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**2009 Load Impact
Evaluation of California
Statewide Aggregator
Demand Response
Programs: *Ex Post and Ex
Ante Report***

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

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

Voice 608.231.2266 Fax 608.231.2108

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

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

Voice 608.231.2266 Fax 608.231.2108

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Abstract

This report documents the results of an ex post and ex ante load impact evaluation of aggregator demand response (DR) programs operated by the three major 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 2009. The scope of this evaluation covered three price-responsive programs, including the state-wide Capacity Bidding Program (“CBP”) operated by all three IOUs, Aggregator Managed Portfolio (“AMP”) operated by PG&E, and Demand Response Resource Contracts (“DRC”), operated by SCE. Program options of *day-ahead* (DA) and *day-of* (DO) notice were offered by each program.

In these programs, aggregators contract with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a “portfolio” of individual customer accounts such that their aggregated load participates in the DR programs.

Enrollment in the various programs and program types typically ranged from about 150 to 700 customer accounts. With the exception of PG&E’s CBP program, enrollment in the DO program type generally exceeded that in the corresponding DA program type. The largest enrollment was in SCE’s DRC day-of program, at more than 1,200 customer accounts. However, not all of them were typically nominated in any given month.

The number of events called in 2009 varied considerably across utilities and program types. Some, such as PG&E CBP and AMP, and SCE DRC were called only once or twice for test events. In contrast, SDG&E’s CBP DA and DO were called 6 and 7 times respectively, and SCE’s CBP DA was called twenty-six times.

Ex post hourly load impacts were estimated for each program and event, using regression analysis of hourly customer-specific load, weather, and event data. Estimated load impacts were reported at the program level for each event, for both program types (DA and DO). Load impacts for the average event were also reported by industry type and CAISO local capacity area where relevant. Ex ante load impacts for 2010 through 2020 were developed using reference load profiles and per-customer load impacts generated from the ex post load impact results, along with enrollment forecasts provided by the utilities.

Estimated *ex post* load impacts on an average hourly basis for the average event for the statewide CBP program at PG&E, SCE and SDG&E were 21.5 MW, 0.8 MW, and 10.3 MW respectively, for the DA option, and 22.4 MW, 25.4 MW, and 12.5 MW for the DO option. Average hourly load impacts for PG&E’s AMP DA and DO program types were 38.5 MW and 83.9 MW, while those for SCE’s DRC DA and DO program types were 3.9 MW and 63.6 MW.

Based on anticipated aggregator contract quantities and changes in enrollments, estimated average hourly *ex ante* load impacts for 2012, for a typical event day in a 1-in-2 weather

scenario, are the following: For PG&E's CBP DA and DO options – 13.8 MW and 39.7 MW; for SCE's CBP DA and DO options – 0.7 MW and 13.3 MW; and for SDG&E's CBP DA and DO options – 11.6 MW and 17.1 MW. Finally, for PG&E's AMP DA and DO options, the expected average hourly load impacts are 57.2 MW and 151.8 MW, for SCE's DRC DA and DO options – 3 MW and 131 MW, and for SDG&E's new AMP DO program type – 36.5 MW.

Executive Summary

This report documents the results of an 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 2009. In these programs, aggregators contract with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a “portfolio” of individual customers such that their aggregated load participates in the DR programs. Aggregators enroll and nominate customers in a mix of day-ahead (“DA”) and day-of (“DO”) program types.

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

The primary goals of this evaluation study were the following:

1. Estimate the *ex post* load impacts for program year 2009; and
2. Estimate *ex ante* load impacts for the programs for 2010 through 2020

ES.1 Program Resources

CBP

The statewide CBP program provides monthly capacity payments (\$/kW) based on amounts of load reductions that participating aggregators elect each month, plus additional energy payments (\$/kWh) based on the actual kWh reductions (relative to the program baseline) that are achieved when an event is called.¹ Participants may adjust their nomination each month, as well as their choice of available event type and window options (e.g., *day-ahead* or *day-of* events, and 4-hour, 6-hour or 8-hour event lengths). 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. Baseline loads, which serve as the basis for calculating load reductions for settlement, are calculated on the summed loads of an aggregated group of customers, based on the “highest 3-in-10” method.

PG&E had six CBP aggregators at the time of its one test event in July. For that month, two aggregators nominated DA products only, three nominated DO products only, and one nominated both DA and DO products. Three of SCE’s six aggregator contracts offer DO portfolios, two offer DA portfolios, and one aggregator offers both DA and DO portfolios. SDG&E has four CBP aggregators that offer DA products, one that offers DO products, and one that offers both types.

PG&E called one CBP event in 2009, in which both *day-ahead* and *day-of* program-types were called. SCE called twenty-six DA events, two of which were also called as DO events. SDG&E called nine events, some of which were DA only, some DO only, and for

¹ Capacity Payment Adjustments may be applied for performance of less than 100 percent of the nominated amount.

some events both program types were called. Events were also called for varying time periods.

AMP

PG&E has five AMP aggregator contracts. Four aggregators offer DO products, while one offers DA products. Under AMP, aggregators may create their own aggregated DR program by which participating customers achieve load reductions. Up to 50 hours of events may be called each year, during the hours of 11 a.m. and 7 p.m. Three AMP events were called in 2009, but the second one was not included in the analysis because only one aggregator, with only one nominated customer account, was called. In the first and third events, both DA and DO program types were called.

DRC

SCE has five DRC aggregators, three of which offered only DO contracts in 2009, one that offered only DA contracts, and one that offered both types. The terms of DRC are similar to those of SCE's CBP program.

Program enrollment

Tables ES.1 through ES.4 summarize 2009 program enrollment in the DA and DO program types across all five aggregator programs at the three utilities.² The first two tables show enrollment in terms of number of customer service accounts (SA IDs), while the second two show enrollment in terms of megawatts (MW) of maximum demand.³

With the exception of PG&E's CBP program, the DO program type generally has substantially greater numbers of customer accounts and larger amounts of load than the DA program type.⁴ The DA program types at several of the utilities have substantial shares of customers and load in the Manufacturing, and Offices, Hotels, Health and Services industry groups. The DO program types at each of the utilities have attracted a large number of Retail stores, and the AMP and DRC DO program types have enrolled substantial load in the Manufacturing; Wholesale, Transport and other Utilities (primarily water utilities); and Offices, Hotels, Health and Services industry groups.

² Determining which program type CBP customer accounts were enrolled in was only clear-cut for those who were nominated for at least one month in one of the DA or DO program options. The minority of customer accounts who were never nominated were generally assigned to the DO program type.

³ Note that the maximum demand values are provided to illustrate the size, or scale of the total load of enrolled customers. It does not reflect "subscribed demand", which is a measure of potential load impacts.

⁴ One PG&E aggregator offered the DA option to several hundred relatively small customer accounts in the San Francisco area.

**Table ES.1: Aggregator Program Enrollment – Day-Ahead Program Types
(Customer Accounts)**

Industry Type	CBP			AMP	DRC
	PG&E	SCE	SDG&E	PG&E	SCE
1. Agriculture, Mining & Construction	29	0		33	
2. Manufacturing	97	1	35	126	3
3. Wholesale, Transport, other Utilities	50	0	9	20	25
4. Retail stores	118	76	1	1	130
5. Offices, Hotels, Health, Services	219	0	80	33	4
6. Schools	57	0	2	45	
7. Entertainment, Other Services, Gov't	98	0	4	13	3
8. Other/Unknown	12			2	
Total	680	77	131	273	165

**Table ES.2: Aggregator Program Enrollment – Day-Of Program Types
(Customer Accounts)**

Industry Type	CBP			AMP	DRC
	PG&E	SCE	SDG&E	PG&E	SCE
1. Agriculture, Mining & Construction	21	2		156	18
2. Manufacturing	5	19	3	105	67
3. Wholesale, Transport, other Utilities	22	25	24	112	707
4. Retail stores	180	490	189	131	355
5. Offices, Hotels, Health, Services	15	63	46	144	49
6. Schools	10		5	9	19
7. Entertainment, Other Services, Gov't	24	4	33	14	17
8. Other/Unknown	3			1	
Total	280	603	300	672	1232

**Table ES.3: Aggregator Program Enrollment – Day-Ahead Program Types
(MW of Maximum Demand)**

Industry Type	CBP			AMP	DRC
	PG&E	SCE	SDG&E	PG&E	SCE
1. Agriculture, Mining & Construction	8.3	0.0	0.0	8.7	0.0
2. Manufacturing	56.9	1.7	21.6	161.4	1.8
3. Wholesale, Transport, other Utilities	7.3	0.0	2.2	12.2	13.8
4. Retail stores	7.7	7.5	0.0	0.3	43.2
5. Offices, Hotels, Health, Services	44.2	0.0	23.2	20.9	1.4
6. Schools	27.1	0.0	3.1	16.6	0.0
7. Entertainment, Other Services, Gov't	10.1	0.0	1.1	10.3	0.8
8. Other/Unknown	1.5	0.0	0.0	1.5	0.0
Total	163.1	9.2	51.2	232.0	61.1

**Table ES.4: Aggregator Program Enrollment – Day-Of Program Types
(MW of Maximum Demand)**

Industry Type	CBP			AMP	DRC
	PG&E	SCE	SDG&E	PG&E	SCE
1. Agriculture, Mining & Construction	25.4	0.6	0.0	85.4	6.8
2. Manufacturing	11.3	6.9	1.8	101.5	71.6
3. Wholesale, Transport, other Utilities	8.9	7.6	10.5	87.5	165.5
4. Retail stores	65.4	138.7	49.9	61.5	132.6
5. Offices, Hotels, Health, Services	6.3	23.8	17.9	105.5	33.2
6. Schools	6.7	0.0	15.6	52.0	44.9
7. Entertainment, Other Services, Gov't	2.3	1.2	5.8	10.7	9.0
8. Other/Unknown	0.1	0.0	0.0	0.0	0.0
Total	126.4	178.8	101.4	504.1	463.4

ES.2 Evaluation Methodology

Estimates of total program-level load impacts for each program were developed from the coefficients of individual customer regression equations. These equations were estimated over the summer months for 2009, using individual customer load data for all customer accounts enrolled in each program.

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

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours)
- Event indicators—Event indicators, which were invoked when a given customer’s program type was called, were interacted with hourly indicator variables to allow estimation of hourly load impacts for each event.

The resulting equations provide the capability of measuring hourly load impacts on event days, as well as simulating hourly reference load profiles for various day-types and weather conditions. In addition, the customer-specific equations provide the capability to summarize load impacts by industry type and CAISO local capacity area, by adding across customers in any given category, and to analyze the effect of TA/TI and AutoDR participation. Finally, uncertainty-adjusted load impacts were calculated to illustrate the degree of uncertainty that exists around the estimated load impacts.

ES.3 Detailed Study Findings

Summary of ex-post program load impacts

Table ES.5 summarizes estimates of average hourly ex post load impacts for PY 2009 for the average event for each of the three utilities’ aggregator programs and program types (*e.g.*, *day-ahead* and *day-of*).

Table ES.5: Aggregator Program Average Hourly Load Impacts (MW) – by Utility and Program Type (2009)

Program Utility/ Program- type	CBP		AMP/DRC		Total	
	DA	DO	DA	DO	DA	DO
PG&E	21.5	22.4	38.5	83.9	60.0	106.3
SCE	0.8	25.4	3.9	63.6	4.7	89.0
SDG&E	10.3	12.5			10.3	12.5
Total	32.5	60.3	42.4	147.5	74.9	207.9

The utilities have asked for a summary indicator of average event-hour load impacts per enrolled customer for each program and program type. They are the following:

1. PG&E CBP DA – 32 kW
2. PG&E CBP DO – 80 kW
3. SCE CBP DA – 10 kW
4. SCE CBP DO – 42 kW

5. SDG&E CBP DA – 78 kW
6. SDG&E CBP DO – 42 kW
7. PG&E AMP DA – 141 kW
8. PG&E AMP DO – 125 kW
9. SCE DRC DA – 23 kW
10. SCE DRC DO – 52 kW.

Effects of TA/TI and AutoDR

This evaluation included assessments of the load impacts associated with aggregator program customer accounts that participated in TA/TI or AutoDR programs. Two types of analysis were undertaken. First, we report average hourly load impacts for those service accounts that participated in TA/TI or AutoDR. Second, where sufficient numbers were available, we compared the load impacts of TA/TI and AutoDR customer accounts in specific business categories to those of non-TA/TI or AutoDR customer accounts in the same business categories (these accounts were often associated with a single customer, such as a large retailer with multiple stores). The latter comparisons were designed as the best opportunity to estimate *incremental* impacts of TA/TI and AutoDR. However, the samples of customer accounts were quite small, and the load impact comparisons were largely inconclusive due to considerable variability. In some cases, the load impacts for TA/TI and AutoDR customer accounts were greater than those of the comparison customer accounts, and in some cases they were smaller.

Summary of ex-ante enrollment and load impacts

Ex ante forecasts of load impacts for each utility and program type were produced based on per-customer load impacts calculated from the ex post evaluation results, and applied to enrollment forecasts provided by the utilities. The ex ante results include a new AMP DO contract at SDG&E, which involves an aggregator moving from CBP DO to the new AMP contract. Figure ES.1 compares enrolled customer accounts in 2009 to enrollment forecasts for 2012. Enrollment is expected to grow relatively faster for the AMP/DRC programs than for CBP.

Figure ES.1: Aggregator Program Enrollment (Customer Accounts) – by Utility and Program Type – 2009 and 2012

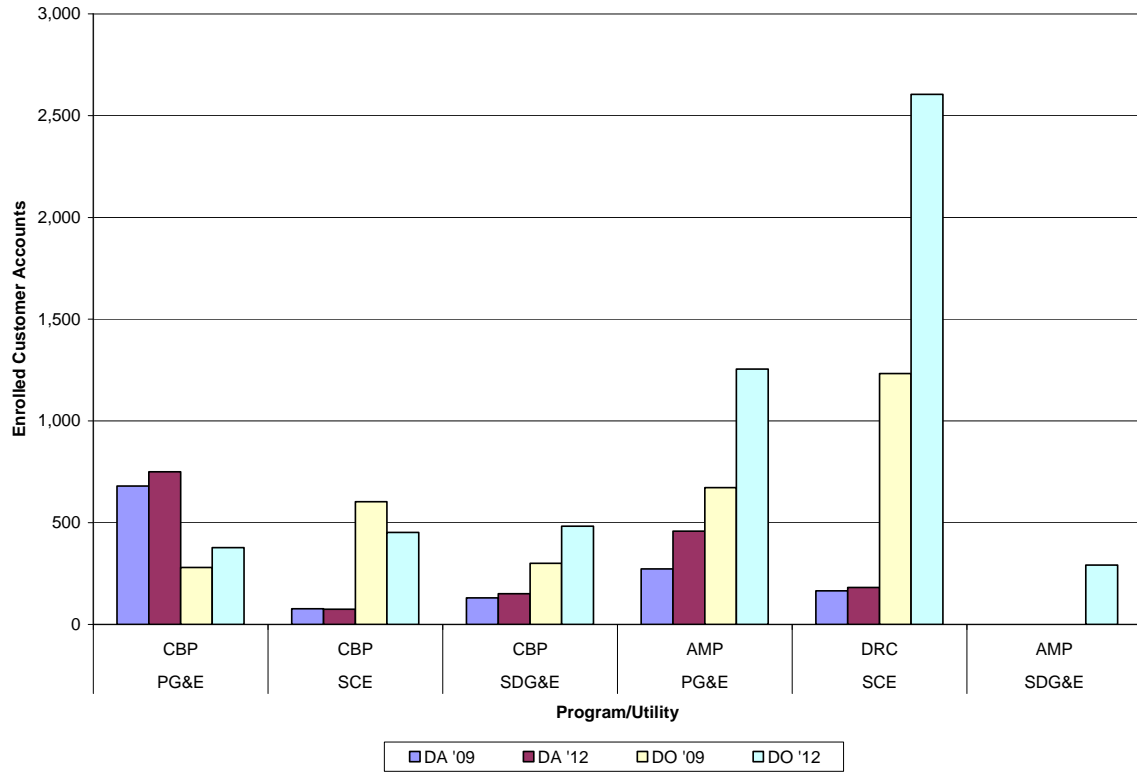
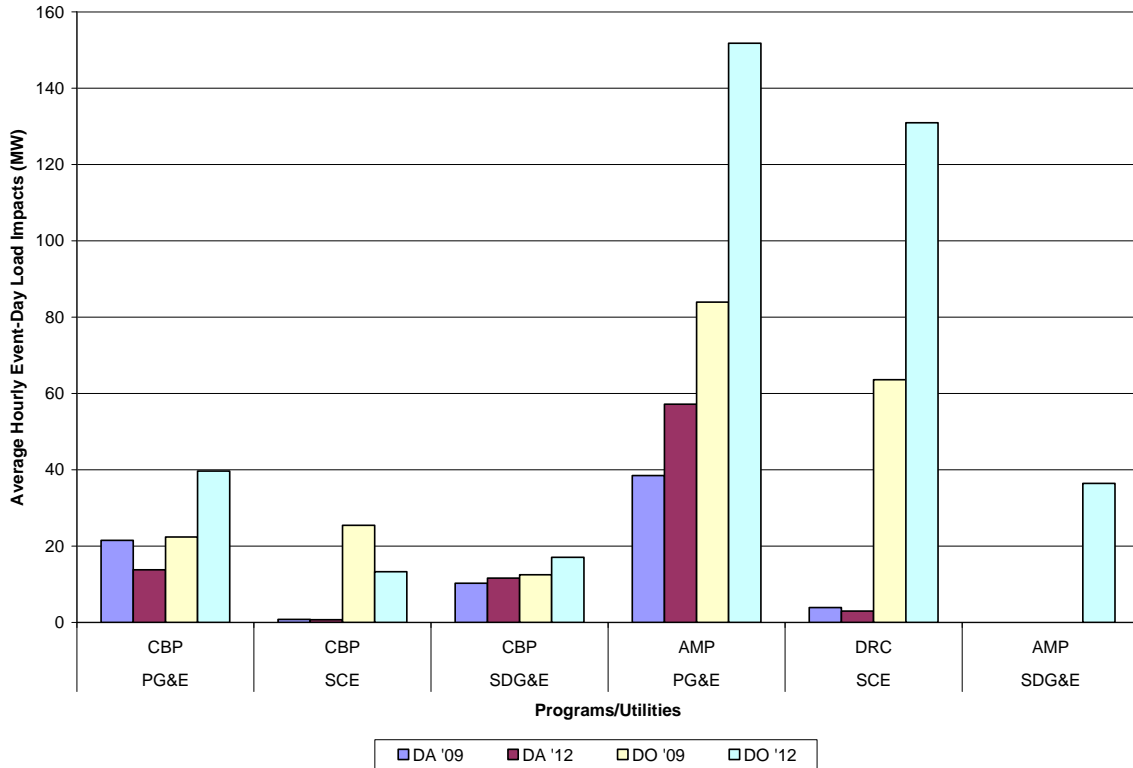


Figure ES.2 compares average hourly load impacts for a typical event day, by utility and program type, for 2009, as estimated in the ex-post evaluation, to those projected for 2012 in the 1-in-2 weather scenario of the ex-ante evaluation. Substantial growth is expected in the DO program types of PG&E and SDG&E’s AMP programs, and SCE’s DRC.

Table ES.7: Average-Hourly Load Impacts (MW) – by Utility and Aggregator Program – 2009 and 2012 (Typical Event Day in 1-in-2 Weather Year)



ES 4 Conclusions

The individual customer regression equations generally worked well in developing load impact estimates and providing the capability of summing across different customer types to produce load impacts at the program level, by industry type, and by CAISO local capacity area, as well as for supporting analysis of the effects of TA/TI participation. Changes in monthly enrollments and nominations across the summer period, particularly between CBP and the aggregator contract programs presented data management and analysis complications in conducting the ex post evaluation. However, we believe that the reported results accurately characterize the aggregator program load impacts in 2009. The total average hourly load impact of all of the aggregator programs combined across the three utilities, for an average event, amounted to nearly 75 MW for the *day-ahead* program type and 208 MW for the *day-of* program type.

1. Introduction and Purpose of the Study

This report documents the results of an evaluation of aggregator demand response (DR) programs operated by the three California investor-owned utilities (IOUs), San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas and Electric (PG&E) for Program Year 2009. In these programs, aggregators contract with non-residential customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a “portfolio” of individual customers such that their aggregated load participates in the DR programs. Aggregators receive both *capacity credits* for monthly nominated load reductions, and *energy payments* based on measured load reductions during events.

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

The primary goals of this evaluation study were the following:

1. Estimate the *ex post* load impacts for program year 2009; and
2. Estimate *ex ante* load impacts for the programs for 2010 through 2020

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

The second goal involved combining the information on historical *ex post* load impacts with utility projections of program enrollment to produce *forecasts of load impacts* for each of the programs through 2020.

After this introductory section, Section 2 describes the aggregator programs, including the characteristics of the enrolled customer accounts. Section 3 discusses evaluation methodology. Section 4 presents *ex post* load impacts. Section 5 describes the *ex ante* forecasts of enrollment and load impacts. Section 6 discusses validity assessment, and Section 7 offers recommendations.

2. Description of Resources Covered in the Study

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

2.1 Description of the aggregator programs

CBP

The CBP program provides monthly capacity payments (\$/kW) based on amounts of load reductions that participating aggregators nominate each month, plus additional energy payments (\$/kWh) based on the actual kWh reductions (relative to the program baseline) that are achieved when an event is called. Capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts.⁵

Participants may adjust their nomination each month, as well as their choice of available event type and window options (*e.g.*, day-ahead (DA) or day-of (DO) events, and 1 to 4, 2 to 6, or 4 to 8-hour events). 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.

Baseline loads, which serve as the basis for calculating load reductions for settlement, are calculated on the summed loads of an aggregated group of customers, based on the “highest 3-in-10” method. That is, the hourly baseline load during the event period is the hourly average across the *three* highest energy-usage (during program hours) days for the group out of the *ten* weekdays prior to the event (excluding holidays and previous event days). The “actual” load reduction in each hour is determined for settlement purposes as the difference between the baseline load and the observed aggregated load in that hour.

PG&E had six CBP aggregators at the time of its one test event in July. For that month, two aggregators nominated DA products only, three nominated DO products only, and one nominated both DA and DO products. Three of SCE’s six aggregator contracts offer DO portfolios, two offer DA portfolios, and one offers both DA and DO portfolios. SDG&E has four CBP aggregators that offer DA products, one that offers DO products, and one that offers both types.

AMP

PG&E has five AMP aggregator contracts. Four aggregators offer DO products, while one offers DA products. Under AMP, aggregators may create their own aggregated DR program by which participating customers achieve load reductions. Up to 50 hours of events may be called each year, during the hours of 11 a.m. and 7 p.m.

DRC

SCE has five DRC aggregators, three of which offered only DO contracts in 2009, one that offered only DA contracts, and one that offered both types. The terms of DRC are similar to those of SCE’s CBP program.

2.2 Participant characteristics

In order to assess the extent to which load impacts differ by customer type, the customers are categorized according to seven industry types. Table 2.1 indicates the industry groups

⁵ Capacity Payment Adjustments may be applied for performance of less than 100 percent of the nominated amount.

and the corresponding North American Industry Classification System (NAICS) codes.⁶ The following tables summarize the characteristics of the participating customer accounts in the aggregator programs, including industry type, local capacity area, and usage characteristics.

Table 2.1: Industry Group Definition

Industry Groups	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, Health, Services	51 - 56, 62, 72
6. Schools	61
7. Entertainment, Other Services, Government	71, 81, 92
8. Other/Unknown	

2.2.1 CBP

Tables 2.2 through 2.7 show enrollment by industry type for the DA and DO CBP program types, for PG&E, SCE, and SDG&E respectively. For purposes of these tables, customer accounts are included in the enrollment figures if they were reported as enrolled *for any month* during May through October of 2009. For PG&E and SCE, several aggregators have customers enrolled in both CBP and either AMP or DRC, and some have both DA and DO program types. Since nominations are made monthly, both enrollments and nominations are month specific. Also, customer accounts are sometimes moved between CBP and either AMP or DRC, and between DA and DO program types. The enrollment numbers in the tables below are generally based on conditions as of the month of the last event, as accounted for in the Protocol tables. The Protocol tables that are provided along with this report show the exact numbers of enrolled, nominated, and called customer accounts for each event, and for the typical event, for each utility and program type.

The first column in the tables reports the number of customer service accounts (SAIDs) that were enrolled in CBP during summer 2009. The second column, labeled “Mean kWh,” represents the sum of enrolled customers’ *average hourly usage* over the summer months. The third column, labeled “Max kW,” represents the sum of enrolled customers’ individual average (non-coincident) *maximum demand* values over the summer months. The fourth column, labeled “Peak kW,” shows average demand during non-holiday *summer weekday peak periods* (hours ending 13-18) on non-event days.⁷ The final two columns indicate the share of Max kW by industry type and the average size (kW) of the customer accounts in a given industry type, measured by maximum demand.

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

⁷ This statistic is designed as an approximation to the average hourly estimated reference load on event days that is reported in the Protocol tables.

The second to last columns in the enrollment tables indicate that the mix of industry types across utilities and program types varies considerably. Of note, Retail stores make up a large share of CBP DO enrolled load at each of the utilities, as well as for the DA program type at SCE. For PG&E and SDG&E DA program types, Manufacturing, and Offices, Hotels, Health and Services are important industry groups, while for SCE DO the latter is the second most important industry type. In addition, CBP customer accounts tend to be relatively small, averaging around 300 kW in maximum demand.

