California Public Utilities Commission to provide the capability to dispatch its CBP and AMP programs on a local basis. PG&E is implementing this capability by geographically defined "sub-laps," which differ from LCAs. However, in this report we continue to follow the Protocol guidelines to report results by LCA.

Figure 4–1: Hourly Loads and Load Impacts – PG&E CBP DO 1-4
July 2, 2013 Event

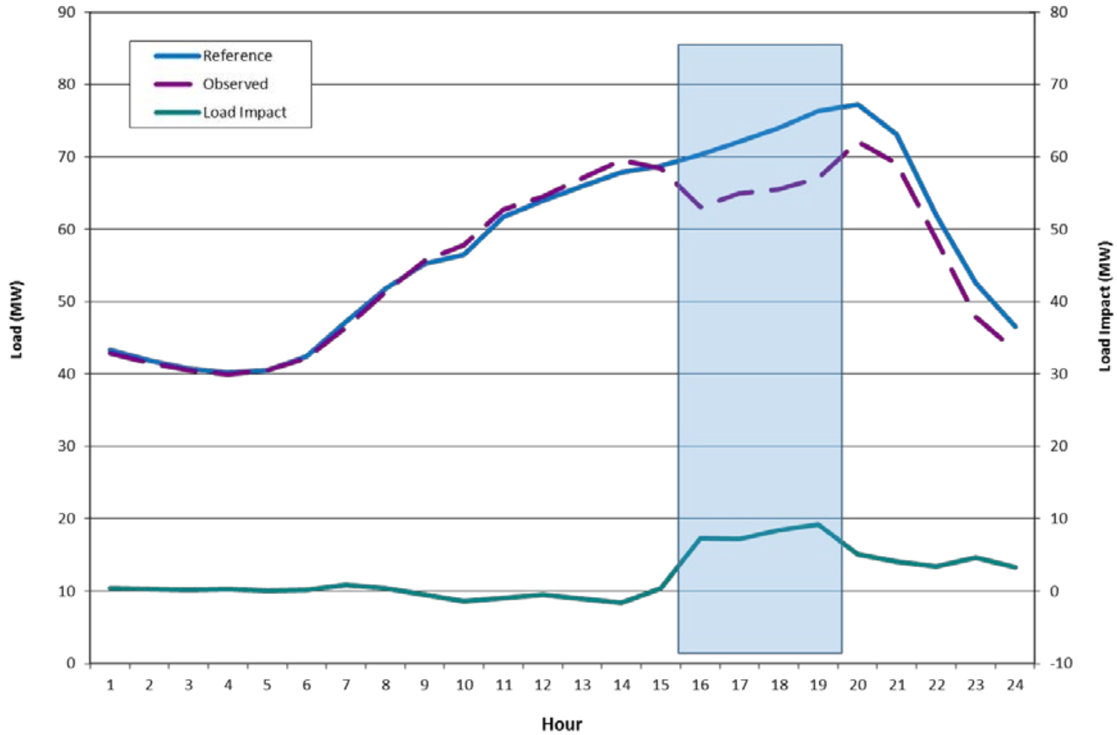
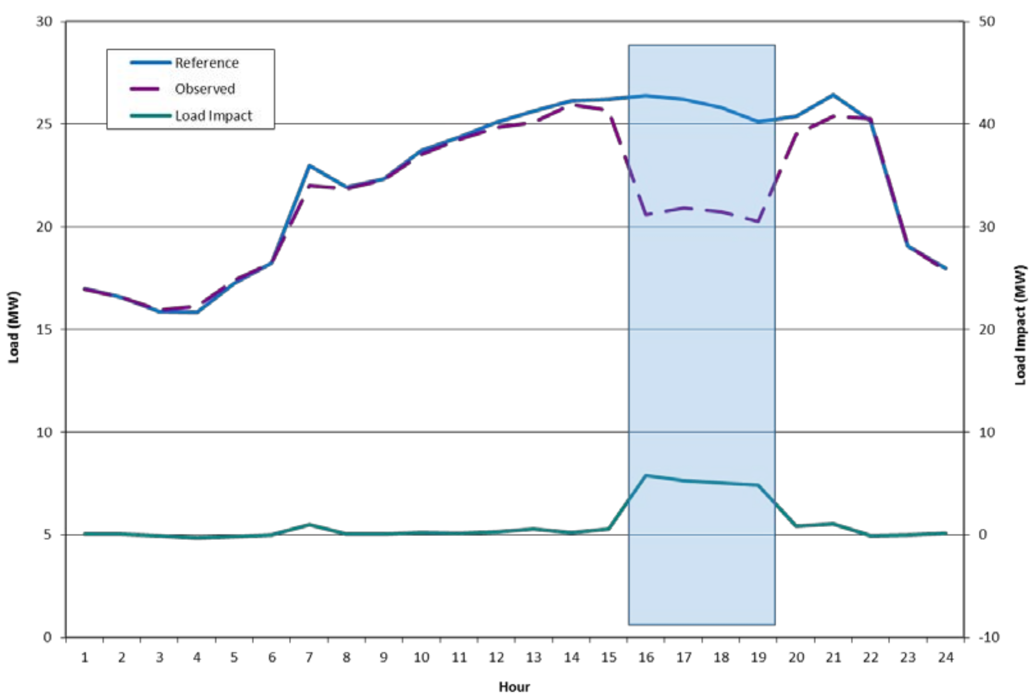


Figure 4–2: Hourly Loads and Load Impacts – PG&E CBP DO 2-6
July 2, 2013 Event



4.1.4 Load impacts of TA/TI and AutoDR participants

This section describes the *ex-post* load impacts achieved by PG&E CBP 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 TA portion of the program subsidizes 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.

Tables 4–5 and 4–6 summarize event-specific *total* load impacts for TA/TI and AutoDR participants, respectively. These represent the sum of the estimated load impacts for customers in each program, as estimated using the customer-level *ex-post* regression methods.

Table 4–5 shows that an average of three CBP DA customers and 39 CBP DO customers participated in TA/TI and achieved load impacts for the average event of 0.02 and 0.92 MW respectively. The rightmost column (Load Shed Test) shows the total load shed amount approved following the TA/TI DR test.

Table 4–5: Load Impacts of TA/TI Participants – *PG&E CBP*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Test MW
DA	7/1/2013						
	7/2/2013						
	7/3/2013						
	9/9/2013						
	9/10/2013						
	Ave. of Typical Events						
DO	6/7/2013						
	7/1/2013	39	15.02	16.10	1.08	7.2%	4.38
	7/2/2013	39	15.28	16.24	0.96	6.3%	4.38
	9/9/2013	39	13.42	14.14	0.72	5.3%	4.38
	9/10/2013						
	Ave. of Typical Events	**39**	**14.58**	**15.50**	**0.92**	**6.3%**	**4.38**

Table 4–6 shows comparable information for CBP customers who have participated in AutoDR. An average of 44 CBP DO customers are AutoDR participants, and their estimated load impacts for the average event are 0.46 MW, representing 4 percent of their reference load. Performance was greater on the September 9 event.

Table 4–6: Load Impacts of AutoDR Participants – *PG&E CBP*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Test MW
DO	6/7/2013						
	7/1/2013	47	13.05	13.04	-0.02	-0.1%	7.65
	7/2/2013	47	12.84	12.84	0.00	0.0%	7.65
	9/9/2013	38	8.16	9.54	1.38	17.0%	6.18
	9/10/2013						
	Ave. of Typical Events	**44**	**11.35**	**11.81**	**0.46**	**4.0%**	**7.16**

4.2 Capacity Bidding Program (CBP) – SCE

4.2.1 Events for SCE CBP

Tables 4–7a and 4–7b list the events called for SCE's CBP program in 2013. Twenty-eight DA events were called over the period from May through September (analysis of the twenty-ninth event in December was not included in this study), though not all DA product types were called for each event. The DO product types were called four times. Events were called for a number of different hour combinations, ranging from one to eight hours in length.

Table 4–7a: Event Summary for 2013 (May – June) – SCE CBP

Event Num.	Date	Day of Week	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
1	5/1/13	Wednesday	DA 1-4 Hour	13 - 15	3	1.63
			DA 2-6 Hour	13 - 15	1	0.10
2	5/2/13	Thursday	DA 1-4 Hour	14 - 17	3	1.63
			DA 2-6 Hour	14 - 17	1	0.10
			DA 4-8 Hour	14 - 17	1	2.53
3	5/3/13	Friday	DA 1-4 Hour	14 - 17	3	1.63
			DA 2-6 Hour	14 - 17	1	0.10
			DA 4-8 Hour	14 - 17	1	2.53
4	5/13/13	Monday	DA 1-4 Hour	14 - 17	3	1.63
			DA 2-6 Hour	14 - 17	1	0.10
			DA 4-8 Hour	14 - 17	1	2.53
			DO 1-4 Hour	14 - 17	4	2.34
			DO 2-6 Hour	13 - 18	2	8.26
5	5/14/13	Tuesday	DA 1-4 Hour	15 - 16	3	1.63
			DA 2-6 Hour	15 - 16	1	0.10
			DA 4-8 Hour	14 - 17	1	2.53
6	5/15/13	Wednesday	DA 1-4 Hour	17	3	1.63
7	5/20/13	Monday	DA 1-4 Hour	17	3	1.63
			DA 2-6 Hour	16 - 17	1	0.10
			DA 4-8 Hour	15 - 18	1	2.53
8	5/21/13	Tuesday	DA 1-4 Hour	15 - 17	3	1.63
			DA 2-6 Hour	15 - 17	1	0.10
9	5/30/13	Thursday	DA 1-4 Hour	15 - 17	3	1.63
			DA 2-6 Hour	15 - 17	1	0.10
10	5/31/13	Friday	DA 1-4 Hour	15 - 18	3	1.63
			DA 2-6 Hour	15 - 18	1	0.10
			DA 4-8 Hour	15 - 18	1	2.53
11	6/28/13	Friday	DA 4-8 Hour	15 - 18	1	1.95
			DO 1-4 Hour	14 - 17	4	3.96
			DO 2-6 Hour	13 - 18	2	8.28

Table 4–7b: Event Summary for 2013 (July – December) – SCE CBP

Event Num.	Date	Day of Week	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
12	7/1/13	Monday	DA 1-4 Hour	15 - 18	2	0.11
			DA 2-6 Hour	14 - 19	1	0.70
			DA 4-8 Hour	13 - 19	1	1.93
13	7/2/13	Tuesday	DA 1-4 Hour	15 - 18	2	0.11
			DA 2-6 Hour	14 - 19	1	0.70
			DA 4-8 Hour	12 - 19	1	1.93
14	7/3/13	Wednesday	DA 1-4 Hour	16 - 17	2	0.11
			DA 2-6 Hour	16 - 17	1	0.70
15	7/9/13	Tuesday	DA 1-4 Hour	16 - 17	2	0.11
			DA 2-6 Hour	16 - 17	1	0.70
16	7/15/13	Monday	DA 1-4 Hour	16 - 17	2	0.11
			DA 2-6 Hour	16 - 17	1	0.70
17	7/16/13	Tuesday	DA 1-4 Hour	16 - 17	2	0.11
			DA 2-6 Hour	16 - 17	1	0.70
18	7/19/13	Friday	DA 1-4 Hour	16 - 17	2	0.11
			DA 2-6 Hour	16 - 17	1	0.70
19	7/22/13	Monday	DA 1-4 Hour	17	2	0.11
20	8/15/13	Thursday	DA 1-4 Hour	17	2	0.65
21	8/22/13	Thursday	DA 1-4 Hour	17	2	0.65
22	8/28/13	Wednesday	DA 1-4 Hour	16 - 17	2	0.65
			DA 2-6 Hour	16 - 17	2	8.23
23	8/29/13	Thursday	DA 1-4 Hour	16 - 17	2	0.65
			DA 2-6 Hour	16 - 17	2	8.23
			DO 1-4 Hour	15 - 18	5	21.1
			DO 2-6 Hour	15 - 19	2	8.23
24	8/30/13	Friday	DA 1-4 Hour	17	2	0.65
			DO 1-4 Hour	12 - 15	5	21.1
			DO 2-6 Hour	12 - 17	2	8.23
25	9/4/13	Wednesday	DA 1-4 Hour	15 - 17	2	0.65
			DA 2-6 Hour	15 - 17	1	0.90
26	9/5/13	Thursday	DA 1-4 Hour	17	2	0.65
27	9/6/13	Friday	DA 1-4 Hour	14 - 17	2	0.65
			DA 2-6 Hour	14 - 18	1	0.90
			DA 4-8 Hour	14 - 18	1	1.92
28	9/9/13	Monday	DA 1-4 Hour	15 - 17	2	0.65
			DA 2-6 Hour	15 - 17	1	0.90
29	12/9/13	Monday	DA 1-4 Hour	18 - 19	2	10.5
			DA 2-6 Hour	18 - 19	1	0.80

4.2.2 Summary load impacts

The two parts of Table 4–8 show average event-hour estimated reference load, observed load, load impacts and percentage load impacts for the DA and DO notice and associated product types, for each of SCE's CBP events, and for averages across each of the respective events by product type.[13] The average event-hour DA load impact was approximately 4 MW across the three product types. Day-of load impacts averaged 9.1 MW for the 1-4 Hour product, and 9.3 MW for the 2-6 Hour product. Average percentage load impacts were 29 and 16 percent for the two DO product types.

[13] The numbers of accounts shown in the table represent the number of nominated customers of a given product type called for an event for whom all data were available and regression models were estimated. These numbers may sometimes differ slightly from the recorded number of nominated customers in cases where complete data for particular customer accounts were not available and regressions could not be estimated.

Table 4–8a: Average Event-Hour Load Impacts by Event (May – July) – *SCE CBP*

Event No.	Event Date	Notice / Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Settlement LI (MW)
1	5/1/13	DA 1-4 Hour	18	402.6	35.5	7.2	0.64	9%	68.9	0.34
		DA 2-6 Hour	6	1,678.8	1,069.6	10.1	6.42	64%	80.0	6.68
2	5/2/13	DA 1-4 Hour	18	398.8	32.7	7.2	0.59	8%	85.1	0.66
		DA 2-6 Hour	6	1,574.3	-86.1	9.4	-0.52	-5%	85.7	0.64
		DA 4-8 Hour	8	322.2	234.9	2.6	1.88	73%	88.0	2.52
3	5/3/13	DA 1-4 Hour	18	424.1	48.4	7.6	0.87	11%	83.4	0.66
		DA 2-6 Hour	6	1,894.7	160.1	11.4	0.96	8%	92.1	0.20
		DA 4-8 Hour	8	460.5	336.8	3.7	2.69	73%	88.0	2.23
4	5/13/13	DA 1-4 Hour	18	412.8	26.4	7.4	0.47	6%	86.9	0.65
		DA 2-6 Hour	6	1,900.2	10.0	11.4	0.06	1%	100.9	-1.31
		DA 4-8 Hour	8	398.8	304.8	3.2	2.44	76%	89.5	1.97
		DO 1-4 Hour	94	107.7	28.8	10.1	2.71	27%	94.1	1.65
		DO 2-6 Hour	207	273.4	51.8	56.6	10.73	19%	89.6	9.93
5	5/14/13	DA 1-4 Hour	18	415.2	37.0	7.5	0.67	9%	74.6	0.52
		DA 2-6 Hour	6	1,673.0	210.1	10.0	1.26	13%	93.1	1.31
		DA 4-8 Hour	8	375.7	292.8	3.0	2.34	78%	74.7	2.06
6	5/15/13	DA 1-4 Hour	18	396.6	27.0	7.1	0.49	7%	70.4	0.37
7	5/20/13	DA 1-4 Hour	18	405.9	1.1	7.3	0.02	0%	77.2	0.01
		DA 2-6 Hour	6	1,861.8	-131.0	11.2	-0.79	-7%	92.3	-1.95
		DA 4-8 Hour	8	395.8	304.4	3.2	2.44	77%	75.2	1.84
8	5/21/13	DA 1-4 Hour	18	391.5	-7.2	7.0	-0.13	-2%	74.0	0.10
		DA 2-6 Hour	6	1,813.8	193.8	10.9	1.16	11%	90.2	0.29
9	5/30/13	DA 1-4 Hour	18	399.4	22.4	7.2	0.40	6%	74.1	0.53
		DA 2-6 Hour	6	1,815.3	-100.6	10.9	-0.60	-6%	88.7	-1.42
10	5/31/13	DA 1-4 Hour	18	402.0	4.0	7.2	0.07	1%	75.0	0.23
		DA 2-6 Hour	6	1,821.0	-94.7	10.9	-0.57	-5%	91.9	-1.44
		DA 4-8 Hour	8	448.0	-9.5	3.6	-0.08	-2%	73.5	-1.12
11	6/28/13	DA 4-8 Hour	7	261.4	63.8	1.8	0.45	24%	82.2	0.24
		DO 1-4 Hour	197	161.6	9.2	31.8	1.80	6%	91.5	2.81
		DO 2-6 Hour	208	279.6	29.8	58.2	6.20	11%	88.2	6.88
12	7/1/13	DA 1-4 Hour	2	276.3	33.9	0.6	0.07	12%	94.4	0.03
		DA 2-6 Hour	2	898.9	426.0	1.8	0.85	47%	82.6	0.81
		DA 4-8 Hour	7	285.3	161.8	2.0	1.13	57%	80.5	1.14
13	7/2/13	DA 1-4 Hour	2	287.4	56.0	0.6	0.11	19%	90.0	0.06
		DA 2-6 Hour	2	1,084.7	618.8	2.2	1.24	57%	74.7	0.82
		DA 4-8 Hour	7	331.6	241.4	2.3	1.69	73%	72.5	1.35
14	7/3/13	DA 1-4 Hour	2	277.4	33.8	0.6	0.07	12%	91.0	0.02
		DA 2-6 Hour	2	843.6	454.3	1.7	0.91	54%	76.9	0.98
15	7/9/13	DA 1-4 Hour	2	287.2	38.1	0.6	0.08	13%	93.5	0.00
		DA 2-6 Hour	2	1,063.9	697.5	2.1	1.40	66%	77.9	0.93
16	7/15/13	DA 1-4 Hour	2	267.8	20.6	0.5	0.04	8%	89.5	0.00
		DA 2-6 Hour	2	676.2	265.4	1.4	0.53	39%	78.7	0.80
17	7/16/13	DA 1-4 Hour	2	284.5	36.7	0.6	0.07	13%	89.1	0.00
		DA 2-6 Hour	2	850.3	436.5	1.7	0.87	51%	78.4	0.80
18	7/19/13	DA 1-4 Hour	2	259.7	-22.8	0.5	-0.05	-9%	91.7	-0.07
		DA 2-6 Hour	2	789.2	-50.9	1.6	-0.10	-6%	73.4	-0.10
19	7/22/13	DA 1-4 Hour	2	257.8	22.5	0.5	0.05	9%	86.7	0.01

Table 4–8b: Average Event-Hour Load Impacts by Event (Aug. – Sept.) – *SCE CBP*

Event No.	Event Date	Notice / Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Settlement LI (MW)
20	8/15/13	DA 1-4 Hour	5	712.4	122.4	3.6	0.61	17%	75.7	0.64
21	8/22/13	DA 1-4 Hour	5	747.3	182.8	3.7	0.91	24%	83.3	0.80
22	8/28/13	DA 1-4 Hour	5	745.2	152.8	3.7	0.76	20%	83.7	0.69
		DA 2-6 Hour	2	823.8	174.9	1.6	0.35	21%	83.3	0.83
23	8/29/13	DA 1-4 Hour	5	742.0	136.7	3.7	0.68	18%	87.2	0.62
		DA 2-6 Hour	2	918.4	259.9	1.8	0.52	28%	86.4	0.81
		DO 1-4 Hour	278	153.0	61.7	42.5	17.15	40%	90.2	17.91
		DO 2-6 Hour	208	281.5	49.8	58.6	10.36	18%	89.2	11.50
24	8/30/13	DA 1-4 Hour	5	776.0	85.7	3.9	0.43	11%	87.0	0.23
		DO 1-4 Hour	278	149.9	53.2	41.7	14.79	35%	89.7	17.34
		DO 2-6 Hour	208	287.2	47.7	59.7	9.92	17%	89.2	11.77
25	9/4/13	DA 1-4 Hour	5	744.5	10.9	3.7	0.05	1%	90.1	-0.05
		DA 2-6 Hour	3	1,427.5	136.0	4.3	0.41	10%	88.3	0.83
26	9/5/13	DA 1-4 Hour	5	783.9	34.7	3.9	0.17	4%	90.5	-0.04
27	9/6/13	DA 1-4 Hour	5	760.5	71.4	3.8	0.36	9%	89.2	0.14
		DA 2-6 Hour	3	1,401.3	184.0	4.2	0.55	13%	88.3	0.99
		DA 4-8 Hour	8	606.6	523.1	4.9	4.18	86%	90.6	2.23
28	9/9/13	DA 1-4 Hour	5	718.7	19.8	3.6	0.10	3%	76.1	0.12
		DA 2-6 Hour	3	1,412.5	219.3	4.2	0.66	16%	89.0	1.06
	Average Event	DA 1-4 Hour	9	460.3	35.7	4.11	0.32	8%	79.8	0.27
		DA 2-6 Hour	4	1,541.0	192.2	5.94	0.74	12%	90.1	0.55
		DA 4-8 Hour	8	392.3	248.9	3.02	1.92	63%	79.6	1.45
		DO 1-4 Hour	212	149.0	43.0	31.5	9.11	29%	90.8	9.93
		DO 2-6 Hour	208	280.4	44.8	58.3	9.30	16%	89.0	10.02

Table 4–9 shows the distribution of average event-hour load impacts for the typical event, by industry type. The majority of DA load impacts came from the Wholesale, Transport, and other utilities industry type. More than half of the DO load impacts were concentrated in the Retail Stores industry type.

