



**2014 Statewide Load Impact
Evaluation of California
Aggregator Demand
Response Programs – *Ex-Post*
and *Ex-Ante* Load Impacts**

CALMAC Study ID PGE0356

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April 1, 2015

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ABSTRACT

This report documents the results of a load impact evaluation of aggregator-based 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 2014.

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 service 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 customer service accounts 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 2014; and
- Estimate *ex-ante* load impacts for the programs for years 2015 through 2025.

Nominated customer service accounts in the day-of versions of all of the programs exceeded those in the day-ahead versions, and were generally higher for AMP than for CBP. Numbers of nominated customer service accounts¹ ranged from less than 100 service accounts for some product types, to nearly 1,400 for PG&E’s AMP DO. A major change in 2014 involved the transfer of one SCE AMP DO portfolio to CBP DO, which involved approximately 800 service accounts.

The various programs and notice types were called from seven to fifteen times in 2014, including one SCE AMP event and several PG&E CBP and AMP events that were called for various combinations of distribution-based geographical locations (SubLaps).

Hourly *ex-post* load impacts were estimated for each program, notice type, and event during the summer of 2014, 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

¹ PG&E refers to these as service agreements.

for the average, or typical event were also reported by industry type and CAISO local capacity area where relevant.

Estimated aggregate load impacts for the typical CBP DA event were 4.9 MW for PG&E, 9.6 MW for SCE, and 9.9 for SDG&E. Load impacts for CBP with DO notice were 10.6 MW for PG&E, 52.7 MW for SCE, and 8.8 for SDG&E. The value for SCE reflects the transfer of an AMP DO portfolio to CBP DO. The typical AMP load impacts were generally larger, with PG&E's and SCE's DO products averaging 123 MW and 90 MW respectively.²

Ex-ante load impact forecasts are developed by combining enrollment forecasts provided by the utilities, and per-customer load impacts generated from analysis of current and prior *ex-post* load impact estimates. The forecast numbers of nominated customer service accounts and aggregate load impacts generally follow patterns in the current year, except in cases of major anticipated changes. These include PG&E anticipating no AMP DA contracts in 2015, and SCE anticipating transfers of a number of CBP DA service accounts to DO, due to the number of events called during the 2014/2015 winter period.

² Load impact values for PG&E's AMP DA are not available due to confidentiality reasons.

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 2014. 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 service accounts, 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 customer service accounts 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 2014; and
- Estimate the *ex-ante* load impacts for 2015 through 2025.

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). For PG&E and SDG&E, 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 for PG&E, and 44 event hours per month for SDG&E. For SCE, CBP events may be called during the above hours on any non-holiday weekday of the year.

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 nearly 1,900 nominated service accounts for the average event, representing nominated load reduction capacity of approximately 235 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 the IOU expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or the IOU, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. Customer service accounts who participate in AMP with *day-ahead* notice are allowed to dually enroll in PG&E's Optional Binding Mandatory Curtailment program, while AMP customer service accounts 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 had five AMP contracts in 2014, only two of which were active. Of the active group, both offered day-of notice, but with different event windows (1 to 4, or 1 to 6 Hours). However, one of the active contracts, for DO 1-4 Hours, had its entire portfolio transferred to CBP at the end of June. The remaining contract included approximately 900 customer service accounts, with a DR resource capacity of nearly 115 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 service accounts nominated for the DA and DO notice types across all aggregator programs at the three utilities in 2014, where the values represent the number of nominated customer service accounts for the average of typical events, and thus do not necessarily equal the number nominated in any

particular month or for any particular event. Generally, more service accounts are nominated for DO product types than for DA product types.³

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

Program	Utility	Nominated Accounts	
		DA	DO
CBP	PG&E	33	542
	SCE	231	1,236
	SDG&E	163	237
AMP	PG&E	502	1,397
	SCE	-	920

ES.2 Summary of Study Findings

Events called

Table ES–2 summarizes the numbers of aggregator program events called in 2014, by utility, program and notice type. The various program types were called from seven to fifteen times during 2014. One of SCE’s AMP events, and several of PG&E’s CBP and AMP events were called for only some SubLaps, or geographical areas. With the exception of a February event, all of SCE’s CBP DO events were called in July or later, after the transfer of AMP DO service accounts into the program.

Table ES–2: Aggregator Program Events Called in 2014

Program	Utility	Number of Events by Notice Type	
		DA	DO
CBP	PG&E	10	15
	SCE	14	14
	SDG&E	14	7
AMP	PG&E	14	15
	SCE		12

Estimated ex-post load impacts

Table ES–3 summarizes estimates of average event-hour *ex-post* load impacts for PY 2014, 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 average

³ The relatively large number of CBP DO service accounts reflects the transfer of one AMP DO portfolio to CBP DO as of July 1.

nominated resource capacity amounts across the typical events.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 capacity.

Table ES-3: Average Event-Hour Load Impacts – Per-Customer and Aggregate by Utility and Notice

Program	Utility	DA			DO		
		LI per Cust. (kW)	Agg. LI (MW)	Nom. Capacity (MW)	LI per Cust. (kW)	Agg. LI (MW)	Nom. Capacity (MW)
CBP	PG&E	148.3	4.9	7.9	19.5	10.6	13.7
	SCE	41.5	9.6	10.3	42.6	52.7	57.1
	SDG&E	60.6	9.9	9.0	37.0	8.8	9.9
AMP	PG&E				87.9	122.7	166.9
	SCE	-	-	-	98.2	90.3	113.4

Ex-ante load impacts

Table ES-4 shows aggregate *ex-ante* load impact forecasts for 2015 for an August peak day for each utility’s program, by notice and weather scenario. Since the large business customers in the aggregator-based programs are typically not highly weather sensitive, the load impacts generally do not vary greatly across weather scenarios. However, the values in the utility-peak scenarios are generally slightly higher than under CAISO peak conditions.

Table ES-4: Ex-Ante Load Impacts for August Peak Day in 2015 under Alternative Weather Scenarios (MW)

Program	Utility	Notice	Utility Peak		CAISO Peak	
			1-in-2	1-in-10	1-in-2	1-in-10
CBP	PG&E	DA	5.45	5.49	5.41	5.46
		DO	9.94	10.26	9.65	10.02
	SCE	DA	5.46	5.55	5.45	5.52
		DO	48.8	49.5	48.8	49.3
	SDG&E	DA	11.90	12.28	11.99	12.02
		DO	9.78	10.01	9.90	9.91
AMP	PG&E	DO	128.2	129.1	126.9	128.3
	SCE	DO	93.5	94.5	93.4	94.0

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 are contractually based.

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 2014. In these programs, third-party DR aggregators contract with the IOUs and with selected commercial and industrial customers to arrange reductions in electricity usage when the utilities call DR events. The aggregators act on behalf of their enrolled customer service accounts with respect to all aspects of the DR program, including receiving event notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties for non-performance (if warranted) to the utility. Each aggregator forms a “portfolio” of individual service accounts, 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 customer service accounts 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 its customers.

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

The primary goals of this evaluation study are the following:

- Estimate the *ex-post* load impacts for program year 2014; and
- Estimate the *ex-ante* load impacts for 2015 through 2025.

The first goal involves estimating *hourly load impacts* for each 2014 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 to estimating load impacts involved estimating *individual customer regressions*, which provides a flexible basis for analyzing and reporting load impact results at various levels of aggregation, including at the total program level, and by various subgroups (*e.g.*, by industry group and CAISO local capacity area, and by those customer service accounts 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 2025, by combining the information on historical *ex-post* load impacts with utility projections of program enrollment or contracted load nominations.

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).⁵ Additional energy payments (\$/kWh) are made to bundled⁶ 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, participants receive the monthly capacity payment in accordance with their nominations, 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). For PG&E and SDG&E, 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 for PG&E, and 44 event hours per month for SDG&E. For SCE, CBP events may be called on any non-holiday weekday of the year. Customer service accounts 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).

Table 2–1 summarizes the number of service accounts that were nominated for the typical CBP event at each utility in 2014, by type of notice and industry group, along with their associated coincident maximum demand.^{7 8} Since nominations vary by month, we use the convention of reporting the average number of nominated service accounts for the typical event.⁹

⁵ Participants may be individual customers or aggregators, but most all are aggregators.

⁶ The program is also open to Direct Access and Community Choice Aggregation customers.

⁷ Coincident maximum demand (“Sum of Max Demand (MW)” in the tables) is calculated as the sum over customers of their reference load in the hour of maximum demand during the hours of typical events for the relevant program. Customers’ reference load on an event day is defined as their observed load, plus their estimated load impacts added back in.

⁸ The number of accounts nominated for SCE CBP DO is indicated as applying only for July through October. This is the case because one aggregator transferred customers from a DO 1-4 Hour contract’s portfolio from AMP to CBP effective in July.

⁹ We report nominations because CBP customers are not assigned to DA or DO product types until they are nominated in a particular month. The average number of nominated service accounts may not equal the number called for any particular event. That number is shown for each event in the load impact tables. The reported numbers of customers nominated reflects service accounts whose load data were available and included in this study.

Substantially larger numbers of service accounts were nominated for the day-of notice option at all three utilities. Retail stores make up a large share of CBP DO nominated customer service accounts at each of the utilities, as well as CBP DA at SCE. Approximately half of SDG&E's DA product consists of customer service accounts in Offices, Hotels, Health, and Services.¹⁰

Table 2–1: CBP Nominated Service Accounts, by Utility and Industry Group (2014)

Utility	Industry Type	Day-Ahead		Day-Of	
		Accounts	Sum of Max Demand (MW)	Accounts	Sum of Max Demand (MW)
PG&E	1. Agriculture, Mining & Construction	20	3.33		
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities				
	4. Retail stores			517	80.75
	5. Offices, Hotels, Health, Services				
	6. Schools				
	7. Entertainment, Other Services, Gov't				
	8. Other/Unknown				
	Total PG&E	33	15.0	544	92.3
SCE (July - Oct. for DO)	1. Agriculture, Mining & Construction			132	8.6
	2. Manufacturing	32	52.2	20	24.3
	3. Wholesale, Transport, other Utilities	17	7.2	181	27.2
	4. Retail stores	161	52.3	808	185.2
	5. Offices, Hotels, Health, Services			66	31.4
	6. Schools			12	6.0
	7. Entertainment, Other Services, Gov't			16	2.9
	8. Other/Unknown				
	Total SCE	235	129.0	1,234	285.6
SDG&E	1. Agriculture, Mining & Construction	-	-	-	-
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities				
	4. Retail stores	35	7.7	213	46.2
	5. Offices, Hotels, Health, Services	77	22.4	15	6.2
	6. Schools	26	5.3	-	0.0
	7. Entertainment, Other Services, Gov't				
	8. Other/Unknown				
	Total SDG&E	163	54.5	237	59.0

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.

¹⁰ In this report, blank cells or rows in tables reflect values that are redacted by the utilities due to confidentiality concerns about cases of small numbers of customers.

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 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.

2.2.1 PG&E’s AMP

PG&E has AMP contracts with five aggregators. Four offer DO contracts, and one offers 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 the utility expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or the utility, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. In 2014, PG&E dispatched a number of localized events for which only some SubLaps were called. These events are described in Section 4.

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 customer service accounts nominated for the typical PG&E AMP DA and DO event, by industry type, along with their coincident maximum demand. The aggregators nominated nearly 1,900 service accounts across both notice types. 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 Service Accounts, by Industry Group

Industry Type	Day-Ahead		Day-Of	
	Accounts	Sum of Max Demand (MW)	Accounts	Sum of Max Demand (MW)
1. Agriculture, Mining & Construction	40	9.6	539	100.8
2. Manufacturing	141	114.0	120	136.4
3. Wholesale, Transport, other Utilities	59	16.5	154	71.5
4. Retail stores	138	33.4	247	56.2
5. Offices, Hotels, Health, Services	52	24.8	213	92.4
6. Schools	33	9.7	25	12.6
7. Entertainment, Other Services, Gov't	26	10.9	45	31.0
8. Other/Unknown	14	2.3	54	16.5
Total	502	221.2	1,397	517.4

2.2.2 SCE's AMP

SCE had five AMP contracts in 2014, only two of which were active. Of the active group, both offered day-of notice, but with different event windows (1 to 4, or 1 to 6 hours). However, one of the active contracts, for DO 1-4 Hours, had its entire portfolio transferred to CBP at the end of June. To ensure appropriate accounting for the transferred service accounts, Table 2–4 shows the number of nominated service accounts for only the DO 1-6 Hour contract, after the transfer of the other contract's portfolio to CBP (as noted above, the transferred accounts are reflected in Table 2.1 for CBP). Accounts participating in SCE's AMP may dually enroll 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.

Nominated customer service accounts for AMP DO are spread over several industry types, with the majority in Retail stores; and Wholesale, Transport, and other Utilities.

Table 2–4: SCE AMP Nominated Service Accounts, by Industry Group

Industry Type	Day-Of (July-Oct.)	
	Accounts	Sum of Max Demand (MW)
1. Agriculture, Mining & Construction	97	26.6
2. Manufacturing	89	51.4
3. Wholesale, Transport, other Utilities	365	81.2
4. Retail stores	275	74.6
5. Offices, Hotels, Health, Services	81	30.8
6. Schools		
7. Entertainment, Other Services, Gov't		
8. Other/Unknown		
Total	920	296.8

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 service 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 the primary factors that affect consumers’ hourly demand levels, including called events, such as:

- *Seasonal and hourly time patterns* (e.g., month, day-of-week, and hour, plus various hour/day-type interactions to allow hourly load patterns to vary by day-type);
- *Weather*, including hour-specific weather variables;
- *Event variables*. Indicator variables are included to account for each hour of each event day, for all DR programs in which the service account participates, which allows estimation of aggregator program load impacts for all hours across each event day, for each service account.

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each service account that was nominated and called for at least one event in 2014. 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-day coefficient of –100 for a particular event implies that the service account reduced load by 100 kWh during hour 15 of that event day relative to what its usage in that hour would have been otherwise, under the observed day-type and weather conditions on

that day. Weekends and holidays were excluded from the estimation database because aggregator events may be called only on non-holiday 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 ex-post estimation methods

3.2.1 Regression Model

The model shown below characterizes the nature of the regression equations, which were estimated separately for each service account. Table 3–1 describes the terms included in the equation.

$$\begin{aligned}
 Q_{i,d} = & a + \sum_{Evt=1}^E \sum_{i=1}^{24} (b_{i,Evt}^{AGG} \times h_{i,t} \times AGG_d) + \sum_{i=1}^{24} (b_i^{MornLoad} \times h_{i,t} \times MornLoad_d) \\
 & + \sum_{i=1}^{24} (b_i^{OTH} \times h_{i,t} \times OtherEvt_d) + \sum_{i=1}^{24} (b_i^{Weather} \times h_{i,t} \times Weather_{t,d}) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_d) \\
 & + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_d) + \sum_{i=2}^{24} (b_i^{SUMMER} \times h_{i,t} \times SUMMER_d) + \sum_{i=2}^{24} (b_i^h \times h_{i,t}) \\
 & + \sum_{i=2}^5 (b_i^{DTYPE} \times DTYPE_{i,d}) + \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,d}) + e_{t,d}
 \end{aligned}$$

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

Variable Name / Term	Variable / Term Description
$Q_{t,d}$	The demand in hour t , on day d 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 (<i>i.e.</i> , $h_{i,t} = 1$ if $i=t$, and 0 otherwise)
$AGG_{t,d}$	An indicator variable for aggregator program event days
$Weather_{t,d}$	The weather variables selected in our model screening process
E	The number of event days that occurred during the program year
$MornLoad_d$	The average of day d 's load in hours 1 through 10
$OtherEvt_d$	Equals one on event days of other demand response programs in which the customer is enrolled
MON_d	An indicator variable for Mondays
FRI_d	An indicator variable for Fridays
$SUMMER_d$	An indicator variable for the summer pricing season ¹¹
$DTYPE_{i,d}$	A series of indicator variables for each day of the week
$MONTH_{i,d}$	A series of indicator variables for each month
$e_{t,d}$	The error term.

The OtherEvt variables help the model explain load changes that occur on event days in cases in which aggregator service accounts are dually enrolled in other DR programs. (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 service accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group and local capacity area (LCA).

¹¹ 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. Since the summer pricing season for PG&E overlaps exactly with the months included in the regression analysis, no *Summer* variable is included in the regressions for PG&E.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of *ex-post* load impacts, the parameters that constitute the load impact estimates for each hour are surrounded by a range of uncertainty that is indicated by the standard errors associated with the load impact coefficients. We base the uncertainty-adjusted load impacts on the variances (*i.e.*, the square of the standard errors) associated with the estimated load impact coefficients.

For each event, to calculate the range of uncertainty at an aggregate level, we add the variances of the estimated customer-level load impacts across the customers who were called for the event in question. These aggregations are performed at either the program level, by industry group, or by LCA, as appropriate. The uncertainty-adjusted scenarios are then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated customer-level load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

In order to develop the uncertainty-adjusted load impacts associated with the *average* event hour (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), we estimated two additional sets of customer-specific regression models. In the first model, we estimated the average event-hour load impact for *each* event-day, by using a single event variable (rather than the hour-specific variables used in the primary model described above). The standard errors associated with these event-specific coefficients serve as the basis of the average event-hour uncertainty-adjusted load impacts for each *ex-post* event day, which are shown on the last row of event-specific tables. The second model includes a single event-hour variable that applies to *all* event hours of the typical (or average) event day during the program year. The standard error associated with this estimate serves as the basis of the average event-hour uncertainty-adjusted load impacts for the typical *ex-post* event day.¹² In each case, the standard errors are used to develop the uncertainty-adjusted scenarios in the same manner as the hour-specific standard errors in the primary model. These values are shown in the bottom row of the table for the typical event day.

4. 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:

¹² The typical event day for the aggregator-based programs, as described in Section 4, is the average of all system-wide events that have the same event-window hours (*e.g.*, hours-ending 16 to 19).

- Events that were called in 2014;
- For each event, the number of service 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;¹³
- 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 2014, including day of week, event type, event hours, and number of service accounts called. A number of localized events were called for only some SubLaps, as indicated in the column labeled “Event Type”. Typical events, indicated by shading, are those that were called system-wide for hours-ending 16 to 19.

¹³ Aggregator events may be called for different aggregators, different locations, and for different hours. This feature complicates both the definition of an “average,” or “typical” event, and the reporting of estimated load impacts for the average event-hour. The typical events selected for each program and utility are described below.

Table 4–1: Event Summary for 2014 – PG&E CBP

Date	Day of Week	Event Type	Notice	Product	Event Hours Ending	Num. of Accounts
05/14/14	Wed	4 SubLaps	DA	1-4 Hour	17 - 19	
			DO	1-4 Hour 2-6 Hour	16 - 19	146 37
05/15/14	Thu	System	DA	1-4 Hour	16 - 19	31
			DO	1-4 Hour 2-6 Hour	16 - 19	434 106
06/09/14	Mon	System	DO	1-4 Hour 2-6 Hour	16 - 19	449 105
06/30/14	Mon	System	DO	1-4 Hour 2-6 Hour	16 - 19	449 105
07/07/14	Mon	System	DA	1-4 Hour	17 - 19	36
		2 SubLaps	DO	1-4 Hour 2-6 Hour	16 - 19	80
07/14/14	Mon	3 SubLaps	DA	1-4 Hour	16 - 19	28
		7 SubLaps	DO	1-4 Hour 2-6 Hour	16 - 19	90 17
07/25/14	Fri	3 SubLaps	DA	1-4 Hour	16 - 19	24
		2 SubLaps	DO	1-4 Hour 2-6 Hour	16 - 19	94
07/28/14	Mon	System	DA	1-4 Hour	16 - 19	36
			DO	1-4 Hour 2-6 Hour	16 - 19	433 103
07/29/14	Tue	System	DA	1-4 Hour	17 - 19	35
			DO	1-4 Hour 2-6 Hour	17 - 19	433 103
08/01/14	Fri	12 SubLaps	DA	1-4 Hour	16 - 19	37
			DO	1-4 Hour 2-6 Hour	16 - 19	402 100
09/02/14	Tue	Fresno	DO	1-4 Hour 2-6 Hour	16 - 19	52
09/15/14	Mon	System	DA	1-4 Hour	16 - 19	32
			DO	1-4 Hour 2-6 Hour	16 - 19	422 106
10/02/14	Thu	1 SubLap	DA	1-4 Hour	16 - 19	
			DO	1-4 Hour 2-6 Hour	16 - 19	24
10/03/14	Fri	1 SubLap	DA	1-4 Hour	16 - 19	
			DO	1-4 Hour 2-6 Hour	16 - 19 15 - 19	24
10/06/14	Mon	3 SubLaps	DO	1-4 Hour	16 - 19	119
				2-6 Hour	15 - 19	20

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 the typical event. Also shown are average event-hour temperatures, and the amount of monthly nominated capacity for the relevant product types and SubLaps called. The nominated capacity values may be compared to the aggregate load impact estimates in the fourth column from the right. The average event-hour DA load impact for the typical event was 4.9 MW, while DO load impacts averaged 5.8 MW for the 1-4 Hour product, and 4.8 MW for the 2-6 Hour product. Average percentage load impacts for the typical event ranged from 10 to 37 percent across the three product types.