Table 2.2: Enrollment by Industry group – PG&E CBP DA

Industry Type	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Ave size
1. Agriculture, Mining & Construction	29	3,468	8,314	4,398	5%	287
2. Manufacturing	97	33,204	56,927	40,256	35%	587
3. Wholesale, Transport, other Utilities	50	3,301	7,273	3,351	4%	145
4. Retail stores	118	3,918	7,729	5,807	5%	66
5. Offices, Hotels, Health, Services	219	24,395	44,232	34,227	27%	202
6. Schools	57	13,719	27,056	17,497	17%	475
7. Entertainment, Other Services, Gov't	98	5,096	10,080	6,966	6%	103
8. Other/Unknown	12	865	1,460	1,090	1%	122
Total	680	87,966	163,071	113,594	100%	240

Table 2.3: Enrollment by Industry group – PG&E CBP DO

Industry Type	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Ave size
1. Agriculture, Mining & Construction	21	17,504	25,426	20,812	20%	1,211
2. Manufacturing	5	7,847	11,317	9,770	9%	2,263
3. Wholesale, Transport, other Utilities	22	3,901	8,890	4,863	7%	404
4. Retail stores	180	42,692	65,434	53,510	52%	364
5. Offices, Hotels, Health, Services	15	3,470	6,254	5,269	5%	417
6. Schools	10	3,205	6,734	4,588	5%	673
7. Entertainment, Other Services, Gov't	24	945	2,255	1,192	2%	94
8. Other/Unknown	3	54	128	82	0%	43
Total	280	79,617	126,439	100,086	100%	452

Table 2.4: Enrollment by Industry group – SCE CBP DA

Industry Type	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction	0	0	0	0	0%	
2. Manufacturing	1	831	1,720	1,045	19%	1,720
3. Wholesale, Transport, other Utilities	0	0	0	0	0%	
4. Retail stores	76	3,925	7,480	5,865	81%	98
5. Offices, Hotels, Health, Services	0	0	0	0	0%	
6. Schools	0	0	0	0	0%	
7. Entertainment, Other Services, Gov't	0	0	0	0	0%	
Total	77	4,756	9,200	6,910	100%	119

Table 2.5: Enrollment by Industry group – SCE CBP DO

Industry Type	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction	2	263	578	384	0%	289
2. Manufacturing	19	2,966	6,865	3,796	4%	361
3. Wholesale, Transport, other Utilities	25	4,585	7,571	4,591	4%	303
4. Retail stores	490	97,339	138,738	114,303	78%	283
5. Offices, Hotels, Health, Services	63	12,534	23,778	14,631	13%	377
6. Schools						
7. Entertainment, Other Services, Gov't	4	475	1,248	615	1%	312
Total	603	118,162	178,778	138,320	100%	296

Table 2.6: Enrollment by Industry group – SDG&E CBP DA

Industry Groups	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% Max kW	Average Size
1. Agriculture, Mining & Construction						
2. Manufacturing	35	11,464	21,637	15,565	42%	618
3. Wholesale, Transport, other Utilities	9	877	2,161	614	4%	240
4. Retail stores	1	12	27	22	0%	27
5. Offices, Hotels, Health, Services	80	12,232	23,204	18,095	45%	290
6. Schools	2	1,629	3,081	1,767	6%	1,540
7. Entertainment, Other Services, Gov't	4	777	1,119	871	2%	280
Total	131	26,992	51,230	36,933	100%	391

Table 2.7: Enrollment by Industry group – SDG&E CBP DO

Industry Groups	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% Max kW	Average Size
1. Agriculture, Mining & Construction						
2. Manufacturing	3	920	1,799	1,278	2%	600
3. Wholesale, Transport, other Utilities	24	4,084	10,498	2,779	10%	437
4. Retail stores	189	34,264	49,854	43,098	49%	264
5. Offices, Hotels, Health, Services	46	10,175	17,938	12,394	18%	390
6. Schools	5	3,118	15,553	3,578	15%	3,111
7. Entertainment, Other Services, Gov't	33	3,586	5,796	4,210	6%	176
Total	300	56,148	101,438	67,338	100%	338

Tables 2.8 through 2.11 show CBP DA and DO enrollment by CAISO Local Capacity Area (LCA) for PG&E and SCE.⁸

⁸ The entire SDG&E service area is considered to be one local capacity area.

Table 2.8: Enrollment by Local Capacity Area – PG&E CBP DA

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Ave size
Greater Bay Area	524	48,795	89,510	65,954	55%	171
Greater Fresno	24	7,586	14,008	9,218	9%	584
Humboldt	1	29	55	47	0%	55
Kern	1	36	69	56	0%	69
Northern Coast	19	2,369	4,937	3,186	3%	260
Sierra	20	2,209	6,369	3,528	4%	318
Stockton	9	1,059	2,175	1,494	1%	242
Not in any LCA	82	25,883	45,947	30,112	28%	560
Total	680	87,966	163,071	113,594	100%	240

Table 2.9: Enrollment by Local Capacity Area – PG&E CBP DO

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Ave size
Greater Bay Area	141	25,941	40,486	32,401	32%	287
Greater Fresno	36	8,108	15,483	10,744	12%	430
Humboldt	2	955	1,554	1,413	1%	777
Kern	16	4,090	7,486	5,218	6%	468
Northern Coast	16	4,402	6,703	5,352	5%	419
Sierra	13	3,047	4,839	3,854	4%	372
Stockton	9	2,951	5,010	4,140	4%	557
Not in any LCA	47	30,124	44,878	36,965	35%	955
Total	280	79,617	126,439	100,086	100%	452

Table 2.10: Enrollment by Local Capacity Area – SCE CBP DA

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
LA Basin	60	3,248	6,178	4,750	67%	103
Outside LA Basin	5	226	428	386	5%	86
Ventura	12	1,282	2,594	1,774	28%	216
Total	77	4,756	9,200	6,910	100%	119

Table 2.11: Enrollment by Local Capacity Area – SCE CBP DO

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
LA Basin	497	94,772	144,426	110,621	81%	291
Outside LA Basin	36	8,674	12,389	10,435	7%	344
Ventura	70	14,716	21,963	17,264	12%	314
Total	603	118,162	178,778	138,320	100%	296

2.2.2 AMP and DRC

Tables 2.12 through 2.19 show comparable enrollment information for PG&E’s AMP DA and DO program types, and SCE’s DRC DA and DO program types. PG&E’s AMP DA has a large share of Manufacturing customers, while DO enrollment is spread over several

industry types. DRC DA and DO have large shares in the Wholesale, Transportation and other Utilities, and Retail industry groups.

Table 2.12: Enrollment by Industry Group – PG&E AMP DA

Industry Group	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction	33	3,043	8,747	3,783	4%	265
2. Manufacturing	126	104,831	161,444	117,978	70%	1,281
3. Wholesale, Transport, other Utilities	20	5,842	12,198	5,566	5%	610
4. Retail stores	1	105	255	150	0%	255
5. Offices, Hotels, Health, Services	33	12,377	20,923	16,193	9%	634
6. Schools	45	7,009	16,644	10,903	7%	370
7. Entertainment, Other Services, Gov't	13	7,544	10,336	8,459	4%	795
8. Other/Unknown	2	712	1,488	816	1%	744
Total	273	141,462	232,034	163,849	100%	850

Table 2.13: Enrollment by Industry Group – PG&E AMP DO

Industry Group	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction	156	53,185	85,445	59,903	17%	548
2. Manufacturing	105	55,610	101,510	67,734	20%	967
3. Wholesale, Transport, other Utilities	112	53,455	87,495	57,285	17%	781
4. Retail stores	131	38,408	61,483	48,650	12%	469
5. Offices, Hotels, Health, Services	144	56,830	105,460	78,544	21%	732
6. Schools	9	25,048	52,002	30,426	10%	5,778
7. Entertainment, Other Services, Gov't	14	6,862	10,669	8,387	2%	762
8. Other/Unknown	1	2	15	3	0%	15
Total	672	289,401	504,080	350,930	100%	750

Table 2.14: Enrollment by Local Capacity Area – PG&E AMP DA

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
Greater Bay Area	81	39,265	60,203	47,515	26%	743
Greater Fresno	34	15,777	28,039	18,856	12%	825
Humboldt						
Kern						
Northern Coast	25	5,919	11,418	7,456	5%	457
Sierra	26	4,189	10,096	6,141	4%	388
Stockton	11	8,301	12,349	9,473	5%	1,123
Not in any LCA	96	68,011	109,930	74,406	47%	1,145
Total	273	141,462	232,034	163,849	100%	850

Table 2.15: Enrollment by Local Capacity Area – PG&E AMP DO

Local Capacity Area	Num. of SAIDs	Mean kWh	Max kW	Peak kW	% of Max kW	Average Size
Greater Bay Area	226	84,008	157,930	115,941	31%	699
Greater Fresno	152	46,640	93,495	53,095	19%	615
Humboldt	8	4,113	7,077	5,342	1%	885
Kern	38	37,118	49,779	39,631	10%	1,310
Northern Coast	47	9,321	19,239	12,521	4%	409
Sierra	21	9,331	13,912	10,550	3%	662
Stockton	25	9,203	19,287	10,896	4%	771
Not in any LCA	155	89,667	143,361	102,953	28%	925
Total	672	289,401	504,080	350,930	100%	750

Table 2.16: Enrollment by Industry group – SCE DRC DA

Industrial Group	Num. of SAIDs	Mean kW	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction						
2. Manufacturing	3	850	1,834	1,186	3%	611
3. Wholesale, Transport, other Utilities	25	8,289	13,833	7,072	23%	553
4. Retail stores	130	20,557	43,244	33,006	71%	333
5. Offices, Hotels, Health, Services	4	618	1,386	806	2%	347
6. Schools						
7. Entertainment, Other Services, Gov't	3	369	786	548	1%	262
Total	165	30,683	61,083	42,619	100%	370

Table 2.17: Enrollment by Industry group – SCE DRC DO

Industrial Group	Num. of SAIDs	Mean kW	Max kW	Peak kW	% of Max kW	Average Size
1. Agriculture, Mining & Construction	18	2,850	6,755	3,549	1%	375
2. Manufacturing	67	41,926	71,570	47,868	15%	1,068
3. Wholesale, Transport, other Utilities	707	100,742	165,475	91,456	36%	234
4. Retail stores	355	91,007	132,555	110,609	29%	373
5. Offices, Hotels, Health, Services	49	19,000	33,151	20,986	7%	677
6. Schools	19	29,902	44,886	36,136	10%	2,362
7. Entertainment, Other Services, Gov't	17	4,263	9,026	4,760	2%	531
Total	1,232	289,689	463,418	315,363	100%	376

Table 2.18: Enrollment by LCA – SCE DRC DA

Local Capacity Area	Num. of SAIDs	Mean kW	Max kW	Peak kW	% of Max kW	Average Size
LA Basin	136	26,006	52,382	35,324	86%	385
Outside LA Basin	9	1,161	2,111	1,964	3%	235
Ventura	20	3,516	6,590	5,331	11%	330
Total	165	30,683	61,083	42,619	100%	370

Table 2.19: Enrollment by LCA – SCE DRC DO

Local Capacity Area	Num. of SAIDs	Mean kW	Max kW	Peak kW	% of Max kW	Average Size
LA Basin	905	216,626	348,334	236,716	75%	385
Outside LA Basin	212	23,674	40,055	22,447	9%	189
Ventura	115	49,389	75,029	56,200	16%	652
Total	1,232	289,689	463,418	315,363	100%	376

2.3 Program events

2.3.1 CBP

PG&E called one CBP event in 2009, on July 27, as shown in Table 2.20. Both *day-ahead* and *day-of* program types were called. The DA event was nominally called for hours-ending 14 to 15, while the DO event was called for hours-ending 16-18. However, one of the DA aggregators inadvertently notified its customers that the event hours were HE 15 to 16. The average-hourly and hourly load impacts reported in Section 4 below account for the actual event hours faced by each DA customer account.

Table 2.20: PG&E CBP Events – 2009

Event #	Date	Type	Aggregators	Hours
1	July 27, 2009	DA	2	14 - 15
		DA	1	15 - 16
		DO	4	16 - 18

SCE called twenty-six events, as shown in Table 2.21. All included DA program types, while two were also called as DO events (one being a test event). SDG&E called nine events, as shown in Table 2.22. Some events were DA only, some DO only, and for some both program types were called. Events were also called for varying time periods, as indicated in the table.

Table 2.21: SCE CBP Events – 2009

Event #	Date	Type	Event Hours	Duration
1	July 14, 2009	DA	15 - 17	3 hrs
2	July 15, 2009	DA	14 - 18	5 hrs
3	July 16, 2009	DA	15 - 17	3 hrs
4	July 17, 2009	DA	15 - 18	4 hrs
5	July 20, 2009	DA	15 - 17	3 hrs
6	July 21, 2009	DA	15 - 17	3 hrs
7	July 23, 2009	DA	16	1 hr
8	July 27, 2009	DA	16	1 hr
9	July 28, 2009	DA	15 - 17	3 hrs
10	August 4, 2009	DA	16 - 17	2 hrs
11	August 11, 2009	DA	16 - 17	2 hrs
12	August 12, 2009	DA	16 - 17	2 hrs
13	August 13, 2009	DA	16 - 17	2 hrs
14	August 14, 2009	DA	16	1 hr
15	August 17, 2009	DA	16 - 17	2 hrs
16	August 19, 2009	DA	16 - 17	2 hrs
17	August 27, 2009	DA	14 - 19	6 hrs
		DO (Test)	15 - 18	4 hrs
18	August 28, 2009	DA	15 - 18	4 hrs
		DO	15 - 18	4 hrs
19	August 31, 2009	DA	15 - 17	3 hrs
20	September 1, 2009	DA	14 - 18	5 hrs
21	September 2, 2009	DA	15 - 18	4 hrs
22	September 3, 2009	DA	15 - 18	4 hrs
23	September 4, 2009	DA	15 - 18	4 hrs
24	September 8, 2009	DA	15 - 18	4 hrs
25	September 9, 2009	DA	16 - 17	2 hrs
26	September 10, 2009	DA	16 - 17	2 hrs

Table 2.22: SDG&E CBP Events – 2009

Event	Date	Number of Contracts		Contract Types -- Hours Ending (Num. of Contracts)		
		DA	DO	DA	DO	
1	July 21, 2009	0	9		15-18 (9)	
2	August 26, 2009	0	9		14-17 (9)	
3	August 27, 2009	4	9	15-18	15-18 (7)	14-19 (2)
4	August 28, 2009	4	9	15-18	15-18 (7)	14-19 (2)
5	September 2, 2009	0	9		16-19 (9)	
6	September 3, 2009	4	9	15-18	15-18 (4)	14-19 (3) 13-19 (2)
7	September 4, 2009	4	0	15-18		
8	September 24, 2009	4	9	14-17	14-17 (4)	13-18 (3) 14-18 (2)
9	September 25, 2009	4	0	14-17		

2.3.2 AMP and DRC

Tables 2.23 and 2.24 list the events for PG&E’s AMP and SCE’s DRC programs, respectively. Three AMP events were called, all of which were test events. However, the

second event was not included in the analysis because only one aggregator, with only one nominated customer account, was called. SCE called one DRC DA event and one DO event, each of which was a monitoring and evaluation (M&E) test event.

Table 2.23: AMP (PG&E) Events (Test) – 2009

Event #	Date	Type	Aggregators	Hours
1	July 16, 2009	DA	1	16 - 17
		DO	3	16 - 17
2	July 27, 2009	DO	1	
3	August 28, 2009	DA	1	16 - 17
		DO	3*	15 - 16

* Includes two of the three aggregators in Event 1

Table 2.24: DRC (SCE) Events – 2009

Event #	Date	Type	Event Hours	Duration
1	July 14, 2009	DA (M&E)	15 - 17	3 hrs
2	September 23, 2009	DO (M&E)	15 - 16	2 hrs

3. Study Methodology

3.1 Overview and questions addressed

Direct estimates of total program-level ex post load impacts for each program were developed from the coefficients of individual customer regression equations. These equations were estimated over the summer months for 2009, primarily by using individual data for all customer accounts enrolled in each program. In some cases, aggregate equations were also estimated, for diagnostic purposes and cross checking of results.

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

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, hourly CDH)
- Event indicators—Event indicators, combined with information on which customer accounts were nominated in each month for a program type (*e.g.*, day-of program for two to four hours), and which program types were called for each event, were interacted with hourly indicator variables to allow estimation of hourly load impacts for each event.

The resulting equations provide the capability of simulating hourly reference load profiles for various day-types and weather conditions, as well as measuring hourly load changes on event days. The models use the *level* of hourly usage as the dependent variable and a separate equation is estimated for each enrolled and nominated customer. As a result, the

coefficients on the event day/hour variables are direct estimates of the ex post load impacts. For example, a CBP hour-14 coefficient of -100 for Event 1 means that the customer reduced load by 100 kWh during hour 14 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.⁹ Finally, uncertainty-adjusted load impacts were calculated to illustrate the degree of statistical confidence that exists around the estimated load impacts.

3.2 Primary regression equation specifications

Ex post load impacts were estimated using customer-level hourly data from May through October. The primary regression model is characterized as follows:

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

In this equation, Q_t represents the demand in hour t for a customer nominated in the month of the event date; the b 's are estimated parameters; $h_{i,t}$ is a dummy variable for hour i ; AGG_t is an indicator variable for program event days; CDH_t is cooling degree hours;¹⁰ E is the number of event days that occurred during the program year; $MornLoad_t$ is a variable equal to the average of the day's load in hours 1 through 10; MON_t is a dummy variable for Monday; FRI_t is a dummy variable for Friday; $DTYPE_{i,t}$ is a series of dummy variables for each day of the week; $MONTH_{i,t}$ is a series of dummy variables for each month; $Summer_t$ is a variable defining summer months (defined as mid-June through mid-August)¹¹, which is interacted with the weather and hourly profile variables; and e_t is the error term. The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for load levels on a particular day, particularly for customers whose daily loads vary substantially for no observable reason (such as more or less intensive than average operations on the part of manufacturing customers). Because of the

⁹ Including weekends and holidays would require the addition of variables to capture the fact that load levels and patterns on weekends and holidays can differ greatly from those of non-holiday weekdays. Because event days do not occur on weekends or holidays, the exclusion of these data does not affect the model's ability to estimate ex post load impacts.

¹⁰ Cooling degree hours (CDH) was defined as $MAX[0, Temperature - 50]$, where Temperature is the hourly temperature in degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

¹¹ This variable was initially designed to reflect the load changes that occur when schools are out of session. We have found the variable to be a useful part of the base specification, as it helps somewhat in modeling schools and does not appear to harm load impact estimates even in cases in which the customer does not change its usage level or profile substantially during the summer months.

autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

Separate models were estimated for each customer. The estimated load impacts, in the form of hourly event coefficients, were aggregated across customers to arrive at program-level load impacts, and results by industry group and LCA. Overall program-level and aggregator-level regressions were also estimated in some cases, primarily to provide consistency checks for the individual customer results.

3.3 Uncertainty-Adjusted Load Impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of *ex post* load impacts, the parameters that constitute the load impact estimates are not estimated with certainty. Therefore, we base the uncertainty-adjusted load impacts on the variances associated with the estimated load impacts.

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

4. Detailed Study Findings

This section describes the results of our estimation of *aggregate* event-day load impacts for each utility, and for the DA and DO program types of each aggregator program (in addition, the Protocol table spreadsheet provided in conjunction with this report includes estimates of load impacts *per-enrolled customer*). For each program and program type, we summarize the load impacts estimated for 2009 at three levels of aggregation. First, using the metric of *average hourly load impacts*, we summarize loads and load impacts for each event and the average event, as well as the distribution of load impacts for the average event across industry types and local capacity areas (for PG&E and SCE).

Second, we report average event-hour load impacts *for each hour that was included in the event window for any event*, where the average is across only those customer accounts and event days for which that hour was involved in an event.¹² These tables also include load impacts *per called customer*. Finally, we provide overall examples at the level of the DA and DO program types of the formal tables required by the Protocols. These tables show estimated hourly reference loads, observed loads, and estimated load impacts for the

¹² This distinction is necessary for the aggregator programs because of the many different sets of hours that were called for some of the program types. This is in contrast, for example, to the utilities' critical-peak pricing rates, in which the same hours are called for each event.

average event, as well as uncertainty-adjusted load impacts at different probability levels.¹³ Complete sets of tables are provided in an appendix. Hourly load impact results are also illustrated in figures.

We begin with CBP at each of the three utilities, and then turn to AMP (PG&E) and DRC (SCE).

4.1 CBP – PG&E

4.1.1 Summary load impacts

Tables 4.1 and 4.2 show average hourly estimated *reference load*, *observed load*, *load impacts* and percent load impact, by industry group, for the DA and DO components respectively, of PG&E’s single CBP event on July 27, 2009. The average hourly DA load impact was 21.5 MW, while the DO load impact averaged 22.4 MW. The DO load impact was averaged over hours-ending (HE) 16 – 18. For DA, the official event hours were HE 14 – 15. However, one aggregator mistakenly notified its customers that the event hours were HE 15 – 16. Table 4.1 contains results for the overlapping hour 15.

The Manufacturing industry group accounted for the largest share of DA load impacts, while the Agriculture, Mining and Construction, and Retail industry groups provided the largest share of DO load impacts. At a more detailed level, more than 40 percent of the total estimated load impacts for both the DA and DO program types were accounted for by single customer accounts, while the top 6 responders accounted for 60 percent of the total DA load impact, and the top 4 responders accounted for nearly 50 percent of the total DO load impact.

Table 4.1: Average Hourly Load Impacts (HE 15) by Industry Group – PG&E CBP DA

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	21	3,228	1,706	1,522	47%
2. Manufacturing	78	30,944	16,124	14,820	48%
3. Wholesale, Transport, other Utilities	43	2,859	1,922	937	33%
4. Retail stores	87	4,164	3,713	451	11%
5. Offices, Hotels, Health, Services	207	32,536	31,355	1,180	4%
6. Schools	52	17,648	15,183	2,465	14%
7. Entertainment, Other Services, Gov't	82	6,834	6,690	144	2%
8. Other/Unknown	11	977	1,012	-35	-4%
Total	581	99,191	77,707	21,484	22%

¹³ In these tables, average values of loads and load impacts for all 24 hours represent averages for those hours over all event days included in the definition of an average event, regardless of how many event days each hour was included in an event (e.g., hour-ending 14 may have been within the event window for only 2 of 8 events for a given program).

Table 4.2: Average Hourly Load Impacts by Industry Group – PG&E CBP DO

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	8	18,199	7,502	10,697	59%
2. Manufacturing	3	1,388	751	637	46%
3. Wholesale, Transport, other Utilities	14	2,143	256	1,887	88%
4. Retail stores	160	51,539	43,040	8,499	16%
5. Offices, Hotels, Health, Services	5	2,593	2,511	83	3%
6. Schools	6	2,967	2,362	605	20%
7. Entertainment, Other Services, Gov't	2	160	157	3	2%
8. Other/Unknown					
Total	198	78,989	56,579	22,410	28%

Tables 4.3 and 4.4 show average hourly load impacts for DA and DO by LCA. The largest shares of the load impacts for both program types were outside of any LCA. Large impacts were also observed in the Greater Bay Area and Greater Fresno LCAs.

Table 4.3: Average Hourly Load Impacts by LCA – PG&E CBP DA

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	474	58,878	55,084	3,794	6%
Greater Fresno	19	7,278	5,291	1,987	27%
Humboldt	0	0	0	0	
Kern	1	0	0	0	
Northern Coast	13	2,585	1,847	738	29%
Sierra	14	2,507	1,703	804	32%
Stockton	6	1,354	864	490	36%
Not in any LCA	54	26,523	12,854	13,670	52%
Total	581	99,124	77,643	21,482	22%

Table 4.4: Average Hourly Load Impacts by LCA – PG&E CBP DO

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	91	28,664	24,284	4,381	15%
Greater Fresno	29	8,508	5,723	2,785	33%
Humboldt					
Kern	13	3,572	2,722	851	24%
Northern Coast	14	5,054	4,006	1,048	21%
Sierra	13	4,417	3,394	1,023	23%
Stockton	7	2,830	2,243	587	21%
Not in any LCA	30	25,697	14,013	11,684	45%
Total	197	78,743	56,383	22,360	28%

4.1.2 Hourly load impacts

Tables 4.5 and 4.6 show average event-hour load impacts for the hours that were included in each event. In the case of PG&E CBP, the average DA and DO event is the same as the single event that was called for both program types. However, calculating average load impacts by event hour for DA is complicated due to the one aggregator’s mistaken notification of the event hours. As a result, event hours 14 and 16 applied to different numbers of customer accounts, while HE 15 applied to all DA customer accounts that were called for the event. Average event-hour load impacts for DA were greatest for the overlapping hour 15 which served as the basis for the average hourly tables in the previous section. Note that the values for HE 14 and 16 in Table 4.5 differ from those shown in Protocol Table 4.7 below. This is the case because Table 4.5 includes results only for those customer accounts that were called for each hour of the event, while Table 4.7 includes results for all customer accounts called for the event, regardless of which event hours applied to them.

For DO, average event-hour load impacts for HE 16 – 18 were nearly constant, ranging from 22.3 to 22.5 MW, or about 28 percent of the reference load. Average event-hour load impacts per called customer were about 113 kW.

Table 4.5: Average Event-Hour Load Impacts – PG&E CBP DA

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
14	447	57,165	52,814	4,352	78	1	9.7	8%
15	581	99,191	77,707	21,484	84	1	37.0	22%
16	134	40,427	24,533	15,894	93	1	118.6	39%

Table 4.6: Average Event-Hour Load Impacts – PG&E CBP DO

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
16	198	80,282	57,995	22,287	92	1	112.6	28%
17	198	79,148	56,704	22,443	92	1	113.3	28%
18	198	77,538	55,038	22,500	90	1	113.6	29%

Tables 4.7 and 4.8 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the PG&E CBP *DA* and *DO* events respectively, in the Protocol table format. Hourly load impacts for the DA event were 22 percent of the reference load of nearly 100 MW in the one overlapping hour that applied to all customer accounts, and were 28 percent of the reference load of 80 MW for DO. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to be 9 percent below and above the estimated load impacts for the overlapping event hour for DA, and 5 percent for the DO event.

Figure 4.1 shows the hourly reference load, observed load, and estimated load impacts (see right axis) for the PG&E CBP DA event on July 27, 2009, while Figure 4.2 shows comparable information for the DO event on the same day.

Table 4.7: Hourly Load Impacts – PG&E CBP Average DA Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	58,236	57,945	291	65	-1,666	-510	291	1,092	2,248
2	57,365	57,429	-64	64	-2,021	-865	-64	737	1,894
3	56,844	57,075	-231	63	-2,187	-1,031	-231	569	1,725
4	57,485	57,964	-480	61	-2,435	-1,280	-480	320	1,476
5	59,895	60,780	-886	61	-2,843	-1,687	-886	-85	1,072
6	64,478	65,687	-1,209	60	-3,162	-2,008	-1,209	-409	745
7	70,693	72,136	-1,443	60	-3,396	-2,242	-1,443	-644	510
8	79,382	80,584	-1,201	62	-3,161	-2,003	-1,201	-399	759
9	86,429	87,073	-644	65	-2,605	-1,447	-644	159	1,317
10	91,654	91,300	354	68	-1,611	-450	354	1,158	2,319
11	95,922	94,184	1,738	72	-223	935	1,738	2,540	3,699
12	97,773	96,015	1,758	75	-205	955	1,758	2,561	3,720
13	97,699	92,218	5,481	79	3,519	4,678	5,481	6,283	7,442
14	99,599	84,817	14,782	82	12,819	13,978	14,782	15,585	16,745
15	99,191	77,707	21,484	84	19,520	20,680	21,484	22,288	23,448
16	97,248	78,360	18,888	86	16,923	18,084	18,888	19,692	20,853
17	93,411	81,606	11,805	86	9,840	11,001	11,805	12,609	13,770
18	86,266	80,595	5,671	83	3,707	4,867	5,671	6,474	7,634
19	78,830	73,869	4,961	80	2,999	4,158	4,961	5,764	6,924
20	75,553	70,889	4,664	76	2,700	3,860	4,664	5,467	6,627
21	73,364	69,100	4,264	72	2,301	3,461	4,264	5,067	6,226
22	72,748	69,830	2,918	70	955	2,115	2,918	3,721	4,881
23	69,968	66,490	3,478	68	1,514	2,674	3,478	4,281	5,441
24	67,508	64,845	2,663	67	698	1,859	2,663	3,467	4,628
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,887,539	1,788,499	99,040	56.9	n/a	n/a	n/a	n/a	n/a

Table 4.8: Hourly Load Impacts – PG&E CBP Average DO Event

Table Removed for Confidentiality Reasons.