Table 4–9: Distribution of Average Event-Hour Load Impacts by Industry Type – SC*E CBP*

			Average Customer		Aggregate			
Notice	Industry	Number of Accounts	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	2	775.4	481.9	1.55	0.96	62%	77.2
	Manufacturing	1	883.5	51.2	1.04	0.06	6%	86.0
	Wholesale, Transport, other utilities	10	754.6	175.1	7.86	1.82	23%	89.0
	Retail stores	5	309.0	15.7	1.69	0.09	5%	76.7
	Offices, Hotels, Finance, Services	1	659.1	30.8	0.93	0.04	5%	78.1
	Schools	-	-	-	-	-	-	-
	Institutional/Government	-	-	-	-	-	-	-
	Other or unknown							
	Total DA	**20**	**638.2**	**145.4**	**13.1**	**3.0**	**23%**	**85.1**
DO	Agriculture, Mining & Construction	7	125.8	30.5	0.88	0.21	24%	89.6
	Manufacturing	8	952.9	133.2	7.38	1.03	14%	93.0
	Wholesale, Transport, other utilities	5	1,325.6	1,047.5	6.63	5.24	79%	86.6
	Retail stores	392	186.7	29.3	73.24	11.50	16%	89.3
	Offices, Hotels, Finance, Services	3	178.2	63.6	0.45	0.16	36%	86.2
	Schools	4	238.2	57.6	0.95	0.23	24%	91.3
	Institutional/Government	1	276.3	44.0	0.28	0.04	16%	89.7
	Other or unknown							
	Total DO	**420**	**214.1**	**43.9**	**89.8**	**18.4**	**21%**	**89.6**

Table 4–10 shows the distribution of average event-hour load impacts by LCA. Most of the load impacts for both notice types occurred in the LA Basin.

Table 4–10: Distribution of Average Event-Hour Load Impacts by LCA – *SCE CBP*

			Average Customer		Aggregate			
Notice	LCA	Number of Accounts	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.
DA	LA Basin	17	653.4	123.8	10.9	2.1	19%	85.7
	Outside LA	-	-	-	-	-	-	-
	Ventura	4	573.1	238.1	2.2	0.9	42%	81.0
	Total DA	**20**	**638.2**	**145.4**	**13.1**	**3.0**	**23%**	**85.1**
DO	LA Basin	317	219.3	48.3	69.4	15.3	22%	89.5
	Outside LA	29	224.6	32.9	6.5	0.9	15%	94.3
	Ventura	74	187.8	29.6	13.9	2.2	16%	87.8
	Total DO	**420**	**214.1**	**43.9**	**89.8**	**18.4**	**21%**	**89.6**

Table 4–11 summarizes average event-hour load impacts for SCE CBP customer accounts located in the Southern Orange County and South of Lugo areas.[14]

[14] Load impacts for each event are available in the *ex-post* table generators.

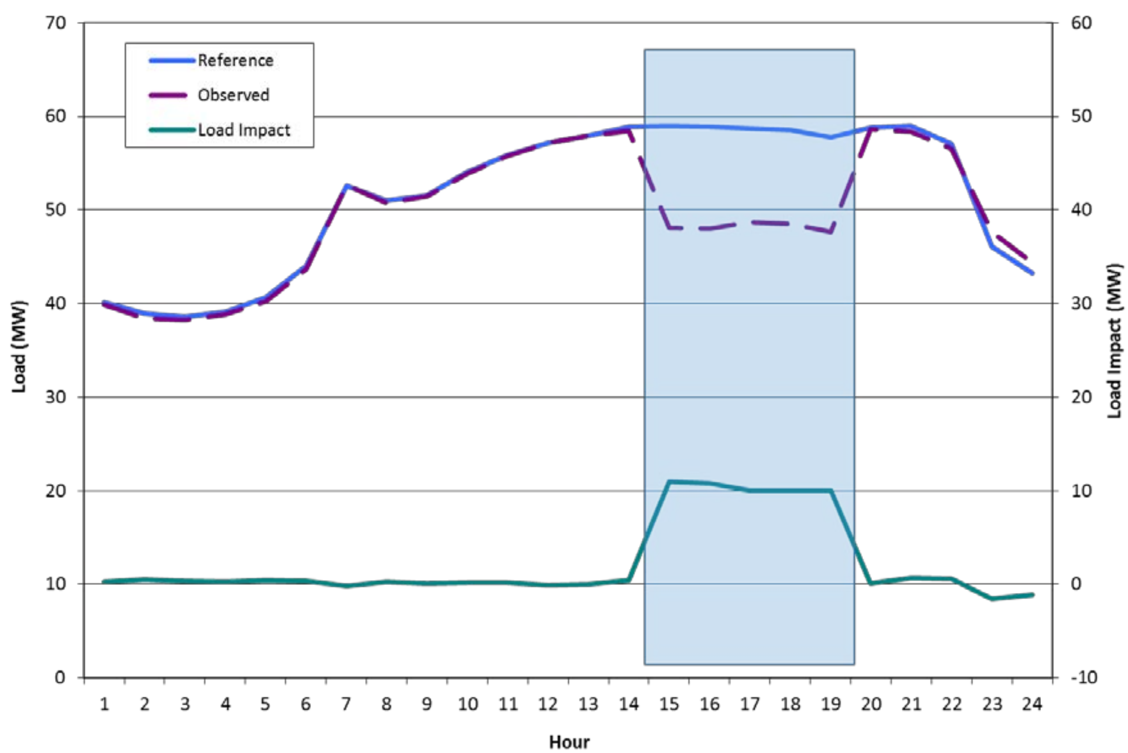
Table 4–11: Average Event-Hour Load Impacts – *SCE CBP*
(Southern Orange County and South of Lugo)

Area	Event	Notice / Product	Number of Accounts	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.
Southern Orange County	Average Event	DA 1-4 Hour	3	562.1	25.9	1.58	0.07	5%	76.5
		DA 2-6 Hour	1	627.0	15.5	0.63	0.02	2%	80.3
		DA 4-8 Hour	-	-	-	-	-	-	-
		DO 1-4 Hour	26	109.4	21.7	2.84	0.56	20%	85.4
		DO 2-6 Hour	23	290.9	42.3	6.69	0.97	15%	84.4
South of Lugo	Average Event	DA 1-4 Hour	2	510.3	80.1	1.08	0.17	16%	88.8
		DA 2-6 Hour	2	1,963.5	164.2	3.93	0.33	8%	88.2
		DA 4-8 Hour	-	-	-	-	-	-	-
		DO 1-4 Hour	65	133.8	28.4	8.66	1.84	21%	93.4
		DO 2-6 Hour	53	286.4	51.2	15.18	2.71	18%	93.0

4.2.3 Hourly load impacts

Figure 4–3 illustrates the hourly profiles of the estimated reference load, observed load, and estimated load impacts (in MW) of the SCE CBP DO 2-6 product type for the five-hour August 29 event, which was called from hours-ending 15 to 19. Estimated load impacts are approximately 10 MW in each event-hour.

Figure 4–3: Hourly Loads and Load Impacts – SCE CBP DO 2-6
August 29 Event



4.2.4 Load impacts of TA/TI and AutoDR participants

Table 4–12 shows average event-hour load impacts by event for CBP customer accounts that have participated in TA/TI. Their load impacts averaged 1.2 MW, which compares favorably to their approved load shed test of 1.8 MW.

Table 4–12: Load Impacts of TA/TI Participants – *SCE CBP*

Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
5/13/13	35	9.8	8.6	1.2	12.5%	1.8
6/28/13	35	9.9	9.1	0.8	8.0%	1.8
8/29/13	37	10.4	9.1	1.3	12.8%	1.8
8/30/13	37	10.7	9.3	1.4	12.7%	1.8

Table 4–13 shows load impacts for AutoDR participants in CBP. The differences in numbers of customers across events reflects relatively small numbers of DA customers, who generally provided less than 100 kW of load impacts, compared to their load shed test amounts of 0.5 to 1 MW. About 160 AutoDR participants in CBP DO provided 2.6 MW of load impacts for the two late-August DO events, about half of their load shed test amount of approximately 5.5 MW.

Table 4–13: Load Impacts of AutoDR Participants – *SCE CBP*

Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
5/1/13	4	3.0	2.9	0.05	2%	1.14
5/2/13	4	2.9	2.8	0.09	3%	1.14
5/3/13	4	3.0	2.8	0.15	5%	1.14
5/13/13	88	9.5	7.9	1.62	17%	3.22
5/14/13	4	2.9	2.8	0.15	5%	1.14
5/15/13	3	2.2	2.1	0.11	5%	0.69
5/20/13	4	2.9	2.8	0.05	2%	1.14
5/21/13	4	3.0	2.9	0.13	4%	1.14
5/30/13	4	2.8	2.7	0.12	4%	1.14
5/31/13	4	2.8	2.9	-0.04	-1%	1.14
6/28/13	158	12.7	11.0	1.71	13%	5.20
7/1/13	2	0.7	0.7	0.01	1%	0.46
7/2/13	2	0.7	0.7	0.02	3%	0.46
7/3/13	2	0.7	0.6	0.03	5%	0.46
7/9/13	2	0.7	0.6	0.04	6%	0.46
7/15/13	2	0.7	0.7	-0.01	-2%	0.46
7/16/13	2	0.7	0.7	0.01	1%	0.46
7/19/13	2	0.6	0.7	-0.04	-6%	0.46
7/22/13	1	0.1	0.1	0.00	0%	0.01
8/15/13	2	1.2	1.2	0.07	6%	0.14
8/22/13	2	1.3	1.2	0.07	5%	0.14
8/28/13	3	2.0	1.9	0.08	4%	0.59
8/29/13	160	15.5	12.9	2.56	17%	5.76
8/30/13	159	14.8	12.2	2.58	17%	5.30
9/4/13	3	2.0	1.8	0.18	9%	0.59
9/5/13	2	1.3	1.2	0.07	5%	0.14
9/6/13	3	2.1	1.9	0.17	8%	0.59
9/9/13	3	2.0	1.9	0.08	4%	0.59

4.3 Capacity Bidding Program (CBP) – SDG&E

4.3.1 Events for SDG&E CBP

Table 4–14 lists SDG&E's CBP events in 2013. One was a DA-only event, three were DO-only events, and the remainder were combination DA and DO events. Also indicated are four days on which CPP-D events were called along with CBP events. Due to dual enrollment in those programs by a few customer accounts, the load impacts reported below differ somewhat between CBP-only and CBP/CPP-D event days.

Table 4–14: Event Summary for 2013 – *SDG&E CBP*

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
6/28/2013	Friday	DO	1-4 Hour	15-18	3	6.74
			2-6 Hour	15-18	3	3.56
7/1/2013	Monday	DA	1-4 Hour	15-18	3	9.15
8/28/2013	Wednesday	DO	1-4 Hour	16-19	3	7.85
			2-6 Hour	16-19	3	3.56
8/29/2013*	Thursday	DA	1-4 Hour	16-19	5	10.2
		DO	1-4 Hour	15-18	3	7.85
			2-6 Hour	15-18	3	3.56
8/30/2013	Friday	DA	1-4 Hour	15-18	5	10.2
		DO	1-4 Hour	14-17	3	7.85
			2-6 Hour	14-17	3	3.56
9/3/2013	Tuesday	DO	1-4 Hour	14-17	3	7.66
			2-6 Hour	14-17	3	3.59
9/4/2013*	Wednesday	DA	1-4 Hour	14-17	5	10.2
		DO	1-4 Hour	14-17	3	7.66
			2-6 Hour	14-17	3	3.59
9/5/2013*	Thursday	DA	1-4 Hour	14-17	5	10.2
		DO	1-4 Hour	14-17	3	7.66
			2-6 Hour	14-17	3	3.59
9/6/2013*	Friday	DA	1-4 Hour	14-17	5	10.2
		DO	1-4 Hour	14-17	3	7.66
			2-6 Hour	14-17	3	3.59

*Indicates CPP-D event day

4.3.2 Summary load impacts

Table 4–15 shows average event-hour estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO notice and associated product types, for each of SDG&E's CBP events, and for averages across each of the respective typical events. The average event-hour DA load impact was 10.8 MW, while DO load impacts averaged 6 MW for the 1-4 Hour product, and 4.5 MW for the 2-6 Hour product. Average percentage load impacts were 25 percent for the DA product, and 16 to 19 percent for the two DO product types.

Table 4–15: Average Event-Hour Load Impacts by Event – *SDG&E CBP*

				Average Customer		Aggregate				
Event Date	Notice	Product	Accounts Called	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.	Nominated Capacity (MW)
6/28/2013	DO	1-4 Hour	163	188.1	31.6	30.7	5.1	17%	81.5	6.7
		2-6 Hour	80	287.2	51.0	23.0	4.1	18%	82.8	3.6
7/1/2013	DA	1-4 Hour	132	286.3	62.8	37.8	8.3	22%	81.5	9.1
8/28/2013	DO	1-4 Hour	184	204.6	34.9	37.6	6.4	17%	82.2	7.9
		2-6 Hour	80	286.8	54.7	22.9	4.4	19%	82.7	3.6
8/29/2013*	DA	1-4 Hour	143	284.2	81.6	40.6	11.7	29%	86.1	10.2
	DO	1-4 Hour	184	211.3	38.6	38.9	7.1	18%	86.2	7.9
		2-6 Hour	80	293.6	58.3	23.5	4.7	20%	86.5	3.6
8/30/2013	DA	1-4 Hour	143	307.2	80.8	43.9	11.6	26%	89.0	10.2
	DO	1-4 Hour	184	220.8	29.2	40.6	5.4	13%	89.6	7.9
		2-6 Hour	80	307.8	58.4	24.6	4.7	19%	89.8	3.6
9/3/2013	DO	1-4 Hour	182	205.7	32.2	37.4	5.9	16%	86.0	7.7
		2-6 Hour	80	296.8	57.8	23.7	4.6	19%	86.6	3.6
9/4/2013*	DA	1-4 Hour	144	318.1	79.9	45.8	11.5	25%	89.4	10.2
	DO	1-4 Hour	182	208.3	34.9	37.9	6.4	17%	87.9	7.7
		2-6 Hour	80	299.9	57.9	24.0	4.6	19%	88.5	3.6
9/5/2013*	DA	1-4 Hour	144	317.7	72.6	45.8	10.5	23%	87.5	10.2
	DO	1-4 Hour	182	205.8	31.0	37.5	5.6	15%	86.5	7.7
		2-6 Hour	80	296.9	56.6	23.7	4.5	19%	87.0	3.6
9/6/2013*	DA	1-4 Hour	144	313.6	76.7	45.2	11.0	24%	91.5	10.2
	DO	1-4 Hour	182	211.1	31.5	38.4	5.7	15%	90.0	7.7
		2-6 Hour	80	300.1	57.3	24.0	4.6	19%	90.6	3.6
Average of Typical Events	DA	1-4 Hour	142	304.8	75.9	43.2	10.8	25%	87.7	10.0
	DO	1-4 Hour	180	207.2	33.0	37.4	6.0	16%	86.4	7.6
		2-6 Hour	80	296.1	56.5	23.7	4.5	19%	86.9	3.6

*Indicates CPP-D event day

Table 4–16 shows the distribution of average event-hour load impacts for the average event by industry type. Most of the DA load impacts came from a small number of large Manufacturing customer accounts, while the larger number of commercial building accounts produced 0.8 MW of load reductions. The majority of DO load impacts were provided by retail stores.

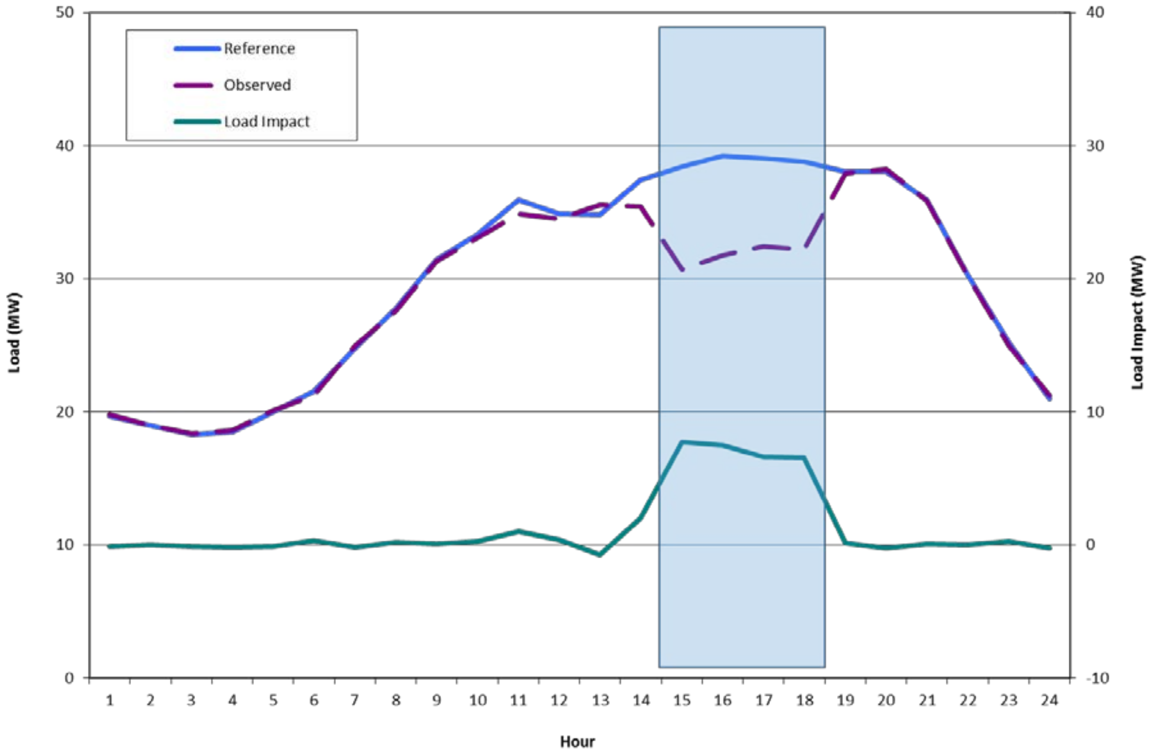
Table 4–16: Distribution of Average Event-Hour Load Impacts by Industry Type – *SDG&E CBP*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	-	-	-	-	-	-	-
	Manufacturing	12	1,054.0	702.8	13.0	8.7	0.67	86.7
	Wholesale, Transport, other utilities	7	327.7	127.2	2.2	0.9	0.39	94.2
	Retail stores	33	198.3	5.5	6.4	0.2	0.03	89.3
	Offices, Hotels, Finance, Services	78	258.5	9.9	20.2	0.8	0.04	86.7
	Schools	9	78.9	10.5	0.7	0.1	0.13	95.2
	Institutional/Government	3	208.4	56.4	0.6	0.2	0.27	85.8
	Other or unknown							
	Total DA	**142**	**304.8**	**75.9**	**43.2**	**10.8**	**0.25**	**87.7**
DO	Agriculture, Mining & Construction	-	-	-	-	-	-	-
	Manufacturing	3	184.1	37.5	0.5	0.1	0.20	84.1
	Wholesale, Transport, other utilities	10	126.7	55.9	1.3	0.6	0.44	88.7
	Retail stores	217	209.0	26.7	45.4	5.8	0.13	86.7
	Offices, Hotels, Finance, Services	28	343.8	23.8	9.5	0.7	0.07	85.5
	Schools	-	-	-	-	-	-	-
	Institutional/Government	3	1,480.4	1,119.9	4.4	3.4	0.76	91.9
	Other or unknown							
	Total DO	**260**	**234.6**	**40.2**	**61.1**	**10.5**	**0.17**	**86.6**

4.3.3 Hourly load impacts

Figure 4–4 illustrates the hourly profiles of the estimated reference load, observed load, and estimated load impacts (in MW) of the SDG&E DO 1-4 product type for the four-hour August 29 event, which was called for hours-ending 15-18.

Figure 4–4: Hourly Loads and Load Impacts – SDG&E CBP DO 1-4
August 29 Event



4.2.4 Load impacts of TA/TI and AutoDR participants

Table 4–17 shows load impacts for TA/TI participants in SDG&E's CBP program. Eight DA customers and 56 DO customers were on TA/TI. They provided averages of 0.3 and 1.9 MW in load impacts for the average event.

Table 4–17: Load Impacts of TA/TI Participants – *SDG&E CBP DA and DO*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
DA	7/1/2013	8	6.05	5.78	0.26	4.3%	1.23
	8/29/2013	8	5.41	5.18	0.22	4.2%	1.23
	8/30/2013	8	6.26	6.03	0.23	3.8%	1.23
	9/4/2013	8	6.72	6.22	0.50	7.5%	1.23
	9/5/2013	8	6.60	6.01	0.59	8.9%	1.23
	9/6/2013	8	6.35	6.20	0.15	2.4%	1.23
	Ave. of Typical Events	**8**	**6.23**	**5.90**	**0.33**	**5.3%**	**1.23**
DO	6/28/2013	58	17.31	15.29	2.03	11.7%	3.32
	8/28/2013	58	17.47	15.23	2.25	12.9%	3.32
	8/29/2013	58	17.84	15.49	2.35	13.2%	3.32
	8/30/2013	58	18.45	16.66	1.79	9.7%	3.32
	9/3/2013	57	17.82	15.98	1.84	10.3%	3.19
	9/4/2013	57	17.94	16.12	1.82	10.1%	3.19
	9/5/2013	57	17.72	16.02	1.70	9.6%	3.19
	9/6/2013	57	17.98	16.39	1.59	8.8%	3.19
	Ave. of Typical Events	**58**	**17.82**	**15.90**	**1.92**	**10.8%**	**3.25**

Table 4–18 shows load impacts for AutoDR participants, which included 3 DA customers and 36 DO customers. Those customers provided load impacts of 0.08 and 0.5 MW for the average event.