Table 4–2: Average Event-Hour Loads and Load Impacts by Event – PG&E CBP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.	Nom. Capacity (MW)
				Ref. Load (MW)	Load Impact (kW)	Ref. Load (MW)	Load Impact (MW)			
5/14/14	DA	1-4 Hour								
	DO	1-4 Hour	146	121.8	9.9	17.8	1.45	8%	87	2.67
		2-6 Hour	37	223.2	37.3	8.3	1.38	17%	89	2.03
5/15/14	DA	1-4 Hour	31	441.0	102.8	13.7	3.19	23%	90	6.78
	DO	1-4 Hour	434	122.3	14.0	53.1	6.06	11%	87	8.17
		2-6 Hour	106	243.0	38.4	25.8	4.07	16%	88	5.78
6/9/14	DO	1-4 Hour	449	132.0	12.1	59.3	5.43	9%	92	8.65
		2-6 Hour	105	265.4	44.3	27.9	4.65	17%	92	4.95
6/30/14	DO	1-4 Hour	449	129.4	11.4	58.1	5.11	9%	90	8.65
		2-6 Hour	105	259.9	47.5	27.3	4.99	18%	90	4.95
7/7/14	DA	1-4 Hour	36	421.8	227.1	15.2	8.17	54%	88	8.01
	DO	1-4 Hour	80	124.5	16.9	10.0	1.35	14%	85	1.42
		2-6 Hour								
7/14/14	DA	1-4 Hour	28	428.5	261.2	12.0	7.31	61%	99	6.87
	DO	1-4 Hour	90	141.3	19.7	12.7	1.77	14%	101	2.38
		2-6 Hour	17	294.4	57.9	5.0	0.98	20%	101	0.87
7/25/14	DA	1-4 Hour	24	253.3	70.3	6.1	1.69	28%	99	6.07
	DO	1-4 Hour	94	145.7	13.1	13.7	1.23	9%	92	2.09
		2-6 Hour								
7/28/14	DA	1-4 Hour	36	351.1	136.7	12.6	4.92	39%	89	8.01
	DO	1-4 Hour	433	131.2	14.0	56.8	6.08	11%	84	9.22
		2-6 Hour	103	251.8	47.1	25.9	4.85	19%	84	4.71
7/29/14	DA	1-4 Hour	35	341.0	68.0	12.0	2.40	20%	92	8.01
	DO	1-4 Hour	433	139.5	18.6	60.4	8.05	13%	88	9.22
		2-6 Hour	103	260.2	51.0	26.8	5.25	20%	88	4.71
8/1/14	DA	1-4 Hour	37	389.1	25.5	14.4	0.94	7%	97	10.18
	DO	1-4 Hour	402	140.0	17.2	56.3	6.91	12%	92	8.26
		2-6 Hour	100	268.5	49.7	26.9	4.97	18%	92	4.52
9/2/14	DO	1-4 Hour	52	142.9	9.3	7.4	0.48	7%	101	0.90
		2-6 Hour								
9/15/14	DA	1-4 Hour	32	404.2	205.4	12.9	6.57	51%	86	8.99
	DO	1-4 Hour	422	131.8	14.7	55.6	6.21	11%	84	8.84
		2-6 Hour	106	246.1	50.9	26.1	5.39	21%	82	4.81
10/2/14	DA	1-4 Hour								
	DO	1-4 Hour	24	118.8	13.1	2.9	0.31	11%	84	0.45
		2-6 Hour								
10/3/14	DA	1-4 Hour								
	DO	1-4 Hour	24	122.8	4.9	2.9	0.12	4%	83	0.45
		2-6 Hour								
10/6/14	DO	1-4 Hour	119	119.4	14.2	14.2	1.69	12%	92	1.90
		2-6 Hour	20	252.2	69.2	5.0	1.38	27%	92	0.98
Typical Event	DA	1-4 Hour	33	396.4	148.3	13.1	4.89	37%	89	7.92
	DO	1-4 Hour	437	129.3	13.2	56.6	5.78	10%	87	8.70
		2-6 Hour	105	253.2	45.6	26.6	4.79	18%	87	5.04

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

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

Notice	Industry	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Agriculture, Mining & Construction	20	117.6	65.1	2.4	1.32	55%	99
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores							
	Offices, Hotels, Finance, Services							
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DA	33	396.4	148.3	13.1	4.9	37%	89
DO	Agriculture, Mining & Construction							
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores	517	143.8	19.0	74.31	9.81	13%	88
	Offices, Hotels, Finance, Services							
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DO	542	153.3	19.5	83.2	10.6	13%	87

Table 4–4 shows the distribution of average event-hour load impacts by LCA. 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.

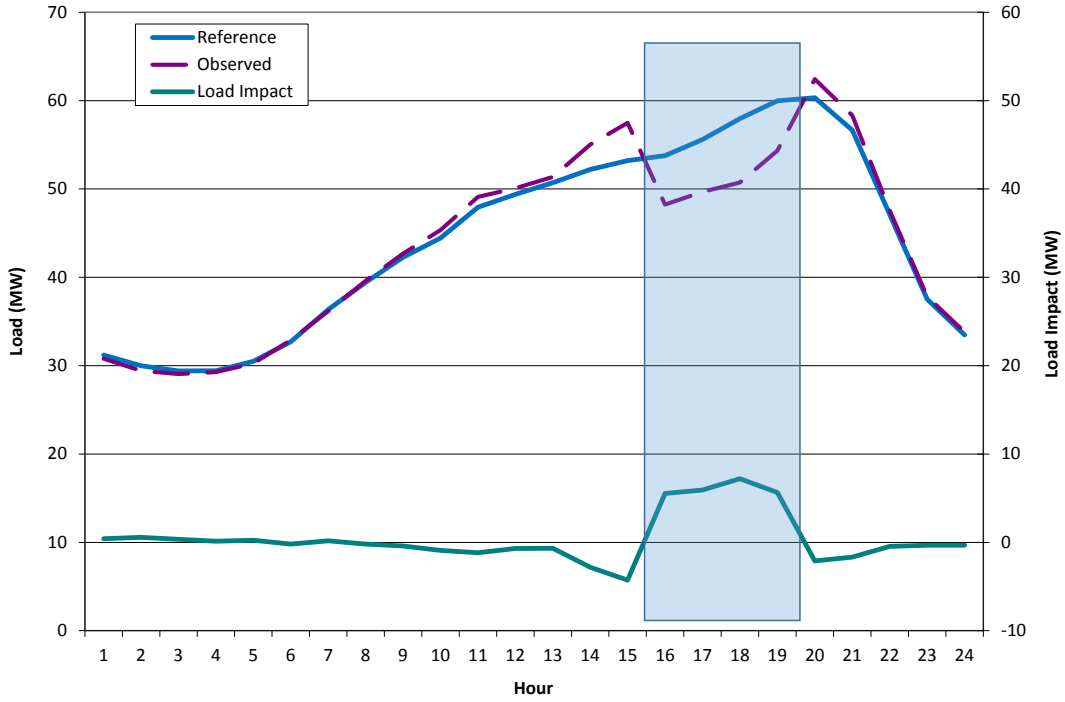
Table 4–4: Distribution of Average Event-Hour Load Impacts by LCA – PG&E CBP

Notice	LCA	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Greater Bay Area							
	Greater Fresno							
	Humboldt							
	Kern							
	Northern Coast							
	Not in any LCA							
	Sierra							
	Stockton							
	Total DA	33	396.4	148.3	13.1	4.9	37%	89
DO	Greater Bay Area	249	150.2	16.5	37.5	4.11	11%	81
	Greater Fresno	48	175.1	23.8	8.4	1.15	14%	102
	Humboldt							
	Kern	27	192.9	23.9	5.3	0.66	12%	102
	Northern Coast	43	159.9	18.4	6.9	0.80	12%	85
	Not in any LCA	114	147.7	23.1	16.8	2.62	16%	88
	Sierra	26	146.2	25.3	3.8	0.66	17%	94
	Stockton	29	135.4	17.4	3.9	0.50	13%	95
	Total DO	542	153.3	19.5	83.2	10.6	13%	87

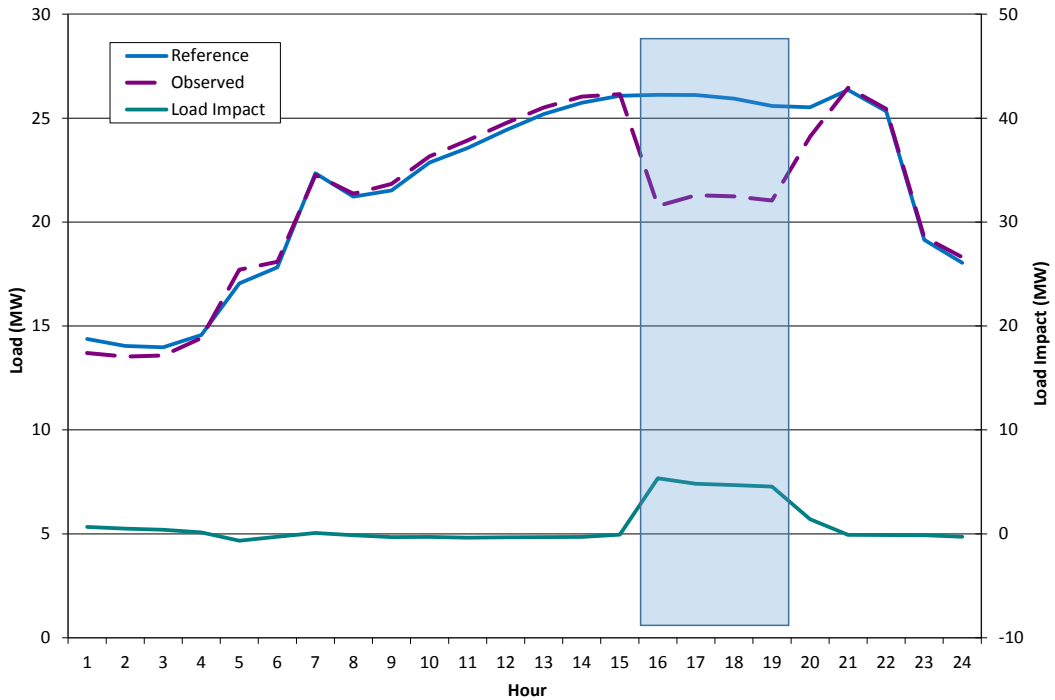
4.1.3 Hourly load impacts

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 28 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.

**Figure 4–1: Hourly Loads and Load Impacts – PG&E CBP DO 1-4
July 28, 2014 Event**



**Figure 4–2: Hourly Loads and Load Impacts – PG&E CBP DO 2-6
July 28, 2014 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 service accounts that participated in TA/TI or AutoDR at some point in the current or previous years. The *ex-post* load impacts reported here for these customers should not, however, be interpreted as the incremental impacts due to the technology programs.

The Automated Demand Response (AutoDR) program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies.

The Technical Assistance and Technology Incentives (TA/TI) program is no longer offered by the IOUs, but we summarize load impacts from customers that received program incentives in the past. The program had two parts: technical assistance (TA) in the form of energy audits, and technology incentives (TI). The objective of the TA portion of the program was to subsidize customer energy audits that had the objective of identifying ways in which customers could reduce load during DR events. The TI portion of the program provided incentive payments for the installation of equipment or control software supporting DR.

Table 4–5 and 4–6 summarize event-specific *total* load impacts for TA/TI and AutoDR participants, respectively, that received TA/TI or AutoDR incentives at some point prior to the DR event(s) summarized. 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 one CBP DA customer and 35 CBP DO customers participated in TA/TI and achieved load impacts for the average event of 0.2 and 1.22 MW respectively. The rightmost column (Load Shed Test) shows the total load shed amounts approved following the TA/TI DR test, which are .76 MW and 4 MW for DA and DO respectively.

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	Load Shed Test (MW)
DA	5/15/2014						
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014						
	7/29/2014						
	8/1/2014						
	9/15/2014						
	Average of Typical Event						
DO	5/14/2014						
	5/15/2014	37	11.6	10.8	0.75	7%	4.09
	6/9/2014	35	12.0	11.1	0.86	7%	4.00
	6/30/2014	35	11.7	10.9	0.73	6%	4.00
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014	35	11.4	9.9	1.51	13%	4.00
	7/29/2014	35	12.1	10.2	1.90	16%	4.00
	8/1/2014	34	12.1	10.7	1.47	12%	3.98
	9/2/2014						
	9/15/2014	33	10.7	9.4	1.30	12%	3.83
	10/6/2014						
Average of Typical Event	35	11.7	10.4	1.22	10%	3.98	

Table 4–6 shows comparable information for CBP customers that received AutoDR incentives at some point prior to the DR event(s) summarized. An average of 12 DA and 44 DO customers are AutoDR participants, and their estimated load impacts for the average event are 0.52 MW and 0.82 MW. The load shed test amounts are 1.5 MW for DA and 7.4 MW for DO.

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	Load Shed Test (MW)
DA	5/15/2014						
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014						
	7/29/2014						
	8/1/2014						
	9/15/2014						
	Average of Typical Event						
DO	5/14/2014						
	5/15/2014	37	7.5	7.0	0.55	7%	6.18
	6/9/2014	46	10.4	9.9	0.48	5%	7.66
	6/30/2014	46	10.1	9.4	0.70	7%	7.66
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014	46	10.1	9.4	0.73	7%	7.66
	7/29/2014	46	11.1	9.6	1.49	13%	7.66
	8/1/2014	42	9.8		1.07	11%	7.03
	9/2/2014						
	9/15/2014	46	9.8	9.0	0.87	9%	7.66
	10/2/2014						
	10/3/2014						
10/6/2014							
Average of Typical Event	44	9.8	9.0	0.82	8%	7.36	

4.2 Capacity Bidding Program (CBP) – SCE

4.2.1 Events for SCE CBP

Table 4–7 lists the events called for SCE’s CBP program in 2014. An unusual February event was called in 2014. Most events were called for only DA or DO notice. Only the events on September 15 and 16, and October 6 involved all DA and DO product types. Events were called for as short as one hour, and as long as six hours in length. Shaded areas indicate typical events, which have common event windows of HE 16 – 19.

Table 4–7: Event Summary for 2014 – SCE CBP

Date	Day of Week	Event Type	Notice	Product (Hour Window)	Event Hours Ending	Num. of Accounts
02/06/14	Thu	Heat Rate	DA	1-4 Hours	19	240
		CAISO	DO	1-4 Hours	16-19	136
				2-6 Hours	16-19	
05/15/14	Thu	Heat Rate	DA	1-4 Hours	16-18	220
07/03/14	Thu	Heat Rate	DO	1-4 Hours	16-17	1,045
07/07/14	Mon	Heat Rate	DA	1-4 Hours	16	252
07/14/14	Mon	Heat Rate	DA	1-4 Hours	16-19	252
07/15/14	Tu	Heat Rate	DA	1-4 Hours	18	252
07/30/14	Wed	Heat Rate	DO	1-4 Hours	16-19	1,045
				2-6 Hours		207
07/31/14	Thu	Heat Rate	DO	1-4 Hours	16-19	1,045
				2-6 Hours		207
08/01/14	Fri	Heat Rate	DA	1-4 Hours	18	222
08/11/14	Mon	Heat Rate	DO	1-4 Hours	15-18	1,051
				2-6 Hours	15-19	207
08/14/14	Thu	Heat Rate	DO	1-4 Hours	17-19	1,051
				2-6 Hours		207
08/28/14	Thu	Heat Rate	DO	1-4 Hours	16-19	1,051
				2-6 Hours		207
09/10/14	Wed	Heat Rate	DO	1-4 Hours	17-19	1,015
				2-6 Hours		195
09/11/14	Thu	Heat Rate	DO	1-4 Hours	16-19	1,015
				2-6 Hours	15-19	195
09/12/14	Fri	Heat Rate	DO	1-4 Hours	14-17	1,015
				2-6 Hours	13-18	195
09/15/14	Mon	Heat Rate	DA	1-4 Hours	16-19	219
			DO	1-4 Hours		16-19
				2-6 Hours		
09/16/14	Tu	Heat Rate	DA	1-4 Hours	16-19	219
			DO	1-4 Hours		16-19
				2-6 Hours		
09/17/14	Wed	Heat Rate	DA	1-4 Hours	16-18	219
				2-6 Hours		
10/03/14	Fri	Heat Rate	DA	1-4 Hours	18-19	210
				2-6 Hours		
10/06/14	Mon	Heat Rate	DA	1-4 Hours	17-19	210
			DO	1-4 Hours		16-19
				2-6 Hours		
10/07/14	Tu	Heat Rate	DO	1-4 Hours	16-19	994
				2-6 Hours		15-19
10/13/14	Mon	Heat Rate	DA	1-4 Hours	18-19	209
				2-6 Hours		
10/27/14	Mon	Heat Rate	DA	1-4 Hours	19	209
10/29/14	Wed	Heat Rate	DA	1-4 Hours	19	209

4.2.2 Summary load impacts

Table 4–8 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 SCE’s CBP events, and for averages across typical events. The average event-hour load impact for the DA 1-4 product was 9.7 MW. Day-of load impacts averaged 43 MW for the 1-4 Hour product from July onward (including the customers transferred from AMP), and 9.7 MW for the 2-6 Hour product. Average percentage load impacts ranged from 10 to 20 percent.

Table 4–8: Average Event-Hour Load Impacts by Event – SCE CBP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.	Nom. Capacity (MW)
				Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)			
2/6/14	DA	1-4 Hour	240	353.2	25.7	84.8	6.2	7%	52	10.6
	DO	1-4 Hour	136	59.3	6.7	8.1	0.9	11%	52	1.6
			2-6 Hour							
5/15/14	DA	1-4 Hour	220	566.0	62.7	124.5	13.8	11%	88	7.0
7/3/14	DO	1-4 Hour	1,045	204.9	45.3	214.1	47.3	22%	86	54.6
7/7/14	DA	1-4 Hour	252	508.0	62.8	128.0	15.8	12%	79	8.8
7/14/14	DA	1-4 Hour	252	488.1	35.8	123.0	9.0	7%	74	8.8
7/15/14	DA	1-4 Hour	252	485.1	42.3	122.2	10.7	9%	71	8.8
7/30/14	DO	1-4 Hour	1,045	209.2	43.7	218.6	45.7	21%	86	54.6
		2-6 Hour	207	278.4	47.6	57.6	9.9	17%	85	8.5
7/31/14	DO	1-4 Hour	1,045	211.3	43.5	220.8	45.4	21%	86	54.6
		2-6 Hour	207	280.4	46.2	58.0	9.6	16%	86	8.5
8/1/14	DA	1-4 Hour	222	368.3	40.8	81.8	9.1	11%	84	10.7
8/11/14	DO	1-4 Hour	1,051	195.1	41.2	205.1	43.3	21%	83	53.8
		2-6 Hour	207	269.5	46.7	55.8	9.7	17%	81	8.5
8/14/14	DO	1-4 Hour	1,051	199.5	45.4	209.7	47.7	23%	81	53.8
		2-6 Hour	207	267.5	47.0	55.4	9.7	18%	80	8.5
8/28/14	DO	1-4 Hour	1,051	201.2	42.3	211.5	44.4	21%	86	53.8
		2-6 Hour	207	273.9	50.9	56.7	10.5	19%	86	8.5
9/10/14	DO	1-4 Hour	1,015	196.8	38.1	199.7	38.7	19%	82	46.6
		2-6 Hour	195	266.9	47.0	52.1	9.2	18%	82	8.2
9/11/14	DO	1-4 Hour	1,015	200.8	41.9	203.9	42.6	21%	85	46.6
		2-6 Hour	195	272.2	50.6	53.1	9.9	19%	86	8.2
9/12/14	DO	1-4 Hour	1,015	201.2	41.7	204.3	42.3	21%	89	46.6
		2-6 Hour	195	276.1	49.2	53.8	9.6	18%	88	8.2
9/15/14	DA	1-4 Hour	219	389.5	46.6	85.3	10.2	12%	93	10.6
		2-6 Hour								
	DO	1-4 Hour	1,015	213.4	40.8	216.6	41.4	19%	93	46.6
		2-6 Hour	195	288.8	48.6	56.3	9.5	17%	92	8.2
9/16/14	DA	1-4 Hour	219	393.1	44.9	86.1	9.8	11%	91	10.6
		2-6 Hour								
	DO	1-4 Hour	1,015	213.3	37.6	216.5	38.2	18%	91	46.6
		2-6 Hour	195	286.9	48.4	56.0	9.4	17%	91	8.2
9/17/14	DA	1-4 Hour	219	397.9	53.0	87.1	11.6	13%	88	10.6
		2-6 Hour								
10/3/14	DA	1-4 Hour	210	353.5	44.5	74.2	9.3	13%	89	10.0
		2-6 Hour								
10/6/14	DA	1-4 Hour	210	358.2	43.5	75.2	9.1	12%	84	10.0
		2-6 Hour								
	DO	1-4 Hour	994	192.7	37.0	191.5	36.7	19%	85	38.3
		2-6 Hour	94	258.7	77.5	24.3	7.3	30%	88	5.5
10/7/14	DO	1-4 Hour	994	194.9	37.8	193.7	37.5	19%	85	38.3
		2-6 Hour	94	258.2	79.3	24.3	7.5	31%	87	5.5
10/13/14	DA	1-4 Hour	209	341.4	35.5	71.4	7.4	10%	77	10.0
		2-6 Hour								
10/27/14	DA	1-4 Hour	209	320.3	25.7	66.9	5.4	8%	68	10.0
10/29/14	DA	1-4 Hour	209	331.1	23.3	69.2	4.9	7%	73	10.0
Typical Event	DA	1-4 Hour	230	426.7	42.1	98.1	9.7	10%	84	10.1
		2-6 Hour								
	DO	1-4 Hour*	1,034	209.6	41.6	216.8	43.0	20%	88	49.0
		2-6 Hour	202	281.5	47.9	56.9	9.7	17%	88	8.0

* Results apply from July onward, after transfer of AMP DO 1-4 Hour accounts to CBP.

Table 4–9 shows the distribution of average event-hour load impacts for the typical event, by industry type. Approximately half of both DA and DO load impacts came from Retail stores.

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

Notice	Industry	Number of Accounts	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Agriculture, Mining & Construction							
	Manufacturing	31	1121.2	77.9	34.4	2.4	7%	80
	Wholesale, Transport, other utilities	16	412.5	101.9	6.7	1.7	25%	89
	Retail stores	161	314.1	29.4	50.7	4.7	9%	88
	Offices, Hotels, Finance, Services							
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DA	231	430.5	41.5	99.4	9.6	10%	84
DO (July - October)	Agriculture, Mining & Construction	132	60.9	46.8	8.1	6.2	77%	90
	Manufacturing	20	1139.0	112.1	22.3	2.2	10%	87
	Wholesale, Transport, other utilities	182	127.4	83.7	23.2	15.2	66%	95
	Retail stores	809	225.5	30.4	182.5	24.6	13%	88
	Offices, Hotels, Finance, Services	66	451.3	51.3	29.6	3.4	11%	89
	Schools	12	443.1	55.1	5.4	0.7	12%	88
	Institutional/Government	16	171.8	27.7	2.7	0.4	16%	87
	Other or unknown							
	Total DO	1,236	221.4	42.6	273.7	52.7	19%	88

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

Notice	LCA	Number of Accounts	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	LA Basin	158	431.2	33.8	68.3	5.4	8%	82
	Outside LA	19	326.8	61.4	6.2	1.2	19%	94
	Ventura	54	465.3	57.3	25.0	3.1	12%	88
	Total DA	231	430.5	41.5	99.4	9.6	10%	84
DO (July - October)	LA Basin	858	251.8	43.7	215.9	37.5	17%	88
	Outside LA	79	179.7	39.9	14.1	3.1	22%	94
	Ventura	300	145.4	40.3	43.7	12.1	28%	86
	Total DO	1,236	221.4	42.6	273.7	52.7	19%	88

Tables 4–11 and 4–12 show average event-hour load impacts for two additional geographical areas in the SCE service area – Southern Orange County and South of Lugo.