Figure 4.1: Hourly Loads and Load Impacts – PG&E CBP DA Event (July 27, 2009)

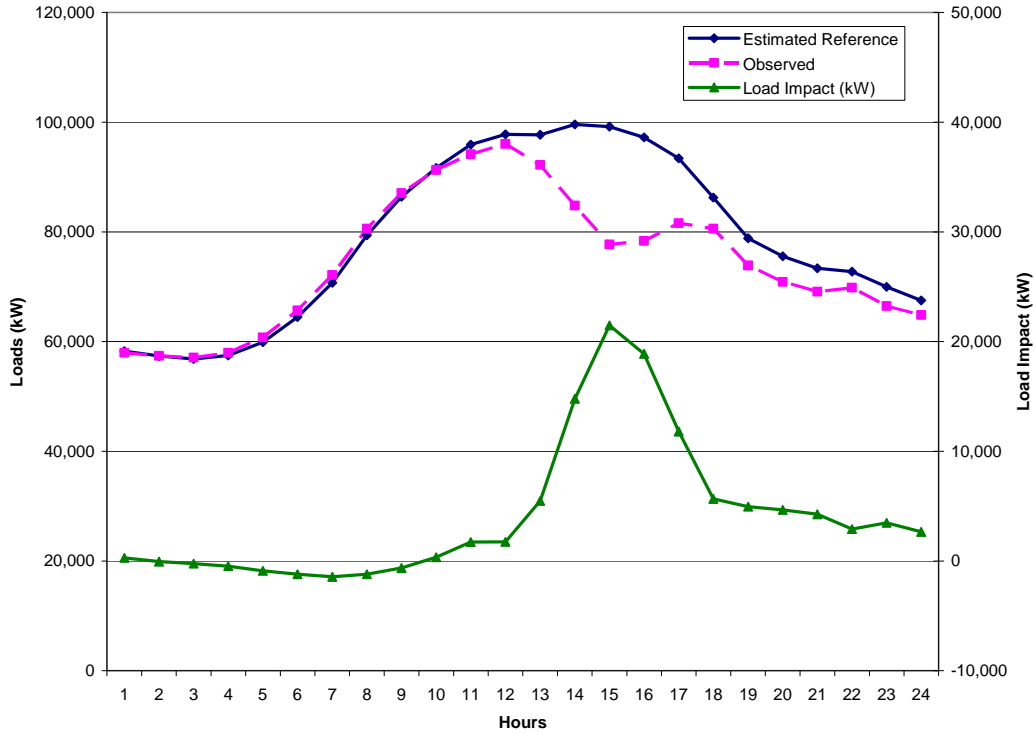


Figure 4.2: Hourly Loads and Load Impacts – PG&E CBP DO Event (July 27, 2009)

Figure Removed for Confidentiality Reasons.

4.2 CBP – SCE

4.2.1 Summary load impacts

Tables 4.9 and 4.10 summarize estimated *average hourly* ex post load impacts for each SCE event, for the DA and DO program types respectively, as well as for typical DA and DO events. The typical DA event was defined as the average of events 20 through 26, in which most of the DA contracts were called, including those newly nominated as of September. The typical average hourly DA load impact was 0.8 MW. The typical DO event was defined as the average of the two DO events on August 27 and 28, for which the average hourly load impact was 25.4 MW.

Table 4.9: Average Hourly Load Impacts by Event (kW) – SCE CBP DA

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	July 14, 2009	Tuesday	2	1,127	934	192	17%
2	July 15, 2009	Wednesday	2	1,130	1,036	94	8%
3	July 16, 2009	Thursday	2	1,219	963	256	21%
4	July 17, 2009	Friday	2	1,363	1,194	169	12%
5	July 20, 2009	Monday	2	1,248	987	262	21%
6	July 21, 2009	Tuesday	2	1,239	978	261	21%
7	July 23, 2009	Thursday	1	806	535	271	34%
8	July 27, 2009	Monday	1	833	537	296	36%
9	July 28, 2009	Tuesday	2	1,199	917	282	23%
10	August 4, 2009	Tuesday	3	2,251	1,998	253	11%
11	August 11, 2009	Tuesday	3	2,249	1,962	287	13%
12	August 12, 2009	Wednesday	3	2,321	1,980	341	15%
13	August 13, 2009	Thursday	3	2,211	2,002	209	9%
14	August 14, 2009	Friday	2	1,686	1,517	169	10%
15	August 17, 2009	Monday	3	2,132	1,802	330	15%
16	August 19, 2009	Wednesday	3	2,253	1,878	375	17%
17	August 27, 2009	Thursday	3	2,126	2,279	-153	-7%
18	August 28, 2009	Friday	3	2,031	2,199	-167	-8%
19	August 31, 2009	Monday	3	2,251	1,944	307	14%
20	September 1, 2009	Tuesday	77	8,316	7,538	778	9%
21	September 2, 2009	Wednesday	77	8,444	7,603	841	10%
22	September 3, 2009	Thursday	77	8,575	7,657	917	11%
23	September 4, 2009	Friday	77	8,189	7,529	660	8%
24	September 8, 2009	Tuesday	77	7,206	6,735	471	7%
25	September 9, 2009	Wednesday	77	7,442	6,524	918	12%
26	September 10, 2009	Thursday	76	7,533	6,689	844	11%
Typical	(Ave. of 20-26)		77	7,958	7,182	776	10%
	Standard Deviation			549	504	161	2%

Table 4.10: Average Hourly Load Impacts by Event (kW) – SCE CBP DO

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	27-Aug-09	Thursday	417	122,304	97,223	25,082	21%
2	28-Aug-09	Friday	417	123,819	98,018	25,801	21%
Average			417	123,062	97,621	25,441	21%

Tables 4.11 and 4.12 show average hourly estimated *reference load*, *observed load*, *load impacts* and percent load impact, by industry group, for the typical event for the DA and DO components respectively of SCE’s CBP program. Retail stores provided all of the DA load impacts and most of the DO load impacts, while the Offices, Hotel, Health, and

Services industry group also provided a substantial amount of the DO load impacts.¹⁴ The average percent load reductions across all industry types was 10 percent for DA and 21 percent for DO.

At a more detailed level, about 20 percent of the estimated DO load impacts were accounted for by a single customer account, while the top 6 responders accounted for a quarter of the total DO load impact.

Table 4.11: Average Hourly Load Impacts by Industry Type – SCE CBP DA

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	1	1,100	1,136	(37)	-3%
2. Manufacturing					
3. Wholesale, Transport, other Utilities	76	6,858	6,046	812	12%
4. Retail stores					
5. Offices, Hotels, Health, Services					
6. Schools					
7. Entertainment, Other Services, Gov't					
8. Other/Unknown					
Total	77	7,958	7,182	776	10%

Table 4.12: Average Hourly Load Impacts by Industry Type – SCE CBP DO

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	2	764	347	417	55%
2. Manufacturing					
3. Wholesale, Transport, other Utilities	16	2,339	347	1,992	85%
4. Retail stores	383	113,011	94,730	18,281	16%
5. Offices, Hotels, Health, Services	16	6,948	2,197	4,751	68%
6. Schools					
7. Entertainment, Other Services, Gov't					
8. Other/Unknown					
Total	417	123,062	97,621	25,441	21%

Tables 4.13 and 4.14 show average hourly load impacts by LCA. Most of the DA and DO load impacts occurred in the LA Basin.

¹⁴ Note that the negative load impact for the one manufacturing customer account in Table 4.9 implies that the regression analysis implied that this customer *increased* usage by a small amount during event hours on average. This occurs occasionally for some customers on the aggregator programs. However, it is unusual, as can be seen from the load reductions in most of the load impact tables.

Table 4.13: Average Hourly Load Impacts by LCA – SCE CBP DA

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	60	5,581	4,971	609	11%
Outside LA Basin	5	434	362	72	16%
Ventura	12	1,943	1,849	95	5%
Total	77	7,958	7,182	776	10%

Table 4.14: Average Hourly Load Impacts by LCA – SCE CBP DO

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	333	95,968	74,853	21,115	22%
Outside LA Basin	29	10,513	8,456	2,057	20%
Ventura	55	16,581	14,312	2,269	14%
Total	417	123,062	97,621	25,441	21%

4.2.2 Hourly load impacts

Tables 4.15 and 4.16 show average event-hour load impacts for SCE’s CBP DA and DO program types. The average DA event was defined as the average of the seven September events, for which the number of customer accounts called reached 77. The average DO event was the average of the two late-August events. Average event-hour load impacts for DA for HE 15 – 18 ranged from 0.7 to 1.1 MW, which represented 7 to 14 percent of the reference load. Load impacts per called customer were relatively small, ranging from 7 to 14 kW.

For DO, average event-hour load impacts for HE 15 – 18 ranged from 23.2 to 28.4 MW, or 19 to 23 percent of the reference load. Average event-hour load impacts per called customer ranged from 56 to 68 kW.

Table 4.15: Average Event-Hour Load Impacts – SCE CBP DA

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
14	1	402	333	69	100	1	69.1	17%
15	77	7,967	6,890	1,076	91	5	14.0	14%
16	77	7,838	7,068	770	90	7	10.0	10%
17	77	8,010	7,437	572	88	7	7.4	7%
18	77	8,420	7,737	683	87	5	8.9	8%

Table 4.16: Average Event-Hour Load Impacts – SCE CBP DO

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
15	417	122,005	93,628	28,377	98	2	68.0	23%
16	417	123,032	97,277	25,755	98	2	61.8	21%
17	417	123,520	99,119	24,400	97	2	58.5	20%
18	417	123,691	100,458	23,233	95	2	55.7	19%

Tables 4.17 and 4.18 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the average SCE CBP *DA* and *DO* events respectively. Hourly load impacts of the *DA* program type, while relatively small, averaged about 18 percent of the reference load. Hourly load impacts of the *DO* program type averaged 20 to 23 percent of the reference load of about 122 MW. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to span a quite narrow range of less than 4 percent below and above the estimated load impacts for the typical *DO* event.

Table 4.17: Hourly Load Impacts – SCE Average CBP DA Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	3,190	3,061	129	72	-153	13	129	244	410
2	3,175	3,057	117	71	-164	2	117	232	399
3	3,044	3,048	-4	70	-282	-118	-4	111	275
4	2,996	3,001	-5	69	-281	-118	-5	108	271
5	3,074	3,028	45	69	-229	-67	45	158	320
6	3,272	3,331	-59	68	-334	-172	-59	54	216
7	3,917	4,349	-432	68	-707	-545	-432	-320	-157
8	5,146	5,608	-462	70	-738	-575	-462	-349	-185
9	6,594	6,728	-134	74	-409	-247	-134	-21	141
10	6,582	6,859	-277	79	-552	-389	-277	-165	-2
11	6,746	6,925	-179	83	-454	-292	-179	-67	96
12	7,059	7,245	-186	86	-462	-299	-186	-73	91
13	7,432	7,431	2	88	-274	-111	2	115	278
14	7,648	7,447	200	89	-76	87	200	313	477
15	7,775	7,092	683	90	408	570	683	796	959
16	7,838	7,068	770	90	494	657	770	883	1,045
17	8,010	7,437	572	88	297	460	572	685	848
18	8,216	7,932	284	87	8	171	284	397	561
19	8,129	8,449	-320	84	-598	-434	-320	-207	-43
20	7,790	8,212	-422	81	-702	-537	-422	-307	-142
21	6,530	6,629	-99	78	-380	-214	-99	16	183
22	4,550	4,615	-65	77	-348	-181	-65	51	218
23	3,572	3,824	-253	75	-534	-368	-253	-138	28
24	3,273	3,351	-78	74	-359	-193	-78	37	202
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	135,558	135,729	-171	123.3	n/a	n/a	n/a	n/a	n/a

Table 4.18: Hourly Load Impacts – SCE Average CBP DO Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	70,608	71,373	-765	74	-1,654	-1,129	-765	-401	124
2	68,497	69,306	-809	73	-1,695	-1,172	-809	-446	77
3	67,073	67,292	-219	71	-1,105	-581	-219	144	668
4	67,525	67,097	429	70	-456	67	429	791	1,313
5	73,019	71,855	1,164	69	279	802	1,164	1,526	2,048
6	78,211	76,212	2,000	69	1,116	1,638	2,000	2,361	2,884
7	93,773	92,332	1,441	68	557	1,079	1,441	1,802	2,325
8	92,838	90,957	1,882	71	998	1,520	1,882	2,243	2,766
9	95,852	94,553	1,300	77	414	937	1,300	1,662	2,186
10	102,255	100,804	1,451	84	562	1,087	1,451	1,815	2,340
11	108,295	106,768	1,526	89	636	1,162	1,526	1,891	2,417
12	113,538	112,149	1,389	93	498	1,025	1,389	1,754	2,280
13	117,913	116,805	1,107	96	216	743	1,107	1,472	1,999
14	120,572	115,964	4,609	97	3,717	4,244	4,609	4,974	5,500
15	122,005	93,628	28,377	98	27,484	28,012	28,377	28,742	29,269
16	123,032	97,277	25,755	98	24,861	25,389	25,755	26,121	26,650
17	123,520	99,119	24,400	97	23,507	24,035	24,400	24,766	25,294
18	123,691	100,458	23,233	95	22,338	22,867	23,233	23,599	24,127
19	123,712	119,569	4,143	92	3,247	3,776	4,143	4,509	5,039
20	124,265	126,243	-1,978	88	-2,874	-2,345	-1,978	-1,612	-1,083
21	121,375	121,744	-369	84	-1,263	-735	-369	-3	525
22	111,459	112,838	-1,379	81	-2,273	-1,745	-1,379	-1,013	-485
23	87,369	88,728	-1,359	80	-2,252	-1,724	-1,359	-993	-465
24	75,570	76,805	-1,235	77	-2,128	-1,600	-1,235	-870	-343
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	2,405,967	2,289,875	116,092	227.6	n/a	n/a	n/a	n/a	n/a

Figure 4.3 shows the profiles of the hourly reference load, observed load, and estimated load impacts (see right axis) for the average SCE CBP DA event. Figure 4.4 shows comparable information for the average DO event.

Figure 4.3: Hourly Loads and Load Impacts – SCE CBP DA Average Event

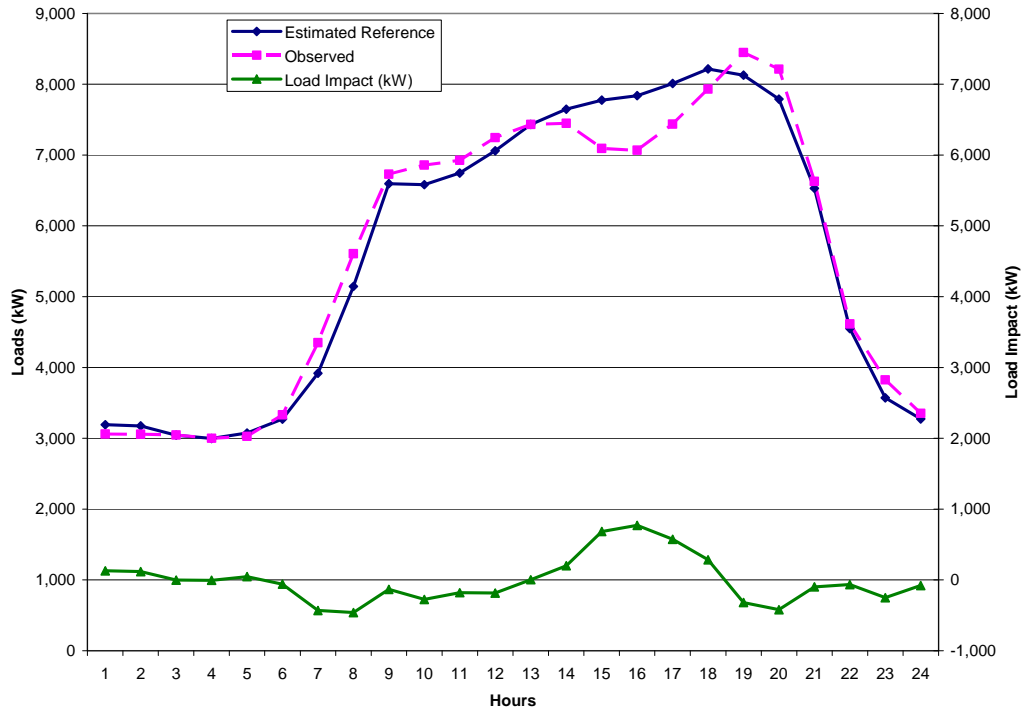
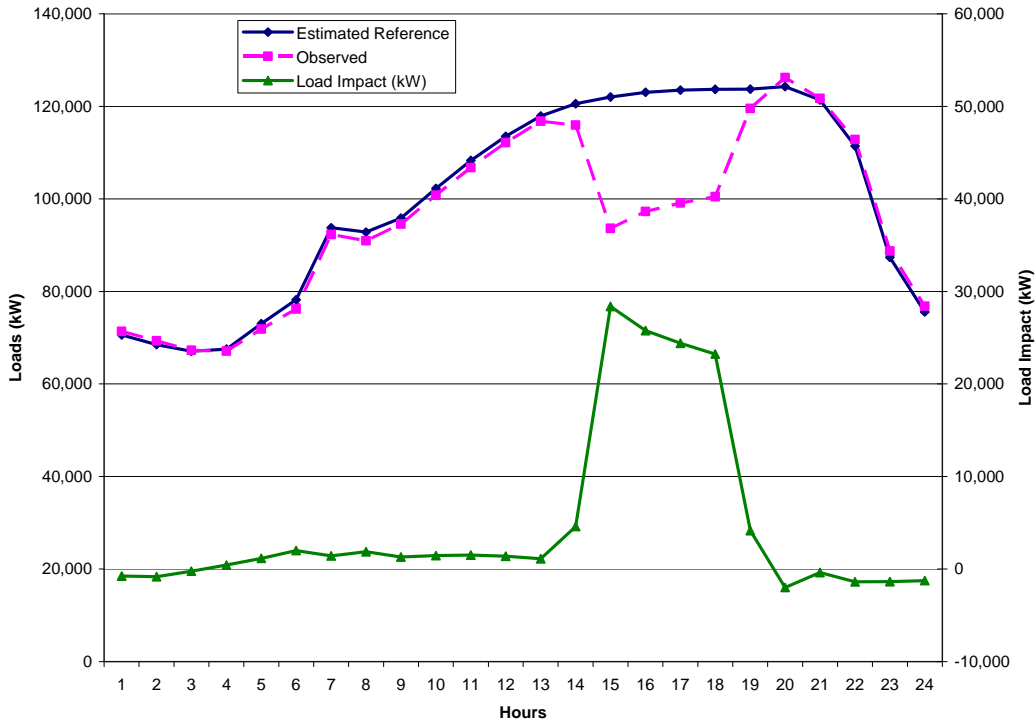


Figure 4.4: Hourly Loads and Load Impacts – SCE CBP DO Average Event



4.3 CBP – SDG&E

4.3.1 Summary load impacts

Tables 4.19 and 4.20 summarize estimated average hourly reference loads and *ex post* load impacts for each event, and for an average event, for the DA and DO program types respectively. In these tables, estimated hourly load impacts are included in the averages only for customer accounts and hours that were included in events. For example, load impacts for hours-ending 15 – 18 are included for DA customer accounts that were called for the 7th event, while load impacts for hours-ending 14 – 17 are included for the 8th event. Average hourly load impacts were quite consistent across events for both DA and DO program types, with an average hourly load impact of 10.3 MW for the average DA event, and 12.5 for the average DO event. Those represent 26 percent of the reference load for DA, and 18 percent for DO.

Table 4.19: Average Hourly Load Impacts (kW) by Event – SDG&E CBP DA

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	July 21, 2009	Tuesday					
2	August 26, 2009	Wednesday					
3	August 27, 2009	Thursday	113	38,814	28,224	10,590	27%
4	August 28, 2009	Friday	113	38,492	28,322	10,170	26%
5	September 2, 2009	Wednesday					
6	September 3, 2009	Thursday	127	41,124	29,486	11,638	28%
7	September 4, 2009	Friday	127	37,606	28,424	9,182	24%
8	September 24, 2009	Thursday	127	40,065	30,412	9,653	24%
9	September 25, 2009	Friday	127	38,055	27,761	10,295	27%
Average			122	39,026	28,771	10,255	26%
Standard Deviation				1,324	985	842	2%

Table 4.20: Average Hourly Load Impacts (kW) by Event – SDG&E CBP DO

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	July 21, 2009	Tuesday	265	62,728	52,417	10,311	16%
2	August 26, 2009	Wednesday	272	70,359	55,151	15,209	22%
3	August 27, 2009	Thursday	272	69,719	55,786	13,934	20%
4	August 28, 2009	Friday	272	68,769	57,140	11,630	17%
5	September 2, 2009	Wednesday	283	72,707	60,594	12,113	17%
6	September 3, 2009	Thursday	283	75,623	60,131	15,492	20%
7	September 4, 2009	Friday					
8	September 24, 2009	Thursday	283	68,114	59,308	8,805	13%
9	September 25, 2009	Friday					
Average			276	69,717	57,218	12,499	18%
Standard Deviation				4,011	2,990	2,506	3%

Tables 4.21 and 4.22 show average hourly program load impacts and percent load impacts by industry type, for the average DA and DO event respectively. The Manufacturing industry group provided the largest share of DA load impacts, while Retail stores provided the largest share of DO load impacts.

At a detailed level, two customer accounts made up 75 percent of the DA load impacts, and the top five responders made up 82 percent. For the DO program type, six customer accounts made up a third of the total load impact.

Table 4.21: Average Hourly Load Impacts by Industry Type – SDG&E CBP DA

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction					
2. Manufacturing	32	16,403	8,095	8,307	51%
3. Wholesale, Transport, other Utilities	8	457	207	251	55%
4. Retail stores	1	23	23	0	
5. Offices, Hotels, Health, Services	75	19,259	18,109	1,150	6%
6. Schools	2	1,913	1,732	181	9%
7. Entertainment, Other Services, Gov't	4	971	606	365	38%
8. Other/Unknown					
Total	122	39,026	28,771	10,255	26%

Table 4.22: Average Hourly Load Impacts by Industry Type – SDG&E CBP DO

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction					
2. Manufacturing	3	1,590	1,284	305	19%
3. Wholesale, Transport, other Utilities	18	2,157	963	1,195	55%
4. Retail stores	175	43,971	37,684	6,286	
5. Offices, Hotels, Health, Services	44	12,652	10,808	1,843	15%
6. Schools	4	4,912	3,466	1,446	29%
7. Entertainment, Other Services, Gov't	32	4,435	3,012	1,423	32%
8. Other/Unknown					
Total	276	69,717	57,218	12,499	18%

4.3.2 Hourly load impacts

Tables 4.23 and 4.24 show average event-hour load impacts for SDG&E’s CBP DA and DO program types. The average DA event was defined as the average of the six DA events, while the average DO event was the average of the seven DO events. Average event-hour load impacts for DA ranged from 9.2 to 11.2 MW across HE 14 – 18, where the averages for HE 14 and 18 include only the event days in which those hours were included in the event window. Percentage load impacts ranged from 23 to 28 percent, and load impacts per customer ranged from 73 to 92 kW.

For DO, average event-hour load impacts range considerably across the hours that were included in the event window for any of the events. For HE 15 – 18, which were included in the event window for most or all events, event-hour load impacts ranged from 10.7 to 13.3 MW, or about 18 percent of the reference load. Average event-hour load impacts per called customer ranged from 43 to 48 kW.

Given the scheduled transition of one of the CBP DO aggregators to a new AMP contract, Table 4.25 shows average event-hour information for all CBP DO customer accounts *except* those of the new AMP aggregator. The remaining customer accounts had event-hour load impacts ranging from 8 to 10.1 MW, or about 3 MW less than the full complement of DO customer accounts. Load impacts per customer of the remaining customers were also somewhat smaller, ranging from 34 to 40 kW.

Table 4.23: Average Event-Hour Load Impacts – SDG&E CBP DA

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
14	127	39,859	30,567	9,292	80	2	73.2	23%
15	122	39,833	29,773	10,060	84	6	82.2	25%
16	122	40,131	28,942	11,189	84	6	91.5	28%
17	122	38,588	28,018	10,570	84	6	86.4	27%
18	120	36,399	27,246	9,153	82	4	76.3	25%

Table 4.24: Average Event-Hour Load Impacts – SDG&E CBP DO

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
13	70	22,294	19,163	3,131	86	2	44.7	14%
14	144	38,839	33,707	5,132	85	5	35.6	13%
15	275	69,311	57,042	12,268	86	6	44.7	18%
16	276	70,401	57,461	12,940	85	7	46.9	18%
17	276	70,252	56,924	13,328	85	7	48.3	19%
18	253	64,080	53,351	10,728	82	6	42.5	17%
19	112	30,479	25,747	4,732	82	4	42.2	16%

Table 4.25: Average Event-Hour Load Impacts – SDG&E CBP DO (less AMP)

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
13	67	21,058	18,078	2,980	87	2	44.5	14%
14	134	33,461	28,479	4,982	86	5	37.2	15%
15	252	57,949	48,627	9,322	86	6	37.0	16%
16	253	58,858	48,916	9,942	85	7	39.3	17%
17	253	58,858	48,759	10,100	86	7	39.9	17%
18	233	54,552	46,586	7,966	82	6	34.2	15%
19	105	26,958	23,078	3,880	82	4	37.0	14%

Tables 4.26 and 4.27 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the average SDG&E CBP *DA* and *DO* program events respectively. Hourly load impacts were 25 to 28 percent of the reference load of about 41 MW for the average *DA* event, and 18 percent of the reference load of 70 MW for *DO*. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to be about 16 percent below and above the estimated load impacts for both the average *DA* and *DO* events.