Table 4–18: Load Impacts of AutoDR Participants – *SDG&E CBP DA and DO*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
DA	7/1/2013	3	2.67	2.56	0.12	4.3%	0.54
	8/29/2013	3	2.38	2.28	0.10	4.2%	0.54
	8/30/2013	3	2.72	2.66	0.06	2.1%	0.54
	9/4/2013	3	2.93	2.89	0.05	1.6%	0.54
	9/5/2013	3	2.91	2.81	0.10	3.3%	0.54
	9/6/2013	3	2.84	2.77	0.07	2.6%	0.54
	Ave. of Typical Events	**3**	**2.74**	**2.66**	**0.08**	**3.0%**	**0.54**
DO	6/28/2013	40	7.01	6.69	0.32	4.6%	2.90
	8/28/2013	36	6.87	6.28	0.59	8.6%	2.64
	8/29/2013	36	7.14	6.40	0.73	10.3%	2.64
	8/30/2013	36	7.52	7.08	0.44	5.9%	2.64
	9/3/2013	34	6.35	5.94	0.41	6.4%	2.41
	9/4/2013	34	6.39	5.97	0.42	6.5%	2.41
	9/5/2013	34	6.34	6.02	0.32	5.1%	2.41
	9/6/2013	34	6.55	6.03	0.51	7.8%	2.41
	Ave. of Typical Events	**36**	**6.77**	**6.30**	**0.47**	**6.9%**	**2.55**

5. STUDY RESULTS – *EX-POST* LOAD IMPACTS FOR AMP PROGRAMS

This section summarizes *ex-post* load impacts for the PG&E and SCE contract-based AMP programs.

5.1 PG&E Aggregator Managed Portfolio (AMP)

5.1.1 Event Characteristics for PG&E AMP

Table 5–1 summarizes features of the AMP DA and DO events in 2013. Three full events involving all DA and DO aggregators were called, on July 1st and 2nd, and September 9th. The first event was a test event, and a re-test was called for two of the aggregators on August 19th. Similar to CBP, the last event was called only for the Fresno area, and thus only involved aggregators who offered a local product and had nominated customers in that area.

Table 5–1: Event Summary for 2013 – *PG&E AMP*

Date	Day of Week	Event Type	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
05/30/13	Thursday	Test	DA	Local	16 - 17	2	72.3
			DO	Local	16 - 17	3	96.2
				System	16 - 17	2	51.1
07/01/13	Monday	Event	DA	Local	16 - 19	2	72.3
			DO	Local	16 - 19	3	107.9
				System	16 - 19	2	60.4
07/02/13	Tuesday	Event	DA	Local	15 - 18	2	72.3
			DO	Local	16 - 19	3	107.9
				System	16 - 19	2	60.4
07/03/13	Wednesday	Event	DA	Local	16 - 19	2	72.3
08/19/13	Monday	Re-Test	DA	Local	17 - 18	1	68.0
			DO	Local	17 - 18	1	21.3
09/09/13	Monday	Event	DA	Local	16 - 19	2	72.3
			DO	Local	16 - 19	3	110.9
				System	16 - 19	2	60.4
09/10/13	Tuesday	Event (Local)	DA	Local	16 - 19	1	15.2
			DO	Local	16 - 19	3	37.5

5.1.2 Summary load impacts

Table 5–2 shows average event-hour estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO notice and associated product types, for each of PG&E's AMP events, and for the average across each of the respective typical events (*i.e.*, those for which all aggregators were called). The average event-hour DA load impact was 43.5 MW, while DO load impacts averaged 92.9 MW for the Local product, and 59.8 MW for the System product. These load impacts represented 24 percent of the reference load for the DA product, and approximately 30 percent for the two DO product types.

Table 5–2: Average Event-Hour Load Impacts by Event – *PG&E AMP*

Date	Notice	Product	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
05/30/13	DA	Local	314	438.1	132.8	137.6	41.7	30%	78.3	72.3
	DO	Local	717	401.5	130.9	287.8	93.9	33%	77.1	96.2
		System	549	303.3	96.5	166.5	53.0	32%	73.5	51.1
7/1/2013*	DA	Local	440	403.2	107.4	177.4	47.3	27%	93.6	72.3
	DO	Local	676	455.9	143.6	308.2	97.1	32%	90.3	107.9
		System	657	333.7	101.3	219.2	66.6	30%	89.0	60.4
7/2/2013*	DA	Local	440	409.4	93.9	180.2	41.3	23%	93.7	72.3
	DO	Local	676	455.4	162.7	307.9	110.0	36%	89.6	107.9
		System	657	336.8	102.3	221.3	67.2	30%	87.9	60.4
07/03/13	DA	Local	440	388.1	88.5	170.7	38.9	23%	93.2	72.3
08/19/13	DA	Local	371	475.4	122.8	176.4	45.6	26%	89.9	68.0
	DO	Local	217	381.0	46.4	82.7	10.1	12%	80.3	21.3
9/9/2013*	DA	Local	493	454.6	98.4	224.1	48.5	22%	89.7	72.3
	DO	Local	792	346.4	96.9	274.3	76.7	28%	84.5	110.9
		System	652	350.2	86.6	228.4	56.5	25%	85.8	60.4
09/10/13	DA	Local	58	989.1	283.1	57.4	16.4	29%	97.6	15.2
	DO	Local	213	254.1	163.6	54.1	34.9	64%	97.1	37.5
Average of Typical Events	DA	Local	425	418.4	102.4	178.0	43.5	24%	90.3	72.3
	DO	Local	715	411.8	132.0	294.6	94.4	32%	85.5	108.9
		System	629	332.1	96.7	208.8	60.8	29%	84.8	60.4

*Indicates PDP event day

Table 5–3 shows the distribution of average event-hour load impacts for the average AMP DA and DO event by industry type. DA load impacts were concentrated largely in the Manufacturing industry type. DO load impacts were spread across several industry types.

Table 5–3: Distribution of Average Event-Hour Load Impacts by Industry Type – *PG&E AMP*

			Average Customer		Aggregate			
Notice	Industry	Accounts Called	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	38	90.0	37.0	3.4	1.4	41%	93.2
	Manufacturing	120	803.8	237.7	96.5	28.5	30%	91.8
	Wholesale, Transport, other utilities	38	225.5	35.4	8.5	1.3	16%	93.8
	Retail stores	131	259.4	21.3	33.9	2.8	8%	90.5
	Offices, Hotels, Finance, Services	38	548.6	173.0	21.0	6.6	32%	83.6
	Schools	32	228.4	23.0	7.4	0.7	10%	89.8
	Institutional/Government	21	300.0	102.3	6.2	2.1	34%	84.9
	Other or unknown							
	Total DA	**425**	**418.4**	**102.4**	**178.0**	**43.5**	**24%**	**90.3**
DO	Agriculture, Mining & Construction	487	174.1	102.3	84.8	49.8	59%	88.1
	Manufacturing	126	1,030.4	259.5	129.3	32.6	25%	90.1
	Wholesale, Transport, other utilities	195	419.1	205.7	81.8	40.2	49%	94.6
	Retail stores	225	232.5	27.0	52.4	6.1	12%	89.1
	Offices, Hotels, Finance, Services	177	519.0	83.3	91.9	14.8	16%	76.8
	Schools	21	703.0	128.8	14.8	2.7	18%	80.5
	Institutional/Government	56	637.8	101.3	35.7	5.7	16%	71.3
	Other or unknown	57	224.0	60.8	12.8	3.5	27%	83.0
	Total DO	**1,344**	**374.6**	**115.5**	**503.4**	**155.2**	**31%**	**85.2**

Table 5–4 shows the distribution of AMP average event-hour load impacts by LCA. The majority of DA load impacts occurred outside of any of the LCAs, while DO load impacts were spread across a number of LCAs.

Table 5–4: Distribution of Average Event-Hour Load Impacts by LCA – *PG&E AMP*

[Table removed for confidentiality reasons.]

5.1.3 Hourly load impacts

Figures 5–1 and 5–2 illustrate the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) of the PG&E AMP DA 1-4 and DO 2-6 product types for the four-hour August 9 event, which was called for hours-ending 16 through19.

Figure 5–1: Hourly Loads and Load Impacts – PG&E AMP DA Local
July 1, 2013 Event

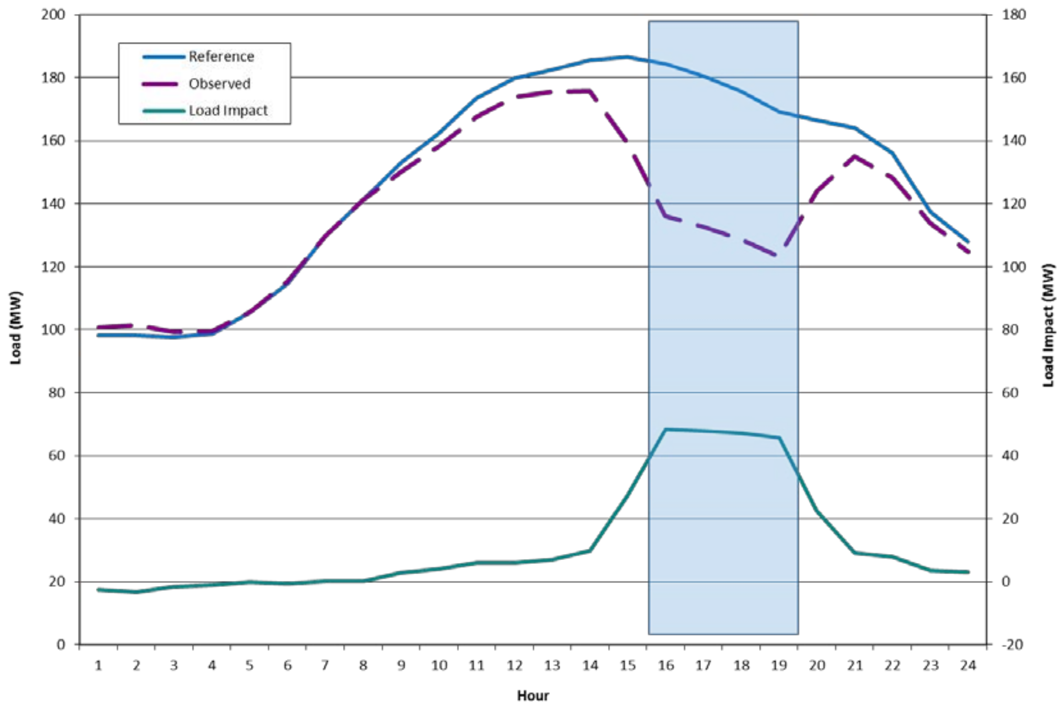
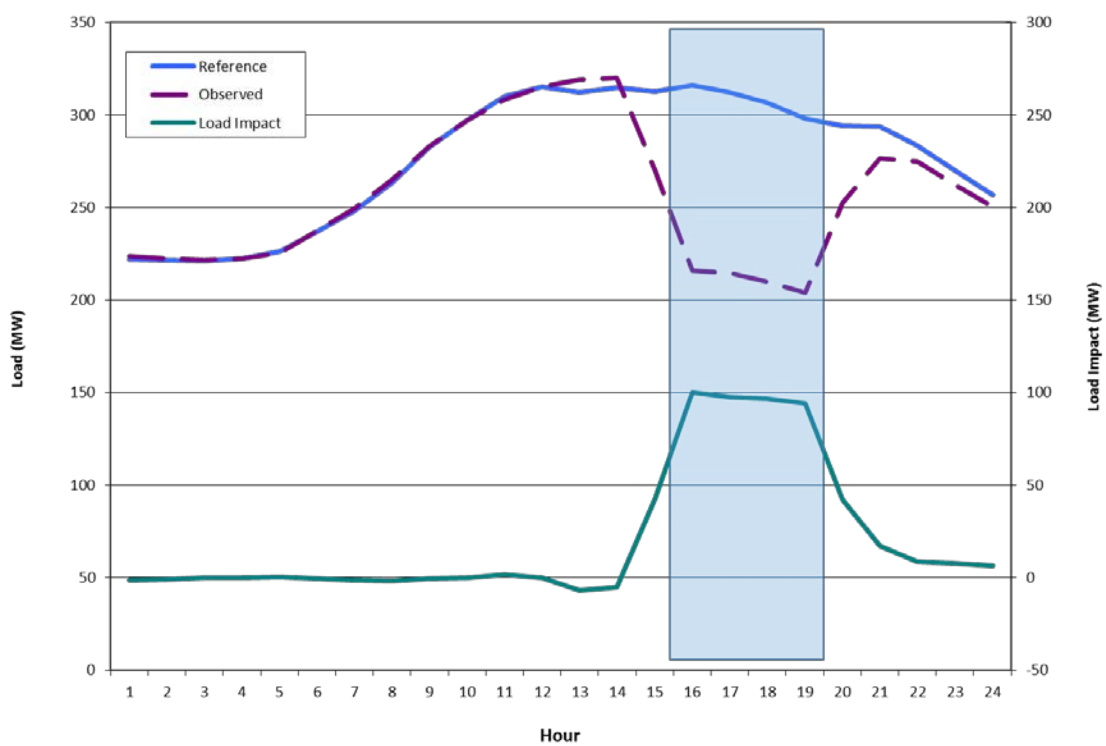


Figure 5–2: Hourly Loads and Load Impacts – PG&E AMP DO Local
July 1, 2013 Event



5.1.4 Load impacts of TA/TI and AutoDR participants

Table 5–5 shows load impacts for TA/TI participants in AMP. An average of 5 DA and 39 DO TA/TI customer accounts provided averages of 6.6 and 4.2 MW of load impacts respectively, compared to approved load shed levels of 10.3 and 15.5 MW.

Table 5–5: Load Impacts of TA/TI Participants – *PG&E AMP*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Test MW
DA	5/30/2013						
	7/1/2013						
	7/2/2013						
	7/3/2013						
	8/19/2013						
	9/9/2013						
	9/10/2013						
	Average of Typical						
DO	5/30/2013	38	19.92	15.00	4.92	24.7%	15.75
	7/1/2013	39	17.23	12.48	4.74	27.5%	15.53
	7/2/2013	39	17.27	12.65	4.61	26.7%	15.53
	9/9/2013	38	15.03	12.47	2.55	17.0%	15.34
	9/10/2013	15	4.08	2.55	1.53	37.5%	3.28
	Average of Typical	**39**	**17.36**	**13.15**	**4.21**	**24.2%**	**15.53**

As shown in Table 5–6, 34 DO AutoDR customer accounts provided 3.4 MW of load impacts, compared to 12.4 MW of approved levels.

Table 5–6: Load Impacts of AutoDR Participants – *PG&E AMP*

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Test MW
DA	7/1/2013						
	7/2/2013						
	7/3/2013						
	8/19/2013						
	9/9/2013						
	Ave. of Typical Events						
DO	5/30/2013	16	9.62	11.77	2.15	22.4%	10.34
	7/1/2013	31	11.91	14.68	2.77	23.3%	13.16
	7/2/2013	31	11.90	15.81	3.90	32.8%	13.16
	8/19/2013						
	9/9/2013	40	19.67	23.28	3.61	18.4%	10.84
	9/10/2013						
	Ave. of Typical Events	**34**	**14.49**	**17.92**	**3.43**	**23.7%**	**12.39**

5.2 SCE's AMP

5.2.1 Event Characteristics for SCE AMP

Table 5–7 summarizes SCE's AMP events in 2013, differentiated by notice and product type. DA events were called on a total of nine days, and DO events on seven days. However, most of the DO events were tests that involved only one or two aggregators, and often involved different event hours.

Table 5–7: Event Summary for 2013 – *SCE AMP*

Date	Day of Week	Product	Trigger Condition	Hours Ending	Nom. Capacity (MW)
5/2/13	Thursday	DA 4	Energy Price	14 - 17	21
5/13/13	Monday	DA 4	Energy Price	14 - 17	21
		DO 1-4	Energy Price	14 - 17	42.5
5/21/13	Tuesday	DO 1-5	Seller-Test	13	17.5
		DO 1-5	Buyer-Test	16	17
		DO 1-6	Buyer-Test	16	89.6
6/27/13	Thursday	DA 4	Energy Price	14 - 17	23
6/28/13	Friday	DA 4	Energy Price	14 - 17	23
		DO 1-6	Seller-Test	15 - 16	95.2
7/1/13	Monday	DA 4	Energy Price	14 - 17	25
7/2/13	Tuesday	DA 4	Energy Price	14 - 17	25
7/31/13	Wednesday	DO 1-5	Seller-Test	17	17
		DO 1-6	Seller-Test	15 - 16	112
8/29/13	Thursday	DO 1-4	Buyer-Test	15 - 18	50
		DO 1-5	Buyer-Test	15 - 18	17
		DO 1-5	Buyer-Test	15 - 18	25
		DO 1-6	Buyer-Test	15 - 18	112
8/30/13	Friday	DO 1-4	Energy Price	15 - 18	50
		DO 1-5	Energy Price	16 - 18	25
		DO 1-6	Energy Price	16 - 19	112
9/4/13	Wednesday	DA 4	Energy Price	14 - 17	29
9/6/13	Friday	DA 4	Energy Price	14 - 17	29
9/9/13	Monday	DA 4	Energy Price	14 - 17	29
10/17/13	Thursday	DO 1-4	Seller-Test	14 - 15	50

5.2.2 Summary load impacts

Table 5–8 shows average event-hour estimated *reference load*, *observed load*, estimated *load impacts* and *percentage load impacts* for the various product types, for each of the SCE AMP events, and for the average event. The far right column also shows load impacts for each event as calculated in SCE's settlement process. In many cases, particularly for the DO products, these estimates align closely with the *ex-post* load impacts calculated in this study. However, the two estimates do not track as closely for the DA product.

The average event for each product type is defined as the average over all events in which that product was called. The average event-hour DA load impact was 7.9 MW, while the average event-hour DO load impacts were 24.5, 15.5 and 86.4 MW for the DO 1-4, 1-5 and 1-6 hour products respectively. Average percentage load impacts ranged from 9 percent for DA to 40 percent for the DO 1-5 product.

Table 5–8: Average Event-Hour Load Impacts by Event – *SCE AMP*

Event Date	Notice / Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Settle-ment LI (MW)
5/2/13	DA 4	179	352.5	53.3	63.1	9.5	15%	85.5	4.7
5/13/13	DA 4	179	379.3	44.7	67.9	8.0	12%	91.4	-1.1
	DO 1-4	221	149.1	62.2	32.9	13.8	42%	88.2	13.2
5/21/13	DO 1-5	24	892.9	701.6	21.4	16.8	79%	68.7	16.6
	DO 1-5	142	169.8	82.1	24.1	11.7	48%	79.1	11.5
	DO 1-6	896	299.7	93.7	268.5	84.0	31%	78.8	84.8
6/27/13	DA 4	221	354.0	42.4	78.2	9.4	12%	87.5	4.8
6/28/13	DA 4	221	349.9	38.9	77.3	8.6	11%	89.3	4.8
	DO 1-6	925	336.0	99.6	310.8	92.2	30%	89.5	10.3
7/1/13	DA 4	235	347.6	30.1	81.7	7.1	9%	88.5	2.3
7/2/13	DA 4	235	347.7	47.7	81.7	11.2	14%	84.5	5.6
7/31/13	DO 1-5	143	220.0	26.7	31.5	3.8	12%	76.8	12.0
	DO 1-6	974	309.5	77.4	301.5	75.4	25%	76.8	108.8
8/29/13	DO 1-4	549	257.3	50.3	141.3	27.6	20%	90.4	29.4
	DO 1-5	1	5,193	1,102	5.2	1.1	21%	68.6	2.4
	DO 1-5	143	208.0	81.0	29.8	11.6	39%	89.9	13.3
	DO 1-6	978	340.0	96.7	332.5	94.5	28%	89.5	98.3
8/30/13	DO 1-4	549	259.1	42.1	142.2	23.1	16%	89.9	28.4
	DO 1-5	1	5,195	1,532	5.2	1.5	29%	75.3	3.0
	DO 1-6	977	330.3	88.1	322.7	86.1	27%	89.2	104.3
9/4/13	DA 4	284	450.6	41.0	128.0	11.6	9%	87.6	10.0
9/6/13	DA 4	284	439.6	8.2	124.8	2.3	2%	88.3	2.8
9/9/13	DA 4	284	417.2	10.4	118.5	3.0	2%	78.2	5.5
10/17/13	DO 1-4	633	224.2	54.7	141.9	34.6	24%	77.2	30.1
Average Event	DA 4	236	387.0	33.3	91.3	7.9	9%	86.4	4.4
	DO 1-4	488	234.8	50.8	114.6	24.8	22%	86.1	25.3
	DO 1-5	143	199.4	63.2	28.4	9.0	32%	81.4	12.3
	DO 1-5	9	1,223.7	749.0	10.6	6.5	61%	70.6	7.3
	DO 1-6	950	323.4	91.0	307.2	86.4	28%	85.0	81.3

Table 5–9 shows the distribution of average event-hour load impacts for the average event by industry type. Nearly half of DA load impacts came from Retail stores. DO load impacts were spread across a range of industry types, topped by the Wholesale, Transport, and other utilities industry type.