Table 4–11: Average Event-Hour Load Impacts in Southern Orange County – SCE CBP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
				Reference Load (kW)	Impact (kW)	Reference Load (MW)	Load Impact (MW)		
2/6/14	DA	1-4 Hour	21	314.5	12.2	6.6	0.3	4%	54
	DO	1-4 Hour	17	63.7	11.0	1.1	0.2	17%	56
5/15/14	DA	1-4 Hour	21	443.4	19.6	9.3	0.4	4%	96
7/3/14	DO	1-4 Hour	95	203.8	35.2	19.4	3.3	17%	78
7/7/14	DA	1-4 Hour	23	393.2	7.5	9.0	0.2	2%	77
7/14/14	DA	1-4 Hour	23	363.8	14.5	8.4	0.3	4%	73
7/15/14	DA	1-4 Hour	23	350.8	19.4	8.1	0.4	6%	70
7/30/14	DO	1-4 Hour	95	217.3	26.4	20.6	2.5	12%	80
		2-6 Hour	24	270.4	43.3	6.5	1.0	16%	80
7/31/14	DO	1-4 Hour	95	215.7	25.3	20.5	2.4	12%	79
		2-6 Hour	24	271.6	43.1	6.5	1.0	16%	79
8/1/14	DA	1-4 Hour	18	427.9	10.5	7.7	0.2	2%	74
8/11/14	DO	1-4 Hour	94	209.2	22.6	19.7	2.1	11%	77
		2-6 Hour	24	266.8	42.3	6.4	1.0	16%	75
8/14/14	DO	1-4 Hour	94	209.6	23.6	19.7	2.2	11%	75
		2-6 Hour	24	263.6	41.3	6.3	1.0	16%	74
8/28/14	DO	1-4 Hour	94	221.8	23.0	20.8	2.2	10%	82
		2-6 Hour	24	271.3	44.5	6.5	1.1	16%	81
9/10/14	DO	1-4 Hour	89	224.8	22.4	20.0	2.0	10%	80
		2-6 Hour	22	263.2	49.0	5.8	1.1	19%	80
9/11/14	DO	1-4 Hour	89	231.0	27.7	20.6	2.5	12%	84
		2-6 Hour	22	268.9	48.7	5.9	1.1	18%	84
9/12/14	DO	1-4 Hour	89	225.5	27.9	20.1	2.5	12%	85
		2-6 Hour	22	271.9	46.6	6.0	1.0	17%	83
9/15/14	DA	1-4 Hour	17	504.4	2.1	8.6	0.0	0%	90
	DO	1-4 Hour	89	242.6	23.3	21.6	2.1	10%	90
		2-6 Hour	22	278.2	48.5	6.1	1.1	17%	89
9/16/14	DA	1-4 Hour	17	507.6	14.6	8.6	0.2	3%	94
	DO	1-4 Hour	89	249.0	24.5	22.2	2.2	10%	94
		2-6 Hour	22	281.3	51.8	6.2	1.1	18%	94
9/17/14	DA	1-4 Hour	17	532.0	43.5	9.0	0.7	8%	85
10/3/14	DA	1-4 Hour	17	444.5	49.6	7.6	0.8	11%	91
10/6/14	DA	1-4 Hour	17	447.3	26.6	7.6	0.5	6%	81
	DO	1-4 Hour	88	221.3	21.6	19.5	1.9	10%	81
10/7/14	DO	1-4 Hour	88	228.0	27.0	20.1	2.4	12%	83
		2-6 Hour							
10/13/14	DA	1-4 Hour	17	416.0	22.1	7.1	0.4	5%	72
10/27/14	DA	1-4 Hour	17	384.2	15.8	6.5	0.3	4%	68
10/29/14	DA	1-4 Hour	17	397.3	23.2	6.8	0.4	6%	73
Typical Event	DO	1-4 Hour	19	448.6	10.8	8.5	0.2	2%	86
		1-4 Hour	92	228.9	24.5	21.1	2.3	11%	85
		2-6 Hour	23	274.4	46.2	6.4	1.1	17%	84

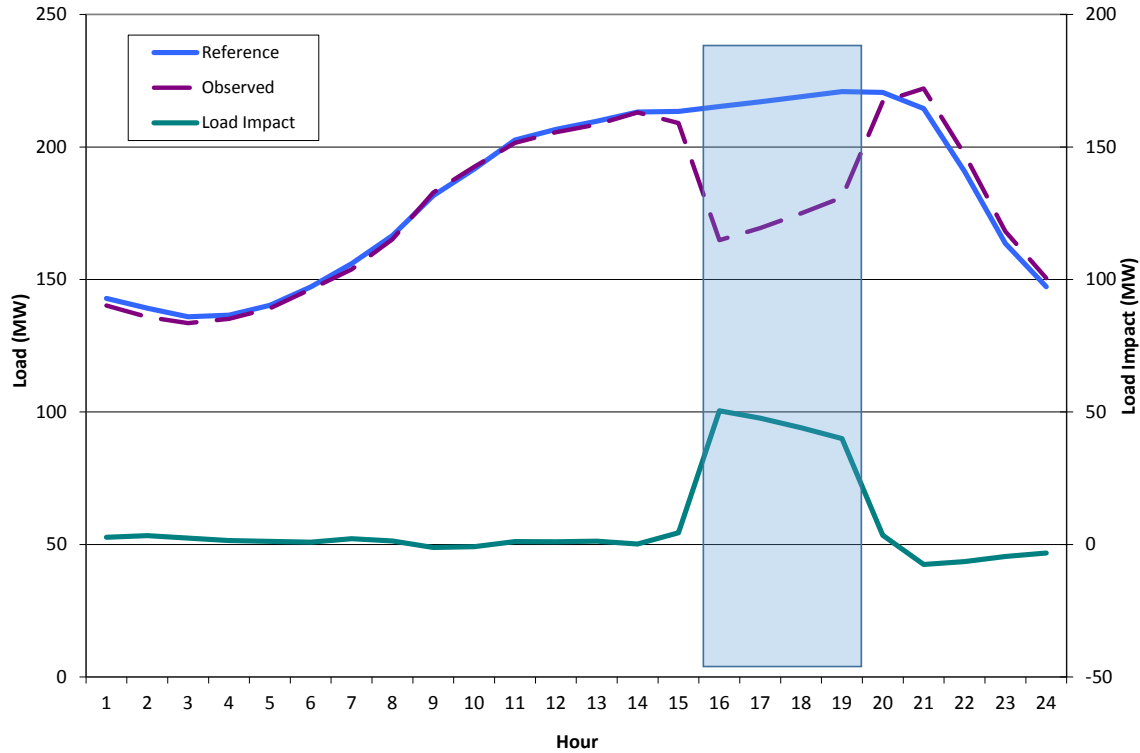
Table 4–12: Average Event-Hour Load Impacts South of Lugo – SCE CBP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
				Reference Load (kW)	Impact (kW)	Reference Load (MW)	Load Impact (MW)		
2/6/14	DA	1-4 Hour	74	246.6	27.8	18.2	2.1	11%	51
	DO	1-4 Hour	37	62.9	2.0	2.3	0.1	3%	51
5/15/14	DA	1-4 Hour	58	382.4	68.6	22.2	4.0	18%	97
7/3/14	DO	1-4 Hour	268	212.7	42.5	57.0	11.4	20%	91
7/7/14	DA	1-4 Hour	67	353.6	48.9	23.7	3.3	14%	90
7/14/14	DA	1-4 Hour	67	328.2	30.8	22.0	2.1	9%	80
7/15/14	DA	1-4 Hour	67	320.2	39.9	21.5	2.7	12%	74
7/30/14	DO	1-4 Hour	268	215.9	40.1	57.9	10.7	19%	88
		2-6 Hour	54	294.2	53.0	15.9	2.9	18%	89
7/31/14	DO	1-4 Hour	268	221.5	45.7	59.4	12.2	21%	89
		2-6 Hour	54	297.9	52.7	16.1	2.8	18%	91
8/1/14	DA	1-4 Hour	64	347.8	38.4	22.3	2.5	11%	87
8/11/14	DO	1-4 Hour	265	206.8	42.0	54.8	11.1	20%	86
		2-6 Hour	54	283.4	55.7	15.3	3.0	20%	85
8/14/14	DO	1-4 Hour	265	212.4	45.8	56.3	12.1	22%	84
		2-6 Hour	54	281.1	54.3	15.2	2.9	19%	84
8/28/14	DO	1-4 Hour	265	215.1	46.7	57.0	12.4	22%	88
		2-6 Hour	54	292.0	60.3	15.8	3.3	21%	89
9/10/14	DO	1-4 Hour	254	211.6	42.7	53.8	10.8	20%	86
		2-6 Hour	52	282.7	49.5	14.7	2.6	18%	86
9/11/14	DO	1-4 Hour	254	213.2	42.9	54.1	10.9	20%	87
		2-6 Hour	52	288.2	59.3	15.0	3.1	21%	89
9/12/14	DO	1-4 Hour	254	214.0	40.4	54.4	10.3	19%	93
		2-6 Hour	52	293.9	59.2	15.3	3.1	20%	93
9/15/14	DA	1-4 Hour	64	374.9	47.1	24.0	3.0	13%	96
	DO	1-4 Hour	254	228.0	46.3	57.9	11.8	20%	95
		2-6 Hour	52	312.4	58.5	16.2	3.0	19%	96
9/16/14	DA	1-4 Hour	64	370.6	40.6	23.7	2.6	11%	92
	DO	1-4 Hour	254	225.3	37.2	57.2	9.4	16%	93
		2-6 Hour	52	309.0	53.7	16.1	2.8	17%	93
9/17/14	DA	1-4 Hour	64	375.5	49.0	24.0	3.1	13%	90
10/3/14	DA	1-4 Hour	59	344.9	49.4	20.3	2.9	14%	93
10/6/14	DA	1-4 Hour	59	334.8	45.2	19.8	2.7	14%	88
	DO	1-4 Hour	255	211.4	48.3	53.9	12.3	23%	88
		2-6 Hour	30	283.9	84.7	8.5	2.5	30%	89
10/7/14	DO	1-4 Hour	255	209.9	45.8	53.5	11.7	22%	88
		2-6 Hour	30	282.2	83.6	8.5	2.5	30%	89
10/13/14	DA	1-4 Hour	59	308.6	36.1	18.2	2.1	12%	79
10/27/14	DA	1-4 Hour	59	293.6	28.0	17.3	1.7	10%	69
10/29/14	DA	1-4 Hour	59	313.4	14.3	18.5	0.8	5%	76
Typical Event	DA	1-4 Hour	65	357.4	39.3	23.2	2.6	11%	90
	DO	1-4 Hour	262	221.0	43.2	57.9	11.3	20%	91
		2-6 Hour	53	300.7	54.8	16.0	2.9	18%	91

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 1-4 product type for the four-hour July 30 event, which was called from hours-ending 16 to 19. Estimated load impacts range from 40 to 50 MW over the event.

**Figure 4–3: Hourly Loads and Load Impacts – SCE CBP DO 1-4
July 30, 2014 Event**



4.2.4 Load impacts of TA/TI and AutoDR participants

Table 4–13 shows average event-hour load impacts by event for CBP service accounts that received TA/TI incentives at some point prior to the DR event(s) summarized. Their load impacts averaged 5.1 MW, which compares to their approved load shed test of 11.1 MW.

Table 4–13: Load Impacts of TA/TI Participants – SCE CBP DO

Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
6-Feb-14						
3-Jul-14	54	28.8	27.2	1.6	5%	7.3
30-Jul-14	165	63.1	57.9	5.2	8%	11.3
31-Jul-14	165	63.6	57.8	5.9	9%	11.3
11-Aug-14	165	59.0	54.1	4.9	8%	11.3
14-Aug-14	165	61.5	55.8	5.8	9%	11.3
28-Aug-14	165	61.4	55.3	6.1	10%	11.3
10-Sep-14	154	58.0	53.8	4.2	7%	10.9
11-Sep-14	154	58.8	53.7	5.0	9%	10.9
12-Sep-14	154	56.6	51.2	5.4	10%	10.9
15-Sep-14	154	62.9	57.9	5.0	8%	10.9
16-Sep-14	154	62.4	58.8	3.6	6%	10.9
6-Oct-14	56	29.6	28.1	1.4	5%	7.6
7-Oct-14	56	30.0	27.8	2.1	7%	7.6
Average of Typical Event*	161	62.7	57.5	5.1	8%	11.1

* Results apply from July onward, after transfer of AMP DO 1-4 Hour accounts to CBP.

Table 4–14 shows CBP load impacts for service accounts that received AutoDR incentives at some point prior to the DR event(s) summarized. An average of 51 DA and 503 DO service accounts participated in AutoDR for the average event. DA participants provided an average of 1.9 MW of load impacts, less than half of their load shed test amount of 4.7 MW. CBP DO participants provided an average of 19.1 MW, compared to their shed test amount of 31.5 MW.

Table 4–14: Load Impacts of AutoDR Participants – SCE CBP

Notice	Event Date	# SAIDs	Reference	Observed	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
			Load (MW)	Load (MW)			
DA	6-Feb-14	31	7.1	6.9	0.2	3%	2.4
	15-May-14	33	10.2	8.0	2.2	22%	2.8
	7-Jul-14	51	12.3	9.5	2.8	23%	4.1
	14-Jul-14	51	13.1	10.4	2.8	21%	4.1
	15-Jul-14	51	13.1	9.8	3.2	25%	4.1
	1-Aug-14	50	12.1	9.2	2.9	24%	4.1
	15-Sep-14	52	14.4	12.7	1.7	12%	4.9
	16-Sep-14	52	14.7	13.8	1.0	6%	4.9
	17-Sep-14	52	14.8	13.5	1.4	9%	4.9
	3-Oct-14	50	12.4	9.6	2.7	22%	4.8
	6-Oct-14	50	13.3	11.3	2.1	15%	4.8
	13-Oct-14	50	12.8	10.8	2.0	16%	4.8
	27-Oct-14	49	10.8	9.7	1.2	11%	3.9
	29-Oct-14	49	10.7	9.3	1.4	13%	3.9
	Average of Typical Event	51	13.9	12.0	1.9	13%	4.7
DO	6-Feb-14	47	4.7	4.3	0.4	9%	4.9
	3-Jul-14	501	82.6	60.2	22.4	27%	30.7
	30-Jul-14	501	83.8	64.1	19.7	23%	30.7
	31-Jul-14	501	84.5	66.1	18.5	22%	30.7
	11-Aug-14	498	82.2	64.2	18.0	22%	31.5
	14-Aug-14	498	82.8	61.9	20.9	25%	31.5
	28-Aug-14	498	85.3	64.8	20.4	24%	31.5
	10-Sep-14	507	80.3	60.7	19.6	24%	32.2
	11-Sep-14	507	82.8	62.8	20.0	24%	32.2
	12-Sep-14	507	83.5	64.8	18.6	22%	32.2
	15-Sep-14	507	88.2	69.1	19.1	22%	32.2
	16-Sep-14	507	87.1	69.2	17.9	21%	32.2
	6-Oct-14	497	75.6	59.5	16.1	21%	30.8
	7-Oct-14	497	76.0	59.4	16.5	22%	30.8
	Average of Typical Event*	503	85.8	66.7	19.1	22%	31.5

* Results apply from July onward, after transfer of AMP DO 1-4 Hour accounts to CBP.

4.3 Capacity Bidding Program (CBP) – SDG&E

4.3.1 Events for SDG&E CBP

Table 4–15 lists SDG&E’s CBP events in 2014. Several were DA-only events, while the remainder were combination DA and DO events.

Table 4–15: Event Summary for 2014 – SDG&E CBP

Date	Day of Week	Notice	Product	Hours Ending	Num. of Accounts
5/1/2014	Thu	DA	1-4 Hour	15-18	161
5/14/2014	Wed	DA	1-4 Hour	16-19	161
		DO	1-4 Hour 2-6 Hour	16-19	168 76
5/15/2014	Thu	DA	1-4 Hour	16-19	161
		DO	1-4 Hour 2-6 Hour	16-19	168 76
7/30/2014	Wed	DA	1-4 Hour	14-17	162
7/31/2014	Thu	DA	1-4 Hour	14-17	162
8/1/2014	Fri	DA	1-4 Hour	15-18	161
8/4/2014	Mon	DA	1-4 Hour	16-19	161
8/27/2014	Wed	DA	1-4 Hour	16-19	161
8/28/2014	Thu	DA	1-4 Hour	16-19	161
9/11/2014	Thu	DA	1-4 Hour	16-19	165
		DO	1-4 Hour 2-6 Hour	16-19	157 77
9/12/2014	Fri	DA	1-4 Hour	16-19	165
		DO	1-4 Hour 2-6 Hour	16-19	157 77
9/15/2014	Mon	DA	1-4 Hour	16-19	165
		DO	1-4 Hour 2-6 Hour	16-19	157 77
9/16/2014	Tu	DA	1-4 Hour	15-18	165
		DO	1-4 Hour 2-6 Hour	16-19	157 77
9/17/2014	Wed	DA	1-4 Hour	15-18	165
		DO	1-4 Hour 2-6 Hour	16-19	157 77

4.3.2 Summary load impacts

Table 4–16 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 the respective typical

events. The average event-hour DA load impact for the typical event was 9.9 MW, while DO load impacts averaged 5 MW for the 1-4 Hour product, and 3.8 MW for the 2-6 Hour product. Average percentage load impacts were 25 percent for the DA product, and 15 to 18 percent for the two DO product types.

Table 4–16: Average Event-Hour Load Impacts by Event – SDG&E CBP

Event Date	Notice	Product	Number of Accounts	Average Customer		Aggregate		% Load Impact	Average Event Temp.	Nom. Capacity (MW)
				Ref. Load (kW)	Load Impact (kW)	Ref. Load (kW)	Load Impact (MW)			
5/1/14	DA	1-4 Hour	161	242.1	58.8	39.0	9.46	24%	87	8.8
5/14/14	DA	1-4 Hour	161	231.0	66.5	37.2	10.71	29%	89	8.8
	DO	1-4 Hour	168	189.3	39.5	31.8	6.64	21%	90	5.5
		2-6 Hour	76	266.4	46.4	20.2	3.53	17%	90	4.2
5/15/14	DA	1-4 Hour	161	225.8	60.0	36.4	9.66	27%	92	8.8
	DO	1-4 Hour	168	194.3	35.7	32.6	5.99	18%	93	5.5
		2-6 Hour	76	269.9	46.3	20.5	3.52	17%	93	4.2
7/30/14	DA	1-4 Hour	162	246.6	63.9	39.9	10.35	26%	82	9.2
7/31/14	DA	1-4 Hour	162	238.2	40.7	38.6	6.59	17%	84	9.2
8/1/14	DA	1-4 Hour	161	251.4	63.4	40.5	10.21	25%	81	9.0
8/4/14	DA	1-4 Hour	161	247.2	57.7	39.8	9.29	23%	80	9.0
8/27/14	DA	1-4 Hour	161	237.8	60.0	38.3	9.66	25%	85	9.0
8/28/14	DA	1-4 Hour	161	251.0	69.1	40.4	11.12	28%	84	9.0
9/11/14	DA	1-4 Hour	165	251.3	57.8	41.5	9.54	23%	82	8.9
	DO	1-4 Hour	157	197.2	30.3	31.0	4.75	15%	82	6.0
		2-6 Hour	77	277.6	51.4	21.4	3.96	19%	82	3.9
9/12/14	DA	1-4 Hour	165	247.6	49.7	40.8	8.20	20%	83	8.9
	DO	1-4 Hour	157	200.6	25.4	31.5	3.99	13%	81	6.0
		2-6 Hour	77	281.4	49.1	21.7	3.78	17%	81	3.9
9/15/14	DA	1-4 Hour	165	278.4	68.9	45.9	11.36	25%	89	8.9
	DO	1-4 Hour	157	211.9	28.7	33.3	4.51	14%	87	6.0
		2-6 Hour	77	290.4	49.5	22.4	3.81	17%	88	3.9
9/16/14	DA	1-4 Hour	165	304.3	66.3	50.2	10.95	22%	93	8.9
	DO	1-4 Hour	157	218.8	27.3	34.4	4.28	12%	91	6.0
		2-6 Hour	77	294.5	51.6	22.7	3.97	18%	91	3.9
9/17/14	DA	1-4 Hour	165	282.2	53.9	46.6	8.89	19%	85	8.9
	DO	1-4 Hour	157	210.8	28.8	33.1	4.52	14%	82	6.0
		2-6 Hour	77	290.7	53.8	22.4	4.15	19%	83	3.9
Typical Event Day	DA	1-4 Hour	163	247.0	60.6	40.4	9.89	25%	87	9.0
	DO	1-4 Hour	160	203.0	30.9	32.5	4.96	15%	87	5.9
		2-6 Hour	77	281.6	49.7	21.6	3.82	18%	87	4.0

Table 4–17 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 relatively small number of large Manufacturing service accounts (primarily two large accounts), while the larger number of commercial building accounts produced 0.6 MW of load reductions. The majority of DO load impacts were provided by retail stores.