Table 4.26: Hourly Load Impacts – SDG&E Average CBP DA Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty-Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	22,765	22,719	46	72	-1,639	-643	46	735	1,730
2	22,450	22,363	87	71	-1,593	-600	87	774	1,766
3	22,056	21,968	89	70	-1,584	-596	89	773	1,762
4	22,272	21,970	302	70	-1,373	-383	302	987	1,977
5	23,805	23,418	387	69	-1,285	-297	387	1,071	2,058
6	27,086	26,602	484	69	-1,189	-200	484	1,169	2,157
7	31,281	31,159	122	69	-1,548	-561	122	806	1,792
8	34,399	33,834	565	73	-1,125	-127	565	1,256	2,255
9	38,107	37,861	246	78	-1,460	-452	246	945	1,953
10	41,458	40,177	1,280	82	-441	576	1,280	1,984	3,001
11	42,264	40,577	1,687	84	-26	986	1,687	2,388	3,400
12	43,339	39,755	3,584	85	1,872	2,883	3,584	4,284	5,296
13	41,321	35,960	5,361	84	3,668	4,668	5,361	6,054	7,054
14	41,326	31,944	9,383	84	7,696	8,693	9,383	10,073	11,069
15	39,833	29,773	10,060	84	8,366	9,367	10,060	10,753	11,754
16	40,131	28,942	11,189	84	9,492	10,495	11,189	11,884	12,886
17	38,588	28,018	10,570	84	8,873	9,875	10,570	11,265	12,267
18	35,829	28,133	7,696	80	6,017	7,009	7,696	8,383	9,375
19	29,232	25,459	3,773	78	2,094	3,086	3,773	4,460	5,451
20	26,232	25,840	392	75	-1,282	-293	392	1,077	2,066
21	25,903	25,406	498	74	-1,169	-184	498	1,179	2,164
22	25,324	24,600	725	73	-947	41	725	1,409	2,396
23	24,124	23,365	759	72	-913	75	759	1,443	2,430
24	22,928	22,254	674	71	-998	-10	674	1,358	2,346
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
	762,056	692,098	69,958	82.3	n/a	n/a	n/a	n/a	n/a

Table 4.27: Hourly Load Impacts – SDG&E Average CBP DO Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty-Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	46,786	47,273	-487	71	-2,552	-1,332	-487	358	1,578
2	45,000	45,800	-800	70	-2,855	-1,641	-800	40	1,254
3	44,431	45,605	-1,174	70	-3,223	-2,012	-1,174	-336	874
4	44,357	45,495	-1,138	70	-3,187	-1,976	-1,138	-300	910
5	46,175	46,769	-595	69	-2,640	-1,431	-595	242	1,450
6	49,168	49,208	-39	69	-2,084	-876	-39	797	2,005
7	54,040	52,859	1,182	70	-861	346	1,182	2,017	3,224
8	57,433	55,646	1,787	75	-297	934	1,787	2,640	3,871
9	63,172	60,409	2,763	80	651	1,899	2,763	3,628	4,876
10	67,373	64,477	2,896	84	778	2,029	2,896	3,763	5,015
11	71,207	68,597	2,610	87	494	1,744	2,610	3,476	4,726
12	70,935	68,873	2,062	88	-43	1,201	2,062	2,923	4,167
13	70,871	68,493	2,378	87	289	1,523	2,378	3,234	4,468
14	70,760	64,538	6,223	87	4,142	5,371	6,223	7,074	8,303
15	70,099	59,603	10,496	86	8,414	9,644	10,496	11,349	12,579
16	70,401	57,461	12,940	85	10,852	12,086	12,940	13,794	15,028
17	70,252	56,924	13,328	85	11,232	12,470	13,328	14,186	15,425
18	68,281	57,977	10,304	83	8,207	9,446	10,304	11,162	12,401
19	66,124	61,186	4,938	81	2,825	4,073	4,938	5,802	7,050
20	64,936	64,884	52	77	-2,035	-802	52	906	2,140
21	62,354	64,065	-1,711	75	-3,786	-2,560	-1,711	-862	364
22	57,077	59,525	-2,448	74	-4,519	-3,295	-2,448	-1,600	-376
23	51,629	54,173	-2,544	73	-4,613	-3,391	-2,544	-1,698	-475
24	49,020	51,839	-2,820	72	-4,889	-3,666	-2,820	-1,973	-750
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
	1,431,881	1,371,677	60,204	110.3	n/a	n/a	n/a	n/a	n/a

Figure 4.5 shows the hourly reference load, observed load, and estimated load impacts (see right axis) for the average SDG&E CBP DA event, while Figure 4.6 shows comparable results for the average DO event.

Figure 4.5: Hourly Loads and Load Impacts – SDG&E Average CBP DA Event

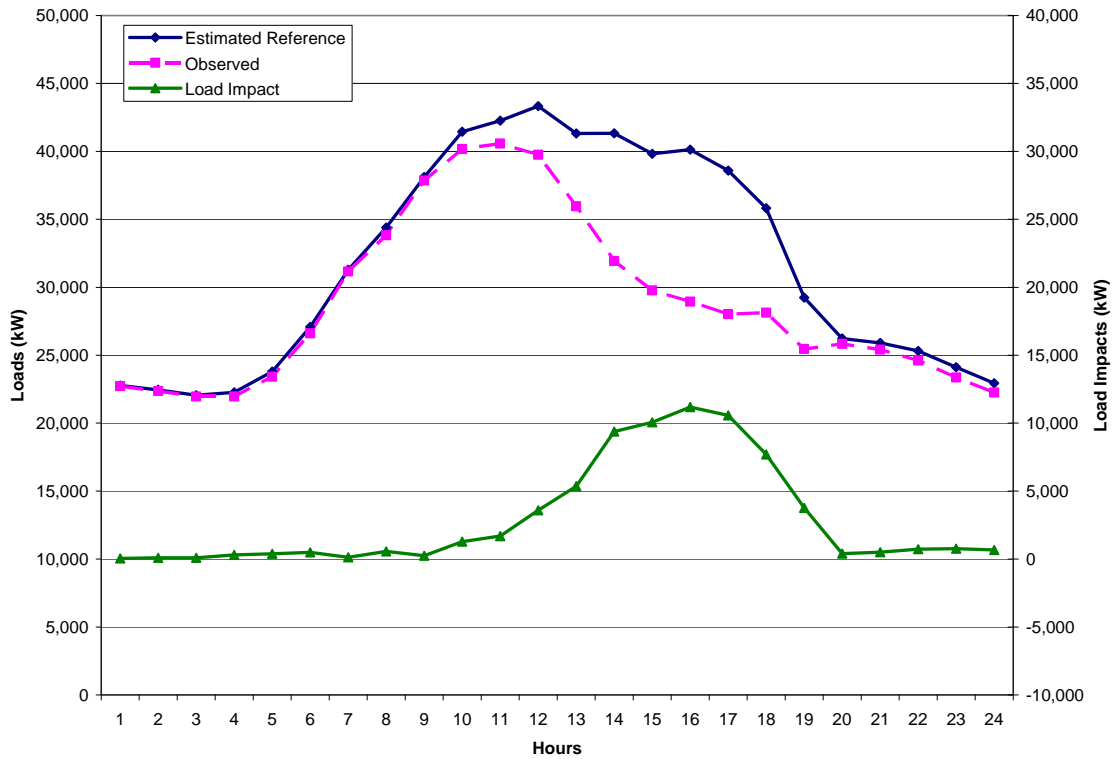
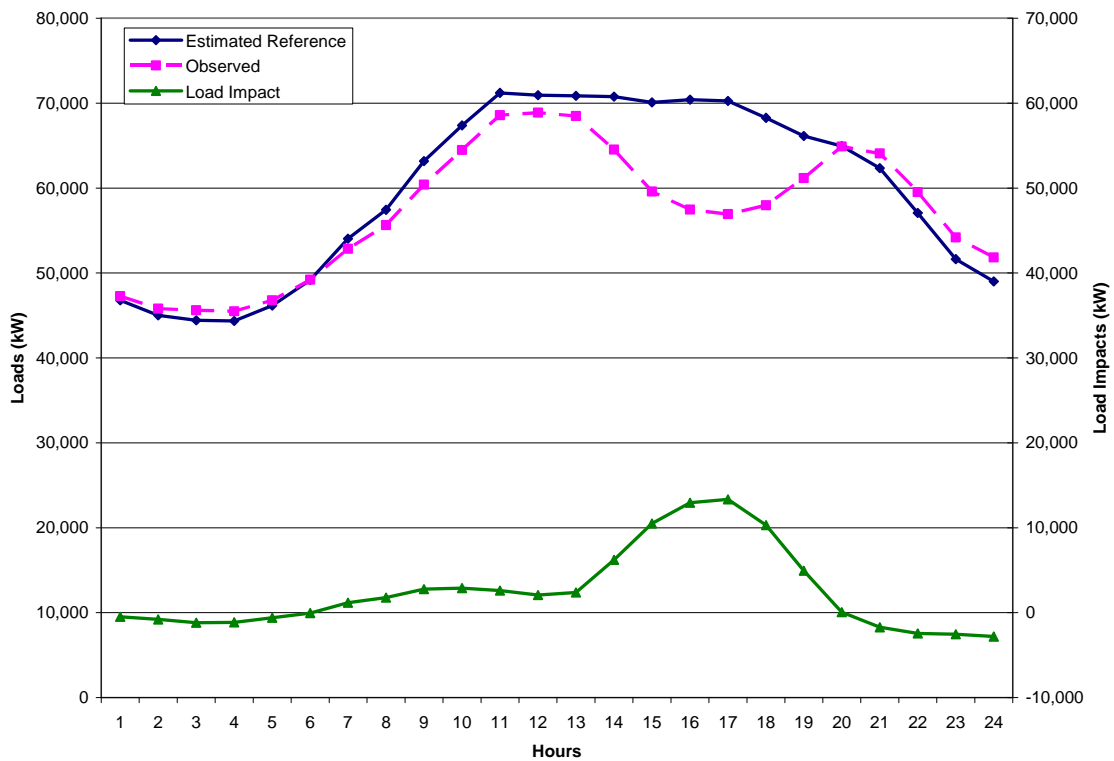


Figure 4.6: Hourly Loads and Load Impacts – SDG&E Average CBP DO Event



4.4 AMP – PG&E

4.4.1 Summary load impacts

Tables 4.28 and 4.29 report estimated average hourly load impacts for the DA and DO program types respectively, for the first and third AMP events, and for the averages over those two events. Average hourly load impacts for the DO program type were calculated over event hours-ending 16 – 17 for the first event and 15 – 16 for the second event. Average hourly load impacts for the average DA event were 38.5 MW, which was 41 percent of the reference load of nearly 95 MW, and for the average DO event were 83.9 MW (34 percent).

Table 4.28: Average Hourly Load Impacts by Event – PG&E AMP DA

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	July 16, 2009	Thursday	105	91,755	55,802	35,953	39%
3	August 28, 2009	Friday	127	97,930	56,910	41,020	42%
Average			116	94,843	56,356	38,486	41%

Table 4.29: Average Hourly Load Impacts by Event – PG&E AMP DO

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	July 16, 2009	Thursday	447	274,273	193,228	81,045	30%
3	August 28, 2009	Friday	347	216,980	130,182	86,798	40%
Average			397	245,626	161,705	83,921	34%

Tables 4.30 and 4.31 show counts of customer accounts called, and average hourly reference and observed loads, and load impacts and percentage load impacts by industry type for the average AMP DA and DO events, where the values for DO are for the overlapping HE 16 across the two events.¹⁵ Manufacturing made up the bulk of the DA load impacts, while Wholesale, Transportation and Other Utilities, and Agriculture, Mining and Construction comprised the majority of DO load impacts.

At a detailed level, 70 percent of the estimated DA load impacts were accounted for by the top 15 responding customer accounts, while the top 15 responders accounted for a third of

¹⁵ Defining an average DO event for 2009 is complicated by the fact that different aggregators, and thus different customer accounts, were called for the two test events (see the fourth column in Table 4.29). As seen in the Protocol table below (Table 4.37), if we average the loads and load impacts for the two events hour by hour, the only hour that shows the full program load impact is HE 16, which was included in the event window for both events. Since this hour is most representative of the full effect of calling the total program, Tables 4.30 through 4.33 show results for HE 16, averaged across the two events, as reflected in the Protocol table. Note that the average load impact in that hour, 83.6 MW, differs slightly from the value shown in Table 4.29 (83.9 MW), because the latter value was calculated by averaging load impacts over the *four* hours that reflected the event windows in both events (e.g., HE 15 –16 in event 1 and HE 16 – 17 in event 2).

the total DO load impact. The DO component of AMP had a number of large responders, with 38 customer accounts providing load reductions of at least 500 kW.

Table 4.30: Average Hourly Load Impacts by Industry Group – PG&E AMP DA

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	18	1,737	1,135	601	35%
2. Manufacturing	54	68,667	43,301	25,366	37%
3. Wholesale, Transport, other Utilities	14	4,975	2,370	2,605	52%
4. Retail stores	0	0	0	0	
5. Offices, Hotels, Health, Services	13	6,751	3,611	3,140	47%
6. Schools	9	5,022	3,567	1,455	29%
7. Entertainment, Other Services, Gov't	8	7,334	2,326	5,007	68%
8. Other/Unknown	1	359	47	312	87%
Total	117	94,843	56,356	38,486	41%

Table 4.31: Average Hourly Load Impacts by Industry Group – PG&E AMP DO

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	95	42,046	20,558	21,488	51%
2. Manufacturing	67	45,473	32,225	13,248	29%
3. Wholesale, Transport, other Utilities	79	55,720	23,814	31,906	57%
4. Retail stores	71	34,071	29,414	4,657	14%
5. Offices, Hotels, Health, Services	75	45,724	37,565	8,160	18%
6. Schools	4	18,430	17,379	1,051	6%
7. Entertainment, Other Services, Gov't	6	4,445	1,327	3,118	70%
8. Other/Unknown					
Total	397	245,909	162,281	83,627	34%

Tables 4.32 and 4.33 report average hourly load impacts by LCA. Nearly half of the load impacts took place outside of any LCA. Large shares also took place in the Greater Bay Area and Greater Fresno LCAs.

Table 4.32: Average Hourly Load Impacts by LCA – PG&E AMP DA

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	28	21,742	17,111	4,631	21%
Greater Fresno	16	14,751	7,573	7,178	49%
Humboldt	0	0	0	0	
Kern	0	0	0	0	
Northern Coast	10	4,567	1,714	2,852	62%
Sierra	11	2,325	1,536	788	34%
Stockton	6	6,547	1,540	5,006	76%
Not in any LCA	46	44,912	26,882	18,031	40%
Total	117	94,843	56,356	38,486	41%

Table 4.33: Average Hourly Load Impacts by LCA – PG&E AMP DO

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	119	71,712	61,506	10,205	14%
Greater Fresno	88	44,428	28,290	16,138	36%
Humboldt	7	1,257	225	1,032	82%
Kern	28	26,420	16,494	9,926	38%
Northern Coast	31	9,160	5,663	3,498	38%
Sierra	9	5,894	4,277	1,617	27%
Stockton	16	9,424	6,478	2,946	31%
Not in any LCA	100	77,613	39,348	38,265	49%
Total	398	245,909	162,281	83,627	34%

4.4.2 Hourly load impacts

Tables 4.34 and 4.35 show average event-hour load impacts for PG&E’s AMP DA and DO program types. The average DA event was defined as the average of the two DA events, as was the average DO event. However, there were some differences in aggregators called for the two DO events, such that 100 fewer customer accounts were called for the second event (as reflected in the results for HE 15). Event-hour load impacts for DA averaged 38.5 MW in both event hours (HE 16 and 17). Percentage load impacts were about 40 percent, and load impacts per called customer were 332 kW.

For DO, average event-hour load impacts for HE 15 – 17 ranged from 81.5 to 87 MW, representing 30 to 40 percent of the reference load. Average event-hour load impacts per called customer ranged from 182 to 251 kW.

Table 4.34: Average Event-Hour Load Impacts – PG&E AMP DA

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
16	116	95,626	57,158	38,468	97	2	331.6	40%
17	116	94,060	55,555	38,505	97	2	331.9	41%

Table 4.35: Average Event-Hour Load Impacts – PG&E AMP DO

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
15	347	217,929	130,983	86,946	96	1	250.6	40%
16	397	245,909	162,281	83,627	95	2	210.6	34%
17	447	272,758	191,273	81,485	95	1	182.3	30%

Tables 4.36 and 4.37 show hourly reference load, observed load, load impact values, and uncertainty-adjusted load impacts for the average PG&E AMP *DA* and *DO* events respectively. Hourly load impacts were about 40 percent of the reference load of about 95 MW for DA, and were 34 percent of the reference load of about 246 MW for DO in the single hour (HE 16) in which all DO program types and events overlapped. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to be about 6 percent below and above the estimated load impacts for the average DA event, and 5 percent for the overlapping hour in the average DO event.

Table 4.36: Hourly Load Impacts – PG&E Average AMP DA Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	84,018	85,473	-1,456	74	-3,756	-2,397	-1,456	-515	844
2	83,476	84,854	-1,377	73	-3,677	-2,318	-1,377	-436	922
3	82,621	84,176	-1,555	71	-3,852	-2,495	-1,555	-615	742
4	82,071	84,357	-2,286	69	-4,584	-3,226	-2,286	-1,347	11
5	82,220	84,029	-1,808	68	-4,105	-2,748	-1,808	-869	488
6	84,492	86,267	-1,775	67	-4,072	-2,715	-1,775	-835	521
7	87,294	88,108	-813	67	-3,112	-1,754	-813	127	1,485
8	90,228	90,699	-470	69	-2,771	-1,412	-470	471	1,830
9	92,468	92,907	-439	72	-2,740	-1,381	-439	502	1,862
10	95,089	95,389	-299	76	-2,603	-1,242	-299	643	2,004
11	96,354	96,147	207	81	-2,096	-735	207	1,149	2,509
12	96,773	96,241	533	86	-1,774	-411	533	1,476	2,839
13	96,864	95,260	1,604	90	-703	660	1,604	2,548	3,911
14	97,893	93,297	4,595	92	2,292	3,653	4,595	5,538	6,898
15	97,953	81,134	16,819	95	14,516	15,877	16,819	17,762	19,123
16	95,626	57,158	38,468	97	36,163	37,525	38,468	39,412	40,774
17	94,060	55,555	38,505	97	36,201	37,562	38,505	39,448	40,809
18	92,420	73,313	19,107	96	16,803	18,164	19,107	20,050	21,411
19	91,003	84,608	6,395	94	4,089	5,451	6,395	7,339	8,701
20	91,513	89,114	2,400	91	90	1,455	2,400	3,345	4,709
21	90,019	89,286	733	87	-1,578	-213	733	1,678	3,043
22	88,627	88,588	39	84	-2,270	-906	39	984	2,349
23	84,747	85,423	-676	81	-2,987	-1,622	-676	269	1,634
24	81,420	83,415	-1,995	79	-4,306	-2,941	-1,995	-1,050	315
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	2,159,250	2,044,798	114,452	186.0	n/a	n/a	n/a	n/a	n/a

Table 4.37: Hourly Load Impacts – PG&E Average AMP DO Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	185,852	186,972	-1,120	74	-5,364	-2,857	-1,120	616	3,124
2	181,569	182,612	-1,043	72	-5,288	-2,780	-1,043	695	3,203
3	178,927	179,563	-636	71	-4,876	-2,371	-636	1,099	3,604
4	176,011	176,858	-846	69	-5,087	-2,582	-846	889	3,394
5	174,703	176,023	-1,320	68	-5,560	-3,055	-1,320	414	2,919
6	181,383	182,079	-695	68	-4,936	-2,431	-695	1,040	3,546
7	193,974	192,765	1,209	67	-3,036	-528	1,209	2,945	5,453
8	205,575	204,433	1,142	69	-3,110	-598	1,142	2,882	5,394
9	215,108	214,817	291	73	-3,965	-1,450	291	2,033	4,547
10	223,808	223,784	25	78	-4,233	-1,717	25	1,767	4,282
11	235,670	236,462	-792	82	-5,043	-2,532	-792	947	3,459
12	241,581	243,500	-1,919	86	-6,168	-3,658	-1,919	-180	2,330
13	241,958	239,438	2,520	89	-1,734	780	2,520	4,261	6,774
14	246,110	230,174	15,936	92	11,681	14,195	15,936	17,678	20,192
15	247,263	192,346	54,917	94	50,659	53,175	54,917	56,659	59,174
16	245,909	162,281	83,627	95	79,370	81,885	83,627	85,369	87,885
17	243,655	186,158	57,497	96	53,243	55,756	57,497	59,238	61,752
18	237,919	220,145	17,774	95	13,521	16,034	17,774	19,514	22,027
19	230,733	226,380	4,353	93	97	2,612	4,353	6,094	8,609
20	225,496	225,387	109	90	-4,152	-1,635	109	1,853	4,370
21	218,554	216,979	1,575	86	-2,686	-169	1,575	3,319	5,836
22	208,904	206,020	2,884	83	-1,378	1,140	2,884	4,628	7,146
23	199,767	196,949	2,818	80	-1,446	1,073	2,818	4,563	7,082
24	190,936	188,930	2,006	78	-2,254	263	2,006	3,749	6,266
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,131,362	4,891,050	240,312	175.9	n/a	n/a	n/a	n/a	n/a

Figure 4.7 illustrates the reference load, observed load, and estimated load impacts for the average DA event, while Figure 4.8 illustrates comparable information for the average DO event. Figure 4.9 shows the estimated hourly DA and DO load impacts separately for the first (July 16) and third (August 28) events, for which both program types were called. Note that the DO program types were called for two different sets of two-hour periods, thus producing the “shifted” load impacts for the two events.

Figure 4.7: Hourly Loads and Load Impacts – Average AMP DA Event

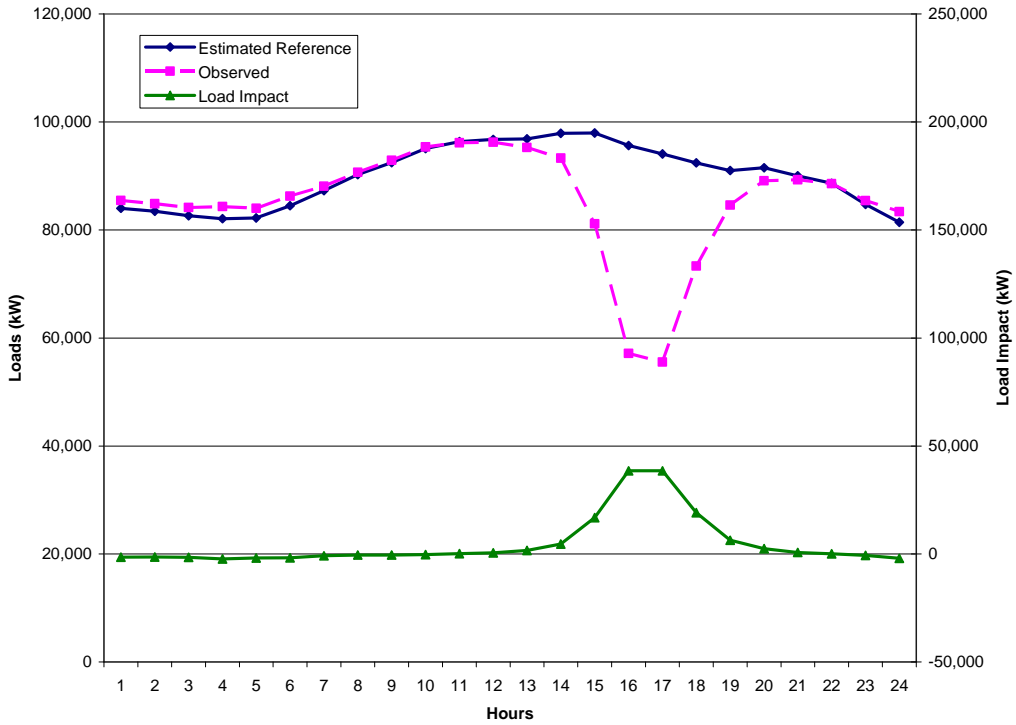


Figure 4.8: Hourly Loads and Load Impacts – Average AMP DO Event

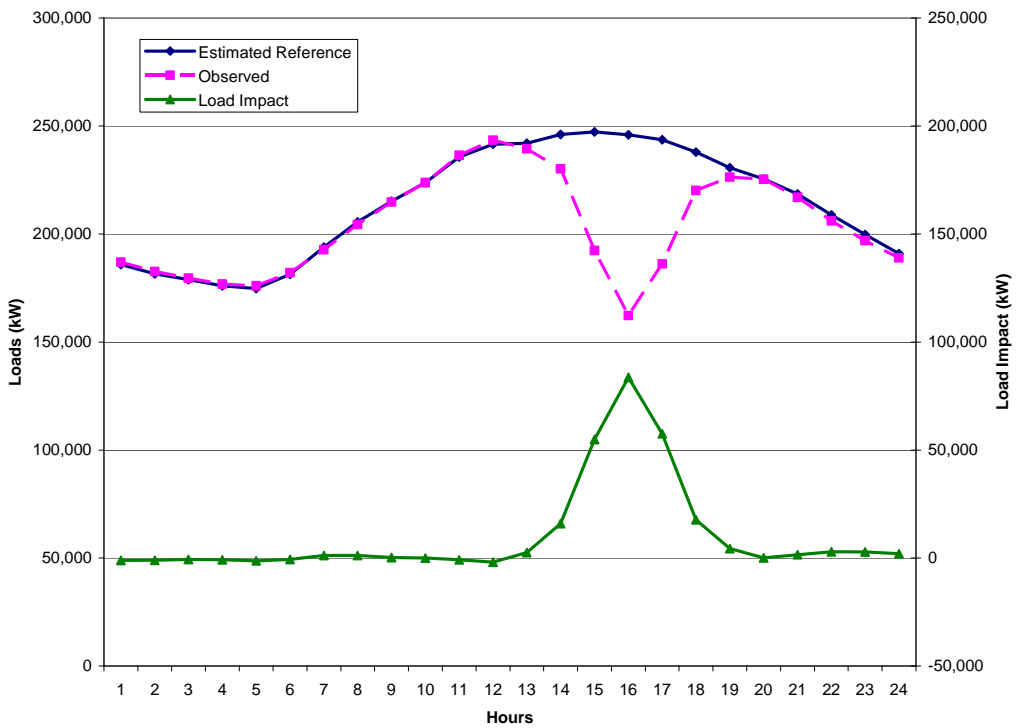
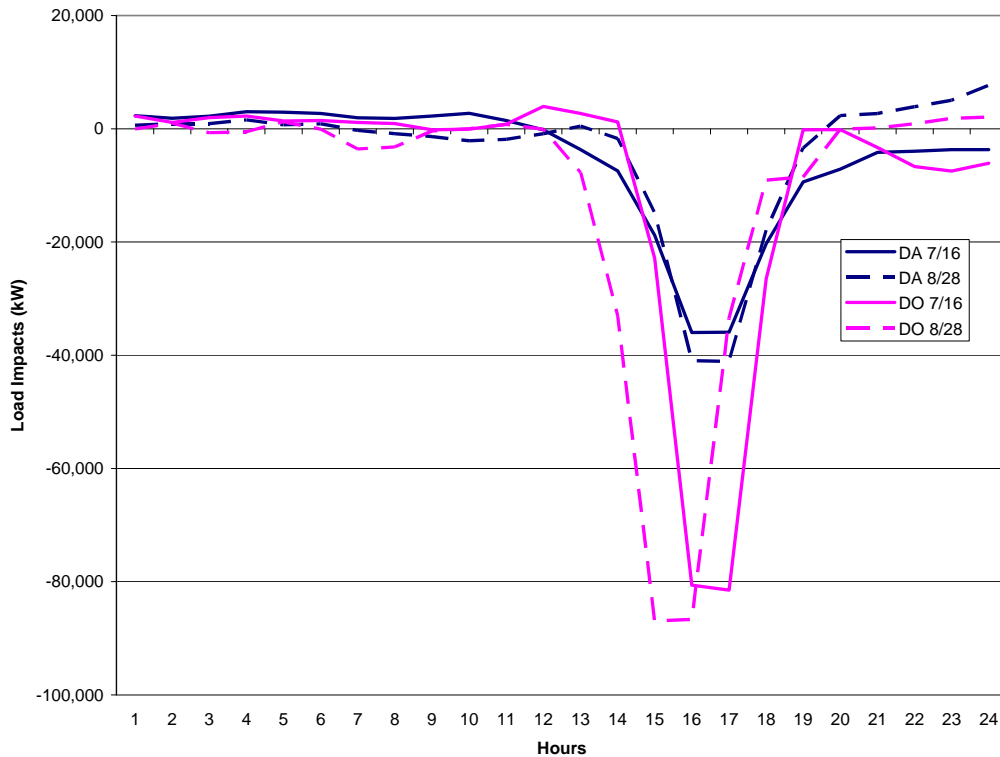


Figure 4.9: Hourly Load Impacts – PG&E AMP Events 1 and 3



4.5 DRC – SCE

4.5.1 Summary load impacts

Tables 4.38 and 4.39 report estimated *average hourly* reference loads, observed loads, and load impacts by industry group for SCE’s two DRC events, the first being a DA event, and the second a DO event. The program total average hourly load impact in the last row of the table shows load reductions averaging 3.9 MW on July 14 for the DA event, 63.6 MW for the DO event on September 23. Most of the DA load impacts were provided by the Retail industry group. The largest DO load impacts were provided by the Wholesale, Transportation and Utilities, Manufacturing, and Retail industry groups.