Table 5–9: Distribution of Average Event-Hour Load Impacts by Industry Type – *SCE AMP*

Notice	Industry	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	7	124.6	22.4	0.8	0.2	18%	93.2
	Manufacturing	66	511.6	36.9	33.8	2.4	7%	82.1
	Wholesale, Transport, other utilities	24	245.6	51.1	6.0	1.2	21%	88.6
	Retail stores	127	361.7	30.3	45.9	3.8	8%	89.3
	Offices, Hotels, Finance, Services	3	712.8	61.8	2.2	0.2	9%	81.0
	Schools	3	285.0	3.5	0.9	0.0	1%	92.4
	Institutional/Government	5	302.0	-4.3	1.6	0.0	-1%	84.8
	Total DA	**236**	**387.0**	**33.3**	**91.3**	**7.9**	**9%**	**86.4**
DO	Agriculture, Mining & Construction	213	155.4	57.5	33.1	12.3	37%	84.6
	Manufacturing	107	659.6	162.7	70.6	17.4	25%	86.3
	Wholesale, Transport, other utilities	504	193.2	121.7	97.5	61.4	63%	86.9
	Retail stores	630	274.2	25.8	172.6	16.2	9%	85.7
	Offices, Hotels, Finance, Services	108	428.9	128.2	46.5	13.9	30%	83.3
	Schools	15	2,335.9	254.9	35.2	3.8	11%	78.6
	Institutional/Government	12	449.0	142.0	5.3	1.7	32%	83.3
	Total DO	**1,589**	**290.0**	**79.7**	**460.8**	**126.7**	**27%**	**84.9**

Table 5–10 shows the distribution of average event-hour load impacts by LCA, most of which occurred in the LA Basin for both AMP DA and DO.

Table 5–10: Distribution of Average Event-Hour Load Impacts by LCA – *SCE AMP*

Notice	LCA	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	LA Basin	170	403.9	32.3	68.5	5.5	8%	85.3
	Outside LA	19	297.9	47.8	5.5	0.9	16%	95.5
	Ventura	48	361.5	31.4	17.2	1.5	9%	88.0
	Total DA	**236**	**387.0**	**33.3**	**91.3**	**7.9**	**9%**	**86.4**
DO	LA Basin	1123	319.5	89.3	358.9	100.4	28%	85.1
	Outside LA	111	181.8	63.8	20.3	7.1	35%	91.7
	Ventura	355	230.2	54.3	81.7	19.2	24%	82.8
	Total DO	**1589**	**290.0**	**79.7**	**460.8**	**126.7**	**27%**	**84.9**

Tables 5–11 and 5–12 show average hourly load impacts by event for two specific geographical areas in the SCE service area – Southern Orange County and South of Lugo.

Table 5–11: Average Event-Hour Load Impacts by Event – *SCE AMP (Southern Orange County)*

Event Date	Notice / Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
5/2/13	DA 4	11	574.7	51.4	6.3	0.6	9%	88.5
5/13/13	DA 4	11	611.6	70.6	6.7	0.8	12%	87.8
	DO 1-4	13	312.2	21.1	4.1	0.3	7%	86.7
5/21/13	DO 1-5	3	547.5	340.2	1.6	1.0	62%	72.9
	DO 1-6	84	269.0	46.4	22.6	3.9	17%	73.9
6/27/13	DA 4	14	588.1	53.1	8.2	0.7	9%	78.0
6/28/13	DA 4	14	588.9	41.3	8.2	0.6	7%	79.0
	DO 1-6	84	298.4	58.4	25.1	4.9	20%	81.3
7/1/13	DA 4	15	554.0	9.5	8.3	0.1	2%	82.9
7/2/13	DA 4	15	548.2	42.2	8.2	0.6	8%	73.4
7/31/13	DO 1-5	2	1,174.4	51.5	2.3	0.1	4%	72.8
	DO 1-6	85	280.8	0.8	23.9	0.1	0%	70.7
8/29/13	DO 1-4	61	221.9	31.6	13.5	1.9	14%	85.9
	DO 1-5	3	831.8	208.3	2.5	0.6	25%	88.0
	DO 1-6	85	314.0	53.6	26.7	4.6	17%	87.0
8/30/13	DO 1-4	61	231.1	22.6	14.1	1.4	10%	88.2
	DO 1-6	85	292.8	35.5	24.9	3.0	12%	88.6
9/4/13	DA 4	18	505.5	26.6	9.1	0.5	5%	88.5
9/6/13	DA 4	18	513.4	14.4	9.2	0.3	3%	88.3
9/9/13	DA 4	18	465.4	-12.1	8.4	-0.2	-3%	73.8
10/17/13	DO 1-4	73	182.7	37.0	13.3	2.7	20%	75.5
Average Event	DA 4	15	543.1	29.6	8.1	0.4	5%	82.0
	DO 1-4	52	216.5	30.2	11.3	1.6	14%	83.9
	DO 1-5	3	810.8	218.6	2.2	0.6	27%	78.8
	DO 1-6	85	291.0	38.9	24.6	3.3	13%	80.3

Table 5–12: Average Event-Hour Load Impacts by Event – *SCE AMP (South of Lugo)*

Event Date	Notice / Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
5/2/13	DA 4	59	347.4	49.2	20.5	2.9	14%	87.1
5/13/13	DA 4	59	376.9	53.0	22.2	3.1	14%	95.8
	DO 1-4	8	365.6	48.1	2.9	0.4	13%	94.4
5/21/13	DO 1-5	21.5	231.2	80.3	5.0	1.7	35%	83.2
	DO 1-6	342	297.5	113.2	101.7	38.7	38%	83.6
6/27/13	DA 4	69	362.4	44.6	25.0	3.1	12%	92.4
6/28/13	DA 4	69	352.8	31.5	24.3	2.2	9%	93.3
	DO 1-6	354	353.7	129.5	125.2	45.8	37%	95.1
7/1/13	DA 4	73	347.6	24.2	25.4	1.8	7%	91.9
7/2/13	DA 4	73	347.0	44.7	25.3	3.3	13%	88.0
7/31/13	DO 1-5	45	383.6	49.8	17.3	2.2	13%	78.6
	DO 1-6	360	313.8	111.9	113.0	40.3	36%	79.8
8/29/13	DO 1-4	101	284.3	25.2	28.7	2.5	9%	91.6
	DO 1-5	44	333.4	107.9	14.7	4.7	32%	91.0
	DO 1-6	357	341.6	117.8	122.0	42.1	34%	91.4
8/30/13	DO 1-4	101	290.5	21.5	29.3	2.2	7%	91.5
	DO 1-6	357	329.4	95.7	117.6	34.2	29%	90.9
9/4/13	DA 4	88	364.3	41.0	32.1	3.6	11%	96.0
9/6/13	DA 4	88	357.7	7.7	31.5	0.7	2%	95.5
9/9/13	DA 4	88	334.5	8.7	29.4	0.8	3%	84.1
10/17/13	DO 1-4	126	236.7	36.6	29.8	4.6	15%	78.3
Average Event	DA 4	74	354.0	32.1	26.2	2.4	9%	91.7
	DO 1-4	84	270.2	28.9	22.7	2.4	11%	87.5
	DO 1-5	37	334.0	78.9	12.3	2.9	24%	83.5
	DO 1-6	354	327.4	113.6	115.9	40.2	35%	88.5

5.2.3 Hourly load impacts

Figure 5–3 illustrates the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) of the SCE DRC DO 1-6 product type for the four-hour August 29 event, which was called for hours-ending 15-18. The estimated load impacts reach close to 100 MW in each of the event hours.

Figure 5–3: Hourly Loads and Load Impacts – SCE AMP DO 1-6
August 29 Event

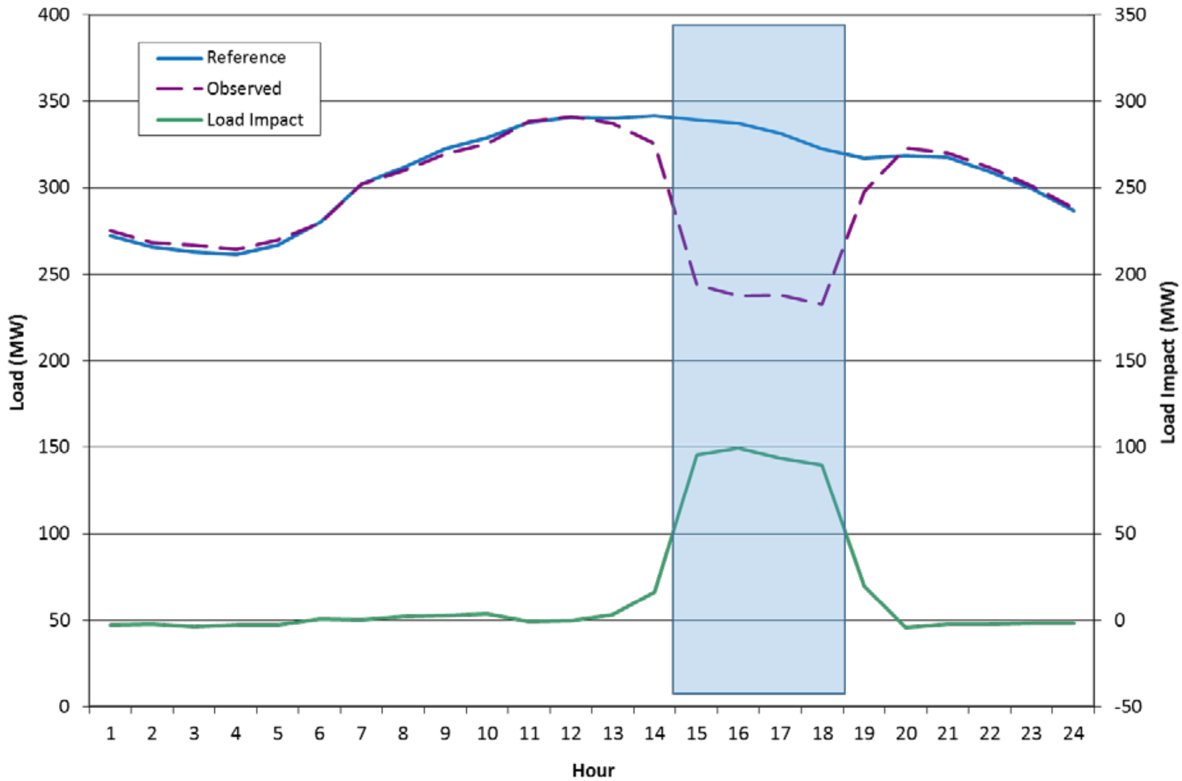


Table 5–13 shows load impacts for TA/TI participants in AMP. The two late-August events provide the most comprehensive information, as all DO product types were called. For those events, 217 TA/TI customer accounts provided an average of nearly 12 MW of load impacts, compared to an approved load shed level of 18.5 MW.

Table 5–13: Load Impacts of TA/TI Participants – *SCE AMP*

Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
5/21/13	164	46.2	36.0	10.2	22%	10.8
6/28/13	161	47.7	38.0	9.7	20%	9.8
7/31/13	163	41.6	36.6	5.0	12%	10.1
8/29/13	217	77.9	65.0	12.8	16%	18.5
8/30/13	217	79.8	69.3	10.5	13%	18.5
9/4/13	1	10.2	10.0	0.2	2%	0.4
9/6/13	1	9.8	9.5	0.3	3%	0.4
9/9/13	1	9.3	9.0	0.3	3%	0.4
10/17/13	54	24.0	20.6	3.4	14%	7.2

Table 5–14 shows results for AutoDR participants in AMP. For the two late-August events, approximately 200 AutoDR participants provided an average of about 14 MW, compared to the load shed test level of approximately 23 MW.

Table 5–14: Load Impacts of AutoDR Participants – *SCE AMP*

Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
5/13/13	102	11.4	7.2	4.1	36%	6.7
5/21/13	43	10.2	4.6	5.6	55%	9.8
6/27/13	1	0.1	0.1	0.0	-2%	0.0
6/28/13	49	16.8	8.4	8.4	50%	10.8
7/1/13	11	1.9	1.9	0.0	2%	0.7
7/2/13	11	1.9	1.7	0.2	10%	0.7
7/31/13	60	20.5	12.7	7.8	38%	13.4
8/29/13	207	52.5	36.7	15.9	30%	23.7
8/30/13	199	49.6	37.7	11.9	24%	22.6
9/4/13	16	2.8	2.5	0.2	8%	0.9
9/6/13	16	2.8	2.8	0.1	2%	0.9
9/9/13	16	2.5	2.4	0.1	2%	0.9
10/17/13	148	32.0	27.8	4.2	13%	10.8

6. *EX-ANTE* LOAD IMPACT FORECASTS

This section describes both the process used to develop the *ex-ante* load impact forecasts for all of the aggregator programs, and the forecasts themselves. The first two sub-sections discuss requirements for the forecasts and the methods used to meet those requirements. The following two sub-sections present forecasts for PG&E's CBP and AMP programs. The next two sub-sections present comparable information for SCE's CBP and AMP programs. The last section describes forecasts for SDG&E's CBP program.

6.1 *Ex-ante* Load Impact Requirements

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

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

under both:

- 1-in-2 weather conditions, and
- 1-in-10 weather 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).

For the aggregator programs, there is no difference between the program- and portfolio-level load impacts

6.2 Description of Methods

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

6.2.1 Development of Customer Groups

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

- Small – maximum demand less than 20 kW;
- Medium – maximum demand between 20 and 199 kW;
- Large – maximum demand greater than or equal to 200 kW.

The specific definition of “maximum demand” was based on the tariff on which the maximum monthly demand during the most recent twelve months. For example, a large customer has maximum monthly demand equal or exceed 200 kW for 3 consecutive months during the past twelve months. The total number of customer “cells” developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

Neither SCE nor SDG&E differentiated their enrollment forecasts by size groups. Therefore, customers within each program were divided into groups according to notice level and LCA.

6.2.2 Development of Reference Loads and Load Impacts

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

1. Define data sources;
2. Estimate *ex-ante* regressions and simulate reference loads by service account and scenario;
3. Calculate percentage load impacts from *ex-post* results;
4. Apply percentage load impacts to the reference loads; and
5. Scale the reference loads using enrollment forecasts.

Each of these steps is described below.

1) Define data sources

For all three utilities and all program types, the reference loads are developed using data for customers enrolled during the 2013 program year. The percentage load impacts are developed using the estimated *ex-post* load impacts for the same customers, using event-specific data for program years 2011, 2012 and 2013.

2) Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations as described below, for each enrolled customer account, using load and weather data for the current program year. The resulting estimates were used to simulate reference loads *for each service account* under the various scenarios required by the Protocols (*e.g.*, the typical event day under 1-in-2 weather conditions).

The re-estimated regression equations were similar in design to the *ex-post* load impact equations described in Section 3.2, differing in two ways. First, the *ex-ante* models excluded the morning-usage variables. While these variables are useful for improving accuracy in estimating *ex-post* load impacts for particular events, they complicate the use of the equations in *ex-ante* simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the *ex-post* and *ex-ante* models is that the *ex-ante* models use CDH60 as the weather variables in place of the weather variables used in the *ex-post* regressions. The primary reason for this is that *ex-ante* weather days were selected based on current-day temperatures, not factoring in lagged values or humidity. Therefore, we determined that including a weather variable that is based on only current-day temperature is the most consistent way of reflecting the 1-in-2 and 1-in-10 weather conditions.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. Most of the differences across scenarios can be attributed to varying weather conditions. The definitions of the 1-in-2 and 1-in-10 weather conditions, developed following PY2009, are the same as those used to develop *ex-ante* load forecasts in previous studies.

3) Calculate forecast percentage load impacts

For each utility and program type, the percentage load impacts were based on the *ex-post* load impacts for each event during the 2011, 2012 and 2013 program years. Specifically, we examined only customers enrolled and nominated in PY2013, but included available data from the 2011 and 2012 program years for customers that were also nominated in those years. This method allowed us to base the *ex-ante* load impacts on a larger sample of events than just the current year, which should improve the reliability and consistency of the load impacts across forecasts.

Specifically, for each service account, we collect the hourly *ex-post* load impact estimates and observed loads for every event available from PY2011, PY2012 and PY2013. For each service account, we calculate the average and standard deviation of the load impacts across the available event days for four hour types: event hours, hours adjacent to events, hours prior to, and hours following the adjacent hours (*i.e.*, morning and late evening). These values are applied to the simulated reference loads to develop each customer's hourly load impact forecast values.

For any given sub-group of customers (*e.g.*, CBP day-of customers greater than or equal to 200 kW in size in the Greater Bay Area), we sum the observed loads, hourly load impacts and their variances across the applicable service accounts for reporting purposes.

We calculate percentage load impacts by the four hour types in order to "standardize" the load impacts for application to the *ex-ante* forecast event window (1:00 to 6:00 p.m. in April through October). That is, it allows us to control for the fact that the historical (*i.e.*, *ex-post*) event hours can differ across customers and event days, and generally differ from the *ex-ante* event window. The use of the load impacts by hour type allows us to simulate load impacts as though all customers (within a program and notice level) are called for the same event window.

The uncertainty-adjusted load impacts (*i.e.*, the 10th, 30th, 50th, 70th, and 90th percentile scenarios of load impacts) are based on the variability of each customer's response across event days. That is, we calculate the standard deviation of each customer's percentage load impact across the available event days. The square of the standard deviation (*i.e.*, the variance) is added across customers within each required subgroup. Each uncertainty-adjusted scenario is then calculated under the assumption that the load impacts are normally distributed with a mean equal to the total estimated load impact and a variance based on the variability of load impacts across event days.

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

5) *Apply forecast enrollments to produce program-level load impacts*.
The utilities provided the enrollment (nomination) forecasts. PG&E provided monthly enrollments through 2024 by program and notice level, with separate enrollments provided by LCA and size group.[15] SCE provided monthly enrollments for 2014, 2015, and 2016 through 2024 (under the assumption that enrollments remain fixed during that time period). SDG&E indicated that it expects enrollments to remain constant during the forecast period. The enrollments are then used to scale up the reference loads and load impacts for each required scenario and customer subgroup. [16]

6.2.3 Reporting ex-ante results

The next five sub-sections report *ex-ante* load impacts for the aggregator programs sponsored by PG&E (CBP and AMP), SCE (CBP and AMP), and SDG&E (CBP) respectively. For each utility program and notice type (DA and DO), we provide summary information on nomination forecasts; the level of forecast load impacts; hourly profiles of reference loads and load impacts for typical event days; and the distribution of load impacts by local capacity area. Comparisons to previous *ex-ante* load impact forecasts and to *ex-post* load impacts are discussed in Section 7.

Together, these summaries provide useful indicators of the anticipated changes in the forecasted load impacts across the various scenarios represented in the Protocol tables. All of the tables required by the Protocols are provided in Appendices.

6.3 *Ex-ante* Load Impacts for PG&E's CBP Program

6.3.1 Enrollment and load impact summary

PG&E forecasts CBP nominations to remain constant across the forecast horizon at 25 service accounts for the DA product and 472 for the DO product. The resulting *ex-ante*

---

[15] PG&E also forecasts separate enrollments for program- and portfolio-level scenarios, where the portfolio-level enrollments account for the effects of dual enrollments. However, because AMP and CBP are capacity-based programs, the program- and portfolio-based load impacts are the same.
[16] For the aggregator programs, nominations are used in place of enrollments, since only nominated customers provide load impacts.

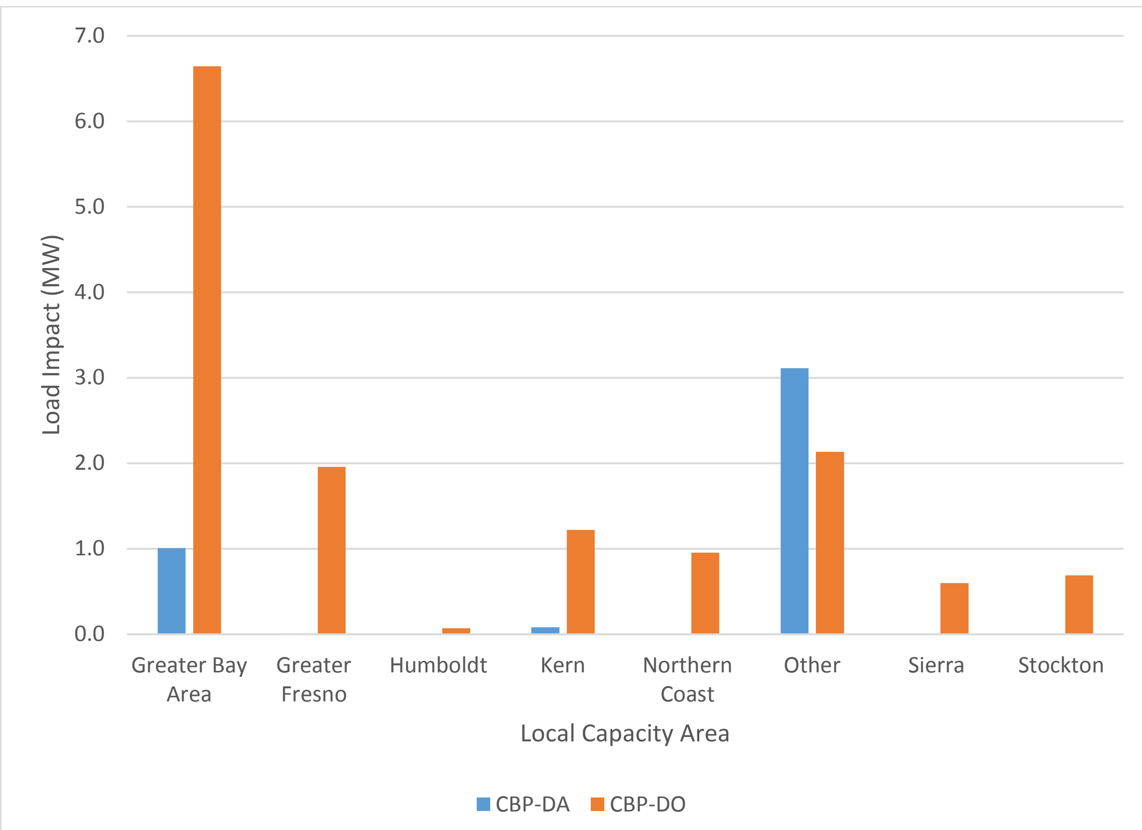
load impact forecasts for an August peak day in the two weather condition scenarios are shown in Table 6.1 for the DA and DO product types.