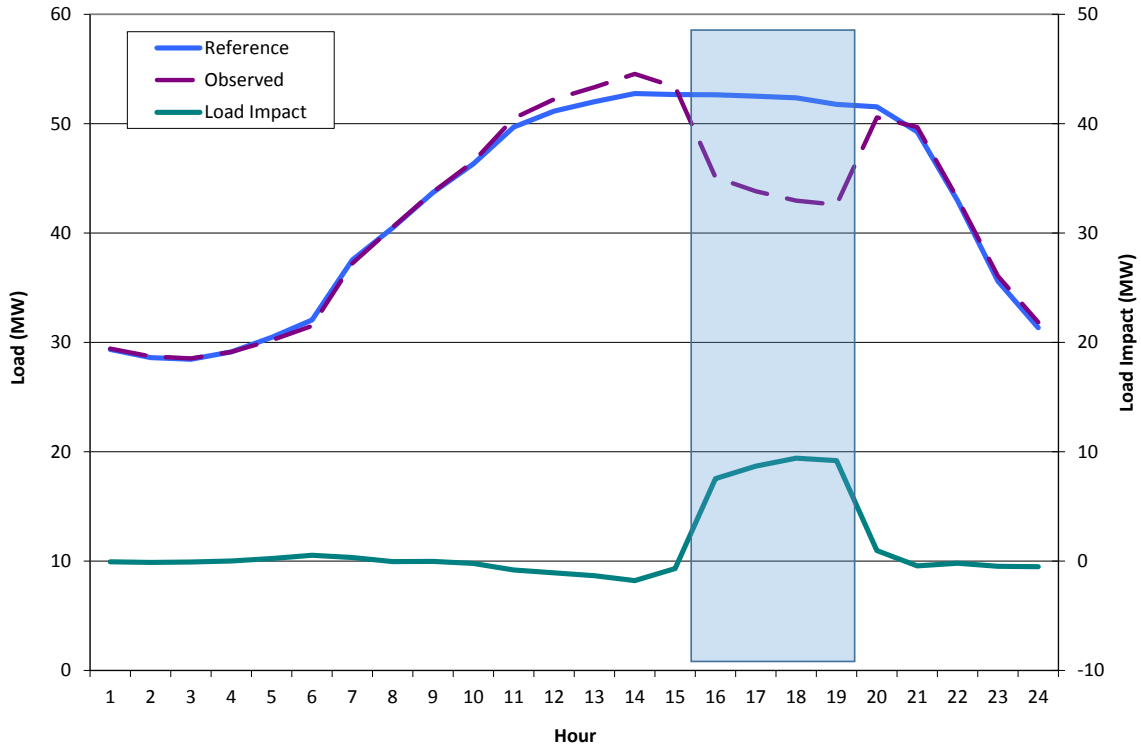
Table 4–17: Distribution of Average Event-Hour Load Impacts by Industry Type – SDG&E CBP

Notice	Industry	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Agriculture, Mining & Construction	-	-	-	-	-	-	-
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores	35	186.3	28.1	6.6	1.00	15%	86
	Offices, Hotels, Finance, Services	77	221.8	7.6	17.2	0.58	3%	87
	Schools	26	51.2	-1.7	1.3	-0.04	-3%	90
	Institutional/Government							
	Other or unknown							
	Total DA	163	247.0	60.6	40.4	9.89	25%	87
DO	Agriculture, Mining & Construction	-	-	-	-	-	-	-
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores	213	205.0	24.5	43.7	5.21	12%	87
	Offices, Hotels, Finance, Services	15	317.3	18.7	4.8	0.28	6%	86
	Schools	-	-	-	-	-	-	-
	Institutional/Government							
	Other or unknown							
	Total DO	237	228.5	37.0	54.1	8.77	16%	87

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 product type (including both DO 1-4 and 2-6) for the four-hour September event, which was called for hours-ending 16-19.

**Figure 4–4: Hourly Loads and Load Impacts – SDG&E CBP DO Total
September 11 Event**



4.2.4 Load impacts of TA/TI and AutoDR participants

Table 4–18 shows CBP load impacts for service accounts that received TA/TI incentives at some point prior to the DR event(s) summarized. On average, six DA and 55 DO customer service accounts were in TA/TI. They provided averages of 0.22 and 1.8 MW in load impacts for the average of typical events.

Table 4–18: Load Impacts of TA/TI Participants – SDG&E CBP

Notice	Event Date	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Test MW
DA	1-May-14						
	14-May-14						
	15-May-14						
	30-Jul-14						
	31-Jul-14						
	1-Aug-14						
	4-Aug-14						
	27-Aug-14						
	28-Aug-14						
	11-Sep-14						
	12-Sep-14						
	15-Sep-14						
	16-Sep-14						
	17-Sep-14						
	Ave. of Typical Events						
DO	14-May-14	54	15.2	13.1	2.12	14%	3.15
	15-May-14	54	15.3	13.4	1.89	12%	3.15
	11-Sep-14	56	14.5	12.8	1.71	12%	2.91
	12-Sep-14	56	14.7	13.2	1.52	10%	2.91
	15-Sep-14	56	15.3	13.7	1.62	11%	2.91
	16-Sep-14	56	15.4	13.8	1.69	11%	2.91
	17-Sep-14	56	15.3	13.4	1.88	12%	2.91
		Ave. of Typical Events	55	15.1	13.3	1.78	12%

Table 4–19 shows CBP load impacts for service accounts that received AutoDR incentives at some point prior to the DR event(s) summarized, which included an average of 7 DA and 57 DO customer service accounts. Those customers provided load impacts averaging 0.18 and 0.94 MW for the typical event.

Table 4–19: 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	Test MW
DA	1-May-14						
	14-May-14						
	15-May-14						
	30-Jul-14						
	31-Jul-14						
	1-Aug-14						
	4-Aug-14						
	27-Aug-14						
	28-Aug-14						
	11-Sep-14						
	12-Sep-14						
	15-Sep-14						
	16-Sep-14						
	17-Sep-14						
	Ave. of Typical Events						
DO	14-May-14	48	8.4	7.5	0.96	11.4%	3.16
	15-May-14	48	8.6	7.5	1.10	12.8%	3.16
	11-Sep-14	60	10.8	9.8	1.00	9.2%	3.84
	12-Sep-14	60	10.9	10.2	0.73	6.7%	3.84
	15-Sep-14	60	11.6	10.9	0.73	6.3%	3.84
	16-Sep-14	60	11.9	10.9	0.99	8.3%	3.84
	17-Sep-14	60	11.6	10.5	1.09	9.3%	3.84
		Ave. of Typical Events	57	10.6	9.6	0.94	8.9%

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 PG&E’s AMP DA and DO events in 2014. Similarly to CBP, shading indicates typical events, which are system-wide events occurring in hours ending 16 to 19. A number of localized events were called for only some SubLaps.

Table 5–1: Event Summary for 2014 – PG&E AMP

Date	Day of Week	Event Type	Notice	Product	Event Hours Ending	Num. of Accounts
05/14/14	Wed	Event	DA	Local (4 SL)	16 - 19	135
			DO	Local (4 SL)	16 - 19	179
05/15/14	Thu	Event	DA	Local	16 - 19	498
			DO	Local System	16 - 19	808 562
06/09/14	Mon	Event	DO	Local System	16 - 19	847 579
06/30/14	Mon	Test	DA	Local	16 - 17	494
		Event	DO	Local System	16 - 19	846 579
07/07/14	Mon	Event	DA	Local	16 - 17	507
			DO	Local (2 SL)	16 - 19	214
07/14/14	Mon	Event	DA	Local (8 SL)	16 - 19	207
			DO	Local (7 SL)	16 - 19	57
07/25/14	Fri	Event	DA	Local (2 SL)	16 - 19	99
			DO	Local (2 SL)	16 - 19	219
07/28/14	Mon	Event	DA	Local	15 - 19	504
			DO	Local System	16 - 19	845 537
07/29/14	Tu	Event	DA	Local	16 - 19	504
			DO	Local System	16 - 19	845 537
08/01/14	Fri	Event	DA	Local (13 SL)	16 - 19	470
			DO	Local (13 SL) System	16 - 19	875 528
09/02/14	Tu	Event	DA	Local (1 SL)	16 - 19	67
			DO	Local (1 SL)	16 - 19	208
09/15/14	Mon	Event	DO	Local System	16 - 19 16 - 19	874 521
10/02/14	Thu	Event	DA	Local (1 SL)	16 - 19	20
			DO	Local (1 SL)	16 - 19	
10/03/14	Fri	Event	DA	Local (1 SL)	15 - 19	20
			DO	Local (1 SL)	15 - 19	
10/06/14	Mon	Event	DA	Local (3 SL)	16 - 19	159
			DO	Local (3 SL)	15 - 19	508

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).¹⁴ The average event-hour DO load impacts averaged 74.1 MW for the Local product, and 48.6 MW for the System product. These load impacts represented 25 to 27 percent for the two DO product types. The DA load impacts are redacted to protect individual aggregator data.

¹⁴ Results for PG&E’s AMP DA are redacted due to confidentiality reasons.

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

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.	Nom. Capacity (MW)
				Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)			
5/14/14	DA	Local								
	DO	Local	179	425.8	41.3	76.2	7.4	10%	90	8.7
5/15/14	DA	Local								
	DO	Local	808	321.3	86.6	259.6	69.9	27%	92	111.7
		System	562	323.6	80.1	181.9	45.0	25%	84	55.3
6/9/14	DO	Local	847	329.4	96.8	279.0	82.0	29%	95	111.7
		System	579	332.1	95.5	192.3	55.3	29%	87	56.4
6/30/14	DA	Local								
	DO	Local	846	333.2	92.3	281.9	78.1	28%	93	111.7
		System	579	330.7	89.7	191.5	52.0	27%	85	56.4
7/7/14	DA	Local								
	DO	Local	214	386.1	128.2	82.6	27.4	33%	94	40.4
7/14/14	DA	Local								
	DO	Local	57	190.6	29.2	10.9	1.7	15%	91	4.6
7/25/14	DA	Local								
	DO	Local	219	393.4	118.3	86.2	25.9	30%	100	40.2
7/28/14	DA	Local								
	DO	Local	845	318.1	93.4	268.8	78.9	29%	87	111.7
		System	537	377.9	88.9	202.9	47.8	24%	84	56.4
7/29/14	DA	Local								
	DO	Local	845	318.9	90.2	269.5	76.2	28%	91	111.7
		System	537	388.5	94.7	208.6	50.8	24%	88	56.4
8/1/14	DA	Local								
	DO	Local	875	334.6	87.9	292.7	77.0	26%	94	105.6
		System	528	345.6	90.2	182.5	47.6	26%	88	54.7
9/2/14	DA	Local								
	DO	Local	208	369.8	110.4	76.9	23.0	30%	102	30.8
9/15/14	DO	Local	874	318.7	67.9	278.5	59.3	21%	88	108.0
		System	521	355.0	78.6	185.0	41.0	22%	82	53.9
10/2/14	DA	Local								
	DO	Local								
10/3/14	DA	Local								
	DO	Local								
10/6/14	DA	Local	159	526.5	47.5	83.7	7.5	9%	92	29.1
	DO	Local								
Typical Event	DA	Local								
	DO	Local	844	323.3	87.8	272.9	74.1	27%	91	111.1
		System	553	350.6	88.0	193.7	48.6	25%	85	55.8

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

Notice	Industry	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Agriculture, Mining & Construction							
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores							
	Offices, Hotels, Finance, Services							
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DA							
DO	Agriculture, Mining & Construction	539	174.5	89.4	94.0	48.2	51%	94
	Manufacturing	120	1044.1	173.0	124.8	20.7	17%	92
	Wholesale, Transport, other utilities	154	440.0	170.2	67.8	26.2	39%	98
	Retail stores	247	227.0	27.0	56.1	6.7	12%	88
	Offices, Hotels, Finance, Services	213	388.6	63.8	82.9	13.6	16%	80
	Schools	25	348.6	74.9	8.7	1.9	21%	83
	Institutional/Government	45	480.6	96.2	21.5	4.3	20%	77
	Other or unknown	54	199.6	22.3	10.8	1.2	11%	82
	Total DO	1,397	334.1	87.9	466.6	122.7	26%	89

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

Notice	LCA	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DA	Greater Bay Area							
	Greater Fresno							
	Humboldt							
	Kern							
	Northern Coast							
	Not in any LCA							
	Sierra							
	Stockton							
	Total DA							
DO	Greater Bay Area	399	373.3	41.2	148.8	16.4	11%	80
	Greater Fresno	221	221.5	104.5	48.8	23.0	47%	102
	Humboldt	16	362.1	171.1	5.7	2.7	47%	70
	Kern	301	159.5	85.4	48.0	25.7	54%	102
	Northern Coast	67	248.7	52.2	16.5	3.5	21%	85
	Not in any LCA	282	565.2	130.2	159.6	36.7	23%	92
	Sierra	36	332.1	144.9	12.0	5.2	44%	95
	Stockton	76	357.0	123.6	27.2	9.4	35%	95
	Total DO	1,397	334.1	87.9	466.6	122.7	26%	89

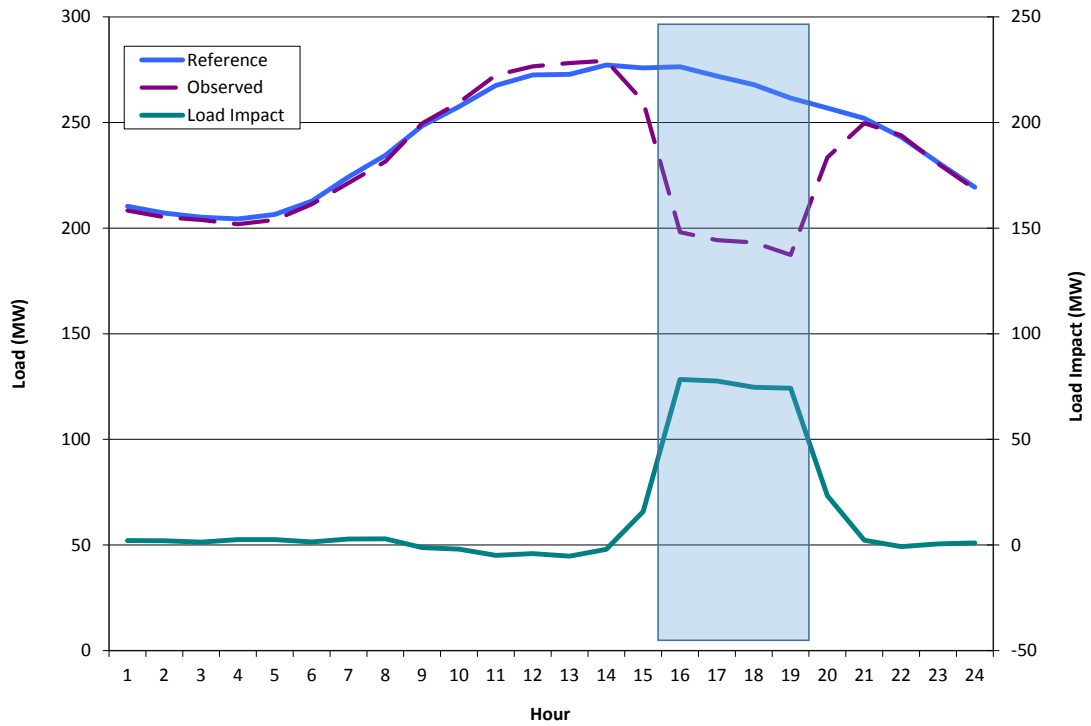
5.1.3 Hourly load impacts

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 Local and DO Local product types for the four-hour July 29 event, which was called for hours-ending 16 through 19.

**Figure 5–1: Hourly Loads and Load Impacts – PG&E AMP DA Local
July 29, 2014 Event**

[Not available due to confidentiality restrictions.]

**Figure 5–2: Hourly Loads and Load Impacts – PG&E AMP DO Local
July 29, 2014 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 7 DA and 28 DO TA/TI service accounts provided averages of 4.6 and 2.4 MW of load impacts respectively, compared to approved load shed levels of 11.2 and 12.0 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	Load Shed Test (MW)
DA	5/14/2014						
	5/15/2014						
	6/30/2014						
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014						
	7/29/2014						
	8/1/2014						
	9/2/2014						
	10/2/2014						
	10/3/2014						
	10/6/2014						
	Average of Typical Event						
DO	5/15/2014	32	14.25	12.07	2.19	15.3%	13.37
	6/9/2014	28	10.52	7.96	2.57	24.4%	11.90
	6/30/2014	28	10.90	8.22	2.69	24.6%	11.90
	7/7/2014						
	7/25/2014						
	7/28/2014	28	9.86	7.78	2.08	21.1%	11.70
	7/29/2014	28	10.15	7.32	2.84	27.9%	11.70
	8/1/2014	28	9.28	7.04	2.24	24.1%	11.86
	9/2/2014						
	9/15/2014	27	9.30	7.22	2.08	22.4%	11.75
	10/6/2014	16	3.27	2.31	0.95	29.2%	8.29
	Average of Typical Event	28	10.6	8.2	2.4	22%	12.0

As shown in Table 5–6, 12 DA and 45 DO AutoDR service accounts provided 0.4 MW and 0.8 MW of load impacts, compared to 0.6 and 7.4 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	Load Shed Test (MW)
DA	5/15/2014						
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014						
	7/29/2014						
	8/1/2014						
	9/15/2014						
	Average of Typical Event						
DO	5/14/2014						
	5/15/2014	37	7.5	7.0	0.55	7%	6.18
	6/9/2014	46	10.4	9.9	0.48	5%	7.66
	6/30/2014	46	10.1	9.4	0.70	7%	7.66
	7/7/2014						
	7/14/2014						
	7/25/2014						
	7/28/2014	46	10.1	9.4	0.73	7%	7.66
	7/29/2014	46	11.1	9.6	1.49	13%	7.66
	8/1/2014	42	9.8		1.07	11%	7.03
	9/2/2014						
	9/15/2014	46	9.8	9.0	0.87	9%	7.66
	10/2/2014						
	10/3/2014						
10/6/2014							
Average of Typical Event	45	9.9	9.0	0.80	8%	7.4	

5.2 SCE's AMP

5.2.1 Event Characteristics for SCE AMP

Table 5–7 summarizes SCE's AMP events in 2014. Only DO notice contracts were active, differentiated by event-window product-type (1-4 and 1-6 Hours). All but the February event were called for only one or other of the product types. A number of the events were called for Measurement and Evaluation (M&E) purposes, one of which on June 26 was limited to two SubLaps. The events for which different sets of event hours are shown, separated by commas, occurred for different reasons, including separate hours considered as M&E events and others related to market prices. Shaded events are considered typical events with common event windows. Since the AMP events were called for a variety of hours, few meet that criterion. For the DO 1-6 Hours product, these are two events called for HE 15 – 16. For the DO 1-4 Hours product, no multiple events cover the same event window. As a result, we treat the four-hour May 14 event, for HE 15 – 18 as typical. Note also that the DO 1-4 Hours contract's associated portfolio was transferred to CBP DO at the end of June.

Table 5–7: Event Summary for 2014 – SCE AMP

Date	Day of Week	Event Type	Notice	Product	Event Hours Ending	Num. of Accounts
2/6/14	Thu	Prices	DO	1-4 Hours	18-21	547
				1-6 Hours	12-17, 18-19	787
5/13/14	Tu	Prices	DO	1-4 Hours	18	817
5/14/14	Wed	Prices	DO	1-4 Hours	15, 16-18	817
5/15/14	Thu	Prices	DO	1-4 Hours	14-17, 18	817
5/29/14	Thu	M&E	DO	1-6 Hours	15-16	889
6/26/14	Thu	M&E/2 SL	DO	1-6 Hours	15-16	611
6/30/14	Mon	M&E	DO	1-4 Hours	14-15	854
7/25/14	Fri	M&E	DO	1-6 Hours	15-16	951
8/11/14	Mon	Prices	DO	1-6 Hours	17-19	963
8/28/14	Thu	M&E	DO	1-6 Hours	15-16	962
		Prices			17-19	
9/11/14	Thu	Prices	DO	1-6 Hours	16-19	959
9/16/14	Tu	Prices	DO	1-6 Hours	15-19	959

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 typical events. As described above, typical events for each product type are defined as the average over the most frequent events of the same event window for which that product was called. The typical event-hour load impact for the DO 1-6 Hour product was 90.3 MW. The typical event for DO 1-4 Hour

was assigned to be the May 14 event, since none of the events had common windows. The average event-hour load impact for that event was 43.2 MW, and average event-hour load impact values across the four events for that product were quite consistent. The value for the typical event for the DO 1-4 Hour product should be considered typical only through the month of June, after which that contract was transferred to CBP. Average percentage load impacts were 25 percent and 30 percent for the two DO products.

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

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.	Nom. Capacity (MW)
				Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)			
2/6/14	DO	1-4 Hour	547	133.2	33.5	72.9	18.3	25%	52	51.5
		1-6 Hour	787	264.5	62.4	208.2	49.1	24%	54	71.7
5/13/14	DO	1-4 Hour	817	210.2	54.2	171.7	44.3	26%	88	53.5
5/14/14	DO	1-4 Hour	817	213.0	52.9	174.0	43.2	25%	94	53.5
5/15/14	DO	1-4 Hour	817	217.1	47.8	177.3	39.1	22%	96	53.5
5/29/14	DO	1-6 Hour	889	331.9	93.7	295.0	83.3	28%	78	100.8
6/26/14	DO	1-6 Hour	611	241.0	92.5	147.3	56.5	38%	82	107.1
6/30/14	DO	1-4 Hour	854	216.6	54.4	185.0	46.5	25%	83	55.0
7/25/14	DO	1-6 Hour	951	330.2	102.4	314.0	97.4	31%	85	126.0
8/11/14	DO	1-6 Hour	963	318.7	87.0	306.9	83.8	27%	80	126.0
8/28/2014*	DO	1-6 Hour	962	330.1	91.8	316.6	88.0	28%	89	126.0
			962	321.4	82.3	308.3	78.9	26%	85	126.0
9/11/14	DO	1-6 Hour	959	324.9	82.2	311.6	78.8	25%	85	119.7
9/16/14	DO	1-6 Hour	959	339.1	85.2	325.2	81.7	25%	91	119.7
Typical Event	DO	1-4 Hour**	817	213.0	52.9	174.0	43.2	25%	94	53.5
		1-6 Hour	920	331.0	98.2	304.5	90.3	30%	82	113.4

* Results shown separately for M&E event in HE 15-16 (first line) and "Prices" event in HE 17-19 (second line)

** Applicable through June only.

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

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

Notice	Industry	Number of Accounts	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DO 1-6 Hour	Agriculture, Mining & Construction	97	276.2	82.2	26.7	7.9	30%	79
	Manufacturing	89	570.4	101.4	50.5	9.0	18%	83
	Wholesale, Transport, other utilities	365	234.8	154.4	85.7	56.3	66%	83
	Retail stores	275	284.0	31.7	77.9	8.7	11%	84
	Offices, Hotels, Finance, Services	81	390.3	49.7	31.4	4.0	13%	80
	Schools							
	Institutional/Government							
	Other or unknown							
	Total		920	331.0	98.2	304.5	90.3	30%

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

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

Notice	LCA	Number of Accounts	Average Customer		Aggregate		% Load Impact	Average Event Temp.
			Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
DO 1-6 Hour	LA Basin	679	345.9	104.7	234.7	71.0	30%	82
	Outside LA	80	172.2	87.5	13.8	7.0	51%	89
	Ventura	162	347.2	76.1	56.1	12.3	22%	78
	Total	920	331.0	98.2	304.5	90.3	30%	82

Tables 5–11 and 5–12 provide average event-hour load impacts in Southern Orange County and South of Lugo respectively.