At a detailed level, the top nine responders provided 30 percent of the total DO load impact, with each providing more than 500 kW.

Table 4.38: Average Hourly Load Impacts by Industry Group – SCE DRC DA

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction					
2. Manufacturing	2	1,069	310	759	
3. Wholesale, Transport, other Utilities	10	4,888	4,170	718	15%
4. Retail stores	110	28,872	26,484	2,388	8%
5. Offices, Hotels, Health, Services					
6. Schools					
7. Entertainment, Other Services, Gov't					
8. Other/Unknown					
Total	122	34,829	30,964	3,865	11%

Table 4.39: Average Hourly Load Impacts by Industry Group – SCE DRC DO

Industry Group	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	11	1,821	706	1,115	61%
2. Manufacturing	46	37,744	20,332	17,413	46%
3. Wholesale, Transport, other Utilities	272	47,831	20,678	27,153	57%
4. Retail stores	236	71,921	60,139	11,781	16%
5. Offices, Hotels, Health, Services	29	12,962	11,219	1,743	13%
6. Schools	13	39,458	35,994	3,463	9%
7. Entertainment, Other Services, Gov't	3	2,822	1,875	947	34%
8. Other/Unknown					
Total	610	214,558	150,944	63,615	30%

Tables 4.40 and 4.41 report average hourly load impacts by LCA for the DA and DO program types. More than two-thirds of the load impacts were in the LA Basin.

Table 4.40: Average Hourly Load Impacts by LCA – SCE DRC DA

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	95	28,024	24,685	3,338	12%
Outside LA Basin	9	2,222	1,994	228	10%
Ventura	18	4,583	4,285	298	7%
Total	122	34,829	30,964	3,865	11%

Table 4.41: Average Hourly Load Impacts by LCA – SCE DRC DO

Local Capacity Area	SAIDs Called	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	472	159,321	118,822	40,499	25%
Outside LA Basin	74	10,766	4,384	6,382	59%
Ventura	64	44,471	27,738	16,734	38%
Total	610	214,558	150,944	63,615	30%

4.5.2 Hourly load impacts

Tables 4.42 and 4.43 show average event-hour load impacts for SCE’s DRC DA and DO program types. The average DA event was the same as the single DA event on July 14, while the average DO event was the same as the single DO event on September 23. As a result, the load impacts shown are the same as those in the hourly Protocol tables below. Event-hour load impacts for DA ranged from 3.4 to 4.3 MW across event hours HE 15 – 17. Percentage load impacts were 10 to 12 percent, and load impacts per called customer ranged from 28 to 35 kW.

For DO, event-hour load impacts for HE 15 and 16 were 62.4 and 64.9 MW respectively, or about 30 percent of the reference load. Average event-hour load impacts per called customer were 102 to 106 kW.

Table 4.42: Average Event-Hour Load Impacts – SCE DRC DA

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
15	122	34,700	30,447	4,253	89	1	34.9	12%
16	122	34,986	31,046	3,940	89	1	32.3	11%
17	122	34,801	31,399	3,402	88	1	27.9	10%

Table 4.43: Average Event-Hour Load Impacts – SCE DRC DO

Hour Ending	Number of SAIDs Called	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temp (°F)	# of Events in which this Hour is Included	Load Impact per Called Customer (kWh/hr)	% Load Impact
15	610	215,866	153,490	62,376	94	1	102.3	29%
16	610	213,251	148,398	64,853	94	1	106.3	30%

Tables 4.44 and 4.45 show hourly reference load, observed load, load impact values, and uncertainty-adjusted load impacts for the average SCE DRC *DA* and *DO* events respectively. Hourly load impacts ranged from 10 to 12 percent of the reference load of about 35 MW for the DA program type, and from 29 to 30 percent of the reference load of nearly 215 MW for DO. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to span about 15 to 19 percent below and above the estimated load impacts for the average DA event, and were about 6 percent for the average DO event.

Table 4.44: Hourly Load Impacts – Average SCE DRC DA Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	14,430	14,333	97	70	-558	-171	97	365	752
2	14,017	13,819	198	68	-457	-70	198	466	852
3	13,848	13,688	160	67	-495	-108	160	428	815
4	13,679	13,469	211	67	-445	-57	211	479	866
5	13,754	13,481	272	66	-382	5	272	540	927
6	14,271	14,310	-39	65	-693	-307	-39	228	615
7	16,811	16,820	-10	66	-664	-277	-10	258	645
8	19,524	19,415	108	71	-547	-160	108	377	764
9	22,276	22,781	-505	75	-1,160	-773	-505	-237	150
10	25,419	25,837	-418	79	-1,074	-686	-418	-150	238
11	32,221	32,427	-205	82	-861	-474	-205	63	451
12	33,318	33,829	-511	85	-1,167	-779	-511	-242	146
13	33,442	34,025	-584	87	-1,241	-853	-584	-315	73
14	33,983	33,789	194	88	-463	-75	194	463	851
15	34,700	30,447	4,253	89	3,596	3,984	4,253	4,522	4,909
16	34,986	31,046	3,940	89	3,283	3,671	3,940	4,208	4,596
17	34,801	31,399	3,402	88	2,746	3,134	3,402	3,670	4,058
18	34,805	34,383	421	86	-235	153	421	689	1,077
19	34,919	35,835	-916	84	-1,572	-1,184	-916	-647	-259
20	35,077	36,054	-977	81	-1,633	-1,245	-977	-709	-321
21	32,674	34,019	-1,346	77	-2,001	-1,614	-1,346	-1,078	-691
22	22,275	23,298	-1,023	74	-1,678	-1,291	-1,023	-755	-368
23	17,511	18,241	-730	71	-1,385	-998	-730	-462	-76
24	15,771	16,413	-642	69	-1,297	-910	-642	-375	12
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	598,510	593,160	5,350	114.4	n/a	n/a	n/a	n/a	n/a

Table 4.45: Hourly Load Impacts – Average SCE DRC DO Event

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	159,389	155,227	4,161	70	506	2,665	4,161	5,657	7,817
2	156,026	151,295	4,731	68	1,078	3,236	4,731	6,226	8,385
3	152,765	147,723	5,042	66	1,387	3,546	5,042	6,538	8,698
4	150,824	146,448	4,376	66	704	2,874	4,376	5,878	8,048
5	152,356	149,236	3,120	63	-564	1,612	3,120	4,627	6,803
6	157,455	155,776	1,680	62	-2,006	172	1,680	3,187	5,365
7	169,263	172,679	-3,416	62	-7,106	-4,926	-3,416	-1,906	275
8	177,618	181,534	-3,917	63	-7,600	-5,424	-3,917	-2,409	-233
9	191,807	193,746	-1,939	70	-5,605	-3,439	-1,939	-439	1,727
10	200,101	201,072	-971	77	-4,640	-2,472	-971	531	2,698
11	211,257	211,820	-563	82	-4,230	-2,063	-563	937	3,104
12	215,502	215,543	-40	87	-3,710	-1,542	-40	1,461	3,630
13	213,762	216,640	-2,878	91	-6,554	-4,383	-2,878	-1,374	798
14	215,755	204,513	11,242	93	7,562	9,736	11,242	12,747	14,921
15	215,866	153,490	62,376	94	58,693	60,869	62,376	63,883	66,059
16	213,251	148,398	64,853	94	61,170	63,346	64,853	66,360	68,537
17	209,951	180,580	29,371	92	25,696	27,868	29,371	30,875	33,046
18	206,005	190,618	15,387	90	11,720	13,886	15,387	16,887	19,054
19	204,809	195,954	8,854	86	5,189	7,354	8,854	10,354	12,520
20	205,282	200,436	4,846	83	1,177	3,344	4,846	6,347	8,515
21	204,647	198,050	6,597	80	2,924	5,094	6,597	8,100	10,271
22	194,189	193,451	738	77	-2,932	-764	738	2,240	4,409
23	175,674	175,548	126	74	-3,538	-1,373	126	1,625	3,790
24	164,292	162,441	1,851	73	-1,813	352	1,851	3,351	5,516
Daily	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	4,517,844	4,302,216	215,628	151.0	n/a	n/a	n/a	n/a	n/a

Figure 4.10 illustrates the reference load, observed loads, and load impacts for the average DA event, while Figure 4.11 illustrates comparable information for the average DO event.

Figure 4.10: Hourly Loads and Load Impacts – Average SCE DRC DA Event

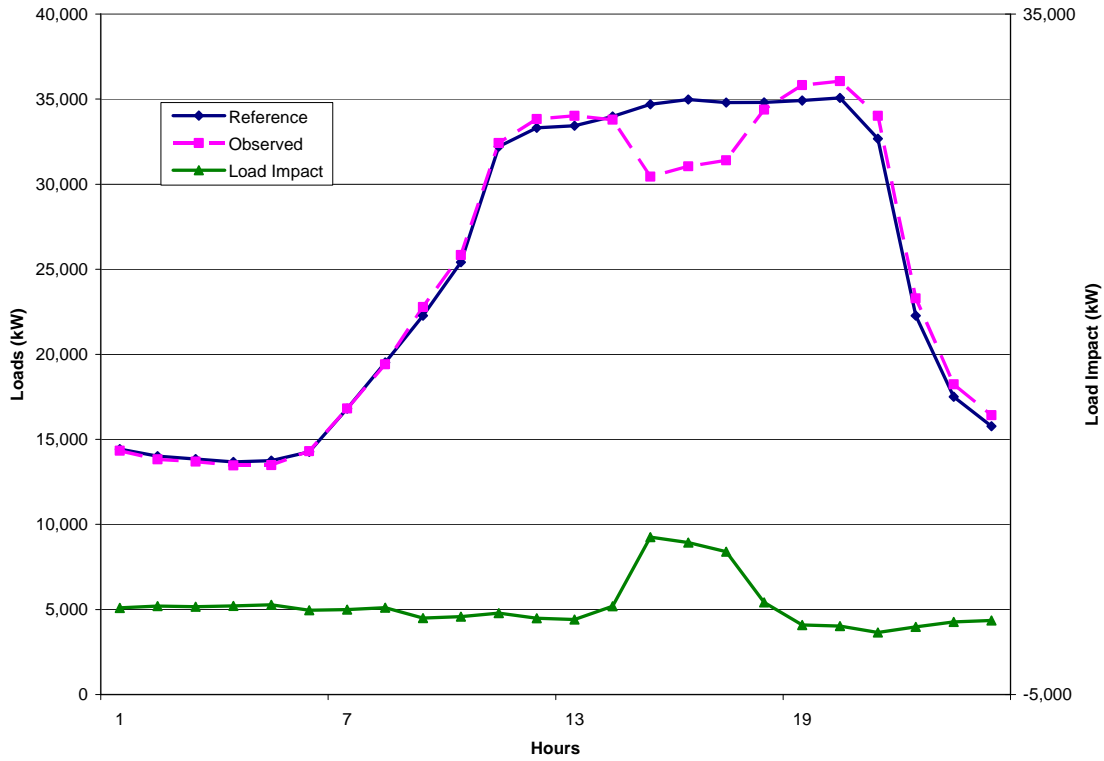
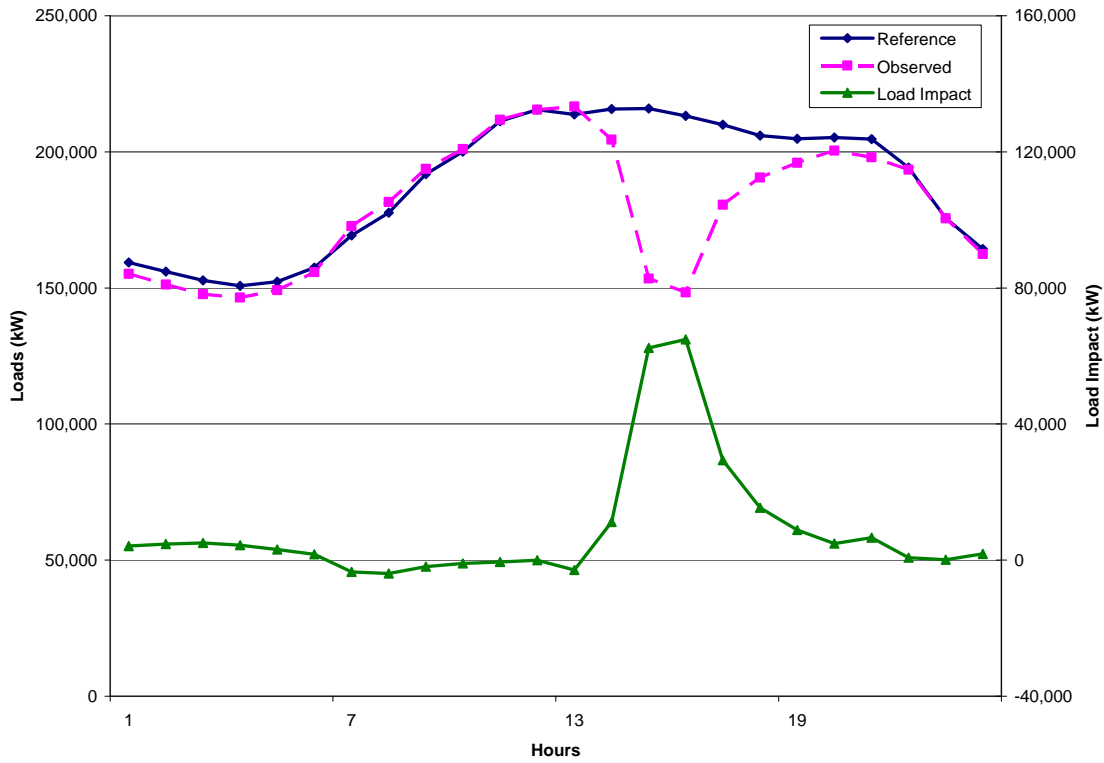


Figure 4.11: Hourly Loads and Load Impacts – Average SCE DRC DO Event



4.6 Average Event-Hour Load Impacts per Enrolled Customer

The utilities have asked for a summary indicator of average event-hour load impacts *per enrolled customer* for each program and program type. They are the following:

1. PG&E CBP DA – 32 kW
2. PG&E CBP DO – 80 kW
3. SCE CBP DA – 10 kW
4. SCE CBP DO – 42 kW
5. SDG&E CBP DA – 78 kW
6. SDG&E CBP DO – 42 kW
7. PG&E AMP DA – 141 kW
8. PG&E AMP DO – 125 kW
9. SCE DRC DA – 23 kW
10. SCE DRC DO – 52 kW.

4.7 TA/TI Impacts

This section describes the *ex post* load impacts achieved by two demand response incentive programs: TA/TI and AutoDR.

The Technical Assistance and Technology Incentives (TA/TI) program has two parts: technical assistance in the form of energy audits, and technology incentives. The objective of the TA portion of the program is to subsidize customer energy audits so that they can identify ways to participate in DR and modify their usage patterns. The TI portion of the program then provides incentive payments for the installation of equipment or control software to support DR.

The Automated Demand Response (AutoDR) program helps customers to activate DR strategies, such as managing lighting or heating, ventilation and air conditioning (HVAC) systems, whereby electrical usage can be automatically reduced or even eliminated during times of high electricity prices or electricity system emergencies. Only SDG&E had aggregator customers participating in AutoDR.¹⁶

For each utility and incentive program, we present two tables of information. The first table contains the *overall load impacts* provided by those service accounts who participated in TA/TI or AutoDR. The second table compares, where possible, the percentage load impacts achieved by TA/TI or AutoDR participants to those of a relevant group of non-participating service accounts. In some cases, results for service accounts are compared to other service accounts of the same “customer.” In this type of table, each row of data shows the outcome for customers within a 6-digit NAICS code or 4-digit SIC code. Where possible, we conduct comparisons of load impacts within these highly disaggregated

¹⁶ A process evaluation conducted in conjunction with the 2008 load impact evaluation of the aggregator programs provides useful information on the operation of the programs and the perspectives of the participating customers on the enrollment process, their stated approach for responding to events, and the type of technology that they or their aggregator may have installed to facilitate responding to events called (see below). See “2008 Process Evaluation of California Statewide Aggregator Demand Response Programs,” prepared by Research Into Action, August 6, 2009.

industry groups. Where a comparison at this level of disaggregation is not possible, we compare at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes. In some cases, the list of service accounts does not contain any reasonable basis of comparison for the participating TA/TI or AutoDR service account. (These cases are denoted as “No Comparables” in the tables.)

We note that the above comparisons do not constitute a formal evaluation of the incremental effect of AutoDR or TA/TI on customers’ demand response load impacts. This is the case largely due to generally small numbers of observations and a lack of complete information. For example, we rarely observe “before and after” load responses for the same service account, because the TA/TI and AutoDR audits and installations typically took place prior to any events in 2009. In addition, enabling technology may be used by some SAIDs that did not participate in AutoDR or TA/TI. Therefore, we cannot even be certain that when we compare TA/TI and non-TA/TI accounts we are actually measuring a “with and without” technology difference.¹⁷ However, given the available data, we believe that the comparisons made in this section are informative and the most relevant ones to provide.

4.7.1 PG&E

Table 4.46 shows the estimated load impact of the one TA/TI service accounts on PG&E’s CBP DO program type. Table 4.47 indicated that that account had a smaller than average load impact compared to other accounts in that business type.

Table 4.46: Total TA/TI Load Impacts by Event – PG&E CBP DO

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
7/27/2009	1	438	422	16	3.7%

Table 4.47: Incremental TA/TI Load Impacts – PG&E CBP DO

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
445110	Supermarkets and Other Grocery Stores	6-digit NAICS, different accounts for same customer	8.5%	3.7%	27	1

The following table shows total load impacts for 53 TA/TI participating service accounts in PG&E’s AMP day-of program. Load impacts amounted to more than 4 MW on average.

¹⁷ Customer surveys undertaken in the 2008 process evaluation found that 40 percent of surveyed participants reported that their facilities had an energy management or building control system prior to the enrollment with their aggregator. Fifteen percent of participants reported installing new equipment before participating, and 42 percent reported that their aggregator had installed new equipment after their enrollment (the equipment was often described as some additional metering technology designed to provide the customer or aggregator with access to timely energy usage information).

Table 4.48: Total TA/TI Load Impacts by Event – PG&E AMP DO

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
7/16/2009	53	27,967	23,331	4,636	16.6%
8/28/2009	53	28,039	24,051	3,987	14.2%
Average	53	28,003	23,691	4,312	15.4%

Table 4.49 compares percentage load impacts for TA/TI and non-TA/TI service accounts. The results are mixed, but two of the groups (NAICS 327320 and 452112 & 452910) show notably higher percentage load impacts for TA/TI accounts.

Table 4.49: Incremental TA/TI Load Impacts – PG&E AMP DO

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
115114	Postharvest Crop Activities	6-digit NAICS	43.3%	32.1%	60	2
327320	Ready-Mix Concrete Manufacturing	6-digit NAICS	10.7%	96.3%	4	2
331511, 334516	Iron Foundries, Analytical Laboratory Instrument Manufacturing	2-digit NAICS	14.8%	11.0%	30	4
452112, 452910	Discount Department Stores, Warehouse Clubs and Supercenters	Different accounts for same customer	9.8%	16.4%	18	96
511210	Software Publishers	6-digit NAICS, different accounts for same customer	1.8%	-1.6%	4	2

4.7.2 SCE

Table 4.50 shows load impacts by event for two TA/TI accounts in SCE’s CBP day-ahead program, where the average hourly load impacts averaged around 0.1 MW.

Table 4.50: Total TA/TI Load Impacts by Event – SCE CBP DA

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
7/14/2009	2	1,127	934	192	17.1%
7/15/2009	2	1,135	1,045	90	7.9%
7/16/2009	2	1,219	963	256	21.0%
7/17/2009	2	1,363	1,194	169	12.4%
7/20/2009	2	1,248	987	262	21.0%
7/21/2009	2	1,239	978	261	21.0%
7/23/2009	1	806	535	271	33.6%
7/27/2009	1	833	537	296	35.5%
7/28/2009	2	1,195	912	283	23.7%
8/4/2009	2	1,090	1,000	90	8.2%
8/11/2009	2	1,036	886	149	14.4%
8/12/2009	2	1,067	985	82	7.7%
8/13/2009	2	1,062	985	77	7.3%
8/14/2009	1	661	478	183	27.7%
8/17/2009	2	990	817	173	17.5%
8/19/2009	2	1,033	868	165	16.0%
8/27/2009	2	1,098	1,031	68	6.2%
8/28/2009	2	1,191	1,138	53	4.5%
8/31/2009	2	1,077	1,037	40	3.7%
9/1/2009	2	1,201	1,208	-7	-0.6%
9/2/2009	2	1,191	1,306	-115	-9.6%
9/3/2009	2	1,207	1,173	34	2.8%
9/4/2009	2	1,241	1,177	64	5.2%
9/8/2009	2	979	952	26	2.7%
9/9/2009	2	979	1,042	-62	-6.4%
9/10/2009	1	653	694	-41	-6.2%
Average	2	1,074	956	118	11.0%

Table 4.51 shows differences in estimated percentage load impacts for the two customer accounts in the previous table compared to other non-TA/TI accounts in the same 4-digit business category (Department stores). In this case, the TA/TI accounts had smaller percentage load impacts.

Table 4.51: Incremental TA/TI Load Impacts – SCE CBP DA

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
5311	Department Stores	4-digit SIC	14.1%	11.0%	518	48

Table 4.52 reports total load impacts for 102 service accounts from SCE’s day-of CBP program type that participated in TA/TI. These accounts accounted for over 4 MW of load impacts for both of the day-of events. Table 4.53 shows differences in estimated percentage load impacts for those accounts, by 4-digit business type (mostly different types of retail stores), compared to similar service accounts that did not participate in TA/TI. For

four of the five business types, the TA/TI accounts' percentage load impacts *exceeded* those of the non-TA/TI accounts.

Table 4.52: Total TA/TI Load Impacts by Event – SCE CBP DO

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
8/27/2009	102	38,119	33,907	4,212	11.0%
8/28/2009	102	39,436	35,055	4,380	11.1%
Average	102	38,777	34,481	4,296	11.1%

Table 4.53: Incremental TA/TI Load Impacts – SCE CBP DO

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
5211	Lumber Dealers	4-digit SIC	21.0%	30.4%	254	4
5311	Department Stores	4-digit, different accounts for same customer	10.3%	10.4%	22	94
5399	Miscellaneous General Merchandise Stores	4-digit, different accounts for same customer	10.4%	12.5%	14	30
5945	Hobby, Toy, and Game Shops	4-digit, different accounts for same customer	12.6%	16.4%	4	52
7991	Physical Fitness Facilities	4-digit, different accounts for same customer	1.8%	0.3%	4	24

SCE's DRC day-of program type included 37 SAIDs that participated in TA/TI, with resulting load impacts as indicated in Table 4.54 and Table 4.55. Those accounts produced 3 MW of load impacts on the one DO event. When categorized by 4-digit SIC code, and compared to other SAIDs in those business types, the results are somewhat mixed. Most of the percentage impacts for both categories of customer accounts are relatively large. In half of the cases, the percentage load impacts are larger for TA/TI accounts than for other accounts in the same business type, and in half they are smaller.

Table 4.54: Total TA/TI Load Impacts by Event – SCE DRC DO

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
9/23/2009	37	22,930	19,851	3,079	15.5%

Table 4.55: Incremental TA/TI Load Impacts – SCE DRC DO

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
723	Crop Preparation Services	4-digit SIC	56.4%	44.2%	4	2
2041	Flour Products	2-digit SIC	13.1%	8.2%	7	1
4222	Refrigerated Storage	4-digit SIC	42.3%	42.5%	2	1
4941	Water Supply	4-digit SIC	44.3%	75.8%	231	6
5141	Groceries, General Line	2-digit SIC	-10.1%	15.4%	3	1
5411	Grocery Stores	4-digit SIC	14.9%	8.9%	96	21
7011	Hotels and Motels	4-digit SIC	6.0%	-3.8%	22	2
8051	Skilled Nursing Care Facilities	No Comparables	n/a	n/a	n/a	n/a
8221	Colleges and Universities	4-digit SIC	3.9%	9.9%	3	1
8422	Arboreta and Botanical or Zoological Gardens	No Comparables	n/a	n/a	n/a	n/a

4.7.3 SDG&E

One service account in SDG&E’s CBP DA program type participated in AutoDR, and produced estimated load impacts of about 20 kW, or 2.3 percent. The same customer had other service accounts enrolled in CBP DA that did not participate in AutoDR. These service accounts averaged a 7 percent load impact, higher than the load impact from the AutoDR account. One factor that may reduce the comparability of these load impacts is that the AutoDR account’s load is significantly higher than the comparison group of non-AutoDR accounts (720 kW vs. 250 kW during the event hours).

Sixty-six service accounts from five customers in the CBP DO program type participated in AutoDR, producing the estimated load impacts shown in Table 4.56, which averaged about 0.6 MW over the seven DO events. When compared to the customers’ non-AutoDR service accounts in the same business type, the differences in percentage load impacts are as shown in Table 4.57. The results are mixed, with two of the cases showing noticeably higher load impacts for AutoDR service accounts; one account showing very little effect; and one wrong-signed effect of AutoDR. Note that the AutoDR accounts were smaller than the non-AutoDR accounts for the second group (NAICS codes 451120 and 452990) and larger than the non-AutoDR accounts for the other three groups.

Table 4.56: Total AutoDR Load Impacts by Event – SDG&E CBP DO

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
7/21/2009	66	5,064	4,472	592	11.7%
8/26/2009	66	5,200	4,763	437	8.4%
8/27/2009	66	5,370	4,698	672	12.5%
8/28/2009	66	5,391	4,758	633	11.7%
9/2/2009	66	5,377	4,790	586	10.9%
9/3/2009	66	5,632	4,879	753	13.4%
9/24/2009	66	5,060	4,499	561	11.1%
Average	66	5,299	4,694	605	11.4%

Table 4.57: Incremental AutoDR Load Impacts – SDG&E CBP DO

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
441222	Boat Dealers	6-digit NAICS, different accounts for same customer	2.0%	10.5%	7	14
451120 & 452990	Hobby, Toy & Game Stores; All Other General Merchandise Stores	2-digit NAICS	9.8%	14.4%	250	238
561439	Other Business Service Centers (including Copy Shops)	6-digit NAICS, different accounts for same customer	15.9%	11.3%	21	84
713940	Fitness and Recreational Sports Centers	6-digit NAICS, different accounts for same customer	6.4%	6.9%	70	126

Table 4.58 shows that four CBP DA customer accounts participating in TA/TI produced load impacts that averaged about 0.2 MW across the six DA events, but with considerable variation across events. However, as shown in Table 4.59, the percentage load impacts were smaller than comparable customer accounts in the same business type (Financial and Real estate organizations). In this case, the TA/TI service accounts were nearly five times larger than the comparison group of non-TA/TI service accounts (approximately 1 MW vs. 215 kW).