Table 6–1: Average Event-Hour Load Impacts (MW) for an August Peak Day in 1-in-2 and 1-in-10 Weather Conditions – *PG&E CBP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2014 - 2024	4.2	4.3	14.3	14.6

Figure 6–1 shows the distribution of load impacts by LCA for CBP DA and DO for an August peak day in a 1-in-2 weather year. DA load impacts are concentrated outside of the seven LCAs. The bulk of DO load impacts occur in the Greater Bay Area, with the remainder spread across the other Fresno LCAs.

Figure 6–1: Distribution of *Ex-Ante* Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Weather Conditions (*PG&E CBP DA and DO*)



6.3.2 Hourly reference loads and load impacts

Figure 6–2 shows the forecast reference load, event-day load, and load impacts for an August peak day in 2015 in 1-in-2 weather conditions for CBP DA. Figure 6–3 shows comparable information for CBP DO.

Figure 6–2: Hourly Event-Day Load Impacts for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *PG&E CBP DA*

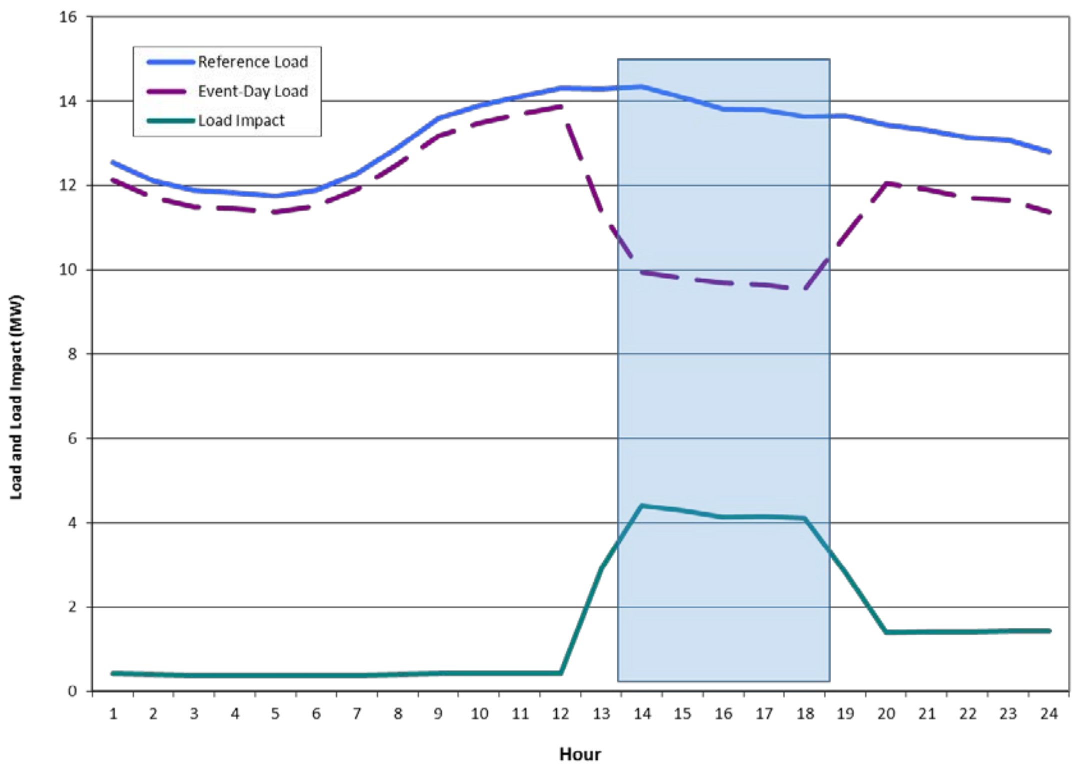
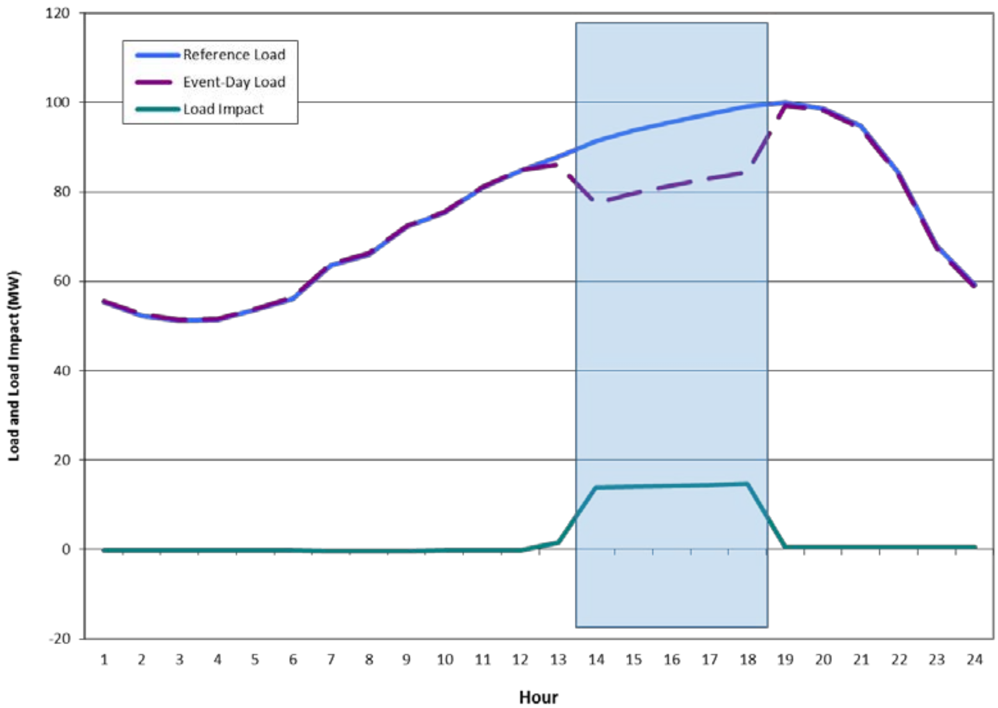


Figure 6–3: Hourly Event-Day Load Impacts for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *PG&E CBP DO*



6.4 *Ex-ante* Load Impacts for PG&E's AMP Program

6.4.1 Enrollment and load impact summary

Due to the contractual nature of the AMP program, PG&E anticipates that nominations will remain flat through the forecast period for AMP DA and DO at 1,142 and 1,514 customer accounts respectively.

Table 6–2 compares *ex-ante* load impacts for AMP DA and DO in 1-in-2 and 1-in-10 weather conditions, which are also assumed to remain constant, showing somewhat larger load impacts in the 1-in-10 scenario.

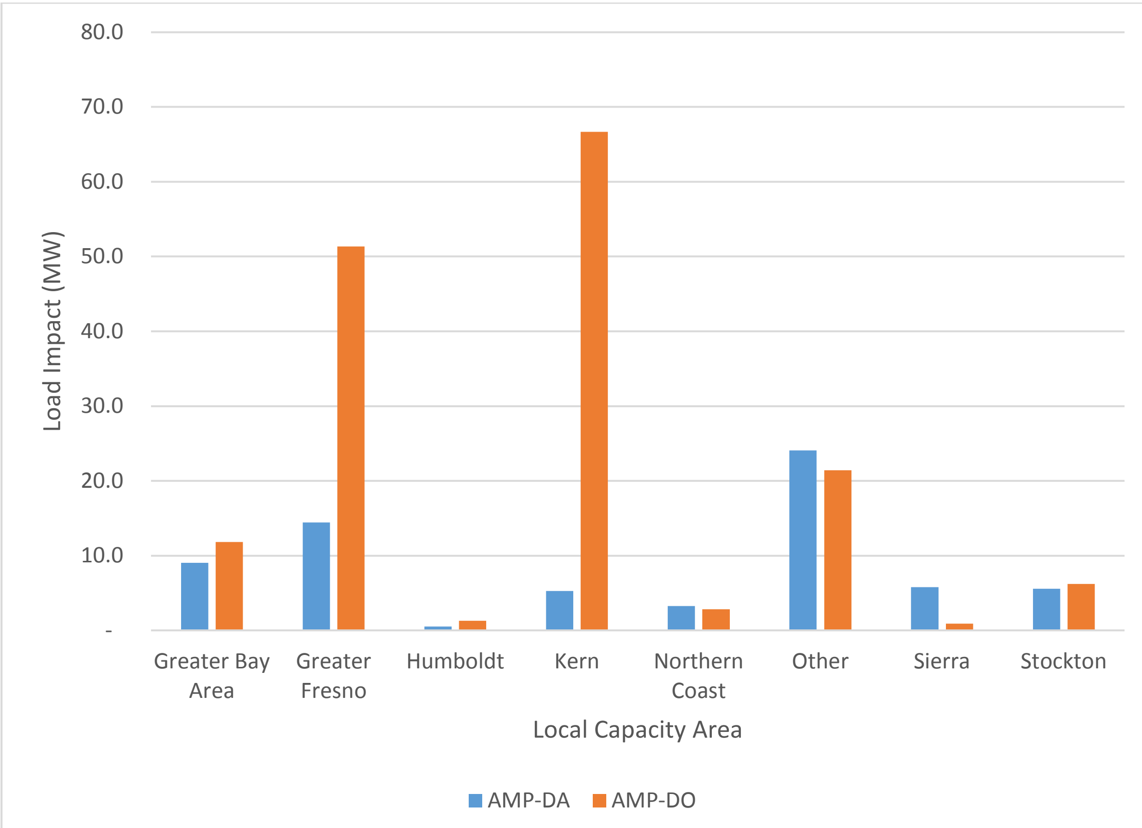
Table 6–2: Average Event-Hour Load Impacts (MW) for an August Peak Day in 1-in-2 and 1-in-10 Weather Conditions – *PG&E AMP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2014 - 2024	68.0	69.2	162.5	165.0

Figure 6–4 shows the distribution of load impacts by LCA for AMP DA and DO for an August peak day in 1-in-2 weather conditions. DA load impacts occur largely in the Greater Bay Area and Greater Fresno LCAs, and outside of any LCA. DO load impacts are

greatest in Kern, with large impacts also in the Greater Bay Area and Greater Fresno LCAs.

Figure 6–4: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *AMP DA and DO*



6.4.2 Hourly reference loads and load impacts

Figure 6–5 shows the forecast reference load, event-day load, and load impacts (right axis) for an August peak day in 2015 in 1-in-2 weather conditions for AMP DA. Figure 6–6 shows comparable information for AMP DO.

Figure 6–5: Hourly Event-Day Load Impacts for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *AMP DA*

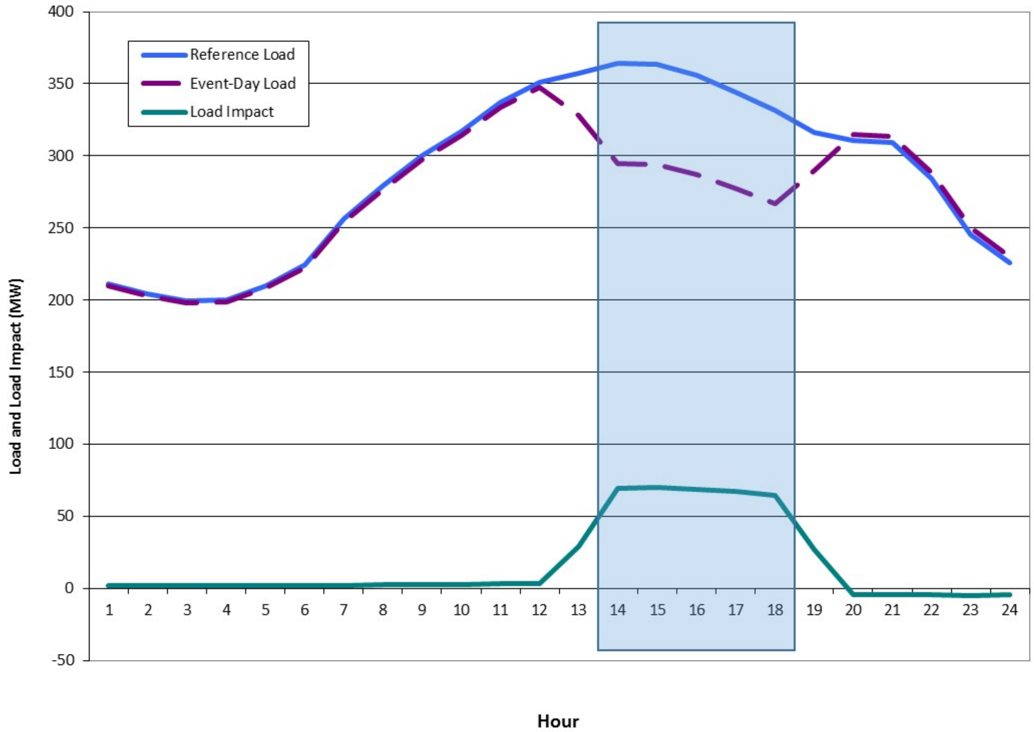
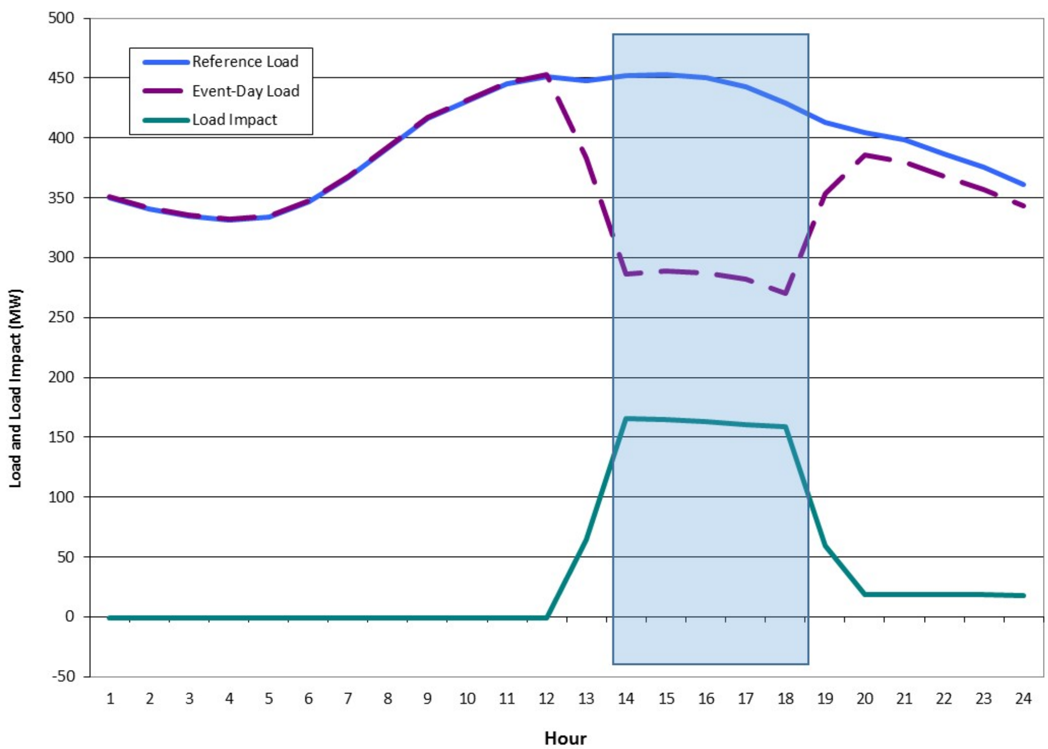


Figure 6–6: Hourly Event Day Load Impacts for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *AMP DO*



6.5 *Ex-ante* Load Impacts for SCE's CBP Program

6.5.1 Enrollment forecasts, reference loads and load impacts

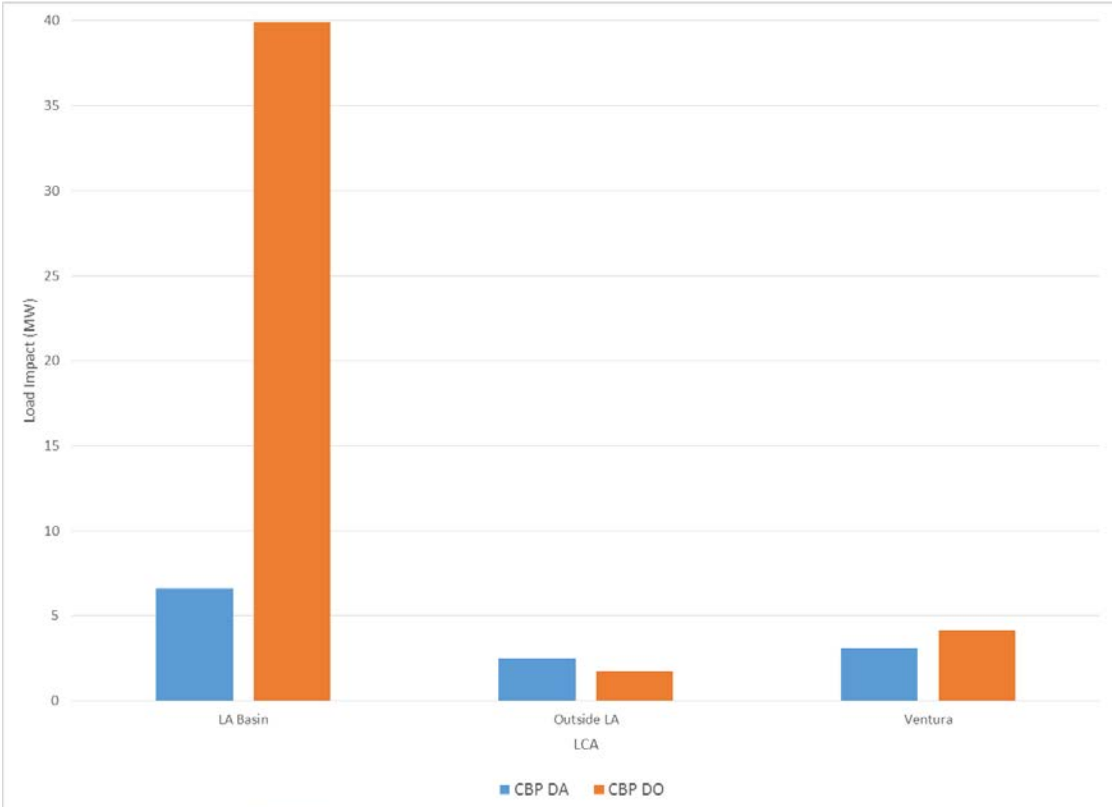
SCE enrollment/nomination forecasts for August of 2014 through 2016 are 261 for CBP DA and 859 for CBP DO. These levels are forecast to remain constant through 2024. Table 6–3 presents *ex-ante* load impacts for SCE's CBP DA and DO. Due to the very small number of DA nominations and imprecise *ex-post* load impacts, *ex-ante* load impacts are shown as zero. DA nominations are expected to remain small, while DO nominations are anticipated to fall over the forecast horizon due to aggregators moving customers from CBP to DRC. CBP DO load impacts fall from about 11 MW in 2013 to 9 MW in 2023.

Table 6–3: Average Event-Hour Load Impacts (MW) for an August Peak Day in 1-in-2 and 1-in-10 Weather Conditions – *SCE CBP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2014 - 2024	12.2	12.4	45.4	45.7

Figure 6–7 shows the distribution of CBP DA and DO load impacts by LCA.

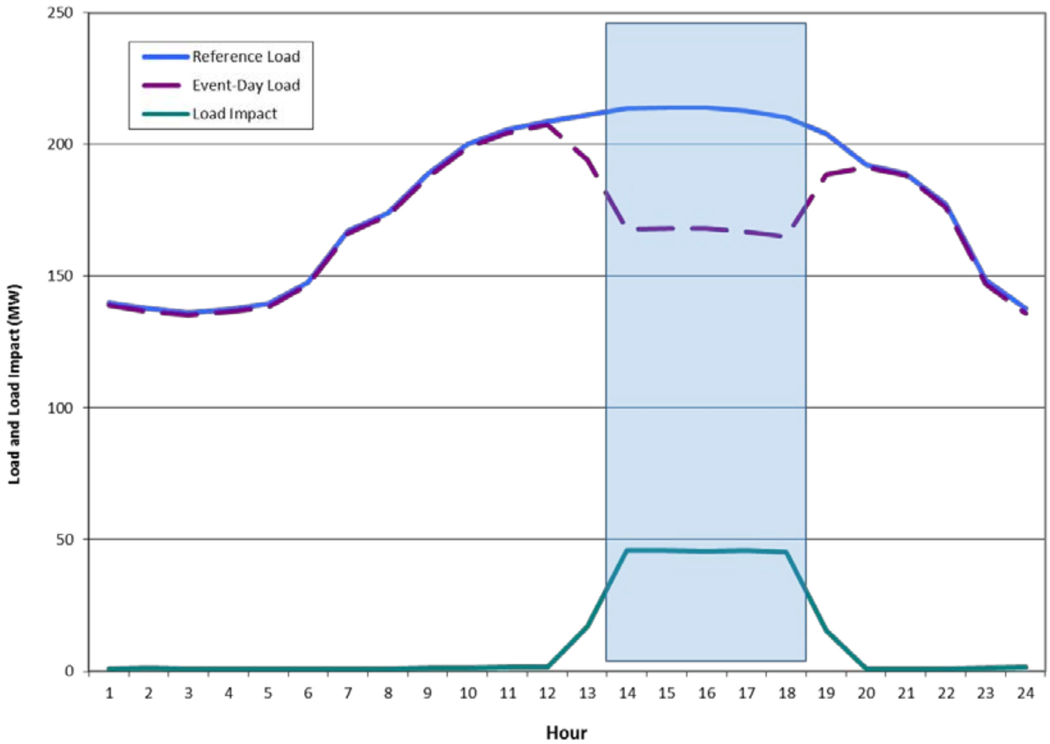
Figure 6–7: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Weather Conditions – *SCE CBP*



6.5.2 Hourly reference loads and load impacts

Figure 6–8 shows hourly forecast reference and event-day loads, and load impacts for a typical event day in a 1-in-2 weather year in August 2015 for SCE CBP DO. Event-hour load impacts average about 45 MW, which is 22 percent of the reference load.