Table 5–11: Average Event-Hour Load Impacts for Southern Orange County – SCE AMP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
				Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
2/6/14	DO	1-4 Hour	63	139.3	23.0	8.8	1.4	17%	53.6
		1-6 Hour	80	325.4	30.8	26.0	2.5	9%	57.6
5/13/14	DO	1-4 Hour	73	223.0	41.1	16.3	3.0	18%	91.0
5/14/14	DO	1-4 Hour	73	229.9	40.8	16.8	3.0	18%	97.0
5/15/14	DO	1-4 Hour	73	225.5	36.6	16.5	2.7	16%	96.4
5/29/14	DO	1-6 Hour	81	347.1	40.3	28.1	3.3	12%	72.4
6/30/14	DO	1-4 Hour	78	190.8	28.1	14.9	2.2	15%	73.9
7/25/14	DO	1-6 Hour	88	373.6	49.7	32.9	4.4	13%	79.6
8/11/14	DO	1-6 Hour	90	354.0	48.2	31.9	4.3	14%	75.0
8/28/14	DO	1-6 Hour	90	392.4	60.2	35.3	5.4	15%	84.0
9/11/14	DO	1-6 Hour	89	392.9	47.0	35.0	4.2	12%	84.9
9/16/14	DO	1-6 Hour	89	431.4	67.5	38.4	6.0	16%	95.1
Typical Event	DO	1-4 Hour	73	229.9	40.8	16.8	3.0	18%	97.0
		1-6 Hour	85	360.9	45.2	30.5	3.8	13%	76.3

Table 5–12: Average Event-Hour Load Impacts for South of Lugo – SCE AMP

Date	Notice	Product	Accounts Called	Average Customer		Aggregate		% Load Impact	Average Event Temp.
				Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)		
2/6/14	DO	1-4 Hour	94	164.9	12.5	15.5	1.2	8%	50.4
		1-6 Hour	312	259.0	84.7	80.8	26.4	33%	52.3
5/13/14	DO	1-4 Hour	204	242.1	56.1	49.4	11.4	23%	89.0
5/14/14	DO	1-4 Hour	204	245.2	51.2	50.0	10.4	21%	95.5
5/15/14	DO	1-4 Hour	204	251.0	43.3	51.2	8.8	17%	97.4
5/29/14	DO	1-6 Hour	348	326.6	85.1	113.7	29.6	26%	83.1
6/26/14	DO	1-6 Hour	296	300.7	105.4	89.0	31.2	35%	82.6
6/30/14	DO	1-4 Hour	208	221.9	50.7	46.2	10.5	23%	83.8
7/25/14	DO	1-6 Hour	356	322.7	105.0	114.9	37.4	33%	92.1
8/11/14	DO	1-6 Hour	353	306.8	88.4	108.3	31.2	29%	84.4
8/28/14	DO	1-6 Hour	353	307.2	90.2	108.5	31.8	29%	90.3
9/11/14	DO	1-6 Hour	353	311.9	80.6	110.1	28.5	26%	88.6
9/16/14	DO	1-6 Hour	353	319.4	85.0	112.7	30.0	27%	93.2
Typical Event	DO	1-4 Hour	204	245.2	51.2	50.0	10.4	21%	95.5
		1-6 Hour	352	324.6	95.1	114.3	33.5	29%	87.4

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 AMP DO 1-6 product type for the two-hour July 25 event, which was called for hours-ending 15-16. The estimated load impacts are slightly above 100 MW in both of the event hours.

**Figure 5–3: Hourly Loads and Load Impacts – SCE AMP DO 1-6
July 25, 2014 Event**

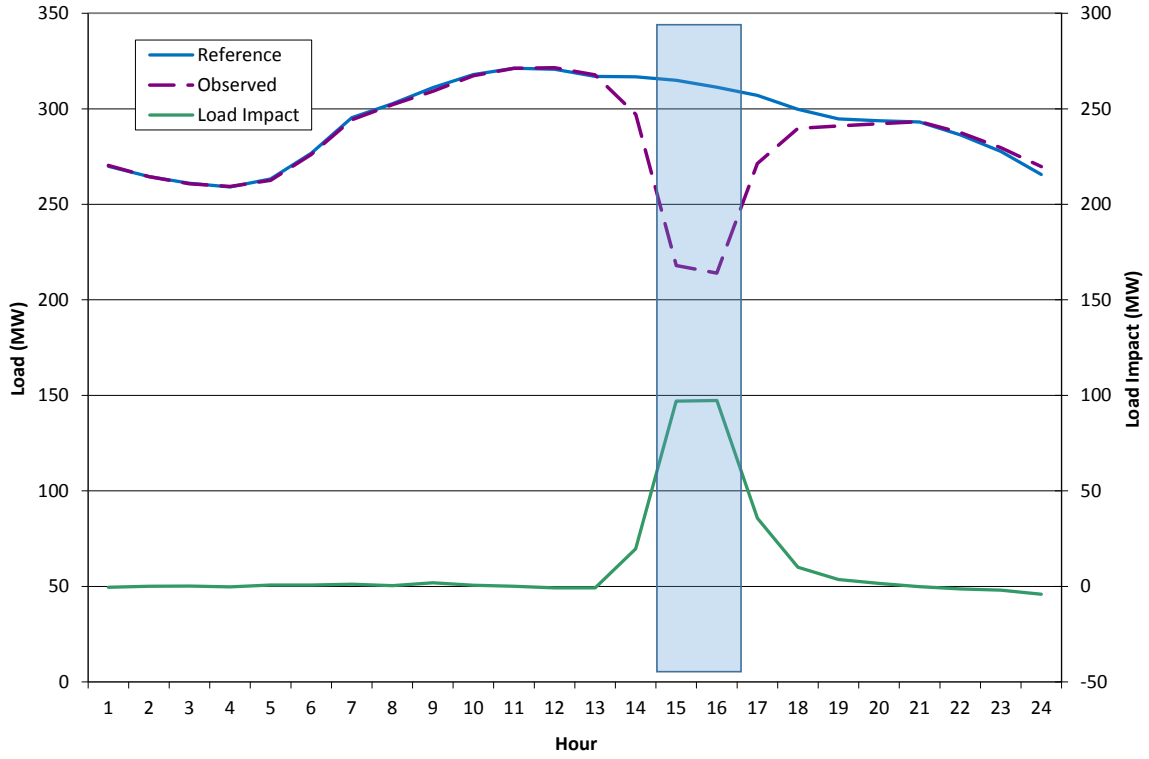


Table 5–13 shows load impacts for TA/TI participants in AMP. Results are differentiated by product type due to the transfer of the DO 1-4 Hour contract to CBP as of July. Focusing on the 1-6 Hour product that was in place throughout the summer, 160 TA/TI service accounts provided an average of 7.2 MW of load impacts, compared to an approved load shed level of 10.1 MW.

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

Event Date	Product	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
6-Feb-14	1-4 Hour						
	1-6 Hour	154	35.9	30.4	5.6	15%	8.3
13-May-14	1-4 Hour	52	28.1	24.1	4.0	14%	7.3
14-May-14	1-4 Hour	52	26.1	23.5	2.7	10%	7.3
15-May-14	1-4 Hour	52	26.2	24.9	1.3	5%	7.3
29-May-14	1-6 Hour	160	39.2	30.8	8.4	21%	9.8
26-Jun-14	1-6 Hour	160	40.8	36.6	4.2	10%	9.8
30-Jun-14	1-4 Hour	53	23.7	21.1	2.7	11%	7.3
25-Jul-14	1-6 Hour	160	44.0	35.4	8.6	20%	9.8
11-Aug-14	1-6 Hour	160	43.5	35.3	8.2	19%	10.3
28-Aug-14	1-6 Hour	160	44.1	38.0	6.1	14%	10.3
11-Sep-14	1-6 Hour	160	45.4	37.8	7.6	17%	10.3
16-Sep-14	1-6 Hour	160	48.8	41.5	7.3	15%	10.3
Average of Typical Event	1-4 Hour*	52	26.1	23.4	2.7	10%	7.3
	1-6 Hour	160	43.7	36.5	7.2	16%	10.1

* Applies only through June. Subsequently, DO 1-4 Hour product transferred to CBP.

Table 5–14 shows results for AutoDR participants in AMP. Results are again differentiated by product type. Through June, 354 AutoDR participants in the DO 1-4 Hour product provided an average of about 17.3 MW in AMP load impacts, compared to the load shed test level of approximately 26.5 MW. The DO 1-6 product included 170 AutoDR participants, who reduced load by an average of 15 MW, out of the load shed test amount of 26.7 MW.

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

Event Date	Product	# SAIDs	Reference Load (MW)	Observed Load (MW)	Load Impact (MW)	% Load Impact	Load Shed Test (MW)
6-Feb-14	1-4 Hour	191	21.4	16.7	4.7	22%	12.2
	1-6 Hour	132	26.2	18.8	7.4	28%	19.5
13-May-14	1-4 Hour	350	66.4	49.0	17.4	26%	26.1
14-May-14	1-4 Hour	350	68.6	51.0	17.6	26%	26.1
15-May-14	1-4 Hour	350	69.2	51.8	17.4	25%	26.1
29-May-14	1-6 Hour	155	37.3	25.5	11.8	32%	22.8
26-Jun-14	1-6 Hour	158	38.0	26.4	11.6	31%	23.8
30-Jun-14	1-4 Hour	367	68.7	51.8	16.9	25%	28.0
25-Jul-14	1-6 Hour	164	43.9	26.1	17.8	41%	25.6
11-Aug-14	1-6 Hour	170	43.6	28.6	15.1	35%	26.4
28-Aug-14	1-6 Hour	170	43.3	30.5	12.8	30%	26.4
11-Sep-14	1-6 Hour	186	49.4	32.7	16.6	34%	31.0
16-Sep-14	1-6 Hour	186	51.9	32.4	19.4	37%	31.0
Average of Typical Event	1-4 Hour*	354	68.2	50.9	17.3	25%	26.5
	1-6 Hour	170	43.9	28.9	15.0	34%	26.7

* Applies only through June. Subsequently, DO 1-4 Hour product transferred to CBP.

6. EX-ANTE LOAD IMPACT FORECASTS

This section describes both the *process* used to develop the *ex-ante* load impact forecasts for each utility's aggregator programs, and the *values* of the forecast load impacts. The first two sub-sections discuss requirements for the forecasts and the methods used to meet those requirements. The following sub-sections present forecasts for PG&E's CBP and AMP programs, SCE's CBP and AMP programs, and 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;¹⁵

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

The basic customer group that serves as the basis for developing *ex-ante* load impacts is each utilities' LCAs. For PG&E's programs, service accounts are additionally assigned to one of three size groups, as follows:

- Small – maximum demand less than 20 kW;

¹⁵ New for this study, load impacts are calculated for both sets of weather conditions under two alternative weather constructs. One is based on typical conditions at the time of each utility's monthly system peak, as in previous studies, though with updated data. The other is based on conditions coincident with CAISO peak loads.

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

The total number of customer “cells” developed for PG&E is therefore equal to 24 (= 3 size groups x 8 LCAs).

6.2.2 Development of Reference Loads and Load Impacts

Reference loads and load impacts for the above customer groups 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 and nominated during the 2014 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 2012, 2013 and 2014.

2) Simulate reference loads

In order to develop reference loads, we first re-estimate regression equations for each nominated customer account, using load and weather data for the current program year. The resulting estimates are 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 are similar in design to the *ex-post* load impact equations described in Section 3.2, differing in two ways. First, the *ex-ante* models exclude 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 for *ex-ante* simulation, because they would essentially require a separate simulation of the level of the morning load variable. 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 alternative 1-in-2 and 1-in-10 weather conditions.

Once these models are estimated, we simulate 24-hour load profiles for each customer account, 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 two sets of 1-in-2 and 1-in-10 weather conditions for each utility have been newly developed for this program year.

3) Calculate percentage load impacts

For each utility and program type, we calculate percentage load impacts for each relevant customer account. These are based on the *ex-post* load impacts for each event during the 2012, 2013 and 2014 program years. Specifically, we examine only customers enrolled and nominated in PY2014, but include available data from the 2012 and 2013 program years for those customers that were also nominated in those years. This method allows 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.

For each service account, we calculate the average and standard deviation of the load impacts across the available event days for four categories of hours: event hours; hours immediately adjacent to events; hours prior to; and hours following the adjacent hours (*i.e.*, morning and late evening). These values of load impacts for categories of hours are applied to the simulated reference loads to produce 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 programs, 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. For the average event-hour (*i.e.*, the values in the bottom row in the Protocol table generators), the variability of the load impacts across the scenarios is set to match the variability across each event hour.¹⁶

4) *Apply percentage load impacts to reference loads for each event scenario.*
In this step, the percentage load impacts are 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 provide the enrollment (nomination) forecasts. PG&E provides monthly enrollments through 2025 by program and notice level, with separate enrollments provided by LCA and size group.¹⁷ SCE provides monthly enrollments for 2015, 2016, and 2017 through 2025 (under the assumption that enrollments remain fixed during that time period). SDG&E expects enrollments to remain constant during the forecast period. The enrollments are then used to scale up the per-customer reference loads and load impacts for each required scenario and customer subgroup.¹⁸

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 forecasts of nominated service accounts; 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 LCA. 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.

¹⁶ This approach is used because of the need to place hours into “bins” to accommodate differences between the *ex-post* and *ex-ante* event windows. Specifically, the variability of the hours within the event-hour bin already reflects the average event-hour variability, so the average event-hour variability simply mimics the variability in the individual event hours.

¹⁷ 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.

¹⁸ For the aggregator programs, nominations are used in place of enrollments, since only nominated customers provide load impacts.

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

6.3.1 Enrollment and load impact summary

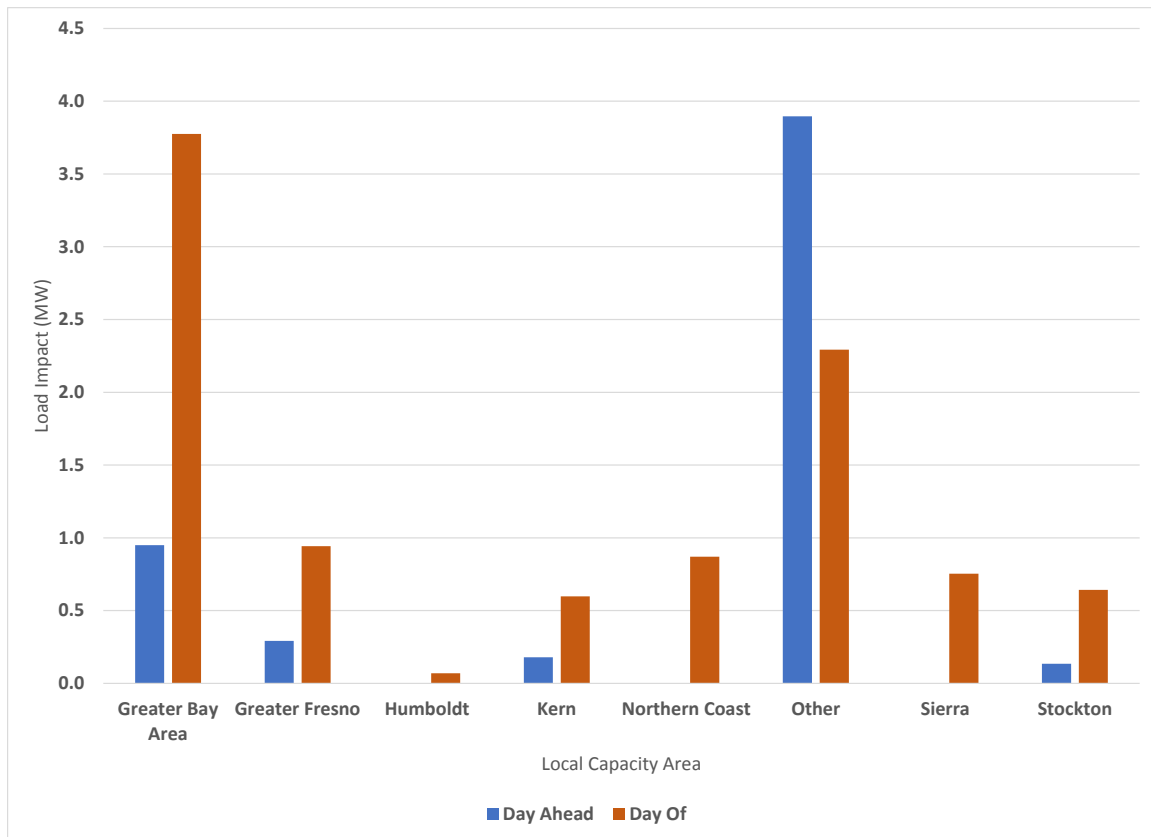
PG&E forecasts CBP nominations to remain constant across the forecast horizon at 37 service accounts for the DA product and 530 for the DO product. The resulting *ex-ante* load impact forecasts for an August peak day in the two sets of weather scenarios are shown in Table 6.1 for the DA and DO product 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

Notice	Utility Peak		CAISO Peak	
	1-in-2	1-in-10	1-in-2	1-in-10
DA	5.45	5.49	5.41	5.46
DO	9.94	10.26	9.65	10.02

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 utility-peak weather year. DA load impacts are concentrated largely outside of the seven LCAs. The bulk of DO load impacts occur in the Greater Bay Area, with the remainder spread across the Fresno and Other LCAs.

Figure 6–1: Distribution of Ex-Ante Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Utility-Peak 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 utility-peak 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

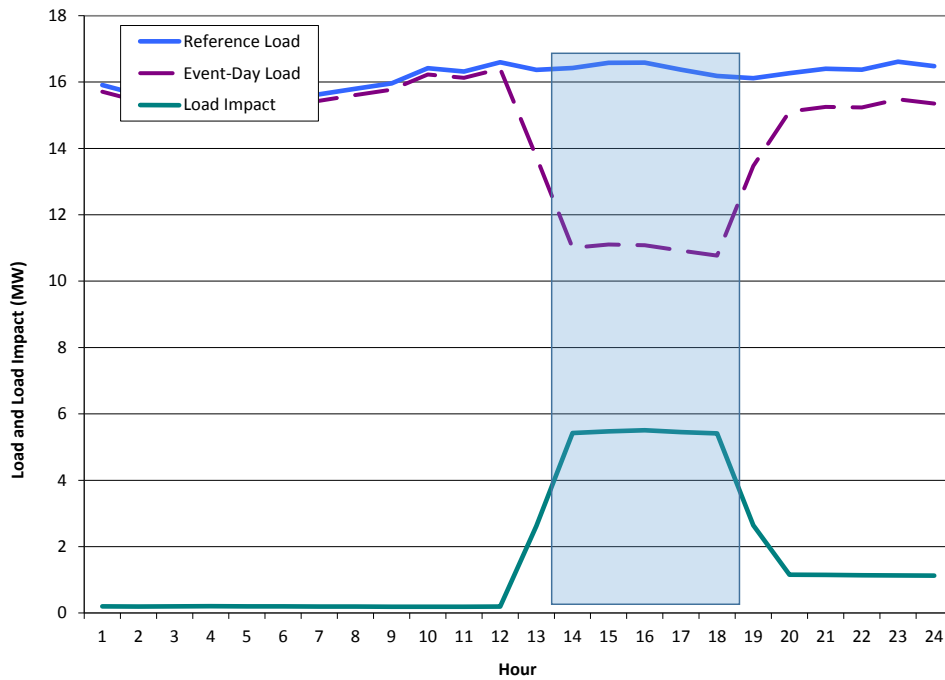
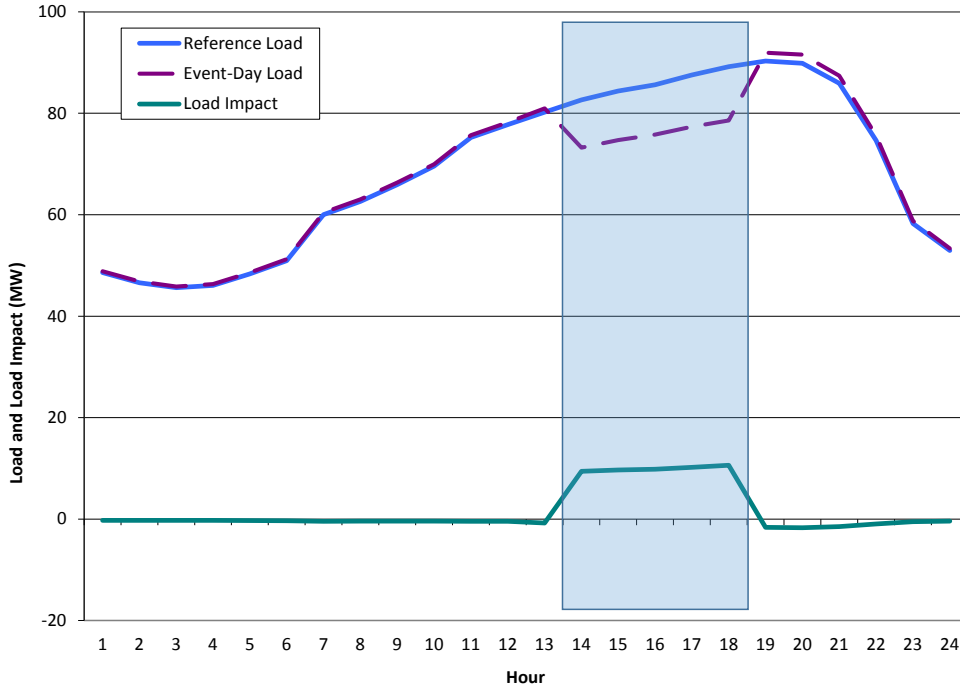


Figure 6–3: Hourly Event-Day Load Impacts for an August Peak Day in 2015 in 1-in-2 Weather Conditions – PG&E CBP DO



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

6.4.1 Enrollment and load impact summary

The *ex-ante* load impact for 2015 is given by the load reduction capacity nominated by the aggregators, adjusted by their performance in 2013 and 2014. PG&E estimates the enrollment by dividing the aggregate *ex-ante* impact by per-customer impacts derived from previous *ex-post* studies, as described above. For the remainder of the forecast horizon, the *ex-ante* impacts and the enrollment are expected to remain flat for AMP DO in the absence of more information. There will be no AMP DA contracts in 2015. As it is not clear whether AMP DA contracts will be executed in the future, PG&E assumes no impacts for AMP DA for 2015-2025.