Table 4.58: Total TA/TI Load Impacts by Event – SDG&E CBP DA

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
8/27/2009	4	4,141	3,775	367	8.9%
8/28/2009	4	3,997	3,961	37	0.9%
9/3/2009	4	4,306	4,013	293	6.8%
9/4/2009	4	3,860	3,864	-4	-0.1%
9/24/2009	4	4,100	4,145	-46	-1.1%
9/25/2009	4	3,938	3,643	295	7.5%
Average	4	4,057	3,900	157	3.9%

Table 4.59: Incremental TA/TI Load Impacts – SDG&E CBP DA

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events Impact	
			No AutoDR	AutoDR	No AutoDR	AutoDR
525930	Real Estate Investment Trusts	6-digit NAICS, different accounts for same customer	7.0%	2.3%	224	6

Finally, one CBP DO customer account in the R&D business area participated in TA/TI and produced load impacts averaging 23 kW, or 11.4 percent. The same customer had other service accounts enrolled in CBP DO that did not participate in TA/TI. These accounts averaged 3 percent load impacts. Unlike the other sub-programs, these TA/TI and non-TA/TI service accounts were comparable in size (200 kW for the TA/TI accounts vs. 275 kW for the non-TA/TI accounts).

5. Ex Ante Load Impacts

This section documents the preparation of ex ante forecasts of reference loads and load impacts for 2010 to 2020 for the aggregator demand response programs offered by PG&E, SCE, and SDG&E. These include CBP for all three utilities, AMP for PG&E and SDG&E¹⁸, and DRC for SCE. In each case, separate load impact forecasts were developed for the *day-ahead* and *day-of* program types, where relevant.

The forecasts of load impacts were developed in two primary stages. First, estimates of reference loads and percentage load impacts, on a per-enrolled customer basis, were developed based on modified versions of the ex-post load impact regressions described in Section 4. Second, the simulated per-customer reference loads under alternative weather (e.g., 1-in-2 and 1-in-10) and event-type scenarios (e.g., typical event, or monthly system peak day), and the estimated percentage load impacts were combined with program enrollment forecasts from the utilities to develop alternative forecasts of aggregate load impacts. Forecasts were developed at the program and program-type (e.g., DA and DO) level, and by CAISO *Local Capacity Area*. The Brattle Group provided enrollment

¹⁸ SDG&E's AMP is a new contract-based aggregator program that split off from CBP after the summer of 2009.

forecasts for PG&E’s programs through a separate contract. SCE and SDG&E provided enrollment forecasts for their programs.

The following subsections describe the nature of the ex ante load impact forecasts required, the methods used to produce them, detailed study findings, and recommendations.

5.1 Ex Ante Load Impact Requirements

The DR Load Impact Evaluation Protocols require that hourly load impact forecasts for event-based DR resources be reported for the following scenarios (in addition to the program-level and LCA breakdown noted above):

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

under both:

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

at both:

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

5.2 Description of Methods

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

5.2.1 Development of Customer Groups

Enrollment forecasts in the various DR programs need to account for the expanded number of customer accounts of increasingly smaller size that will become eligible as they receive interval metering equipment in future years. As a result, customer accounts were assigned to one of three size groups, in addition to the eight industry types (defined in Section 2.2), and any relevant LCA based on information provided by the utilities. The three size groups were the following:

- Small – maximum demand less than 20 kW;¹⁹
- Medium – maximum demand between 20 and 200 kW;
- Large – maximum demand greater than 200 kW.

The specific definition of “maximum demand” differed by utility. For PG&E and SCE, the size definition was based on the tariff on which the customer is served. For example, a tariff may require that a customer’s monthly peak demand exceeds 20kW for three out of

¹⁹ SDG&E and SCE forecast that there will be no customers in this size group on CBP.

the previous twelve months. For SDG&E, the size definition was based on each customer's maximum summer on-peak demand.

PG&E and SCE provided the ability to associate customers with an LCA. PG&E mapped each distribution feeder to one of its seven LCAs, while SCE based its mapping on a combination of substations and zip codes.

5.2.2 Development of Reference Loads and Load Impacts

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

1. Define data sources
2. Estimate ex ante regressions and simulate reference loads by cell and scenario
3. Calculate percentage load impacts by cell
4. Apply percentage load impacts to the reference loads
5. Scale the reference loads using enrollment forecasts

Each of these steps is described below.

1. Define data sources

Since no major design changes are planned for any of the aggregator programs, there is a close link between the results of the ex post analyses conducted for the 2009 program year and the ex ante load impact forecasts.²⁰ That is, the historical customer loads serve as the basis of the ex ante reference loads, and the historical estimated percentage load impacts serve as the basis for constructing the ex ante load impacts.

2. Estimate and simulate reference loads

The objective of this step is to produce average per-customer reference loads under the various scenarios required by the Protocols (*e.g.*, the typical event day in a 1-in-2 weather year) so that they may be applied to the enrollment forecasts to produce program-level results. The required level of aggregation of the reference loads depends on the level of detail of the enrollment forecasts. For example, if only total numbers of enrolled customers are provided, then we can produce a program-level reference load, where the shares of customers of each type are implicitly assumed to remain the same as in the historical year. Alternatively, if enrollment forecasts are provided by size, industry type, and LCA, as for PG&E, then we produce per-customer reference loads at that level of aggregation.

To develop the reference loads, we first re-estimate regression equations for each enrolled customer account, using data for 2009. These equations are used to simulate reference loads by customer type under the alternative scenarios. These loads are then averaged at the appropriate level to produce per-customer loads.

²⁰ One exception is the creation of a new AMP aggregator contract for SDG&E. However, since it consists of customers formerly enrolled in CBP, we can use their load impacts in that program to simulate load impacts for the new program.

The re-estimated regression equations are similar in design to the ex post load impact equations described in Section 3.1, differing primarily in two ways. First, the event variables are modified from the version that produced ex-post estimates of 24 hourly load impact values for *each* event, to a version that produces estimates of *average hourly event-period* load impacts across all events.²¹ Second, the ex ante models exclude the morning-usage variable. While this variable is useful for improving accuracy in estimating ex post load impacts for each event, it complicates the use of the equations in ex ante simulation. That is, it would require a separate simulation of the level of the morning load.

The regression equations contain both weather variables and monthly indicator variables, which provide the capability to simulate customer loads under the different weather and monthly system peak scenarios. The definitions of the 1-in-2 and 1-in-10 weather years differed by utility, and were modified from the definitions used in the 2009 report. Basically, the utilities moved away from using weather for a particular year, to a process for identifying weather extremes on a monthly basis. Details on the development of the weather scenarios for PG&E are provided in a report by Freeman, Sullivan & Company.

The level of aggregation for the reference loads for each of the utilities and programs is as follows. For SCE's CBP and DRC programs, we developed separate load profiles at three levels of aggregation for each size category: all enrolled customers; by industry group; and by LCA. For PG&E's AMP and CBP programs, we developed per-customer load profiles for all interactions of size group, industry group, and LCA. Because of small sample sizes in some cells, we pooled all of the customer load profiles across LCAs to arrive at a set of simulation coefficients that was common to each size and industry group combination. Any differences in the ex ante reference load profiles across LCAs were thus solely due to differences in the weather conditions used in the simulations. This method conformed to the enrollment forecast developed for PG&E by The Brattle Group, which forecast the number of enrolled customers in each cell. As described below, results were ultimately rolled up across industry types to report results at the program and LCA levels.

For SDG&E's CBP program, we developed per-customer load profiles by industry group and program type (*e.g.*, combinations of notice level and event window), after removing the customer accounts for the aggregator that will offer the new AMP DO product. Each industry group was expanded at the same rate over time, corresponding to the enrollment forecast provided by SDG&E, which specified the number of enrolled customers within each program type (*e.g.*, DA and DO, and event window length), but not by industry type. A similar process was applied to the load profiles for the new AMP program type.

3. Calculate forecast percentage load impacts

The first step in developing the forecast percentage load impacts was to determine the definition of a "typical event day" during which the load impacts were to be measured. This was complicated by the fact that the aggregator DR program events differ somewhat from those of other DR programs, in that many of the events vary in terms of event length

²¹ The equations also estimated load impacts for the hours immediately preceding and following an event (since many customers begin reducing load prior to an event and do not immediately increase load following an event), and for all remaining event-day hours.

(e.g., as short as one hour, to as long as 8 hours, depending in part on the aggregator contracts), and the particular hours called. We used the following procedures to define typical events and event hours for both the historical period and the forecast period:

- *Historical period.* The procedure for developing a typical event day varied by utility and program, depending on the nature of the events called in 2009. These definitions of typical DA and DO events were described in Section 4. In all cases, average load impacts in a given hour were calculated over only those customer accounts that were called in that hour.
- *Forecast period.* Although events of several different numbers of hours were called in 2009 for the various programs, a standardized event was needed for the ex ante forecast. PG&E defined a consistent four-hour event across all DR programs, for hours-ending 15-18. SCE and SDG&E wished to characterize load impacts for the entire eight-hour period in which events may be called – hours-ending 12 to 19. We developed *average hourly percentage load impacts* as described below, and applied them to each hour of the prototypical ex ante event.

The percentage load impacts were based on the 2009 ex post load impact estimates. The amount of differentiation in the forecast percentage load impacts differed by utility and program.

- PG&E AMP and CBP: by industry group and notice level;
- SCE CBP: by industry group and notice level;
- SCE DRC: by notice level; and
- SDG&E: by notice level and allowed event duration.

We aggregated customer accounts across the relevant groups and estimated percentage load impacts during event and non-event hours. Percentage load impacts in the *ex post* evaluation were calculated relative to the reference loads of those customer accounts that were actually nominated and called on the various events. However, in the case of the *ex ante* evaluation, percentage load impacts were calculated relative to the reference loads of all *enrolled* customer accounts.²² This was the case because the utilities provided forecasts of enrollments but not of nominations, so that our results needed to be expressed on a per enrolled customer basis. The use of enrolled loads in place of loads of customers who were actually nominated in the month of the event embeds the assumption that future nomination patterns match historical patterns, although as described below, we modified that assumption in the case of SCE's DRC program.

4. *Apply percentage load impacts to reference loads for each event scenario.*

²² That is, in the ex post evaluation we report load impacts as percentages of the reference loads of the customers nominated in the month of an event and called for that event. In the ex ante evaluation, we divide the load impact *level* for the typical event by the reference load of all *enrolled* customers. This allows us to consistently expand the percent load impacts *per-enrolled customer* by the utilities' enrollment forecasts. For some utilities and programs, such as SDG&E CBP, there was little difference between enrolled and called customer accounts in 2009. However, for others, such as for SCE DRC DO, the number of customer accounts nominated and called was approximately half of those enrolled.

In this step, the relevant percentage load impacts per enrolled customer account were applied to the per-customer reference loads for each scenario to produce all of the required scenarios of reference loads, estimated event-day loads, and load impacts.

5. *Apply forecast enrollments to produce program-level load impacts.*

For PG&E's programs, The Brattle Group produced load impacts at the program level and by LCA by applying their enrollment forecasts to the database of *per-customer* reference loads and load impacts that CA Energy Consulting created in the previous step. The per-customer reference loads and load impacts were first scaled to match the expected *size* of customers in the enrollment forecast and then multiplied by the number of enrolled customers to obtain cell-level results. Program-level results were obtained by aggregating results across cells. We report these aggregated results in the required Protocol tables, and summarize them in Section 5.4 below.

For SCE, we scaled the results for all levels of reporting using ratios specific to each program and program type. For CBP, enrollments and load impact results were held constant at 2009 levels for the remainder of the forecast years (after adjusting for the transfer of one aggregator's customers to DRC). For DRC, we applied the following procedures:

SCE provided the following forecast data for 2010 through 2012 (to 2020):

- a forecast of contract MW by notice and year; and
- monthly forecasts of the total number of enrolled customers.

For DA, we assumed that the number of enrolled customers would grow in the same proportion as the level of contract MW across years. Implicitly, this assumes that the share of enrolled customers who are nominated stays at 2009 levels throughout the forecast.

For DO, we set the number of enrolled customers equal to the difference between SCE's *total* enrollment forecast and the enrolled customer accounts assigned to DA above. However, because contract MW grows over time at a faster rate than SCE's enrollments, we needed to take the additional step of assuming that the share of enrolled customers who are nominated increases over time. In 2009, only 47 percent of enrolled DO customers were nominated for the one DO event. After adjustment, the shares of nominated relative to enrolled customers in 2010, 2011, and 2012 are: 51.2, 59.8, and 54.4 percent, respectively. In order to simulate this effect, we changed the percentage load impacts (which were originally calculated relative to the total *enrolled* reference load) by forecast year to reflect the fact that a larger share of enrolled customers is nominated.

We assumed that the newly nominated customers provide the same average per-customer load impact as the historically nominated customers. For example, in 2009 the average event-hour percentage load impact was 13.6 percent of the reference load

of enrolled customers.²³ Because of the change in the share of nominated customers, this value increases in the forecast years to 14.7, 17.2, and 15.7 percent in 2010, 2011, and 2012, respectively.

Within DA and DO, enrollments were divided across LCAs according to the shares (of customers, not load) in 2009. Values beyond 2012 were assumed to remain constant.

For SDG&E's CBP program and its new AMP program, the process of creating the program-level load impacts was similar to the one used for PG&E's programs. That is, per-customer reference loads and load impacts were scaled to program and program type using a forecast of the number of enrolled customers in each program and program type. SDG&E provided the enrollment forecast, which consisted of the monthly number of customers in each program type. The share of customers in each industry group was assumed to remain constant.

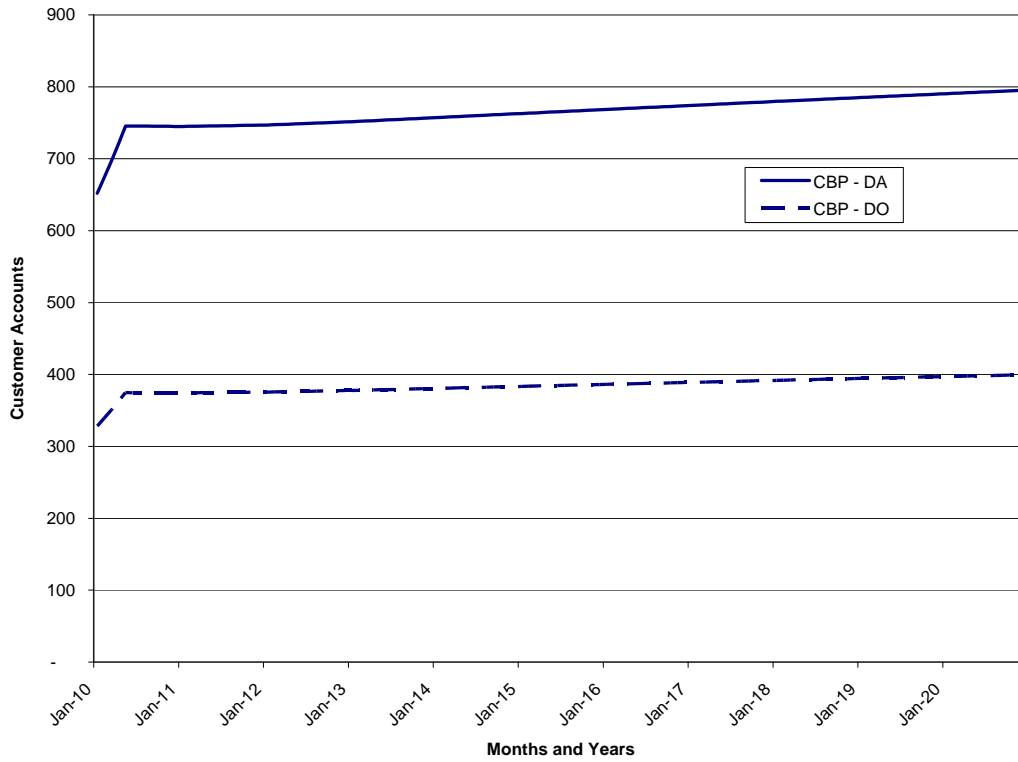
5.3 Enrollment Forecasts

This section summarizes the enrollment forecasts for the different program types at each utility. The following section summarizes the resulting reference loads and ex ante load impact forecasts. Detailed tables of all results required by the Protocols are provided in associated appendices.

Figure 5.1 illustrates PG&E's enrollment forecast for CBP (as developed by The Brattle Group). After an initial increase in 2010, enrollment in both program types expands at a slow rate over time.

²³ The average percentage load impact in the ex post evaluation was 26 percent of the *nominated* reference load.

Figure 5.1: Enrollment Forecasts – PG&E CBP



SCE anticipates that enrollment in CBP will remain stable at 75 DA and 452 DO customer accounts over the forecast horizon.²⁴

Figure 5.2 shows enrollment forecasts for SDG&E's CBP DA and DO program types, as well as its new AMP program. SDG&E anticipates faster growth for the DO program type than for DA.

²⁴ These values reflect a migration of about 100 accounts from CBP to DRC in October 2009.

Figure 5.2: Enrollment Forecasts – SDG&E CBP

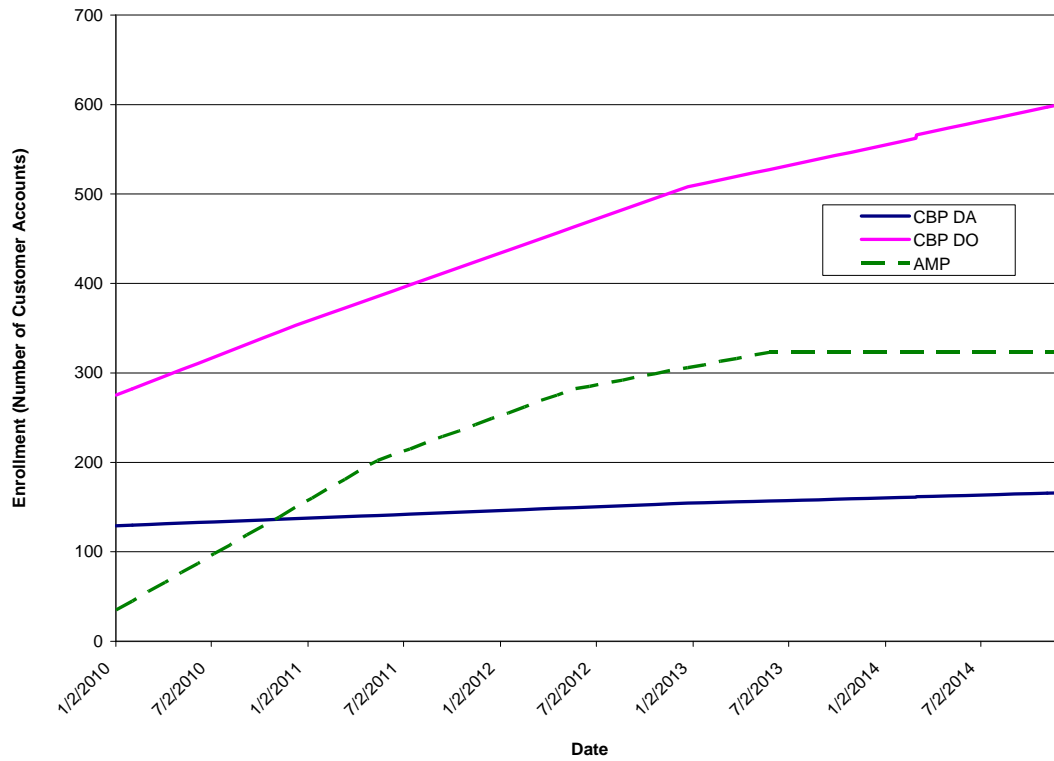


Figure 5.3 summarizes PG&E’s AMP enrollment forecast. Enrollments are expected to increase over the first 18 months, reaching about 460 customer accounts for DA and 1,270 for DO and remaining constant through 2020.

Figure 5.3: Enrollment Forecasts – PG&E AMP

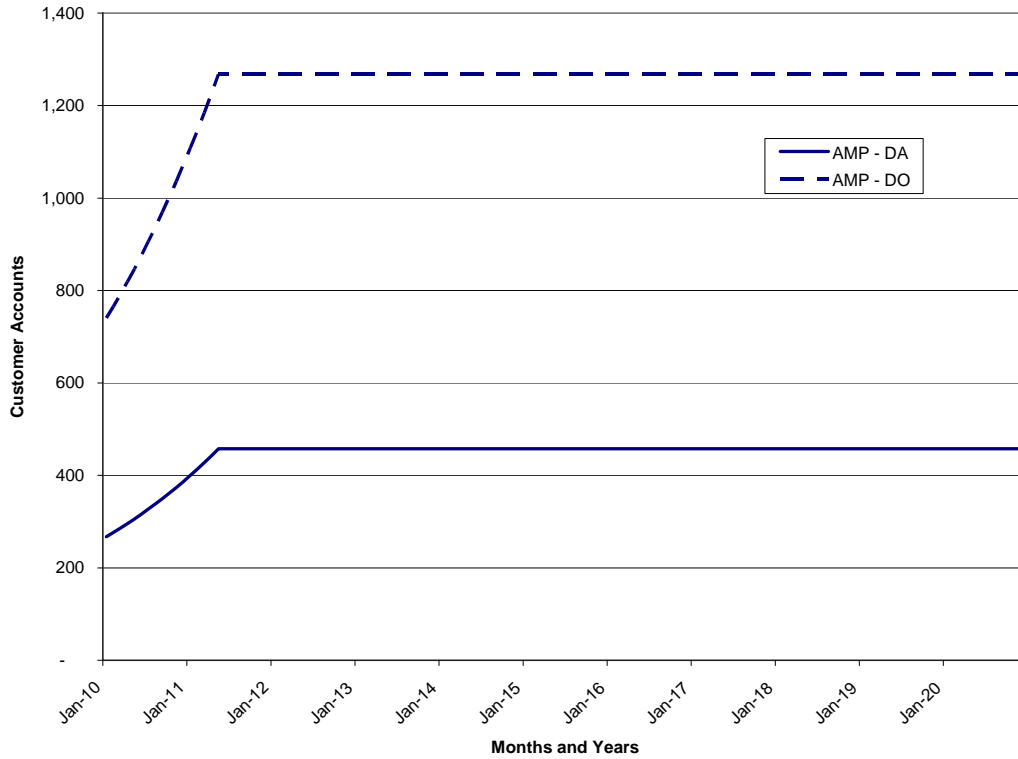


Figure 5.4 summarizes SCE’s DRC contract load amounts for DA and DO program types for 2009, and the anticipated contract amounts through 2012. Figure 5.5 shows SCE’s forecast of annual enrolled customer service accounts in DA and DO based on an allocation of combined enrollment to meet the forecast contract amounts.

Figure 5.4: Expected Contract Amounts – SCE DRC

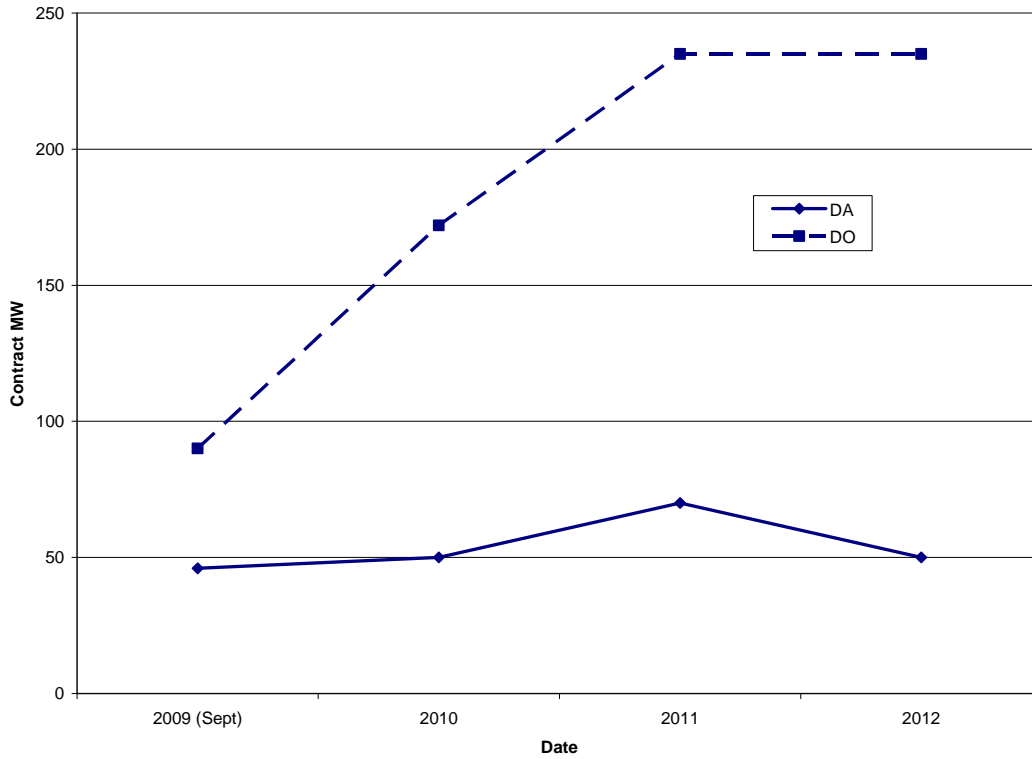
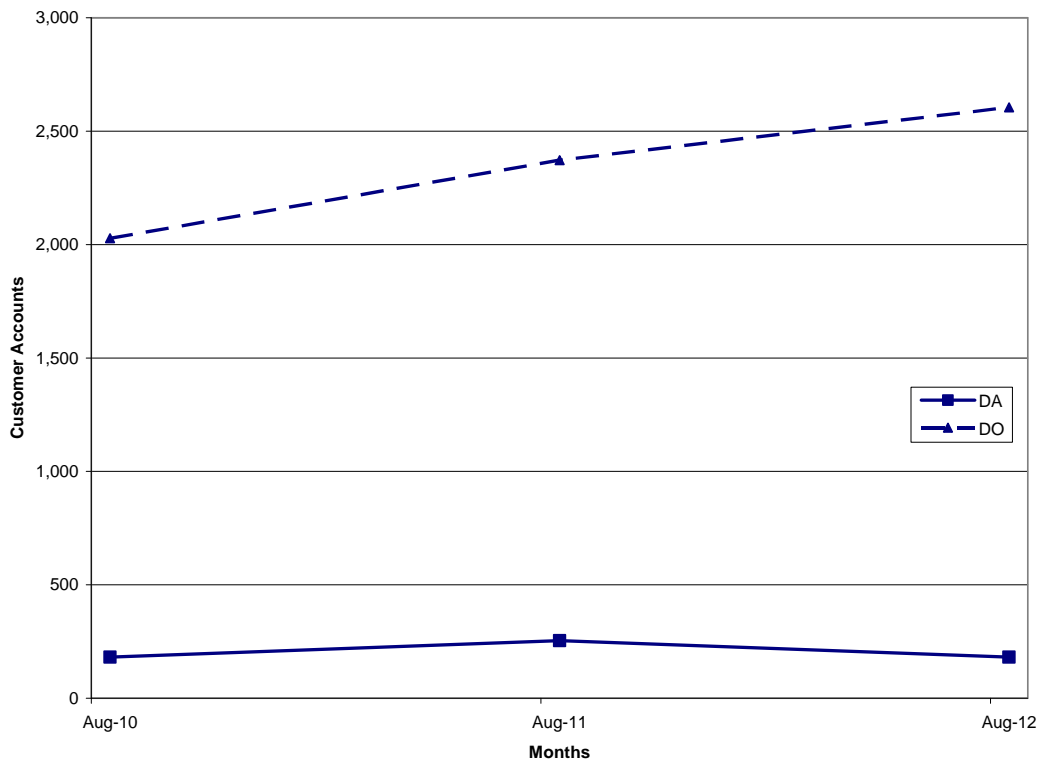


Figure 5.5: SCE DRC Enrollment Forecast



5.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information about the load impact forecasts:

1. Figures showing the hourly profile of the reference load, event-day load, and load impacts for the typical event day in 2012, in a 1-in-2 weather year;
2. Average event-hour load impacts by year; and
3. The allocation of load impacts to LCA, where relevant.