Figure 6–8: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SCE CBP DO*



6.6 *Ex-ante* Load Impacts for SCE's AMP Program

6.6.1 Enrollment forecasts, reference loads and load impacts

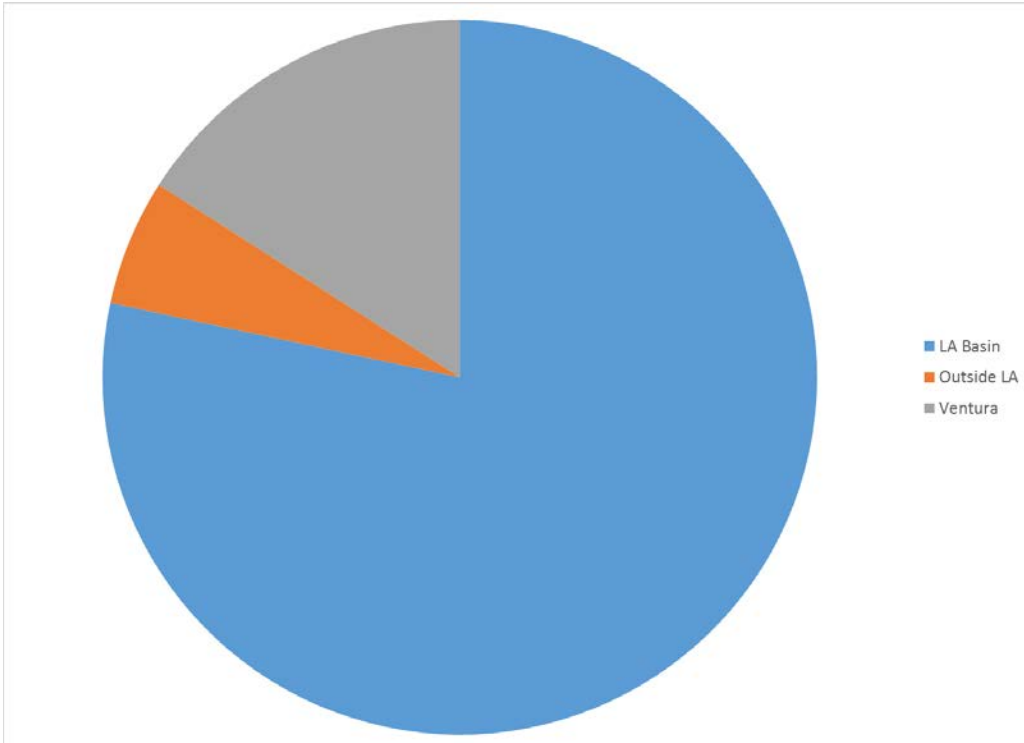
SCE enrollment/nomination forecasts for August of 2014 through 2016 are zero for AMP DA and 1,125 for AMP DO. These levels are forecast to remain constant through 2024. Table 6–4 shows compares *ex-ante* load impacts for AMP DA and DO in 1-in-2 and 1-in-10 weather conditions, showing somewhat larger load impacts in 1-in-10 years.

Table 6–4: Average Event-Hour Load Impacts (MW) for an August Peak Day in 1-in-2 and 1-in-10 Weather Conditions – *SCE AMP*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2014 - 2024	-	-	88.4	89.1

Figure 6-9 shows the distribution of load impacts across LCAs for AMP DO. Nearly 80 percent of load impacts occur in the LA Basin, with most of the remainder in the Ventura LCA.

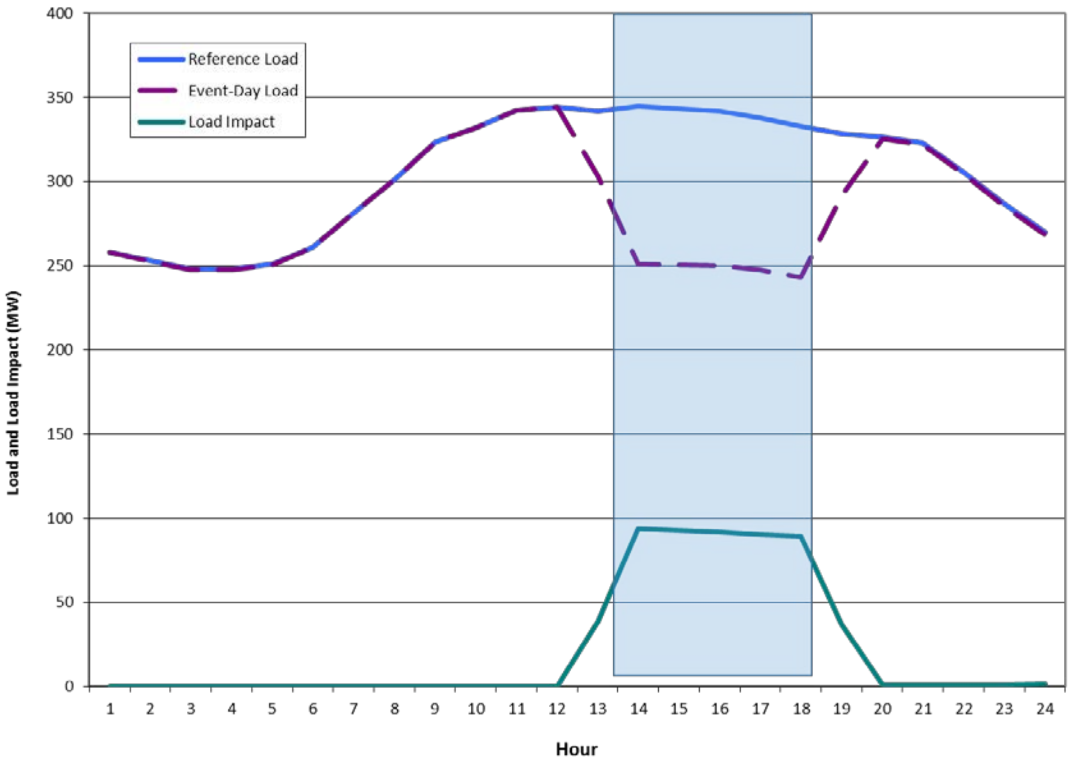
Figure 6–9: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – *CBP DO, and AMP DA and DO*



6.6.2 Hourly reference loads and load impacts

Figures 6–10 and 6–11 show the hourly profiles of forecast loads and load impacts for a typical event day in 2015, in a 1-in-2 weather year, for SCE's AMP DO. Event-hour load impacts average approximately 88 MW, which is 27 percent of the reference load.

Figure 6–10: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SCE AMP DO*



6.7 *Ex-ante* Load Impacts for SDG&E's CBP

6.7.1 Enrollment forecasts, reference loads and load impacts

The enrollment forecast provided by SDG&E for the purpose of this report anticipates that nominations and load impacts for CBP DA and DO will remain constant over the forecast period, at levels as of the end of the summer of 2013. Forecast nominations are 145 customer accounts for DA and 275 for DO. Table 6–5 compares DA and DO load impacts for an August peak day in 1-in-2 and 1-in-10 weather years. Average event-hour load impacts are 9.7 MW for DA and 10.5 MW for DO in 1-in-2 weather scenario.

SDG&E has proposed program changes to its CBP program as part of rulemaking 13-09-011. SDG&E expects that its proposed changes will increase participation in the CBP program. SDG&E has provided a CBP forecast that reflects the proposed program changes in its 2015 and 2016 Demand Response Proposals and Response to Additional Information filed on March 3rd 2014. However, since these proposed changes have not yet been approved by the CPUC the forecast included in this report does not include the expected effect of the proposed changes.

Table 6–5: Average Event-Hour Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2014 – 2024) – *SDG&E CBP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2014 - 2024	9.5	9.5	10.2	10.3

6.7.2 Hourly reference loads and load impacts

Figure 6–11 shows *ex-ante* hourly reference load, event-day load, and load impacts for the August peak day in 2015 in a 1-in-2 weather year for CBP DA. Figure 6–12 shows comparable information for CBP DO.

Figure 6–11: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SDG&E CBP DA*

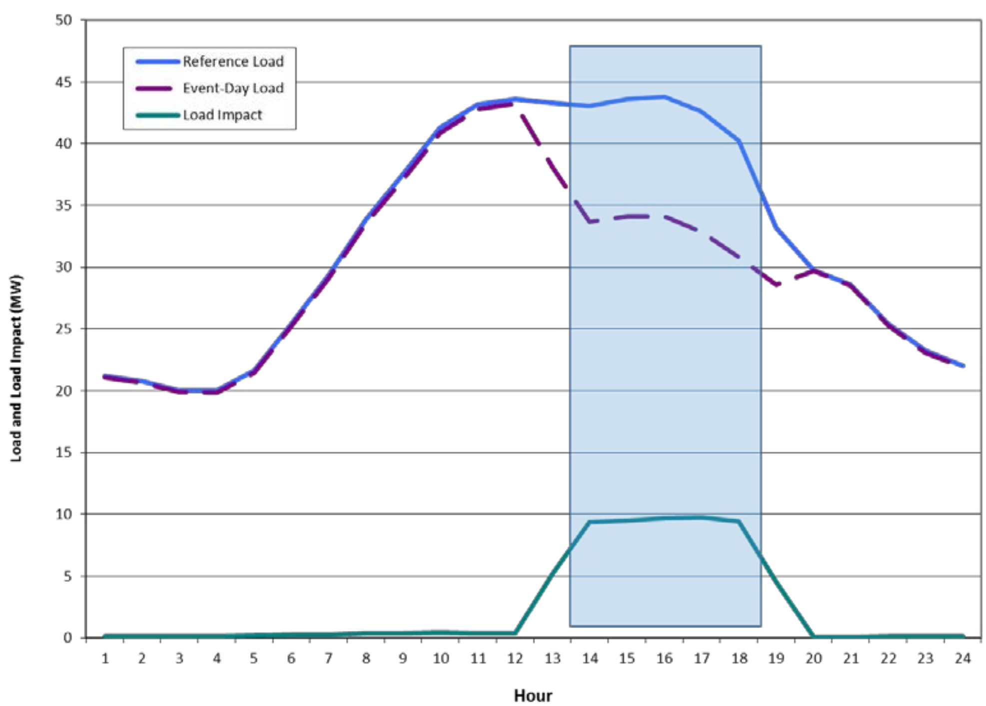
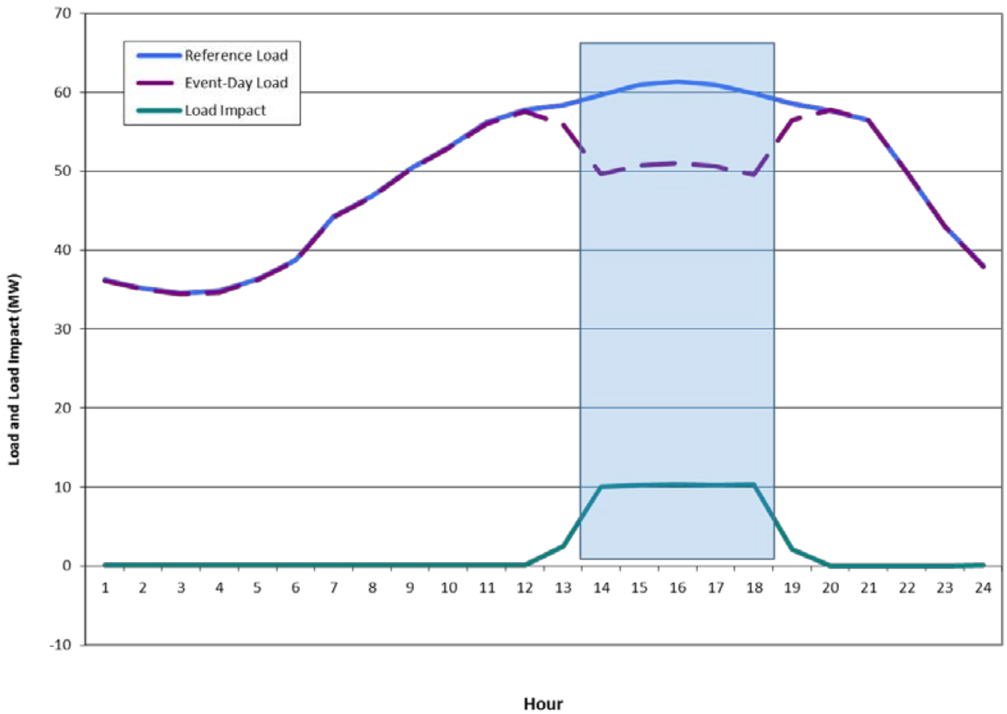


Figure 6–12: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SDG&E CBP DO*



7. COMPARISONS OF *EX-POST* AND *EX-ANTE* RESULTS

In response to requests to improve the transparency of the linkage between *ex-post* and *ex-ante* results, this section compares several sets of estimated load impacts for each utility, including the following:

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

In the third comparison, we illustrate how the *ex-ante* forecast (of the 1-in-2 August peak day) for PY2014 are developed from the PY2013 *ex-post* load impacts.

7.1 Link between *ex-post* results and *ex-ante* forecasts

As a preview to this section, Section 6 described in detail how the *ex-ante* load impact forecasts incorporate historical information from previous *ex-post* load impact evaluations, including the following:

1. Percentage load impacts per customer are constructed from up to three years of *ex-post* load impact results for service accounts that were enrolled in PY2013.

2. Reference loads per customer are simulated for the *ex-ante* weather scenarios using equations developed from regression analysis of load and weather data for the current program year.
3. Average *ex-ante* load impacts per customer are created for each LCA and size category (PG&E only) based on the percentage load reductions developed from previous *ex-post* evaluations and the forecasted reference loads, as described in the previous two points.
4. *Ex-ante* load impacts per customer are then multiplied by the enrollment forecasts provided by the utilities, differentiated by LCA as needed.

The four categories of relationships between *ex-post* and *ex-ante* load impacts are presented in the following sub-sections, organized by utility.

7.2 PG&E CBP and AMP

This section provides information on *ex-post* and *ex-ante* load impacts for PG&E.

7.2.1 Previous and current ex-post, and forecast for 2014

Table 7–1 shows average event-hour reference loads and estimated *ex-post* load impacts for the typical CBP and AMP event (*i.e*., events in which aggregators in the full service area were called) in the current and two previous program years, by notice type. Also shown is the current study's *ex-ante* forecast for 2014.

The estimated *ex-post* load impacts are generally quite similar across years, though with some exceptions. In particular, CBP DA customer nominations and aggregate load impacts were greatest in 2012, and then declined substantially in 2013. CBP DO load impacts also peaked in 2012, though the number of customers nominated grew over the three years. The customer nomination forecasts and ex-ante load impacts for CBP for 2014 are in line with the current-year values, which are lower than in previous years. PG&E believes that aggregators with both CBP and AMP contracts have focused on meeting AMP commitments, possibly by moving more responsive customers from CBP to AMP.

The AMP DA and DO customer nominations and aggregate load impacts are more similar across years than those for CBP. Aggregate load impacts, average customer size, and average percent load impact have fallen somewhat for the DA option, while customer nominations and aggregate load impacts have increased somewhat for the DO option. As discussed in the next sub-section, PG&E bases its enrollment/nomination forecast for AMP largely on the contract commitments.

Table 7–1: ***Ex-Post*** **Results for 2011 through 2013, and** ***Ex-Ante*** **for 2014 –**
PG&E CBP and AMP

Program	Year	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	2011	150	316.0	90.7	47.4	13.6	29%
	2012	166	282.1	122.9	46.8	20.4	44%
	2013	25	604.8	188.0	15.1	4.7	31%
	2014 ExA	25	556.0	168.0	13.9	4.2	30%
CBP DO	2011	219	364.4	79.5	79.8	17.4	22%
	2012	370	272.0	62.8	100.6	23.3	23%
	2013	480	197.8	28.5	94.9	13.7	14%
	2014 ExA	472	202.1	30.3	95.4	14.3	15%
AMP DA	2011	249	625.3	212.0	155.7	52.8	34%
	2012	233	548.6	214.1	127.8	49.9	39%
	2013	425	418.8	102.4	178.0	43.5	24%
	2014 ExA	1,142	308.2	59.5	352.0	68.0	19%
AMP DO	2011	1,069	488.9	131.4	522.6	140.5	27%
	2012	1,125	414.6	115.2	466.5	129.6	28%
	2013	1,344	374.6	115.5	503.4	155.2	31%
	2014 ExA	1,514	294.3	107.3	445.5	162.5	36%

7.2.2 Previous versus current ex-ante

In this sub-section, we compare the *ex-ante* load impact forecasts for 2015 (which in most cases in the current study are the same as those for 2014) that were produced in the current (2013) and previous (2012) studies. Table 7–2 shows forecast customer nominations, reference loads and load impacts for the 2015 August 1-in-2 peak day from the two studies.

As noted above, the results for CBP in 2013, while differing from the forecasts made in 2012, generally reflect the observed *ex-post* results in the current year. For AMP, PG&E's enrollment/nomination forecast is generally based on the size of the contractual commitment. The prior forecast assumed the full contract commitment level without making any adjustment. The current forecast leverages on the latest information from the aggregators to adjust the aggregate load impacts downward by 10 to 15% from the contractual commitment in 2014, and then maintains stable levels throughout the forecast horizon. With those assumptions, anticipated aggregate load impacts for 2015 fell somewhat for both programs and notice types from the previous year.

PG&E obtains the enrollment forecast for AMP by dividing the forecasted contractual MW by the anticipated per-customer load impact. For AMP DA in particular, PG&E projects a higher level of customer nominations in order to achieve the contractual amount of aggregate load impacts, given a lower per-customer load impact in 2013. As reflected in these projections, customer size and percentage load impacts are expected to be smaller than in the 2012 forecast.

Table 7–2: *Ex-Ante* Load Impacts for 2015 from PY 2012 and PY 2013 Studies, *PG&E*

Program	Study Year	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	2012	177	291.0	116.9	51.5	20.7	40%
	2013	25	556.0	168.0	13.9	4.2	30%
CBP DO	2012	394	297.2	77.4	117.1	30.5	26%
	2013	472	202.1	30.3	95.4	14.3	15%
AMP DA	2012	540	465.9	157.4	251.6	85.0	34%
	2013	1,142	308.2	59.5	352.0	68.0	19%
AMP DO	2012	1,793	373.3	101.5	669.4	182.0	27%
	2013	1,514	294.3	107.3	445.5	162.5	36%

7.2.3 Current ex-post compared to previous ex-ante

In this sub-section, we compare estimated *ex-post* load impacts for 2013 to the *ex-ante* forecasts for a 1-in-2 August peak day in 2013 developed in the PY2012 study. With the exception of CBP DO, customer nominations observed in 2013 were somewhat to substantially lower than those anticipated in the forecasts from the 2012 study. For the largest program/notice type, AMP DO, percentage load impacts were slightly higher than forecast, but when combined with the substantially lower customer nominations, resulted in estimated aggregate load impacts about 20 MW lower than forecast. As noted above, this outcome has led to scaling back contract amounts and corresponding customer nomination forecasts for future years.

For CBP DO and AMP DA, percentage load impacts were substantially less than forecast, leading to lower aggregate load impacts than in the forecast, even with the higher than forecast number of customer nominations for CBP DO.

Table 7–3: Current *Ex-Post* and Previous *Ex-Ante* Load Impacts for 2013, *PG&E*

Program	Forecast/ *Ex-Post*	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	Forecast	168	291.1	116.7	48.9	19.6	40%
	Ex-Post	25	604.8	189.0	15.1	4.7	31%
CBP DO	Forecast	374	297.1	77.3	111.1	28.9	26%
	Ex-Post	480	197.8	28.5	94.9	13.7	14%
AMP DA	Forecast	459	466.0	157.3	213.9	72.2	34%
	Ex-Post	425	418.8	102.4	178.0	43.5	24%
AMP DO	Forecast	1,642	376.9	106.7	618.8	175.2	28%
	Ex-Post	1,344	374.6	115.5	503.4	155.2	31%

7.3 SCE CBP and AMP

7.3.1 Previous and current ex-post, and forecast for 2014

The number of customers nominated and estimated load impacts for CBP DA have varied substantially over program years 2011 through 2013. More changes are in store for 2014, as SCE anticipates that the one AMP DA aggregator will move its customer accounts to CBP DA due to problems in meeting contract nominated capacity. CBP DO nominations and load impacts have remained fairly stable over the past three years, but are expected to increase substantially in 2014 due largely to a shift in customer accounts from AMP DO to CBP DO. SCE anticipates moving current AMP DO customers who have not provided consistent load reductions. Customers nominated in AMP DO declined slightly in 2013, but are expected to drop by about 400 with the above movement of customers to CBP DO. Percentage load impacts for AMP DO have been steady, and when applied to the lower forecasted nominations produce correspondingly lower aggregate load impacts.