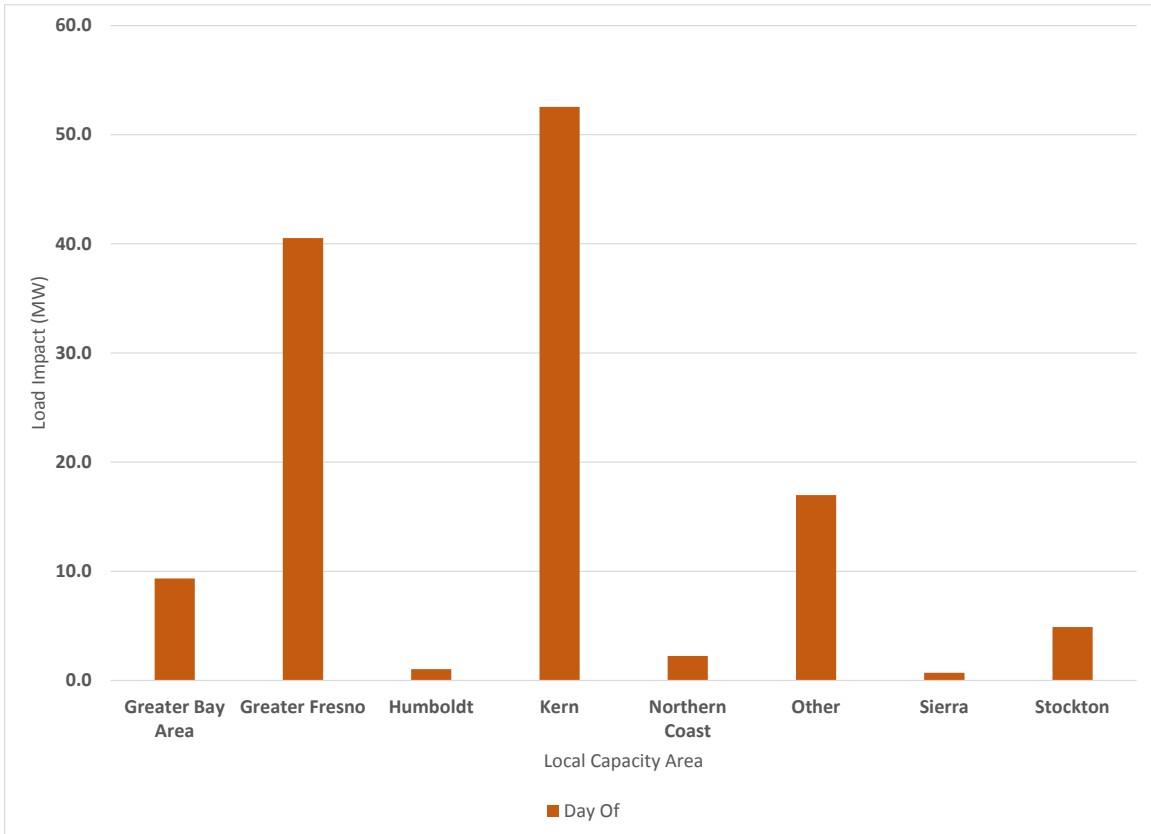
Table 6–2 compares *ex-ante* load impacts for AMP DO in both sets of 1-in-2 and 1-in-10 weather conditions, showing somewhat larger load impacts under utility peak conditions, and in the 1-in-10 scenarios. The load impacts across scenarios are assumed to remain constant over the forecast period.

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 DO

Notice	Utility Peak		CAISO Peak	
	1-in-2	1-in-10	1-in-2	1-in-10
DO	128.2	129.1	126.9	128.3

Figure 6–4 shows the distribution of load impacts by LCA for AMP DO for an August peak day in 1-in-2 weather conditions. DO load impacts are greatest in Kern, with large impacts also in the Greater Fresno LCA.

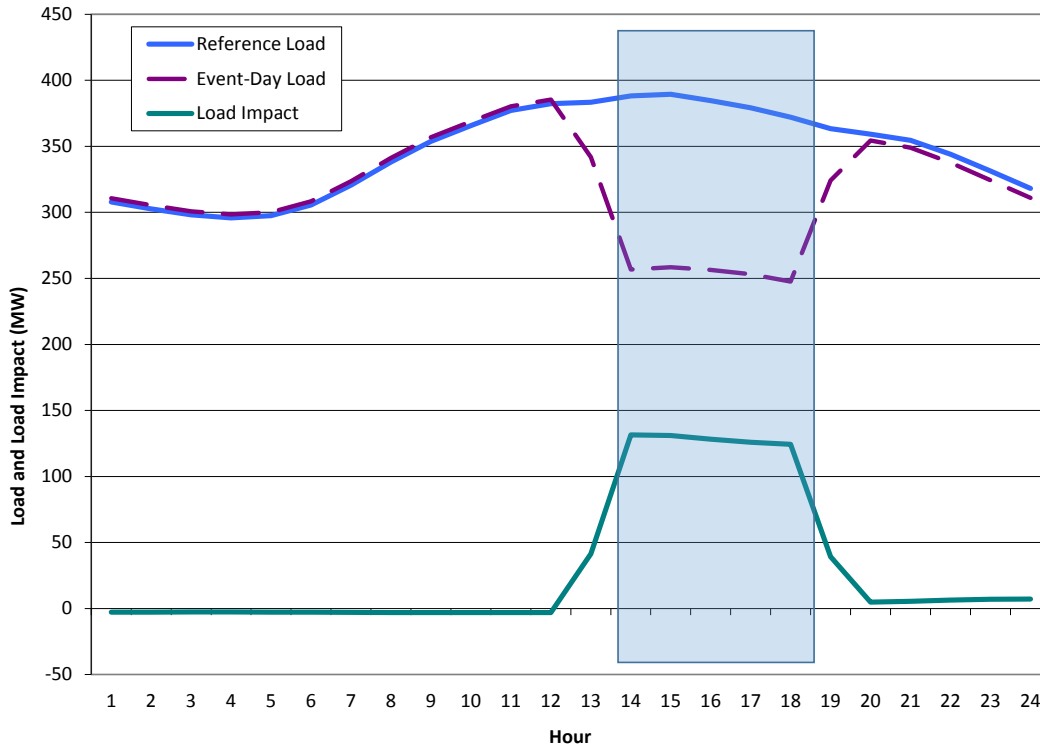
Figure 6–4: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Utility-Peak Weather Conditions – AMP DO



6.4.2 Hourly reference loads and load impacts

Figure 6–5 shows the forecast reference load, event-day load, and load impacts for an August peak day in 2015 in 1-in-2 utility-peak weather conditions 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 DO



6.5 Ex-ante Load Impacts for SCE’s CBP Program

6.5.1 Enrollment forecasts, reference loads and load impacts

SCE provided enrollment/nomination forecasts for 2015 through 2017 for CBP DA and DO. The forecasts differ by summer and winter months, but are otherwise constant over the period. Forecasts for CBP DA are 129 service accounts in the summer months of May through October, and 87 in the non-summer months. Forecasts for CBP DO are 1,162 in the summer months, and 782 in non-summer months. The forecast for CBP DA is down 44 percent from the number of nominated service accounts at the end of the 2014 summer, while the forecast for DO is up by 12 percent. SCE believes that CBP aggregators have moved some customers from DA to DO as a result of a number of events called in the winter of 2014/2015.

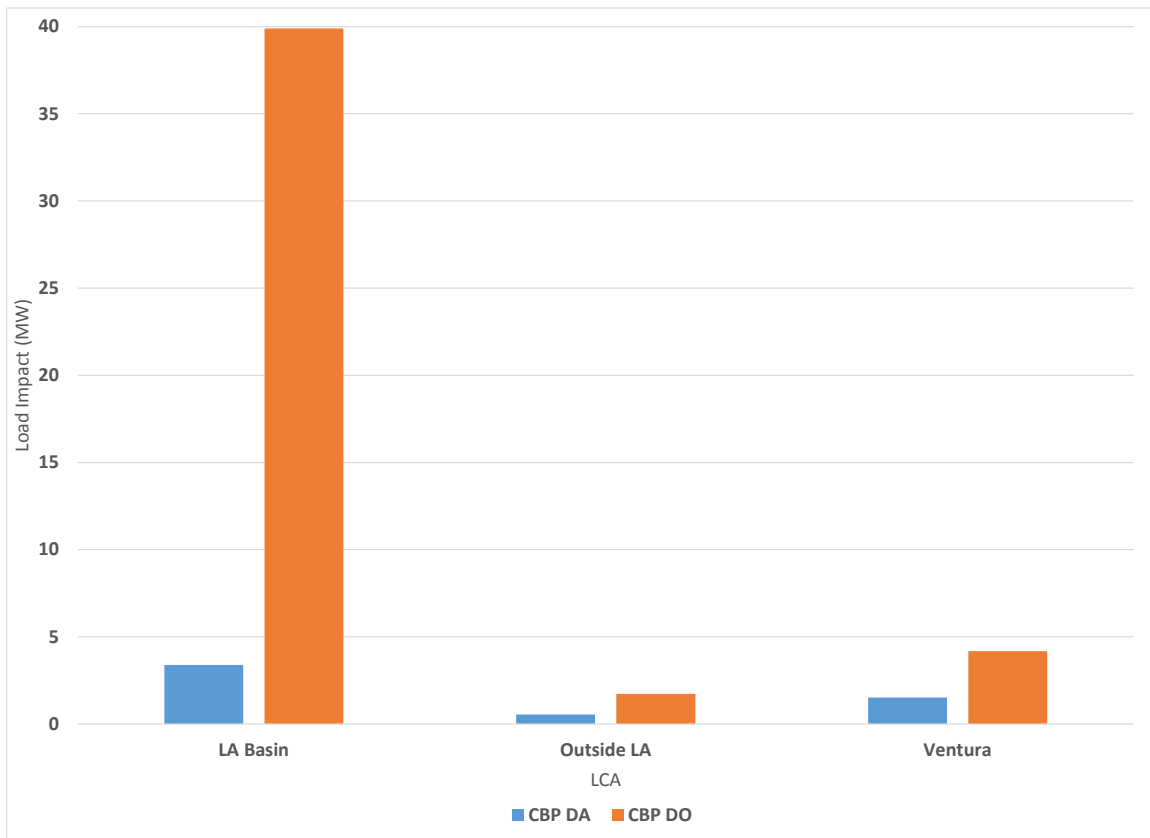
Table 6–3 presents *ex-ante* load impacts for SCE’s CBP DA and DO, in the summer and winter months, and for each weather scenario. CBP DA summer load impacts are projected at approximately 5.5 MW, while DO summer load impacts are at approximately 49 MW.

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

Notice	Season	Utility Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10
DA	Winter	2.63	2.58	2.52	2.59
	Summer	5.46	5.55	5.45	5.52
DO	Winter	23.0	22.6	22.0	22.6
	Summer	48.8	49.5	48.8	49.3

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

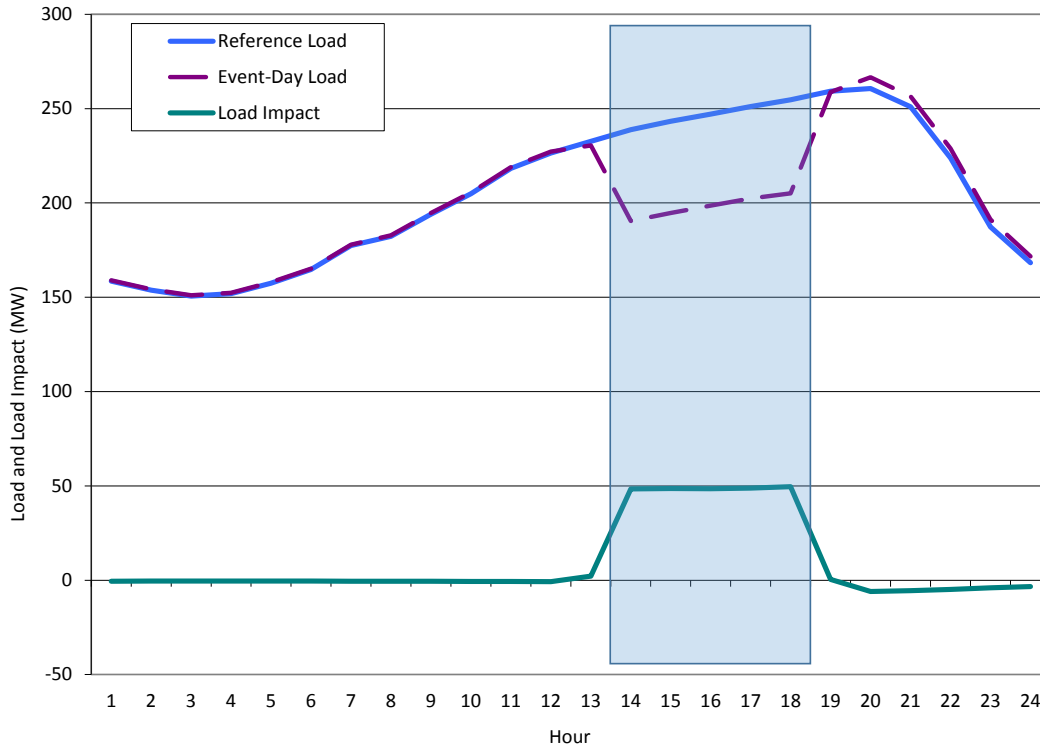
Figure 6–7: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in 1-in-2 Weather Conditions – SCE CBP



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 utility-peak weather year in August 2015 for SCE CBP DO. Event-hour load impacts average about 49 MW, which is 20 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 2015 through 2017 are zero for AMP DA and 1,057 (579 in non-summer months) for AMP DO. The DO forecast for summer is about 11 percent higher than the number of nominated customers at the end of the summer of 2014.

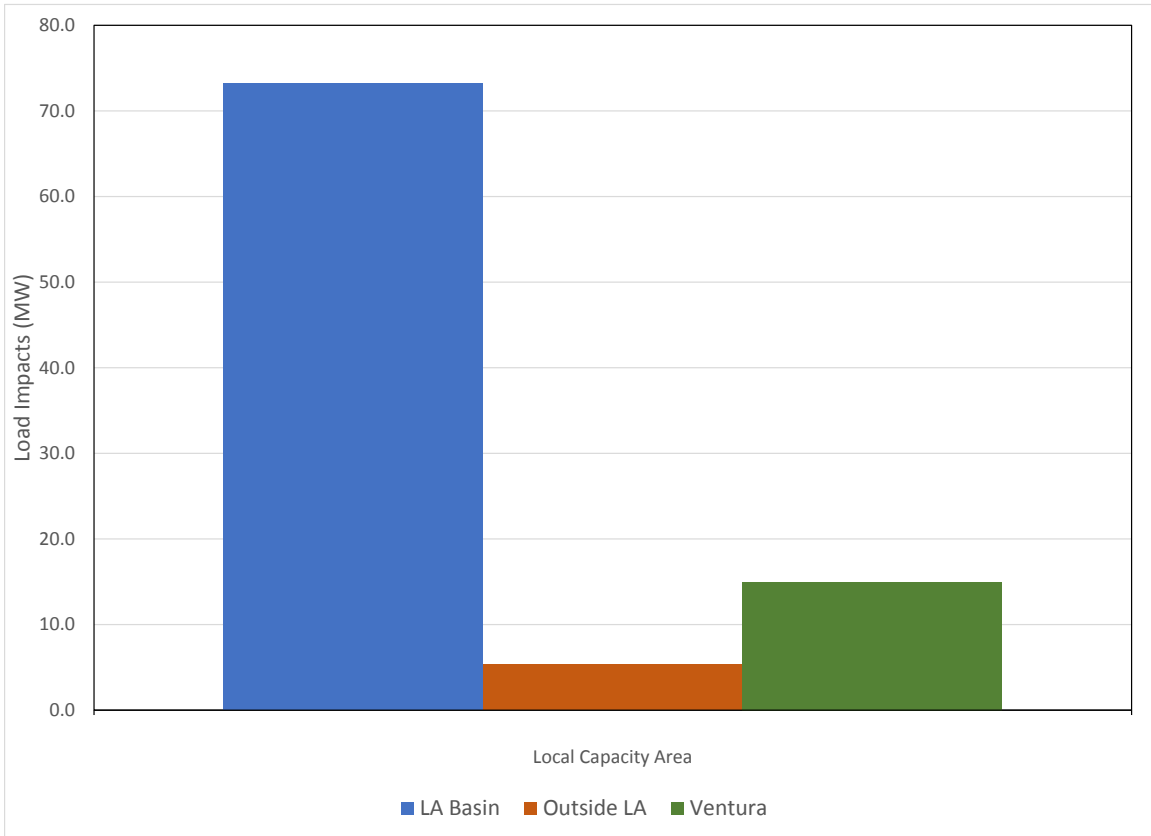
Table 6–4 compares *ex-ante* average event-window load impacts for AMP DO in the two sets of 1-in-2 and 1-in-10 weather conditions, showing somewhat larger load impacts in the 1-in-10 year scenarios.

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 DO

Notice	Season	Utility Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10
DO	Winter	37.8	36.9	35.8	37.0
	Summer	93.5	94.5	93.4	94.0

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.

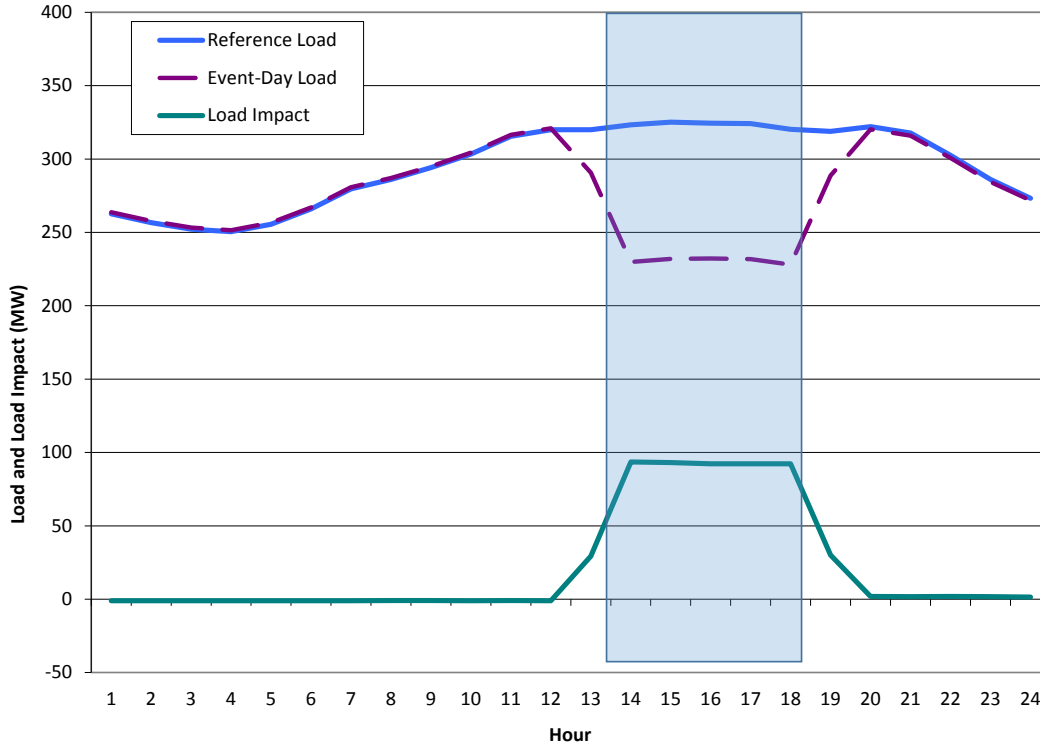
Figure 6–9: Load Impacts by LCA for August Peak Day in a 1-in-2 Utility-Peak Weather Year in 2015 – AMP DO



6.6.2 Hourly reference loads and load impacts

Figure 6–10 shows the hourly profiles of forecast loads and load impacts for an August peak day in 2015, in a utility-peak 1-in-2 weather year, for SCE’s AMP DO. Event-hour load impacts average approximately 93 MW, which is 29 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

SDG&E plans two changes in CBP beginning in 2015. One adds a 30-minute notice option to the two-hour DO product. The other opens CBP to small customers of less than 20 kW in size. However, there is currently not sufficient evidence regarding adoption rates for these options, so we have taken the conservative approach of not adding new small service accounts to the enrollment forecast, and assuming that customers choosing the short-notice option will behave similarly to the current customers. These assumptions may be modified in next year’s evaluation, depending on results of the ex-post load impact analysis.

The enrollment forecast provided by SDG&E for this report anticipates that the number of nominated customer service accounts for CBP DA will remain steady at 159, while CBP DO will increase somewhat through the summer of 2015, from 239 in May, to 284 in October, and then remain constant over the forecast period.

Table 6–6 compares DA and DO (separately for DO 1-4 and 2-6) load impacts for an August peak day in 1-in-2 and 1-in-10 weather years, under the utility-peak and CAISO-peak scenarios. Average event-hour load impacts vary slightly across scenarios in

expected ways, and are 11.9 MW for DA and 9.78 MW for DO in the 1-in-2 utility-peak weather scenario.

Table 6–6: Average Event-Hour Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2015 – 2025) – SDG&E CBP DA and DO

Notice	Utility Peak		CAISO Peak	
	1-in-2	1-in-10	1-in-2	1-in-10
DA 1-4 Hour	11.90	12.28	11.99	12.02
DO 1-4 Hour	5.53	5.71	5.63	5.64
DO 2-6 Hour	4.25	4.30	4.27	4.28
DO All	9.78	10.01	9.90	9.91

6.7.2 Hourly reference loads and load impacts

Figure 6–12 shows *ex-ante* hourly reference load, event-day load, and load impacts for the August peak day in 2015 in a 1-in-2 utility-peak weather year for CBP DA. Figure 6–13 shows comparable information for CBP DO 1-4.