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

5.4.1 PG&E CBP

Figure 5.6 shows the forecast reference load, event-day load, and load impacts for a typical event day in August 2012 in a 1-in-2 weather year for CBP DA.²⁵ Event-hour load impacts average 13.8 MW, which represents approximately 15 percent of the enrolled reference load. Figure 5.7 shows comparable information for CBP DO. Event-hour load impacts for CBP DO average 39.7 MW, which represents approximately 27 percent of the enrolled reference load.

²⁵ For this program, program-level impacts and portfolio-level impacts are the same.

Figure 5.6: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – PG&E CBP - DA

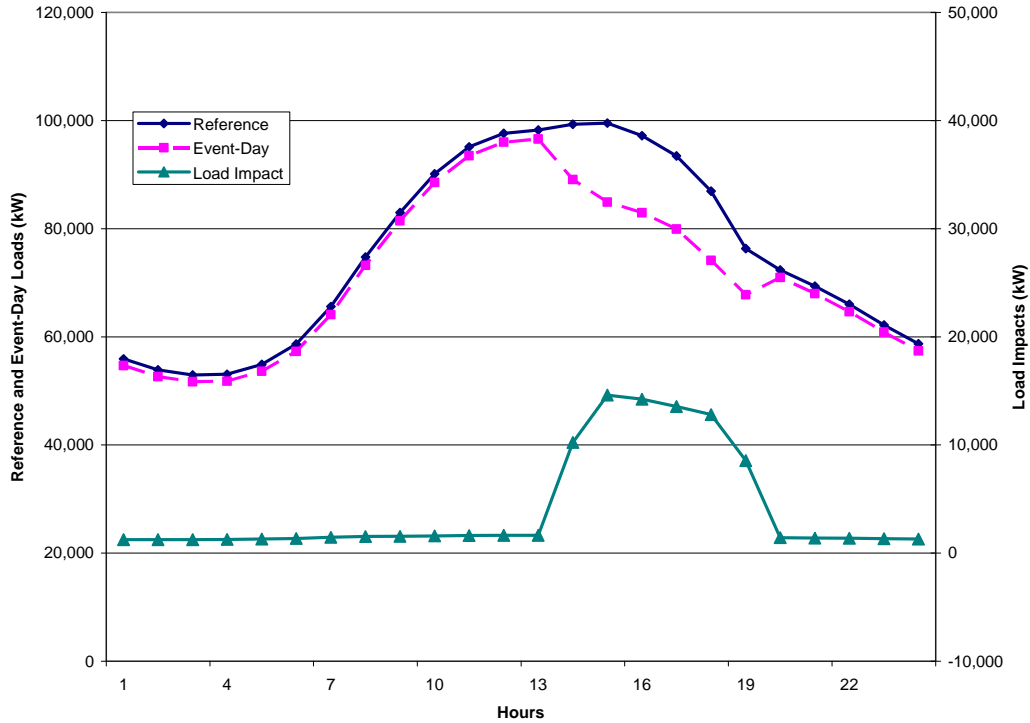


Figure 5.7: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – PG&E CBP - DO

Figure removed for confidentiality reasons.

Figure 5.8 shows forecast load impacts by LCA for the DA and DO program types.

Figure 5.8: Load Impacts by LCA for a Typical Event Day in August 2012 in a 1-in-2 Weather Year (PG&E CBP DA and DO)

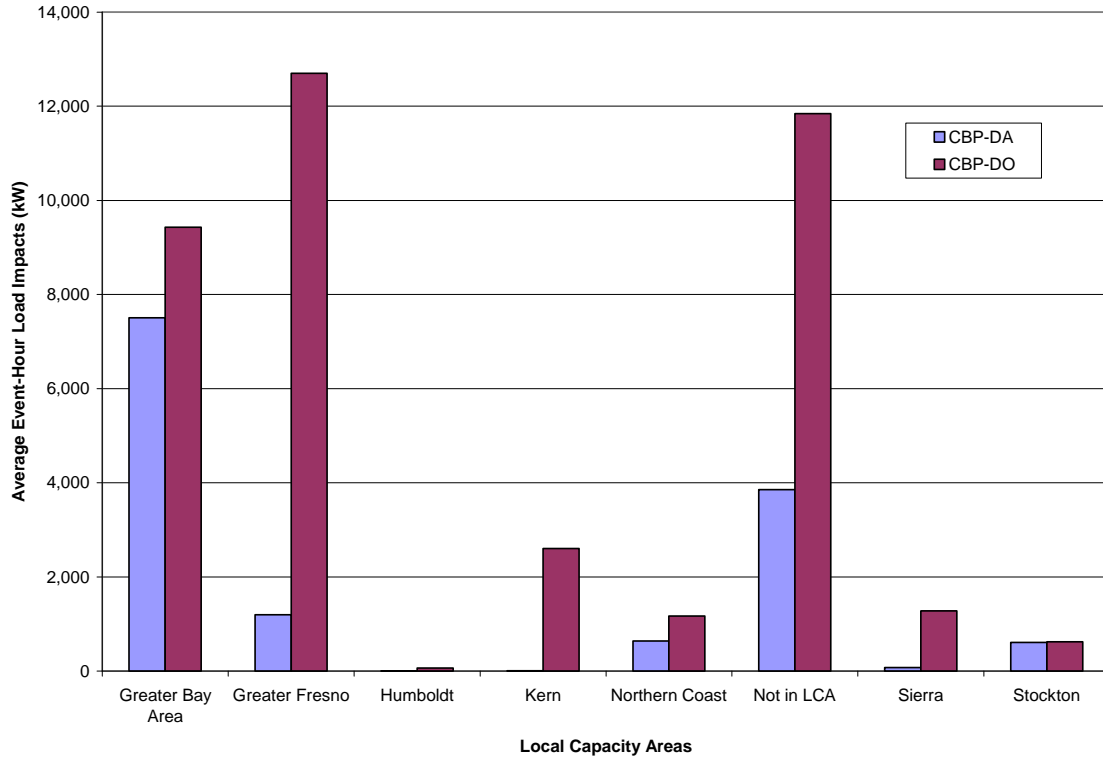
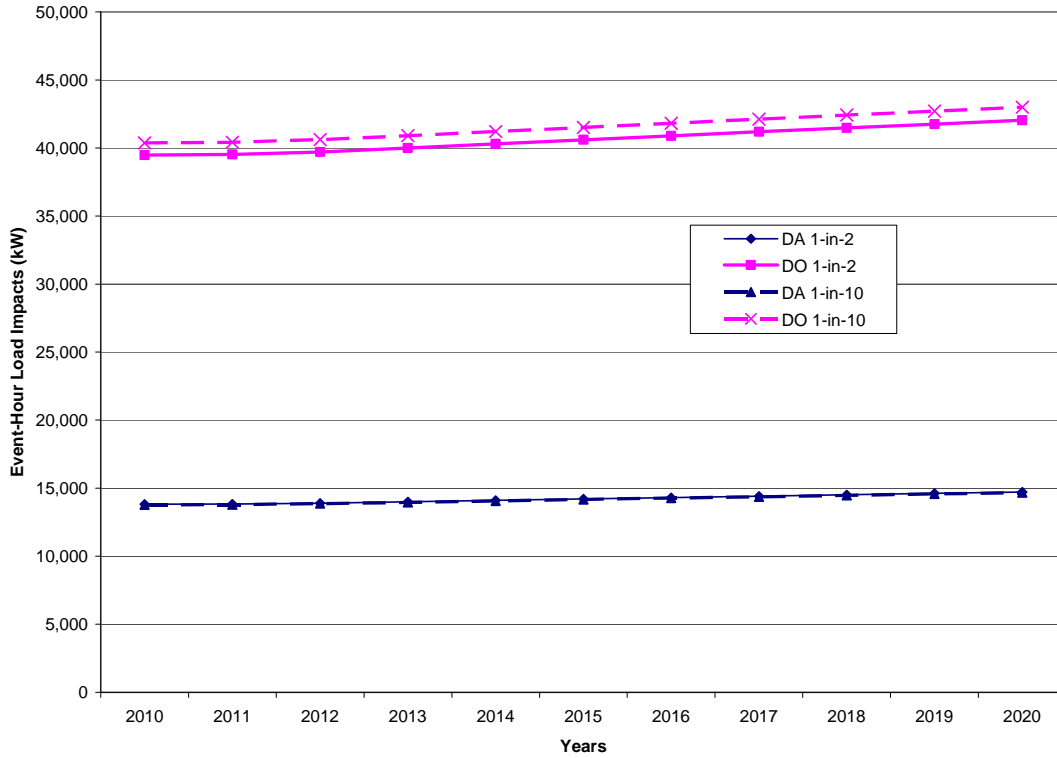


Figure 5.9 illustrates average event-hour load impacts across years for typical event days in August in 1-in-2 and 1-in-10 weather years. The load impacts in this figure mirror the enrollments shown in Figure 5.1, with impacts rising slowly over the forecast period.

Figure 5.9: Average Hourly Load Impacts by Year on Typical August Event Day in 1-in-2 and 1-in-10 Weather Years – PG&E CBP DA and DO



5.4.2 SCE CBP

Figures 5.10 and 5.11 show the forecast reference load and load impacts for a typical event day in a 1-in-2 weather year in 2012 for the SCE CBP DA and DO program types respectively. Event-hour load impacts average about 0.7 MW for the DA program type, which is approximately 10 percent of the enrolled reference load. DO load impacts average about 13.3 MW, or 13.6 percent of the reference load.

Figure 5.10: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SCE CBP DA

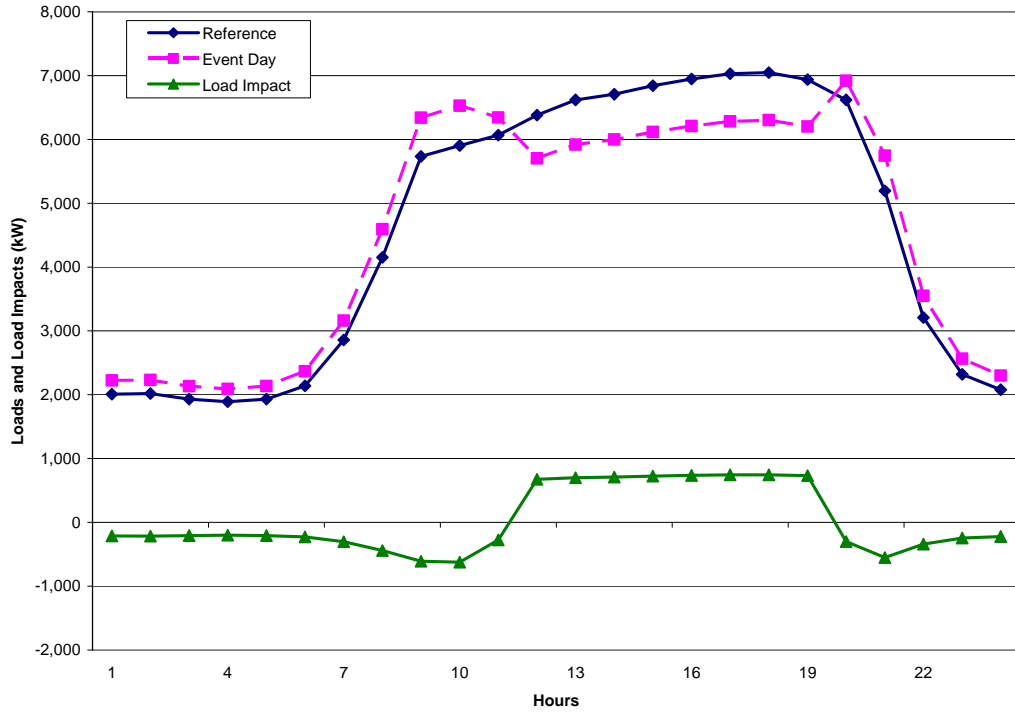


Figure 5.11: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SCE CBP DO

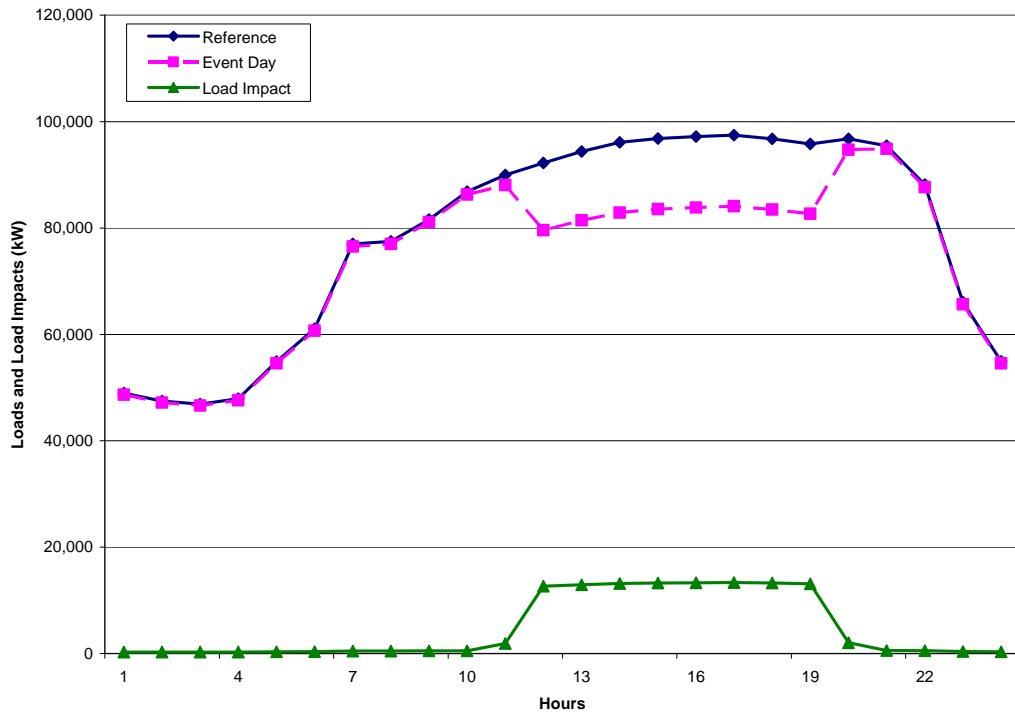


Figure 5.12 illustrates average event-hour load impacts across the first three years of the forecast, for the typical event day in a 1-in-2 weather years. Given the flat enrollment forecasts, the level of load impacts does not change through the forecast period.

Figure 5.12: Average Event-Hour Load Impacts by Forecast Year for the Typical Event Day – SCE CBP DA and DO

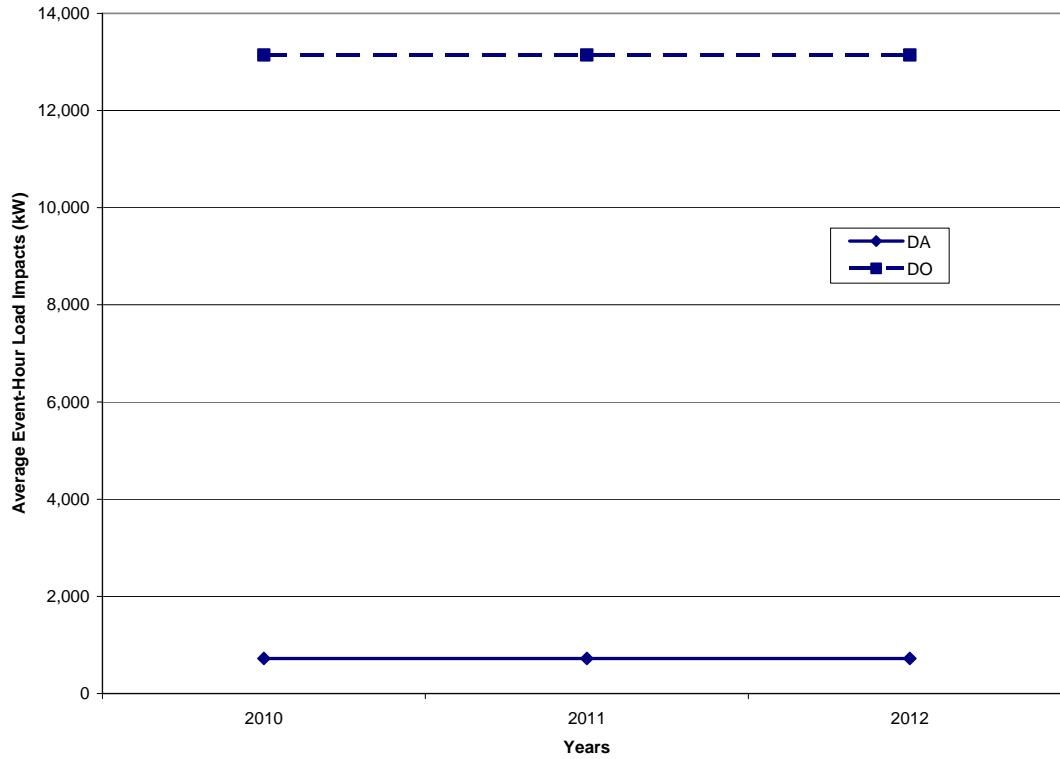
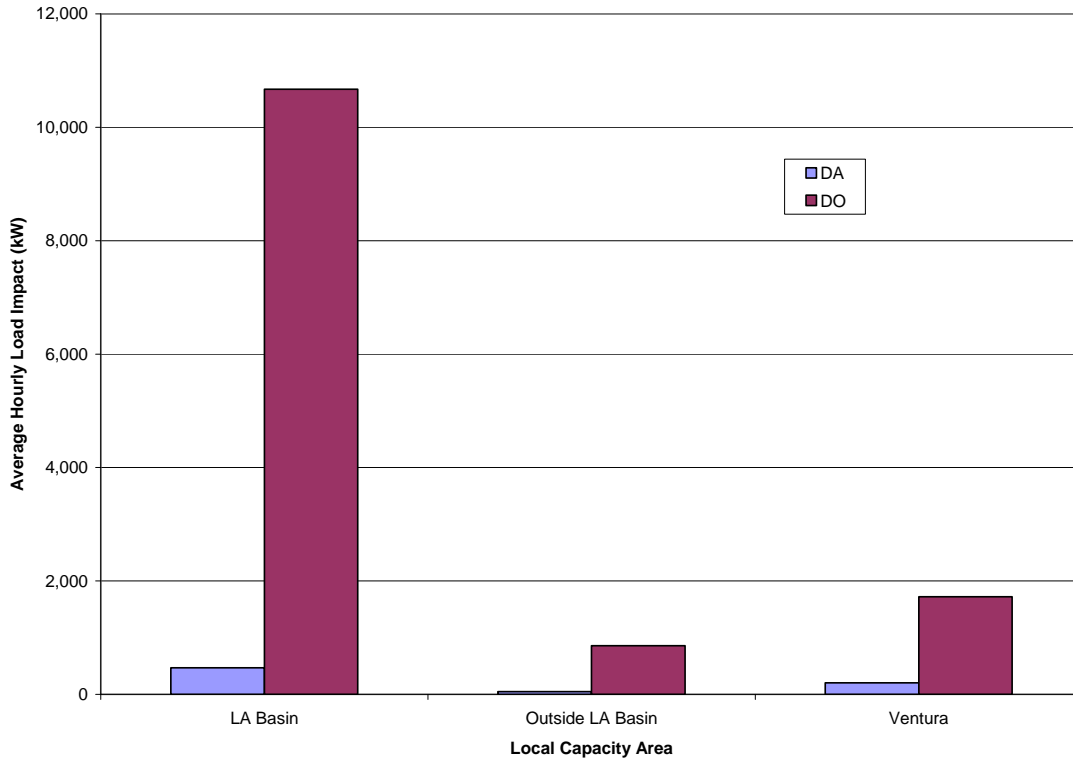


Figure 5.13 shows average event-hour load impacts by LCA for the typical event day in a 1-in-2 weather year in 2012 for the DA and DO program types.

Figure 5.13: Average Event-Hour Load Impacts by LCA for the Typical Event Day in a 1-in-2 Weather Year in 2012 – SCE CBP DA and DO



5.4.3 SDG&E CBP

Figures 5.14 and 5.15 show the forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for the SDG&E CBP DA and DO program types respectively. Event-hour load impacts for DA average about 11.6 MW, which is approximately 26 percent of the enrolled reference load. DO load impacts average 17 MW, or 15 percent.

Figure 5.14: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SDG&E CBP DA

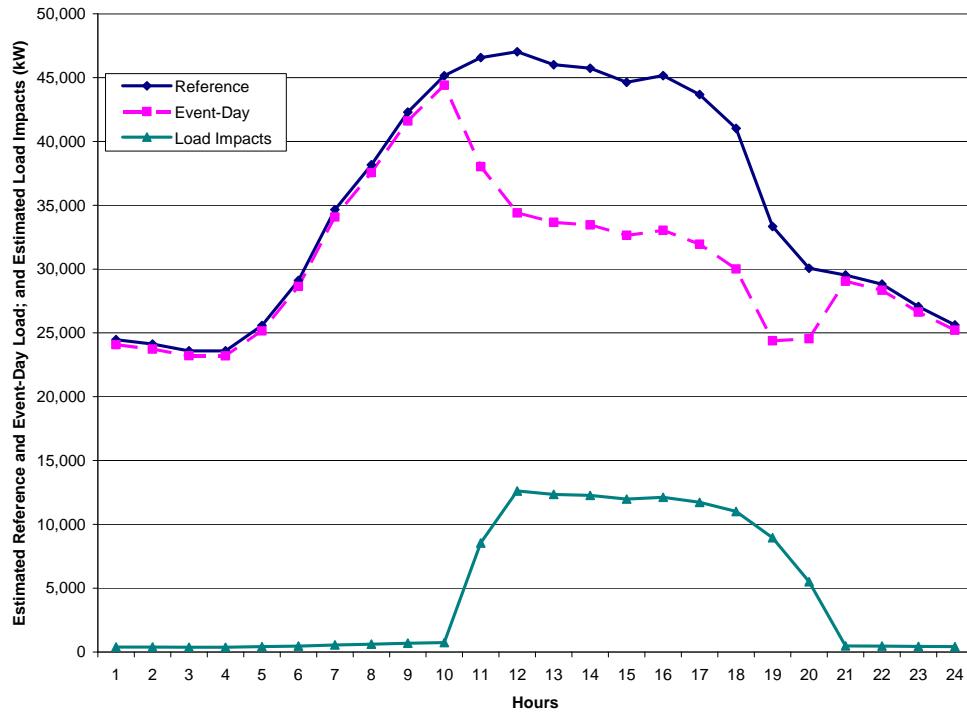


Figure 5.15: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SDG&E CBP DO

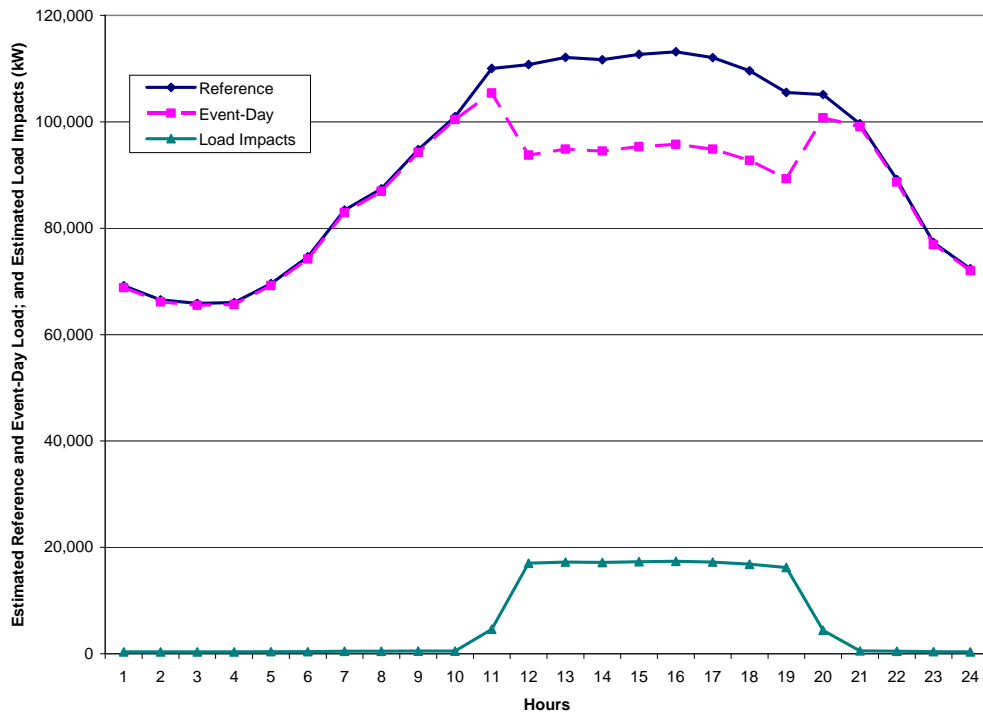
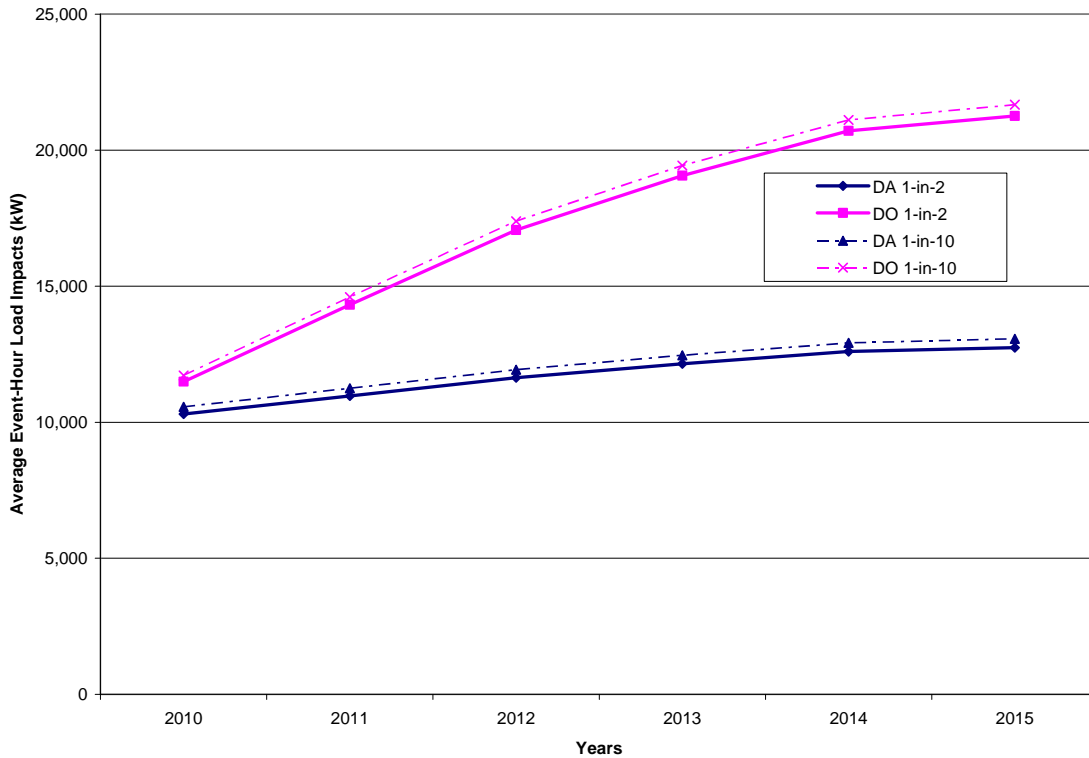


Figure 5.16 illustrates average event-hour load impacts across years for the typical event day in 1-in-2 and 1-in-10 weather years. Given the enrollment forecasts, the levels of load impacts rise until 2015, with DO rising faster than DA, and level off for the remainder of the forecast.