Table 7–4: *Ex-Post* Results for 2011 through 2013, and *Ex-Ante* for 2014 – *SCE CBP and AMP*

			Per Customer (kW)		Aggregate (MW)		
Program	Year	Nom. Accnts.	Reference Load	Load Impact	Reference Load	Load Impact	% Load Impact
CBP DA	2011	90	176.7	46.7	15.9	4.2	26%
	2012	2.2	548.7	18.3	1.19	0.04	3%
	2013	20	638.2	145.4	13.1	3.0	23%
	2014 ExA	261	490.8	46.8	128.1	12.2	10%
CBP DO	2011	412	241.0	46.6	99.3	19.2	19%
	2012	359	243.0	45.9	87.3	16.5	19%
	2013	420	214.1	43.9	89.8	18.4	21%
	2014 ExA	859	246.6	52.8	211.8	45.4	21%
AMP DA	2011	275	228.0	63.3	62.7	17.4	28%
	2012	142	233.4	153.5	33.1	21.8	66%
	2013	236	387.0	33.3	91.3	7.9	9%
	2014 ExA	0	-	-	-	-	-
AMP DO	2011	885	338.0	92.0	299.1	81.4	27%
	2012	1,648	334.1	97.2	550.6	160.1	29%
	2013	1,589	290.0	79.7	460.8	126.7	27%
	2014 ExA	1,125	294.1	78.6	330.8	88.4	27%

7.3.2 Previous versus current ex-ante

Table 7–5 shows *ex-ante* forecasts for 2015 for a 1-in-2 August peak day produced in the PY2012 and current evaluations. The table shows relatively large changes in anticipated customers nominated and load impacts for 2015 between the 2012 and current study years. The bulk of the changes are due to anticipated movement of several hundred customer accounts from both AMP DA and DO to corresponding notification types for CBP. These changes have the effect of increasing the forecasts of aggregate load impacts for both CBP DA and DO, and reducing forecast load impacts for both types of AMP contracts.

Table 7–5: *Ex-Ante* Forecasts for 2015 from PY 2012 and PY 2013 Studies, *SCE*

Program	Study Year	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	2012	3	666.7	0.0	2.0	0.0	0%
	2013	261	490.8	46.8	128.1	12.2	10%
CBP DO	2012	245	235.9	42.4	57.8	10.4	18%
	2013	859	246.6	52.8	211.8	45.4	21%
AMP DA	2012	149	256.4	128.9	38.2	19.2	50%
	2013	0	0.0	0.0	0.0	0.0	na
AMP DO	2012	1,778	330.9	88.0	588.4	156.4	27%
	2013	1,125	294.1	78.6	330.8	88.4	27%

7.3.3 Current ex-post compared to previous ex-ante

Table 7–6 shows two sets of values for 2013 – the line labeled “Forecast” represents the ex-ante forecast for 2013 for a 1-in-2 August peak day, produced in the PY2012 evaluation. The line labeled “Ex-Post” represents the ex-post results for the average event in the current study.

All four program/notice types experienced greater numbers of customers nominated in 2013 than forecast in the 2012 evaluation. As noted above, these larger numbers of customers are anticipated to expand even more for CBP in future years, while customer nominations in the two AMP program types will fall. The forecast and realized percentage load impacts for the two day-of program types, which have the largest numbers of customer accounts and load impact, are quite similar. The current *ex-post* percentage load impact for AMP DA are substantially below the forecast value, which is consistent with that aggregator’s decision to move that contract to CBP DA for next year.

Table 7–6: Current *Ex-Post* and Previous *Ex-Ante* Forecast Load Impacts for 2013, *SCE*

Program	Forecast/ *Ex-Post*	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	Forecast	3	666.7	0.0	2.0	0.0	0%
	Ex-Post	20	638.2	145.4	13.07	2.98	23%
CBP DO	Forecast	255	236.5	42.7	60.3	10.9	18%
	Ex-Post	420	214.1	43.9	89.8	18.4	21%
AMP DA	Forecast	123	256.9	129.3	31.6	15.9	50%
	Ex-Post	236	387.0	33.3	91.3	7.9	9%
AMP DO	Forecast	1,468	331.1	88.0	486.0	129.2	27%
	Ex-Post	1,589	290.0	79.7	460.8	126.7	27%

7.4 SDG&E CBP

7.4.1 Previous and current ex-post, and forecast for 2014

Table 7–7 summarizes the number of nominated customer accounts and average event-hour reference loads and estimated *ex-post* load impacts for the average of the typical CBP events (*i.e.*, events in which all aggregators were called) in the current and two previous program years, by notice type. Also shown is the *ex-ante* forecast for 2014.

The number of customers nominated in CBP DA have increased over the past three years, particularly in 2013. After holding steady for the first two years, customers nominated in CBP DO declined somewhat in 2013. Forecast numbers of customers for 2014 (and 2015) are expected to increase somewhat for both notice types. Despite the increase in the numbers of customers nominated, aggregate estimated *ex-post* load impacts for both notice types have remained fairly level, except for a dip in 2012 for DA.[17] Forecast load impacts are down slightly for both DA and DO in 2014 compared to the 2013 ex-post results, reflecting the use of *ex-post* percentage load impacts for prior years for customers who were nominated in those years.

[17] A review of customer-level data indicates that the smaller aggregate load impact for CBP DA in 2012 compared to the prior and following year was due to smaller estimated load impacts in 2012 for two large customer accounts that make up as much as 80 percent of the program load impacts. The rebound in aggregate load impact in 2013 was caused largely by a return to previous performance by those two customer accounts rather than, for example, the load impacts of the added nominations

Table 7–7: *Ex-Post* Load Impacts for PY2011 through 2013, and 2014 *Ex-Ante* – *SDG&E CBP*

Program	Year	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	2011	48	537.5	235.4	25.8	11.3	44%
	2012	78	320.2	81.6	25.0	6.37	25%
	2013	142	304.8	75.9	43.2	10.8	25%
	2014 ExA	145	294.5	65.5	42.7	9.5	22%
CBP DO	2011	318	200.6	36.2	63.8	11.5	18%
	2012	321	229.7	30.5	73.7	9.8	13%
	2013	260	234.5	40.2	61.1	10.5	17%
	2014 ExA	275	220.4	37.1	60.6	10.2	17%

7.4.2 Previous versus current ex-ante

Table 7–8 compares the CBP *ex-ante* forecasts for 2015 produced as part of this 2013 evaluation and the previous evaluation. In both cases, the forecast represents the 1-in-2 August peak day. There is no difference between the program- and portfolio-level impacts. Between PY2012 and PY2013 there was an increase in expected DA nominations and a reduction in expected DO nominations. Both forecasts assumed that future customer nominations would match those at the end of the given *ex-post* year. Projected percent load impacts, which are based on current and prior years of *ex-post* results for customers nominated in the current year, are somewhat smaller for DA in the current study than last year's study, and are somewhat higher for DO. Both differences result from different mixes of customers who were nominated in the years of the two studies.

The projected aggregate load reduction for the CBP DA option increased from 7.7 MW to 9.5 MW between the two studies. This change is largely explained by two factors. One is that the number of customers nominated in 2013 exceeded the forecast. More important, however, is the return to higher performance of two large customer accounts that comprise much of the aggregate load impact, as described in a footnote above. The projected aggregate load reduction for the CBP DO option is nearly identical (10.4 MW versus 10.2 MW) between the forecast years. In this case, the number of customers nominated in 2013 was below the previous forecast, but this was offset by an increase in the ex-post percentage load reductions in 2013.

Table 7–8: *Ex-Ante* Load Impacts for 2015 from PY 2012 and PY 2013 Studies, *SDG&E*

Program	Study Year	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	2012	81	323.5	95.1	26.2	7.7	29%
	2013	145	294.5	65.5	42.7	9.5	22%
CBP DO	2012	371	221.0	28.0	82.0	10.4	13%
	2013	275	220.4	37.1	60.6	10.2	17%

7.4.3 Current ex-post compared to previous ex-ante

Table 7–9 compares current *ex-post* nominations and load impacts to values for 2013 from the PY2012 *ex-ante* forecast. Current-year nominations were higher than expected for CBP DA and lower than expected for CBP DO, compared to the forecast for 2013 in the PY2012 forecast. Average customer size, as reflected in the reference loads, is similar in the forecast and observed cases for both notice types.

For DA, the aggregate estimated load impact (10.8 MW) was higher than the forecast value (7.7 MW), reflecting a somewhat lower percent load impact, but a larger number of customers than in the forecast. For DO, the aggregate load impact of 10.5 is essentially same as the forecast value, but was produced by a smaller number of customers with a somewhat higher percentage load impact than forecast.

Table 7–9: Current *Ex-Post* and Previous *Ex-Ante* Load Impacts for 2013, *SDG&E*

Program	Forecast/ *Ex-Post*	Nom. Accnts.	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Load Impact
CBP DA	Forecast	81	322.2	95.1	26.1	7.7	30%
	Ex-Post	142	304.8	75.9	43.2	10.8	25%
CBP DO	Forecast	371	221.3	28.0	82.1	10.4	13%
	Ex-Post	260	234.5	40.2	61.1	10.5	17%

8. MODEL SELECTION AND VALIDITY ASSESSMENT

8.1 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the *ex-post* load impact analysis. The basic structure of the model is shown in Section 3.2.1. The tests are conducted using average-customer data (by utility and notice) rather than at the individual customer level. Model variations include 18 different combinations of weather variables. The weather variables include: temperature-humidity index (THI)[18];

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

the 24-hour moving average of THI; heat index (HI)[19]; the 24-hour moving average of HI; cooling degree hours (CDH)[20], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; the 24-hour moving average of CDH; the one-day lag of cooling degree days (CDD)[21]. A list of the 18 combinations of these variables that we tested is provided in Table 8-1.

Table 8–1: Weather Variables Included in the Tested Specifications

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

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

1. Ability to predict usage on event-like *non-event days*. Specifically, we identified a set of days that were similar to event days, but were not called as event days (*i.e.*, "test days"). The use of non-event test days allows us to test model performance against known "reference loads," or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for all of the test days. The model fit (*i.e.*, the difference between the actual and predicted loads on the test days, during afternoon hours

---

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

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

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

in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.

2. Performance on *synthetic* event days (*e.g.*, event-like non-event days that are treated as event days in estimation), to test whether any “event” coefficients demonstrate statistically significant bias, as opposed to expected non-significance, since customers have no reason to modify usage on days that are not actual events. This test is an extension of the previous test. The same test days are used, with a set of hourly “synthetic” event variables included in addition to the rest of the specification to test whether non-zero load impacts are estimated for these days. A successful test involves synthetic event load impact coefficients that are not statistically significantly different from zero.

8.1.1 Selection of Event-Like Non-Event Days

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

Table 8–2: List of Event-Like Non-Event Days by Program

PG&E		SCE				SDG&E
AMP	CBP	AMP DA	AMP DO	CBP DA	CBP DO	CBP
6/7/2013	5/30/2013	5/3/2013	5/3/2013	5/10/2013	6/27/2013	5/3/2013
6/27/2013	6/27/2013	7/8/2013	5/20/2013	5/22/2013	7/1/2013	5/13/2013
6/28/2013	6/28/2013	7/9/2013	6/27/2013	5/29/2013	8/26/2013	6/27/2013
7/8/2013	7/8/2013	8/22/2013	8/1/2013	6/27/2013	8/27/2013	8/22/2013
7/9/2013	7/9/2013	8/27/2013	8/22/2013	7/8/2013	9/3/2013	8/26/2013
7/10/2013	7/10/2013	9/5/2013	8/27/2013	7/18/2013	9/5/2013	8/27/2013
7/18/2013	7/18/2013	9/16/2013	9/5/2013	7/25/2013	9/6/2013	9/23/2013
7/19/2013	7/19/2013		9/16/2013	7/26/2013	9/16/2013	9/30/2013
7/24/2013	7/24/2013		10/18/2013	8/16/2013		10/16/2013
7/25/2013	7/25/2013			8/19/2013		
7/26/2013	7/26/2013			8/23/2013		
8/13/2013	8/13/2013			8/26/2013		
8/14/2013	8/14/2013			8/27/2013		
8/15/2013	8/15/2013			9/3/2013		
8/16/2013	8/16/2013			9/16/2013		
8/20/2013	8/19/2013			9/19/2013		
8/29/2013	8/20/2013			9/24/2013		
8/30/2013	8/29/2013					
9/6/2013	8/30/2013					
	9/6/2013					

8.1.2 Results from Tests of Alternative Weather Specifications

For each utility, program, and notice type, we tested 18 specifications. The aggregate load used in conducting these tests was constructed separately for each utility/program/notice-type and included only nominated service accounts.

The tests are conducted by estimating one model for every utility/program/notice (10), specification (18), and event-like day (19 and 20 for PG&E AMP and CBP, 9 for SDG&E CGP, 7 and 9 for SCE AMP DA and DO, and 17 and 8 for CBP). Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Table 8–3 shows the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) for the selected ("winning") specification for each utility and program.

The range of results across models is relatively small. For example, most adjusted R-squared values lie between 0.92 and 0.99. MPE values generally show biases of less than 1 percent. MAPE values range from 1.2 to 6 percent, with the equations for DO programs generally more accurate than those for the DA programs. Specification 10 in Table 7.1 (including CDH65 and the 24-hour moving average of CDH with a 65 degree threshold) performed best for several programs. However, as shown in the figures below, the outcomes across specifications are generally quite similar.

Table 8–3: Specification Test Results for the "Winning" Model

Utility	Program	Notice	Selected Specification	Adjusted R^2	MPE	MAPE
PG&E	CBP	DA	10	0.92	-0.11%	6.03%
		DO	10	0.98	0.07%	1.59%
	AMP	DA	10	0.94	0.19%	2.83%
		DO	10	0.97	-0.01%	1.21%
SCE	CBP	DA	10	0.81	0.79%	5.39%
		DO	10	0.98	-0.97%	1.46%
	AMP	DA	12	0.99	0.82%	1.28%
		DO	12	0.95	-0.83%	2.75%
SDG&E	CBP	DA	1	0.95	1.20%	5.34%
		DO	1	0.98	0.53%	1.60%

For each specification, we estimated a single model that included all of the days (*i.e.*, not withholding any event-like days), but using a single set of actual event variables (*i.e.*, a 24-hour profile of the average event-day load impacts). The results of these tests reinforced the conclusion that very little is at stake when selecting from the specifications, as the average event-hour load impact profile was quite stable across models.

Figures 8–1 through 8–5 illustrate the results of these estimations of hourly load impacts for the average event, for each of the 18 model specifications. The estimates for the selected specification are highlighted in bold dashed lines. As the figures show, the estimated load impacts are not highly sensitive to the choice of weather specification.