Figure 6–12: Hourly Event-Day Load Impacts for the August Monthly Peak Day in 2015 in a 1-in-2 Utility-Peak Weather Year – SDG&E CBP DA

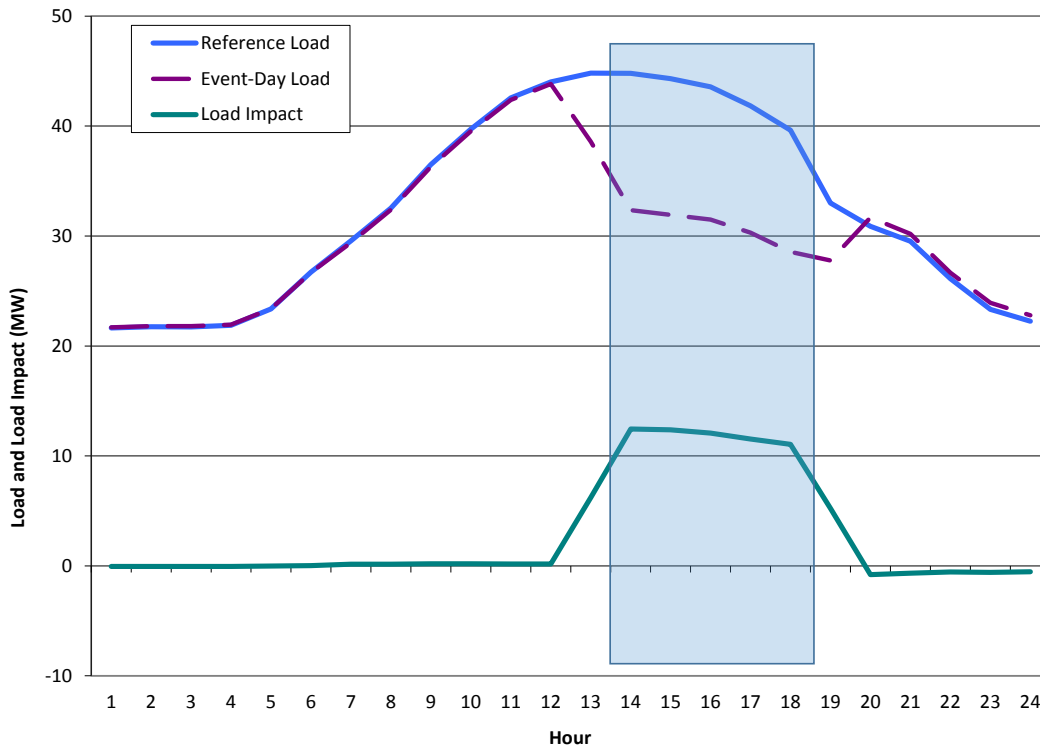
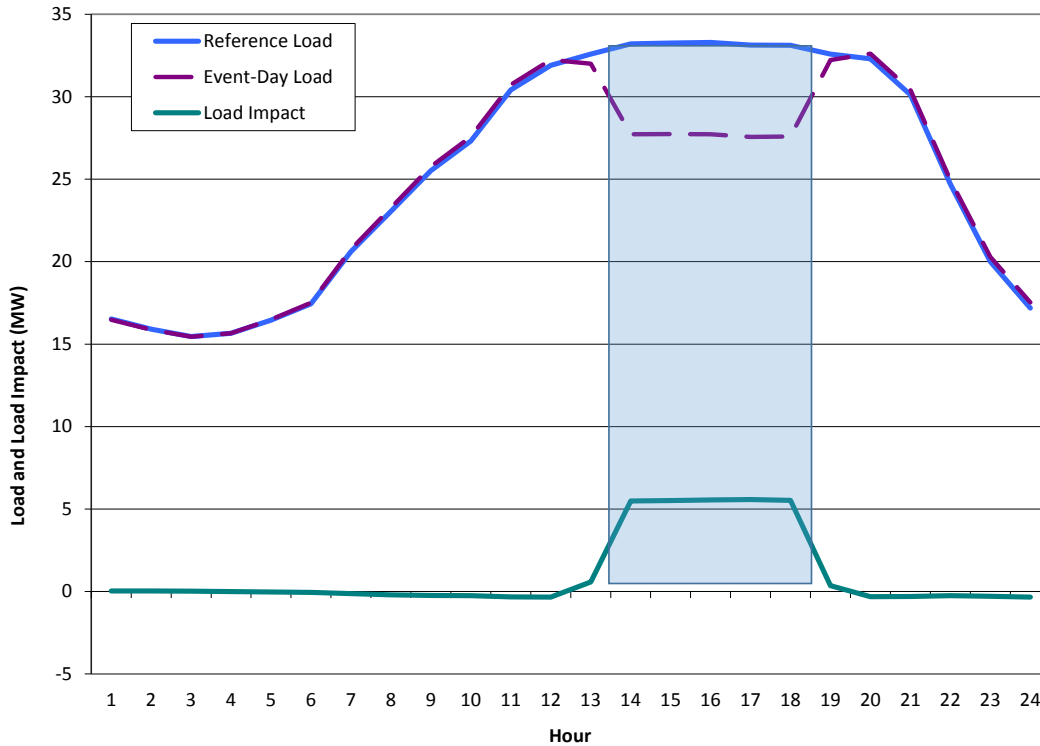


Figure 6–13: Hourly Event-Day Load Impacts for the August Monthly Peak Day in 2015 in a 1-in-2 Utility-Peak Weather Year – SDG&E CBP DO 1-4



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

In an effort to improve the transparency of the relationship between *ex-post* and *ex-ante* results, this section compares several sets of estimated load impacts for each utility and program, 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.

The term “current” refers to this report, which presents *ex-post* results for PY2014, and *ex-ante* forecasts for 2015 through 2025. The term “previous” refers to findings in reports for PY2013, and in some cases earlier. In the tables below, we combine the first and third comparisons above by showing *ex-post* load impacts for the current and two previous studies, along with *ex-ante* forecasts for 2015. We begin in the next subsection by summarizing the process for developing the *ex-ante* forecast (of the 1-in-2 August peak day) for 2015 from the *ex-post* load impacts from PY2014 and, where relevant, from the two prior years.

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

As a preview to this section, we first summarize the detailed description in Section 6 of how the *ex-ante* load impact forecasts for aggregator programs incorporate historical information from previous *ex-post* load impact evaluations, including the following:

1. *Percentage load impacts* for each customer are constructed from up to three years of *ex-post* load impact results for service accounts that were enrolled and nominated in PY2014.
2. *Reference loads* for each customer are simulated for each of the four *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 cell representing an LCA and size category (PG&E only). These averages are based on data on percentage load reductions and forecasted reference loads for each customer account in the relevant cell, which are developed 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 (and size) as needed.

The above 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 2015

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 2015, for an August peak day at utility-peak 1-in-2 weather conditions.

The program-level *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, and then declined in the next two years. Over that time, the number of customers nominated grew; however, per-customer reference loads, as well as per-customer load impacts and percent load impacts, declined, indicating the addition of smaller and less responsive customers. Looking forward, the forecasts of nominated service accounts and *ex-ante* load impacts for CBP for 2015 are comparable to the *ex-post* values in PY 2014.

Nominated service accounts for AMP DA and DO have grown over the three years, though the per-customer reference loads indicate that average customer size has fallen somewhat. Per-customer load impacts and percentage load impacts have also fallen (particularly for DA), producing the general decline in program-level load impacts (with the exception of the DO product in 2013). In an attempt to explain the relatively large difference between the aggregate load impacts in 2013 and 2014 for AMP DO, we analyzed customer-level load impact data for customers that were nominated in both years. That analysis reveals that the same 54 service accounts that produced the largest load impacts in 2013 (approximately 450 kW per customer, and 76.7 MW in total), accounted for only 46.8 MW of load reductions in 2014. The difference of approximately 30 MW accounts for essentially all of the difference between the aggregate load impacts in the two years.

Nominated service accounts and aggregate load impacts are projected to increase modestly from 2014 for the DO option (no DA contracts are anticipated). As discussed in the next sub-section, PG&E bases its *ex-ante* load impact estimates and enrollment forecast for AMP largely on the contract commitments and per-customer load impacts.

Table 7–1: Ex-Post Results for 2012 through 2014, and Ex-Ante for 2015 – PG&E CBP and AMP

Program	Year	Nom. Acnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact	Average Event Temp.
			Reference Load	Load Impact	Reference Load	Load Impact		
CBP DA	2012	166	282.1	122.9	46.8	20.4	44%	95
	2013	25	604.8	188.0	15.1	4.7	31%	86
	2014	33	396.4	148.3	13.1	4.9	37%	89
	2015 ExA	37	444.0	147.4	16.4	5.5	33%	96
CBP DO	2012	370	272.0	62.8	100.6	23.3	23%	88
	2013	480	197.8	28.5	94.9	13.7	14%	90
	2014	542	153.3	19.5	83.2	10.6	13%	87
	2015 ExA	530	162.0	18.8	85.9	9.9	12%	86
AMP DA	2012	233	548.6	214.1	127.8	49.9	39%	95
	2013	425	418.8	102.4	178.0	43.5	24%	90
	2014							
	2015 ExA	-	-	-	-	-	-	-
AMP DO	2012	1,125	414.6	115.2	466.5	129.6	28%	89
	2013	1,344	374.6	115.5	503.4	155.2	31%	85
	2014	1,397	334.1	87.9	466.6	122.7	26%	89
	2015 ExA	1,511	253.3	84.9	382.7	128.2	34%	97

7.2.2 Previous versus current ex-ante

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

As noted above, the projected load impacts for CBP in 2015 generally reflect the observed *ex-post* results in the current year, though they differ somewhat from the forecasts made in 2013. For AMP, PG&E’s enrollment forecast and *ex-ante* load impact estimates are generally based on the aggregators’ nominated capacity, adjusted by past performance. Anticipated aggregate load impacts for 2015 are somewhat lower for CBP DA and AMP DO from the projections 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. Contractual load reduction capacity has been reduced from the anticipated level in the previous study. Customer size, per-customer load impacts, and percentage load impacts are expected to be smaller than in the 2013 forecast based on what is observed in 2014.

Table 7–2: Ex-Ante Load Impacts for 2015 from PY 2013 and PY 2014 Studies, PG&E

Program	Study Year	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	2013	25	556.0	168.0	13.9	4.2	30%
	2014	37	444.0	147.4	16.4	5.5	33%
CBP DO	2013	472	202.1	30.3	95.4	14.3	15%
	2014	530	162.0	18.8	85.9	9.9	12%
AMP DA	2013	1,142	308.2	59.5	352.0	68.0	19%
	2014	-	-	-	-	-	-
AMP DO	2013	1,514	294.3	107.3	445.5	162.5	36%
	2014	1,511	253.3	84.9	382.7	128.2	34%

7.2.3 Current ex-post compared to previous ex-ante

In this sub-section, we compare estimated *ex-post* load impacts for 2014 to the *ex-ante* forecasts for a 1-in-2 August peak day in 2014 that were developed in the PY2013 study. These are shown in Table 7.3. The number of nominated service accounts observed in 2014 were generally somewhat greater than those anticipated in the forecasts from the 2013 study. For the largest program/notice type, AMP DO, percentage load impacts and aggregate load impacts in the current *ex-post* study were lower than forecast in the previous study. Aggregate load impacts for CBP DO were 3 MW less than forecast, which is consistent with smaller per-customer reference loads and load impacts than forecast. *Ex-post* load impacts for AMP DA were close to the forecast. However, no DA contracts are anticipated in 2015.

Table 7–3: Current *Ex-Post* and Previous *Ex-Ante* Load Impacts for 2014, PG&E

Program	Forecast/ <i>Ex-Post</i>	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	Forecast	25	556.0	168.0	13.9	4.2	30%
	<i>Ex-Post</i>	33	396.4	148.3	13.1	4.9	37%
CBP DO	Forecast	472	202.1	30.3	95.4	14.3	15%
	<i>Ex-Post</i>	542	153.3	19.5	83.2	10.6	13%
AMP DA	Forecast	1,142	308.2	59.5	352.0	68.0	19%
	<i>Ex-Post</i>						
AMP DO	Forecast	1,514	294.3	107.3	445.5	162.5	36%
	<i>Ex-Post</i>	1,397	334.1	87.9	466.6	122.7	26%

7.3 SCE CBP and AMP

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

The number of service accounts nominated and the aggregate estimated load impacts for CBP DA have varied substantially over program years 2012 through 2014, and increased substantially in 2014 as a result of an AMP DA aggregator moving its service accounts to CBP DA due to problems in meeting contract nominated capacity. However, SCE has recently observed some transfers of nominated service accounts from CBP DA to DO in 2015 as a result of DA events called in the 2014/2015 winter period, and has thus lowered its forecast of CBP DA nominated service accounts in 2015 and forward. Customer service accounts nominated, and aggregate load impacts for CBP DO remained fairly stable over the years prior to 2014, but increased substantially in 2014 due to a shift in service accounts from AMP DO. Also as a result, service accounts nominated in AMP DO declined substantially in 2014, though they are expected to rise by approximately 130 service accounts in 2015. Percentage load impacts for AMP DO have been steady. With the increase in nominated service accounts for 2015, aggregate load impacts are anticipated to rise from about 90 MW in 2014 to 93.5 MW in 2015.

**Table 7-4: Ex-Post Results for 2012 through 2014, and Ex-Ante for 2015 –
SCE CBP and AMP**

Program/ Notice	Year	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact	Average Event Temp.
			Reference Load	Load Impact	Reference Load	Load Impact		
CBP DA	2012	2.2	548.7	18.3	1.19	0.04	3%	80
	2013	20	638.2	145.4	13.07	2.98	23%	85
	2014	231	430.5	41.5	99.4	9.6	10%	84
	2015 ExA	129	508.1	42.2	65.6	5.5	8%	87
CBP DO	2012	359	243.0	45.9	87.3	16.5	19%	90
	2013	420	214.1	43.9	89.8	18.4	21%	90
	2014*	1,236	221.4	42.6	273.7	52.7	19%	88
	2015 ExA	1,162	212.5	42.0	247.0	48.8	20%	93
AMP DA	2012	142	233.4	153.5	33.1	21.8	66%	91
	2013	236	387.0	33.3	91.3	7.9	9%	86
	2014	-	-	-	-	-	-	-
	2015 ExA	-	-	-	-	-	-	-
AMP DO	2012	1,648	334.1	97.2	550.6	160.1	29%	91
	2013	1,531	293.8	80.1	449.6	122.6	27%	85
	2014	920	331.0	98.2	304.5	90.3	30%	82
	2015 ExA	1,057	306.1	88.5	323.4	93.5	29%	93

* Applies to July through October due to transfer from AMP DO

7.3.2 Previous versus current ex-ante

Table 7-5 shows *ex-ante* forecasts for 2015 for a utility-peak 1-in-2 August monthly peak day, as produced in the current (PY2014) and the PY2013 evaluations. The table reflects anticipated movement of some CBP DA service accounts to the DO product, as described above.

Table 7-5: Ex-Ante Forecasts for 2015 from PY 2013 and PY 2014 Studies, SCE

Program	Study Year	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	2013	261	490.8	46.8	128.1	12.2	10%
	2014	129	508.1	42.2	65.6	5.46	8%
CBP DO	2013	859	246.6	52.8	211.8	45.4	21%
	2014	1,162	212.5	42.0	247.0	48.8	20%
AMP DA	2013	-	-	-	-	-	-
	2014	-	-	-	-	-	-
AMP DO	2013	1,125	294.1	78.6	330.8	88.4	27%
	2014	1,057	306.1	88.5	323.4	93.5	29%

7.3.3 Current ex-post compared to previous ex-ante

Table 7–6 shows two sets of values for 2014 – the line labeled “Forecast” represents the *ex-ante* forecast for 2014 for a utility-peak 1-in-2 August peak day, that was produced in the PY2013 evaluation. The line labeled “Ex-Post” represents the *ex-post* results for the typical event in the current study. The number of service accounts nominated in CBP DA in 2014 was lower than forecast in the 2013 evaluation, resulting in somewhat smaller aggregate load impacts. The larger number of nominated service accounts for CBP DO, as well as the larger aggregate load impacts, are due to the transfer of service accounts from AMP DO. For AMP DO, the lower number of service accounts still yielded a slightly larger aggregate load impact than was forecast.

Table 7–6: Current Ex-Post and Previous Ex-Ante Forecast Load Impacts for 2014, SCE

Program	Forecast/ Ex-Post	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	Forecast	261	490.8	46.8	128.1	12.2	10%
	Ex-Post	231	430.5	41.5	99.4	9.6	10%
CBP DO	Forecast	859	246.6	52.8	211.8	45.4	21%
	Ex-Post	1,236	221.4	42.6	273.7	52.7	19%
AMP DA	Forecast	-	-	-	-	-	-
	Ex-Post	-	-	-	-	-	-
AMP DO	Forecast	1,125	294.1	78.6	330.8	88.4	27%
	Ex-Post	920	331.0	98.2	304.5	90.3	30%

7.4 SDG&E CBP

7.4.1 Previous and current ex-post, and forecast for 2015

Table 7–7 compares estimated *ex-post* load impacts for the average of the typical CBP events in the current and two previous program years, by notice type, along with this year’s *ex-ante* forecast for 2015.

The number of customers nominated in CBP DA have increased steadily over the past three years. Customers nominated in CBP DO have declined over the same years. Forecast numbers of customers for 2015 are expected to remain approximately at the 2014 level for DA, and to increase somewhat for DO from the numbers in 2014. Aggregate estimated *ex-post* load impacts for both notice types have remained fairly level, except for a dip in 2012 for DA.¹⁹ Forecast load impacts for 2015 are up modestly for both DA and DO from the 2014 *ex-post* results. The forecasts are based on the *ex-*

¹⁹ A review of customer-level data indicates that the relatively smaller aggregate load impacts for CBP DA in 2012 were due to smaller estimated load impacts for one or both of two large service accounts that make up as much as 80 to 90 percent of the program load impacts. The rebound in aggregate load impact in 2013 and 2014 was caused largely by a return to previous performance by those two service accounts.

post performance for up to the last three program years for service accounts enrolled and nominated in 2014, and not dropping out of the program before the end of the summer.

Table 7–7: Ex-Post Load Impacts for PY2012 through 2014, and Ex-Ante for 2015 – SDG&E CBP

Program	Year	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact	Average Event Temp.
			Reference Load	Load Impact	Reference Load	Load Impact		
CBP DA	2012	78	320.2	81.6	25.0	6.4	25%	83
	2013	142	304.8	75.9	43.2	10.8	25%	88
	2014	163	247.0	60.6	40.4	9.9	25%	87
	2015 ExA	159	269.4	74.8	42.8	11.9	28%	81
CBP DO	2012	321	229.7	30.5	73.7	9.8	13%	86
	2013	260	234.5	40.2	61.1	10.5	17%	87
	2014	237	228.5	37.0	54.1	8.8	16%	87
	2015 ExA	266	216.8	36.8	57.7	9.8	17%	82

7.4.2 Previous versus current ex-ante

Table 7–8 compares the CBP *ex-ante* forecasts for program-year 2015 that were produced as part of this 2014 evaluation and the previous evaluation. In both cases, the forecast represents the August peak day in the utility-peak 1-in-2 weather scenario. There is no difference between the program- and portfolio-level impacts.

The projected aggregate load reductions for the CBP DA option increase from 9.5 MW to 11.9 MW between the two studies, which is consistent with the larger number of nominated service accounts and an increase in the projected percent load impacts (which is in turn based on the performance of the service accounts remaining in the program at the end of program-year 2014. For CBP DO, the projected aggregate load impact matches the previous forecast quite closely (9.8 MW in the current study compared to 10.2 MW in the previous study).

Table 7–8: Ex-Ante Load Impacts for 2015 from PY 2013 and PY 2014 Studies, SDG&E

Program	Study Year	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	2013	145	294.5	65.5	42.7	9.5	22%
	2014	159	269.4	74.8	42.8	11.9	28%
CBP DO	2013	275	220.4	37.1	60.6	10.2	17%
	2014	266	216.8	36.8	57.7	9.8	17%

7.4.3 Current ex-post compared to previous ex-ante

Table 7–9 compares current PY2014 *ex-post* load impacts to values for 2014 from the PY2013 *ex-ante* forecast. Current-year numbers of nominated service accounts were higher than expected for CBP DA and lower than expected for CBP DO, compared to the forecast for 2014 in the PY2013 forecast. Average customer size, as reflected in the reference loads, is somewhat smaller than anticipated for DA, and slightly larger for DO, while percentage load impacts are similar.

For DA, the aggregate estimated load impact (9.9 MW) was slightly higher than the forecast value (9.5 MW). For DO, the aggregate load impact of 8.8 MW is down somewhat from the forecast value, which is consistent with the smaller number of nominated service accounts than forecast.

Table 7–9: Current Ex-Post and PY2013 Ex-Ante Load Impacts for 2014, SDG&E

Program	Forecast/ Ex-Post	Nom. Accnts.	Per Customer (kW)		Aggregate (MW)		% Load Impact
			Reference Load	Load Impact	Reference Load	Load Impact	
CBP DA	Forecast	145	294.5	65.5	42.7	9.5	22%
	Ex-Post	163	247.0	60.6	40.4	9.9	25%
CBP DO	Forecast	275	220.4	37.1	60.6	10.2	17%
	Ex-Post	237	228.5	37.0	54.1	8.8	16%

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, program, 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)²⁰; the 24-hour moving average of THI; heat index (HI)²¹; the 24-hour moving average of HI; cooling degree hours (CDH)²², including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; the 24-hour moving

²⁰ $THI = T - 0.55 \times (1 - HUM) \times (T - 58)$ if $T \geq 58$ 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").

²¹ $HI = c_1 + c_2T + c_3R + c_4TR + c_5T^2 + c_6R^2 + c_7T^2R + c_8TR^2 + c_9T^2R^2 + c_{10}T^3 + c_{11}R^3 + c_{12}T^3R + c_{13}TR^3 + c_{14}T^3R^2 + c_{15}T^2R^3 + c_{16}T^3R^3$, 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.

²² 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.

average of CDH; the one-day lag of cooling degree days (CDD)²³. 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	Mean17
3	CDH60
4	CDH65
5	CDH60_MA3
6	CDH65_MA3
7	THI THI_MA24
8	CDH60 mean17
9	CDH60 CDH60_MA24
10	CDH65 CDH65_MA24
11	CDH60_MA3 CDH60_MA24
12	CDH65_MA3 CDH65_MA24
13	THI Lag_CDD60
14	CDH65 mean17
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 identify a set of days that are similar to event days, but were not called as event days (*i.e.*, “test days”). The use of non-event test days allows us to test model performance against known “reference loads,” or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for all of the test days. The model fit (*i.e.*, the difference between the actual and predicted loads on the test days, during afternoon hours in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.
2. Performance on *synthetic* event days (*e.g.*, event-like non-event days that are treated as event days in estimation), to test 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

²³ Cooling degree days (CDD) are defined as $\text{MAX}[0, (\text{Max Temp} + \text{Min Temp}) / 2 - 60]$, 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.

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 create an average weather profile using the load-weighted average across customers, each of which is associated with a weather station. We “score” each non-holiday weekday by comparing the dry-bulb temperature and relative humidity to the values for each event day. For example, we calculate the following statistic for each day relative to the first day: $\text{abs}(Temp_t - Temp_{Evt}) / \text{StdDev}(Temp)$. A similar score is calculated for the relative humidity, and the sum of the temperature and humidity scores is 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	CBP	CBP
5/13/2014	5/13/2014	5/1/2014	5/1/2014	5/2/2014
6/10/2014	6/10/2014	5/2/2014	5/2/2014	5/12/2014
7/1/2014	7/1/2014	5/16/2014	5/16/2014	5/13/2014
7/8/2014	7/8/2014	7/8/2014	7/8/2014	5/16/2014
7/15/2014	7/15/2014	7/18/2014	7/18/2014	7/23/2014
7/24/2014	7/24/2014	7/22/2014	7/22/2014	7/24/2014
8/8/2014	8/8/2014	7/23/2014	7/23/2014	7/29/2014
8/28/2014	8/28/2014	7/24/2014	7/24/2014	8/14/2014
8/29/2014	8/29/2014	7/28/2014	7/28/2014	8/29/2014
9/11/2014	9/11/2014	7/29/2014	7/29/2014	9/8/2014
		8/7/2014	8/7/2014	9/10/2014
		8/15/2014	8/15/2014	9/24/2014
		8/26/2014	8/26/2014	10/6/2014
		8/27/2014	8/27/2014	10/7/2014
		9/24/2014	9/24/2014	
		9/25/2014	9/25/2014	

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 (10 for PG&E AMP and CBP, 14 for SDG&E CBP, and 16 for SCE AMP and 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 adjusted R-squared values are generally close to 0.90 or greater. MPE values show biases of less than 2 percent. MAPE values range from 1.3 to 6.6 percent, with the equations for DO programs generally more accurate than those for the DA programs.

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

Utility	Program	Notice	Selected Specification	Adjusted R ²	MPE	MAPE
PG&E	CBP	DA	3	0.67	1.7%	6.6%
		DO	3	0.98	0.1%	2.2%
	AMP	DA	11	0.92	-1.3%	3.5%
		DO	11	0.94	-0.1%	1.8%
SCE	CBP	DA	11	0.99	0.4%	1.5%
		DO	11	0.98	0.6%	1.9%
	AMP	DO	12	0.98	-0.3%	1.3%
SDG&E	CBP	DA	10	0.85	-1.5%	4.5%
		DO	10	0.89	-1.6%	3.5%

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, for the DO products, which generally have larger numbers of nominated customers. 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

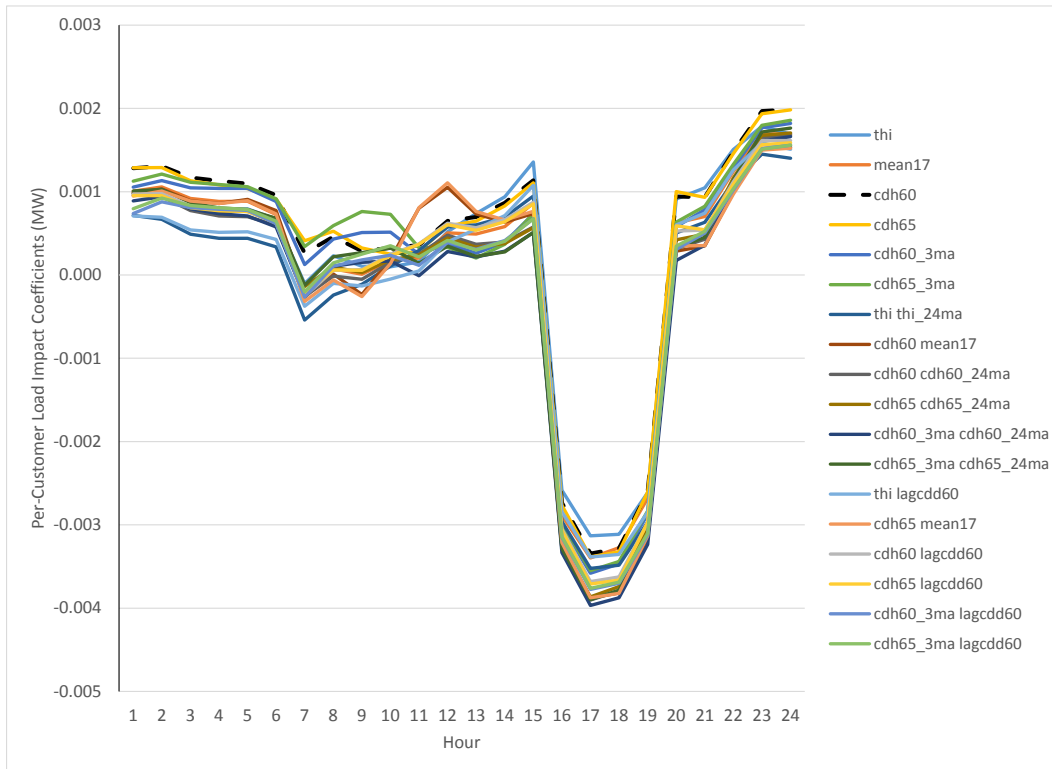


Figure 8–3: Average Event-Hour Load Impacts by Specification, SCE AMP DO

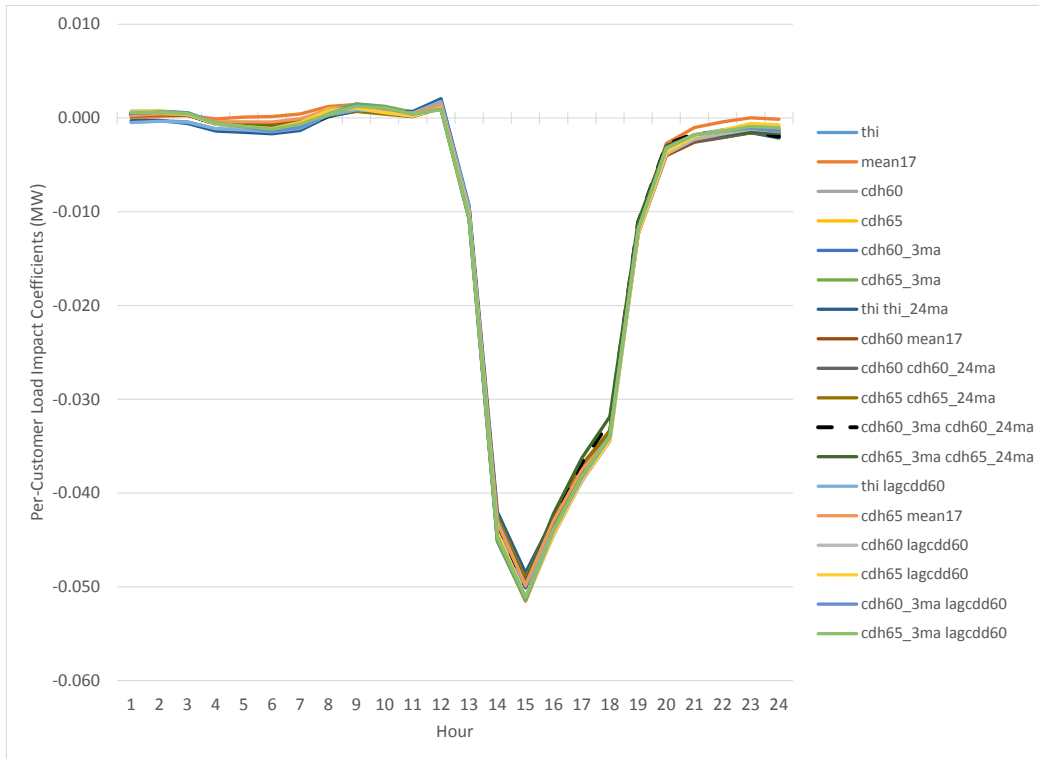


Figure 8–4: Average Event-Hour Load Impacts by Specification, SCE CBP DO

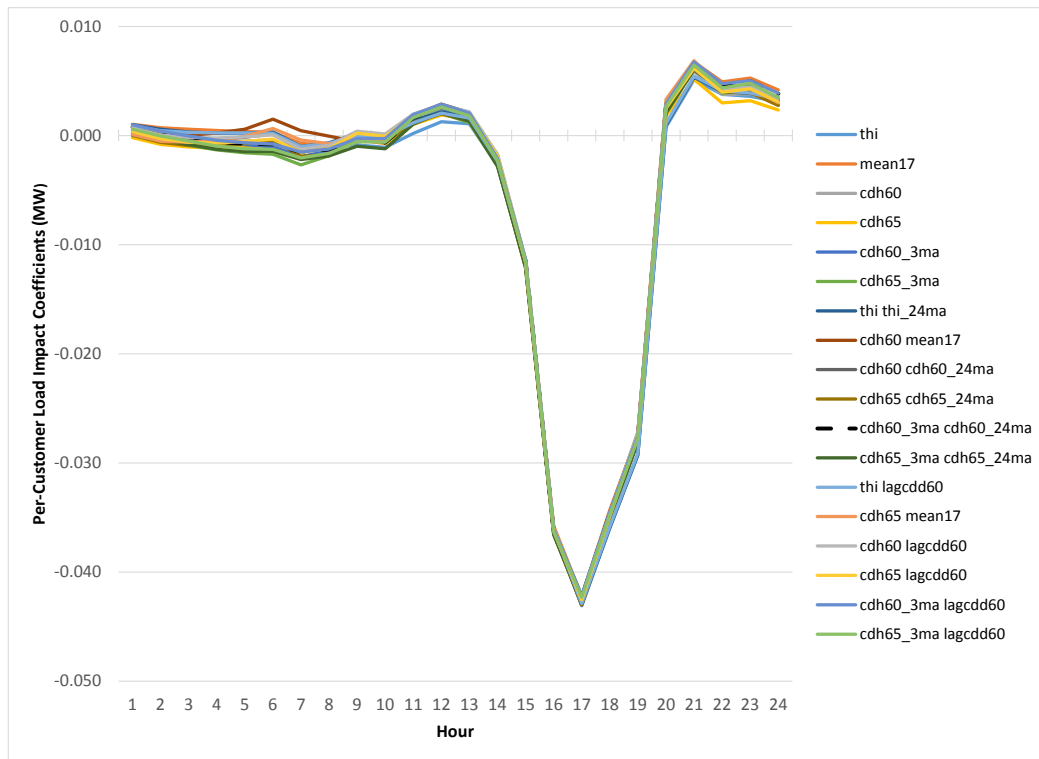
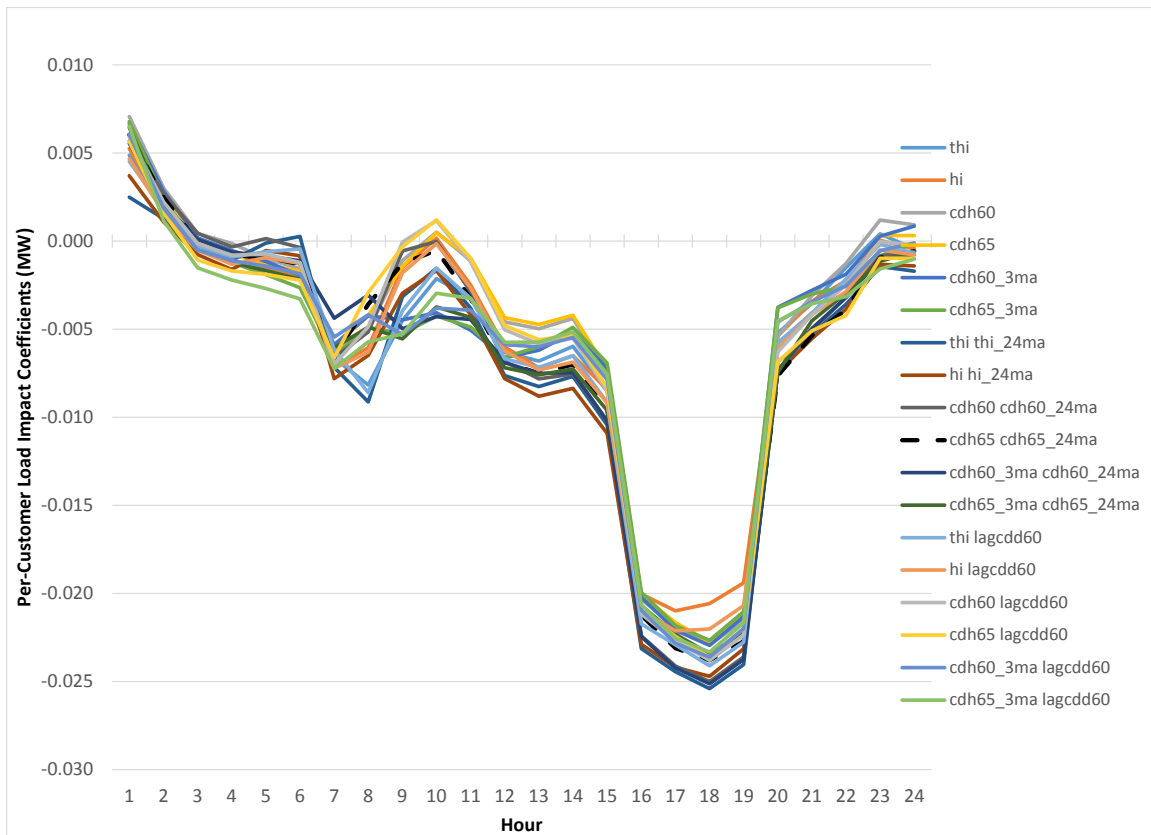


Figure 8–5: Average Event-Hour Load Impacts by Specification, SDG&E CBP DO



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

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

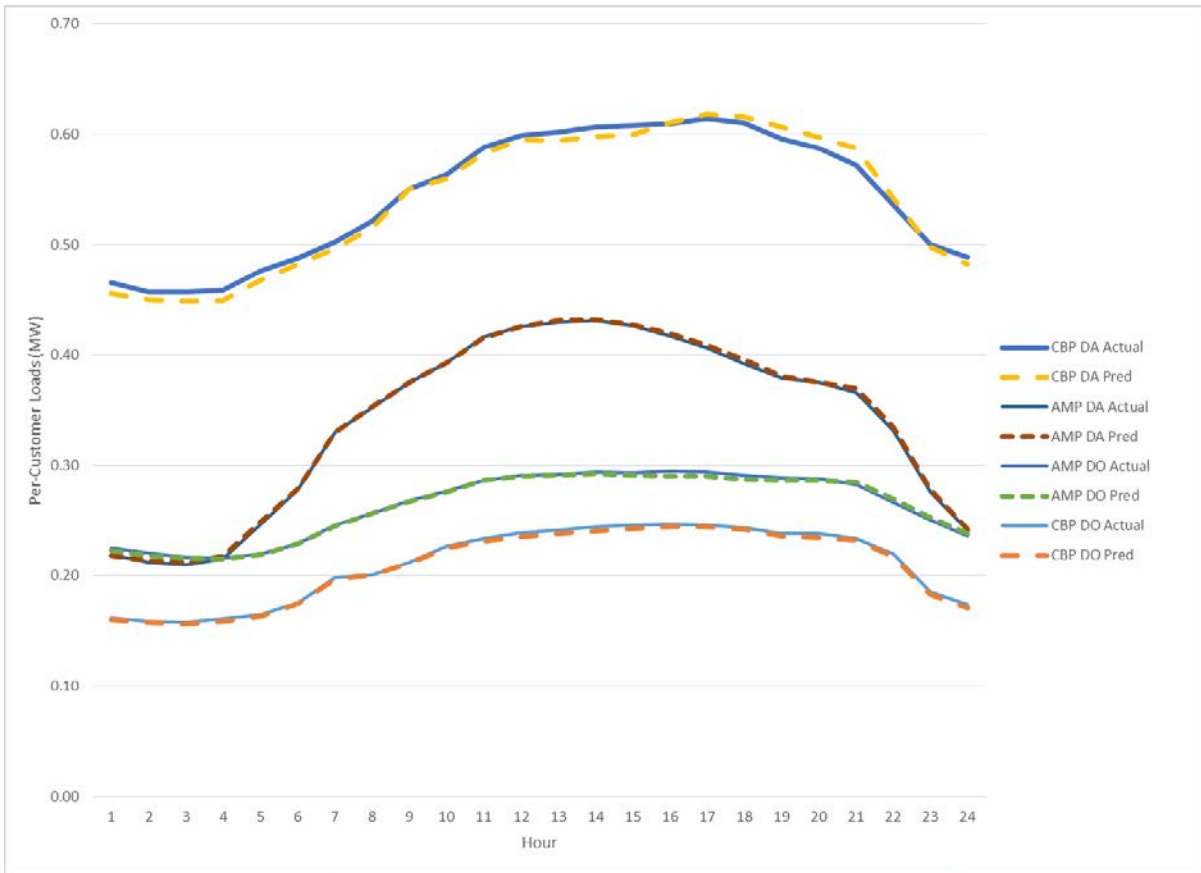
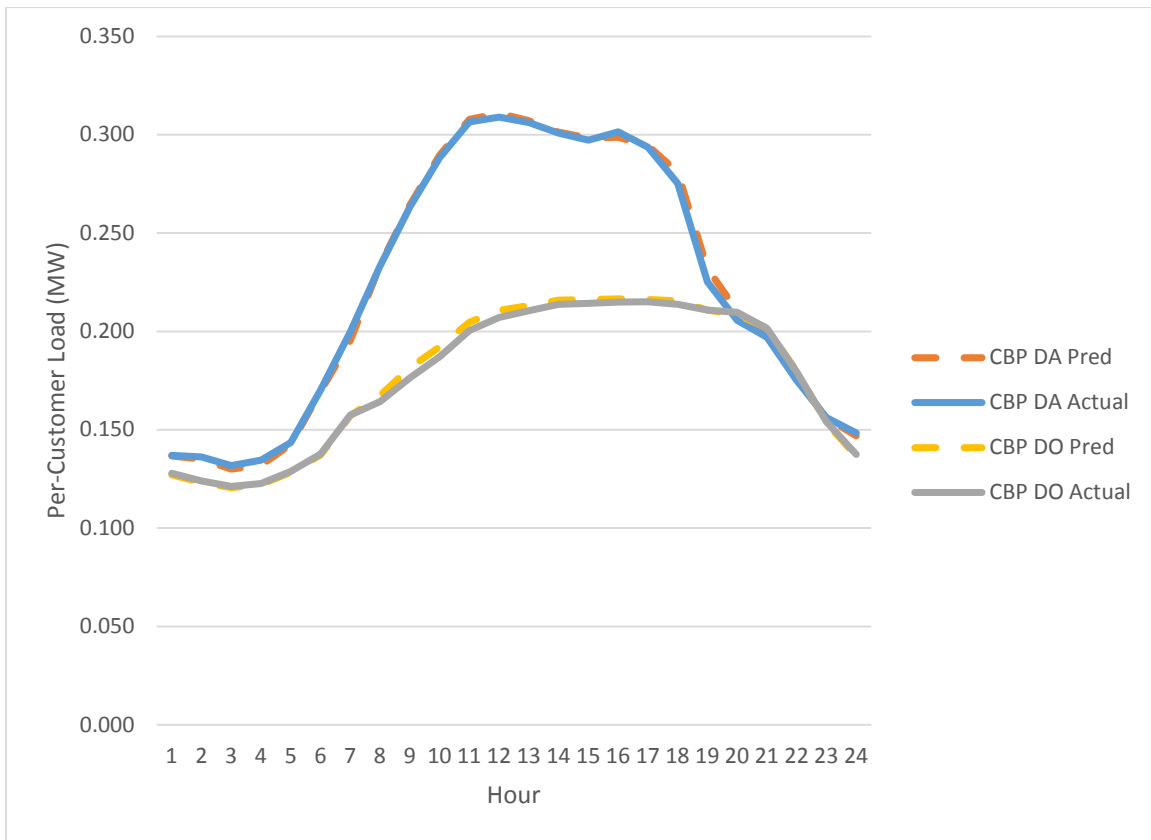


Figure 8–8: Average Predicted and Observed Loads on Event-like Days, SDG&E



8.3 Modifications to Customer-Level Model Results

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 to modify the estimated load impacts for only two service accounts as a result of these inspections. These were for one large PG&E CBP customer whose loads on two event days led the model to estimate load *increases*, whereas an inspection of the data indicated that the customer simply did not reduce load. Thus the load impacts were set to zero.

9. RECOMMENDATIONS

Given the move toward occasional locational dispatch of aggregator events, the DRMEC may want to consider reporting load impacts by sub-LAP (or other relevant location identifiers) in addition to the current LCA.

APPENDICES

The following Appendices accompany this report. All are Excel files that can produce the tables required by the Protocols.

Aggregator Study Appendix A
Aggregator Study Appendix B
Aggregator Study Appendix C
Aggregator Study Appendix D
Aggregator Study Appendix E
Aggregator Study Appendix F
Aggregator Study Appendix G
Aggregator Study Appendix H
Aggregator Study Appendix I
Aggregator Study Appendix J

PG&E CBP Ex-Post Load Impact Tables
SCE CBP Ex-Post Load Impact Tables
SDG&E CBP Ex-Post Load Impact Tables
PG&E AMP Ex-Post Load Impact Tables
SCE AMP Ex-Post Load Impact Tables
PG&E CBP Ex-Ante Load Impact Tables
SCE CBP Ex-Ante Load Impact Tables
SDG&E CBP Ex-Ante Load Impact Tables
PG&E AMP Ex-Ante Load Impact Tables
SCE AMP Ex-Ante Load Impact Tables