Figure 8–1: Average Event-Hour Load Impacts by Specification, *PG&E AMP DO*

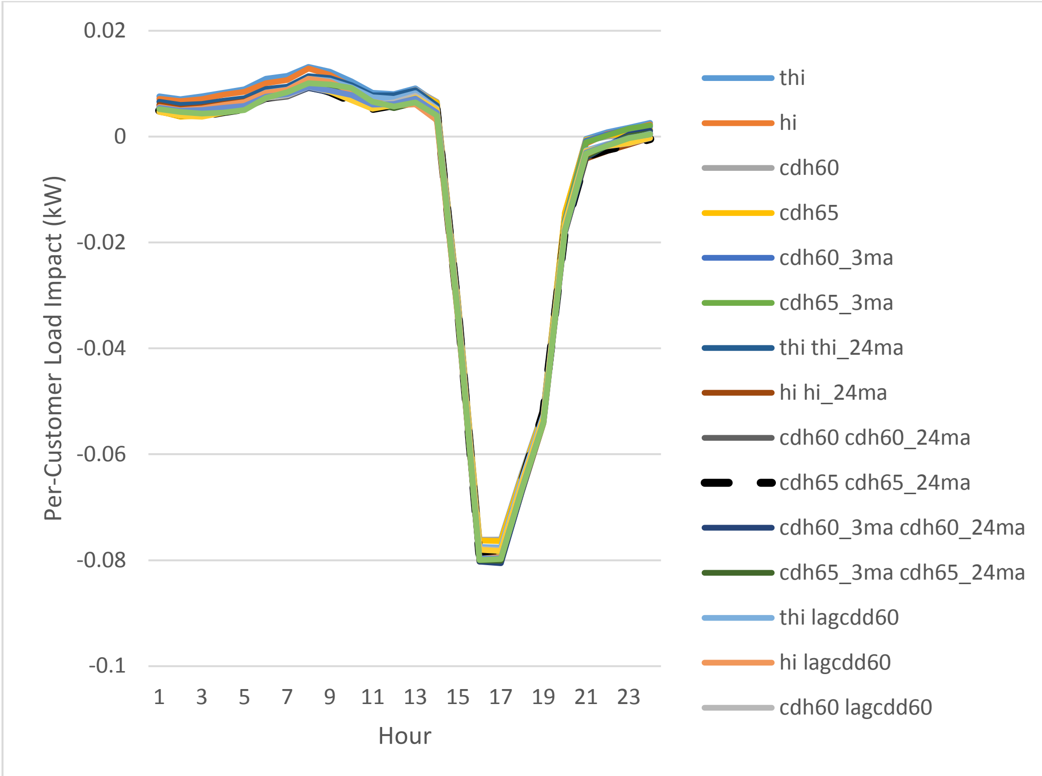


Figure 8–2: Average Event-Hour Load Impacts by Specification, *PG&E CBP DO*

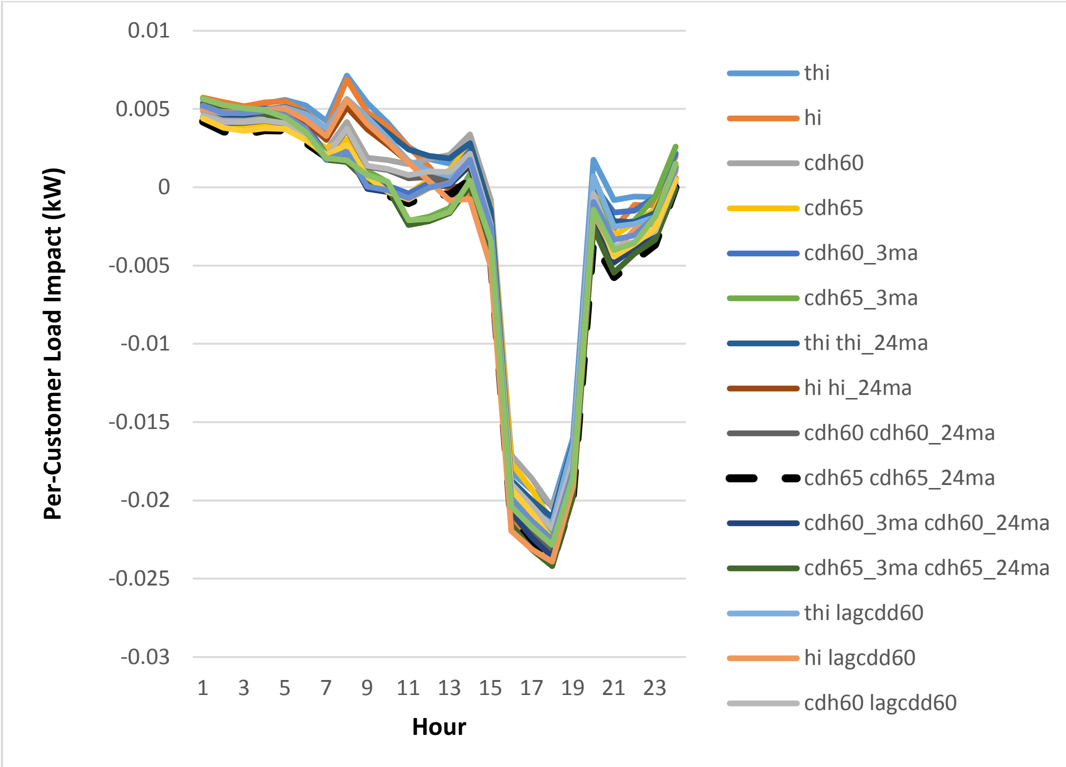


Figure 8–3: Average Event-Hour Load Impacts by Specification, *SCE AMP DO*

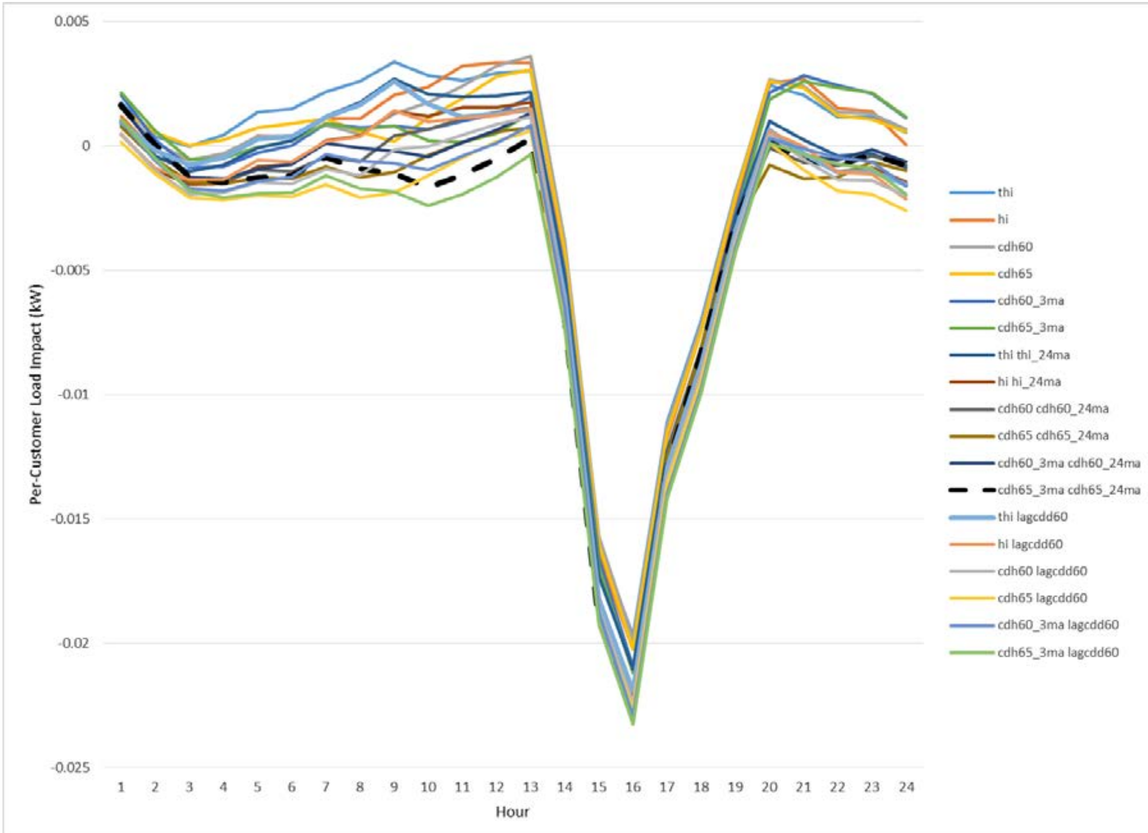


Figure 8–4: Average Event-Hour Load Impacts by Specification, *SCE CBP DO*

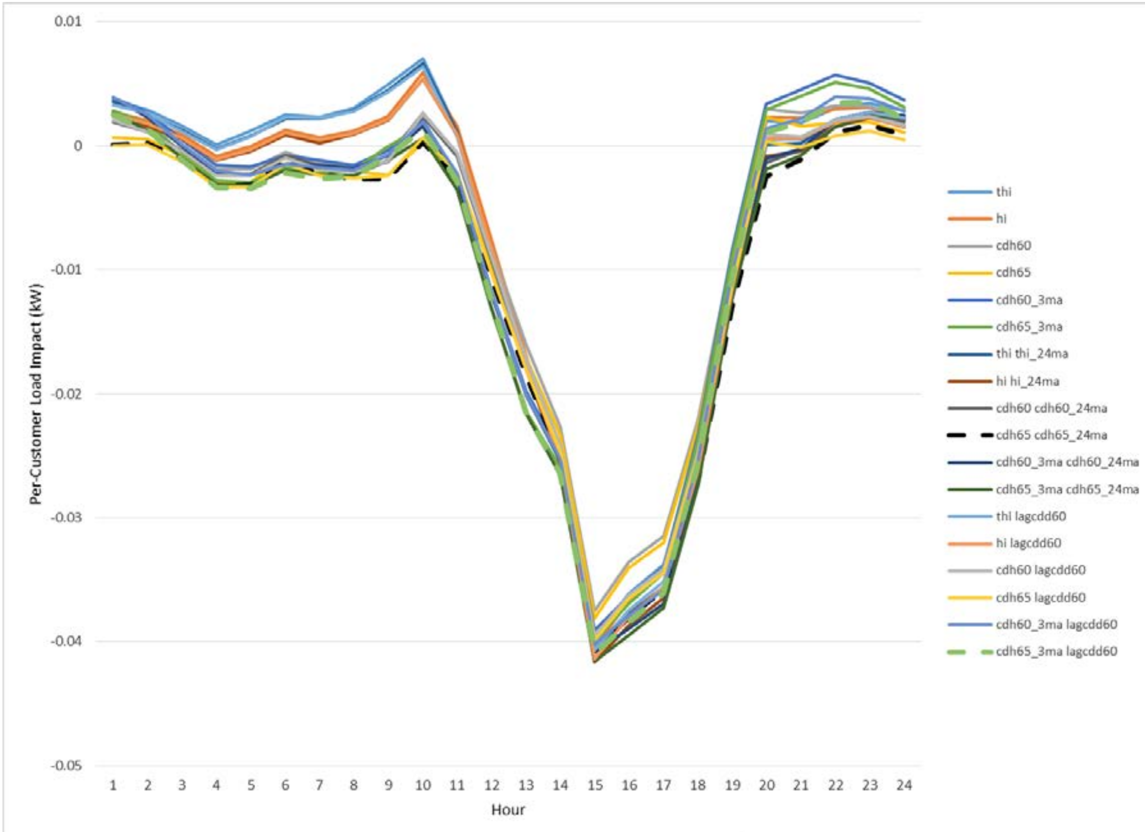
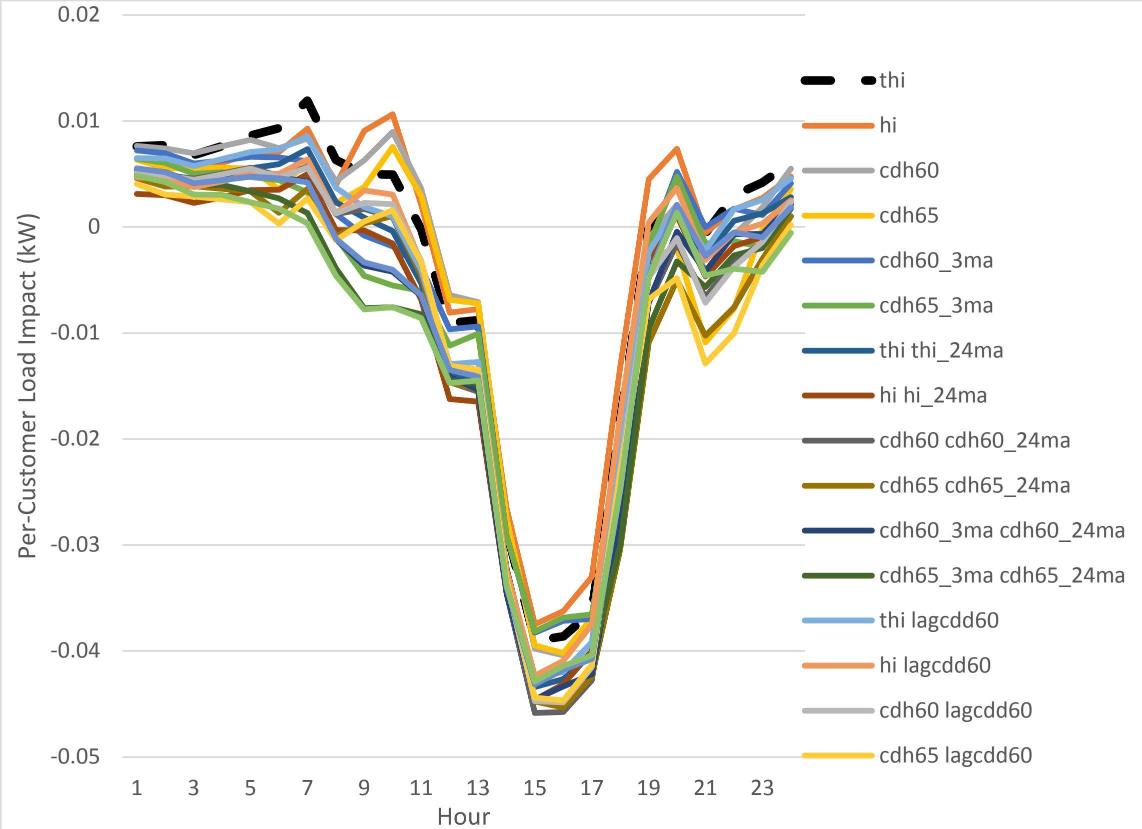


Figure 8–5: Average Event-Hour Load Impacts by Specification, *SDG&E CBP DO*



8.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section 8.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data, including a set of 24 hourly "synthetic" event-day variables. These variables equaled one on the days listed in Table 8–1, with a separate estimate for each hour of the day.

The objective of the test is determine whether the model produces synthetic event-day coefficients that are not statistically significantly different from zero. If that is the case, then the test provides added confidence that our actual event-day coefficients are not biased. That is, the absence of statistically significant results for the synthetic event days indicates that the remainder of the model is doing a good job of explaining the loads on those days.

Table 8–4 presents the results of this test for each utility/program/notice model, showing only the coefficients during a typical event window of hours-ending 14 through 19. The coefficient values represent estimated load impacts on the synthetic event days (*e.g.*, a negative value represents an estimated load reduction). The values in *italics* are p-values, or measures of statistical significance. A p-value that is less than 0.05 indicates that the estimated coefficient is statistically significantly different from zero with 95 percent confidence.

For most programs and notice types, the p-values are uniformly higher than this standard, indicating that the models estimate load impacts that are not statistically significant from zero on non-event days, and thus "pass" this test. For a few models, such as SCE CBP DO and AMP DA, and SDG&E CBP DO, some hours of the period have estimated coefficients that, while small, are statistically significant. However, as shown in the figures below, the estimated load impacts are generally consistent across all model specifications, and would not be improved by changing the model specification.

Table 8–4: Synthetic Event-Day Tests by Program

Utility	Program	Notice	Hour					
			14	15	16	17	18	19
PG&E	CBP DA	Coeff.	0.0117	0.0222	0.0206	0.0176	0.0190	0.0209
		P-value	*0.407*	*0.117*	*0.147*	*0.217*	*0.183*	*0.145*
	CBP DO	Coeff.	0.0008	0.0007	0.0016	0.0013	0.0016	0.0026
		P-value	*0.509*	*0.568*	*0.178*	*0.266*	*0.195*	*0.030*
	AMP DA	Coeff.	-0.0007	-0.0029	-0.0038	-0.0021	0.0006	0.0030
		P-value	*0.879*	*0.532*	*0.405*	*0.643*	*0.894*	*0.523*
	AMP DO	Coeff.	-0.0004	-0.0025	-0.0022	-0.0012	0.0014	0.0047
		P-value	*0.864*	*0.260*	*0.310*	*0.592*	*0.520*	*0.036*
SCE	CBP DA	Coeff.	0.0143	0.0174	0.0075	0.0038	0.0012	-0.0055
		P-value	*0.279*	*0.191*	*0.571*	*0.776*	*0.928*	*0.681*
	CBP DO	Coeff.	0.0046	0.0038	0.0034	0.0027	0.0025	0.0028
		P-value	*0.006*	*0.023*	*0.040*	*0.109*	*0.133*	*0.105*
	AMP DA	Coeff.	-0.0063	-0.0061	-0.0068	-0.0065	-0.0062	-0.0029
		P-value	*0.043*	*0.045*	*0.028*	*0.034*	*0.046*	*0.351*
	AMP DO	Coeff.	-0.0016	-0.0022	-0.0006	-0.0004	-0.0005	-0.0017
		P-value	*0.544*	*0.384*	*0.829*	*0.89*	*0.835*	*0.514*
SDG&E	CBP DA	Coeff.	-0.0020	-0.0027	0.0023	-0.0024	-0.0080	-0.0091
		P-value	*0.699*	*0.612*	*0.660*	*0.643*	*0.127*	*0.082*
	CBP DO	Coeff.	-0.0036	-0.0027	-0.0019	-0.0013	-0.0017	0.0002
		P-value	*0.005*	*0.036*	*0.140*	*0.296*	*0.182*	*0.846*

8.2 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures 8–5 through 8–8 illustrate the average predicted and observed loads for the average customer, across the event-like days, for the various programs. In each figure, the solid lines represent the observed load and the dashed lines represent the load predicted by the statistical model. The predicted loads are generally quite close to the observed loads for the average event-like non-event days for each program and notice type.

Figure 8–6: Average Predicted and Observed Loads on Event-like Days, *PG&E*

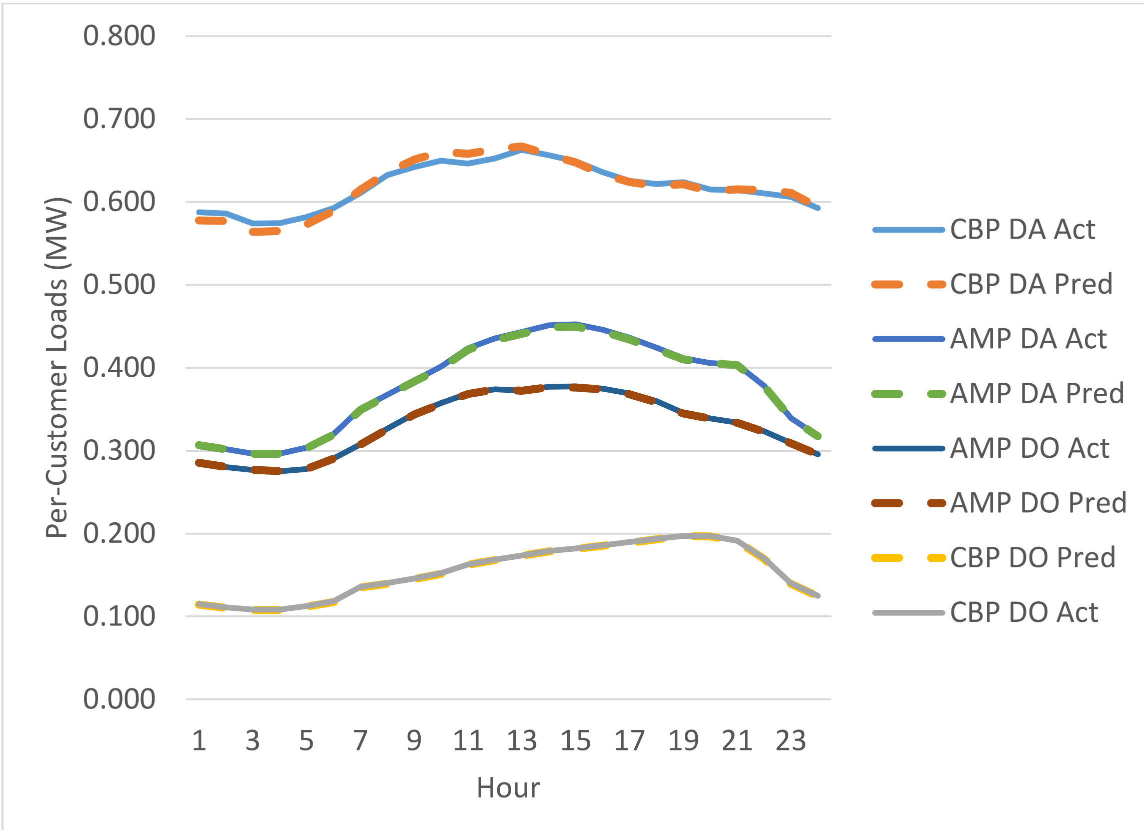


Figure 8–7: Average Predicted and Observed Loads on Event-like Days, *SCE*

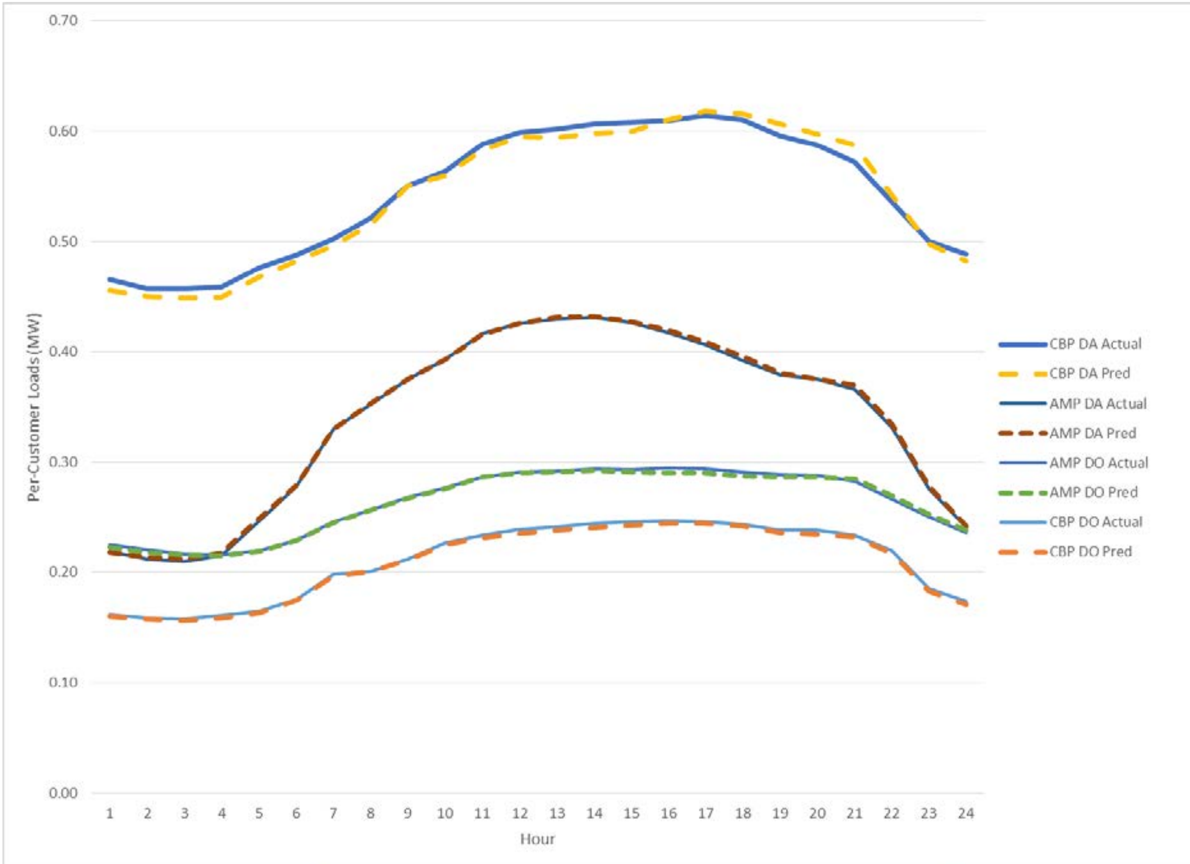
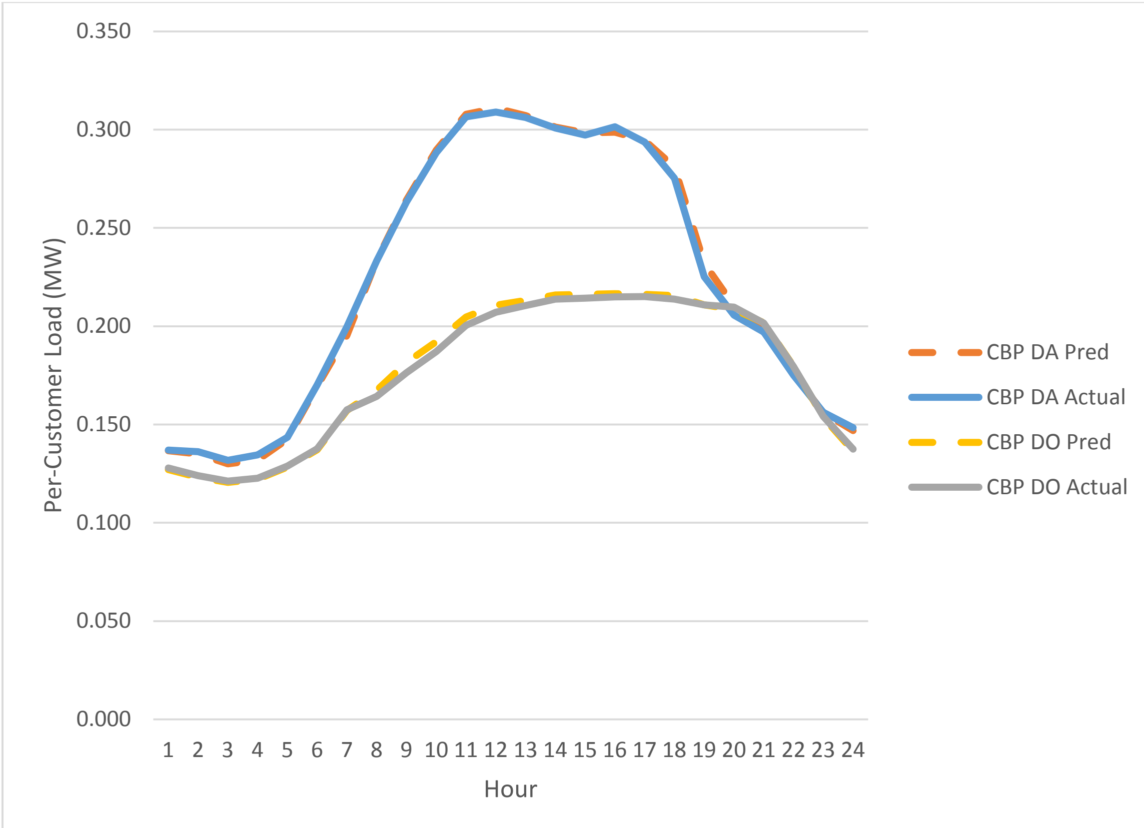


Figure 8–8: Average Predicted and Observed Loads on Event-like Days, *SDG&E*



8.3 Potential Modifications to Customer-Level Models

While the specification tests described in Section 8.1 were conducted on aggregated load profiles for each utility, the *ex-post* load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a "day matching" load impact that may be compared to the estimated load impacts. In this evaluation, we elected not to modify any of the estimated load impacts as a result of these inspections.

9. RECOMMENDATIONS

Given the move toward locational dispatch of aggregator events, the DRMEC should consider reporting load impacts by sub-LAP (or other, more relevant location identifiers) as opposed to LCA.

APPENDICES

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

Study Appendix A	PG&E CBP Ex-Post Load Impact Tables
Study Appendix B	SCE CBP Ex-Post Load Impact Tables
Study Appendix C	SDG&E CBP Ex-Post Load Impact Tables
Study Appendix D	PG&E AMP Ex-Post Load Impact Tables
Study Appendix E	SCE AMP Ex-Post Load Impact Tables
Study Appendix F	PG&E CBP Ex-Ante Load Impact Tables
Study Appendix G	SCE CBP Ex-Ante Load Impact Tables
Study Appendix H	SDG&E CBP Ex-Ante Load Impact Tables
Study Appendix I	PG&E AMP Ex-Ante Load Impact Tables
Study Appendix J	SCE AMP Ex-Ante Load Impact Tables