Figure 5.16: Average Event-Hour Load Impacts by Forecast Year – SDG&E CBP (Typical Event Day)



5.4.4 PG&E AMP

Figures 5.17 and 5.18 show the forecast loads and load impacts for a typical event day in August in a 1-in-2 weather year for the PG&E AMP DA and DO program types.²⁶ Average event-hour load impacts are 57.2 for the DA program, and 151.8 for DO, which represent 18 percent and 22 percent of the enrolled reference loads for DA and DO respectively.

²⁶ For this program, program-level impacts and portfolio-level impacts are the same.

Figure 5.17: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – AMP - DA

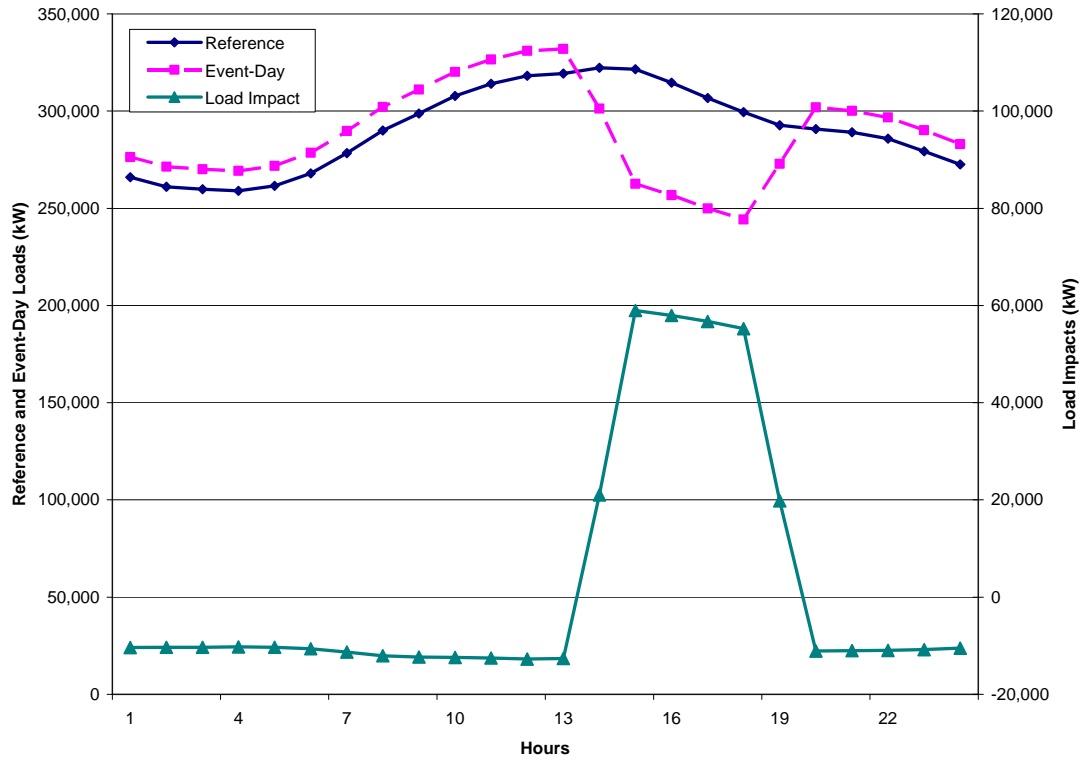


Figure 5.18: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – AMP - DO

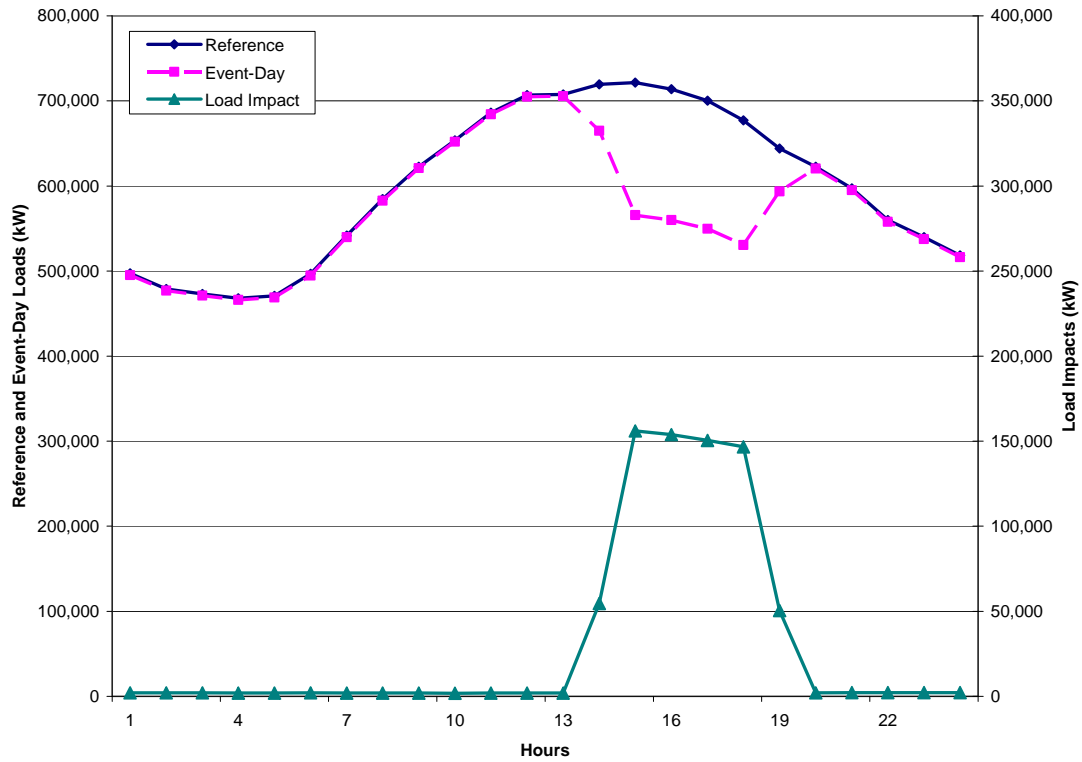


Figure 5.19 shows average event-hour load impacts by LCA for the two program types.

Figure 5.19: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – AMP DA and DO

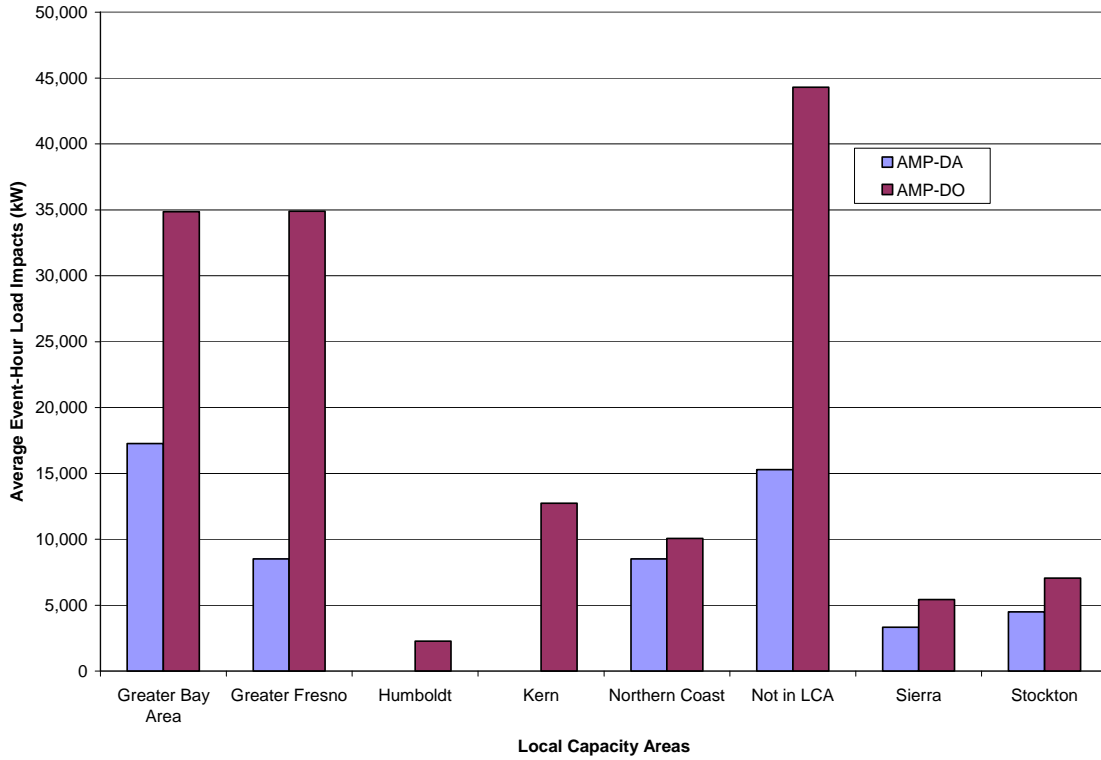
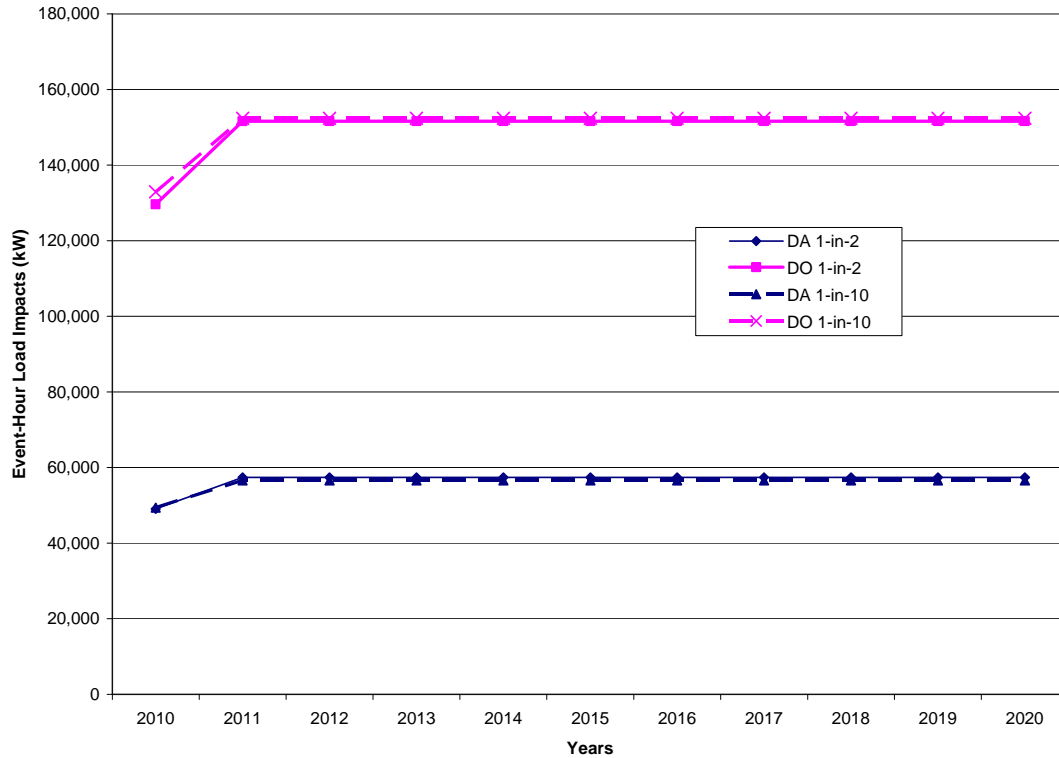


Figure 5.20 illustrates the forecast average event-hour load impact across years for the August peak day in 1-in-2 and 1-in-10 weather years. The load impacts in this figure mirror the enrollment forecast, with impacts increasing through 2011 and then remaining stable.

Figure 5.20: Average Event-Hour Load Impacts by Year for 1-in-2 and 1-in-10 Weather Scenarios – AMP DA and DO



5.4.5 SCE DRC

Figures 5.21 and 5.22 show the hourly profiles of forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for SCE’s DRC DA and DO program types. Event-hour load impacts average approximately 3 MW for DA, which is about 6 percent of the enrolled reference load.²⁷ DO load impacts average 131 MW, which is approximately 19 percent of the enrolled reference load.

²⁷ This level of load impacts for the DA program type is substantially below SCE’s anticipated contract level. However, it is consistent with program performance in 2009.

Figure 5.21: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SCE DRC DA

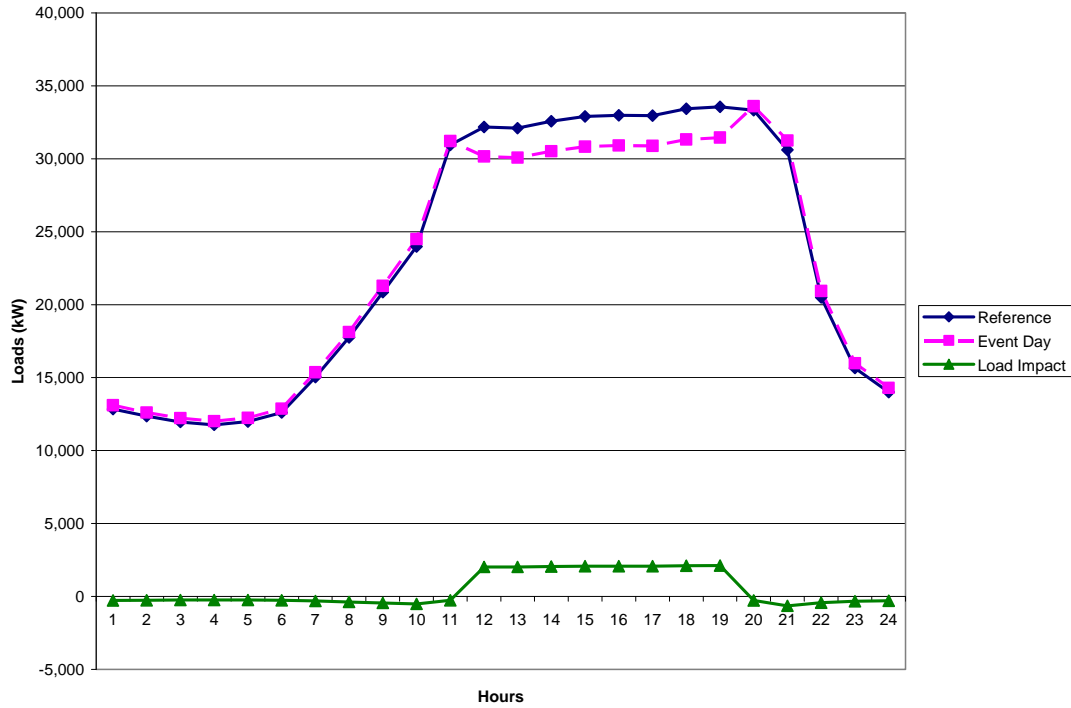


Figure 5.22: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SCE DRC DO

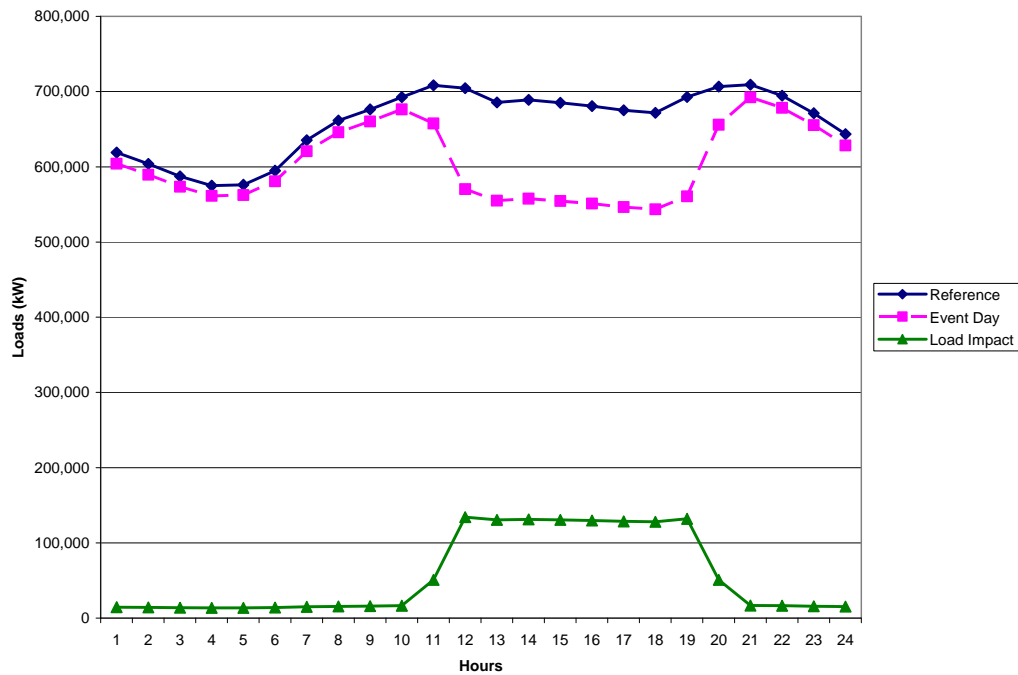


Figure 5.23 illustrates average event-hour load impacts across years for DA (right axis) and DO (left axis) program types, for the typical event day in 1-in-2 weather years. Values are shown through 2012, after which the level of load impacts does not change. Annual values reflect the forecast enrollments, rising for DA in 2011 and then falling to about 3 MW, and rising in 2011 for DO and then remaining level at 131 MW for the remainder of the forecast period.

Figure 5.23: Average Event-Hour Load Impacts by Forecast Year for the Typical Event Day – SCE DRC

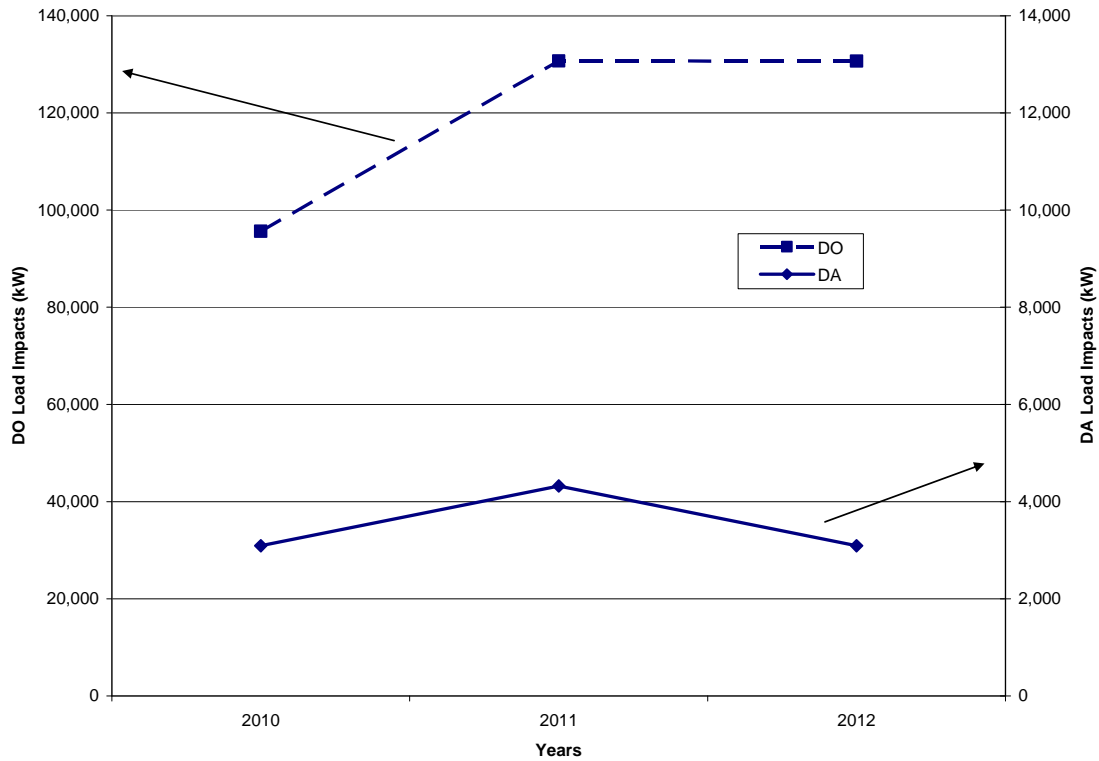
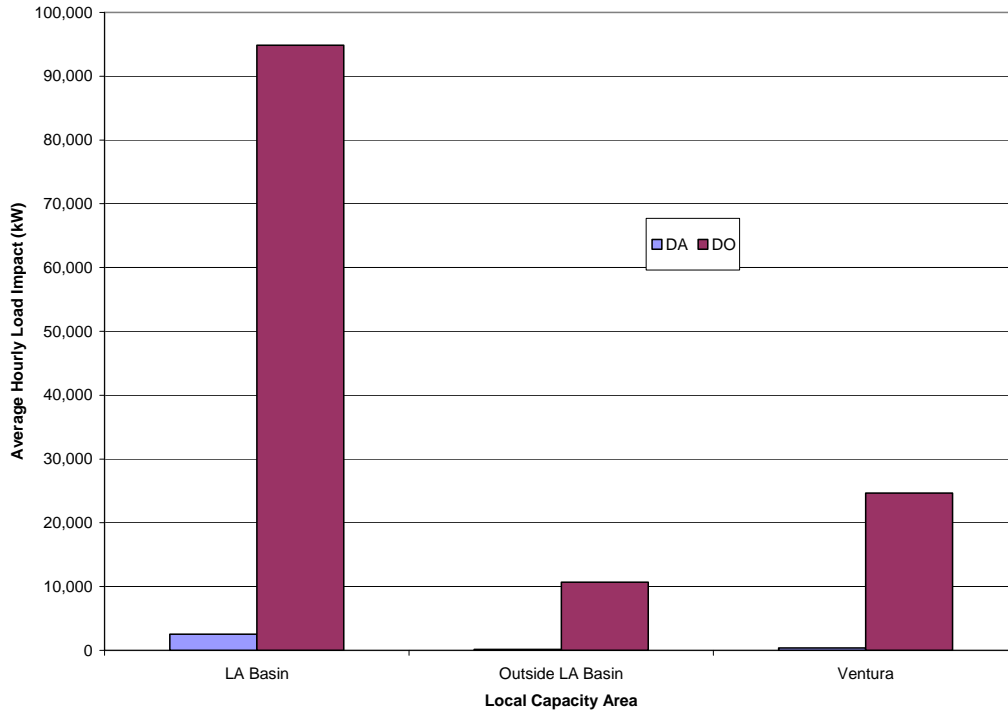


Figure 5.24 shows average event-hour load impacts for the three LCAs for DA and DO.

Figure 5.24: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – DRC DA and DO



5.4.6 SDG&E AMP

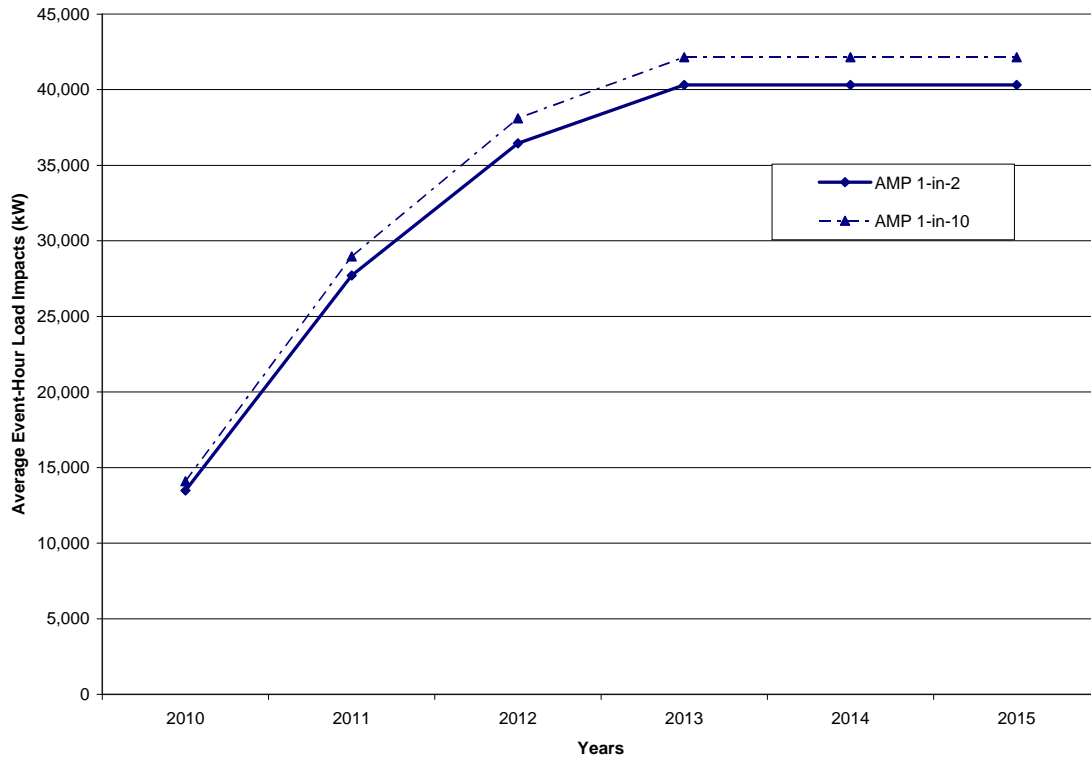
Figure 5.25 shows the hourly profiles of forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for SDG&E’s new AMP program, which only contains the DO program type. Reference loads and per-customer load impacts are based on the historical load data and estimated ex post load impacts for the customer accounts enrolled by one aggregator that has converted his CBP DO program type to an AMP DO contract for 2010. Estimated event-hour load impacts based on the enrollment forecast for the new contract average 36.5 MW, which is about 28 percent of the enrolled reference load.

Figure 5.25: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – SDG&E AMP

Figure removed for confidentiality reasons.

Figure 5.26 illustrates average event-hour load impacts across years for the typical event day in 1-in-2 and 1-in-10 weather years. Load impact values rise to just over 40 MW in 2013 for the 1-in-2 scenario, after which they remain constant.

Figure 5.26: Average Event-Hour Load Impacts for Typical Event Day by Year – SDG&E AMP



6. Validity Assessment

In this study, we estimated customer-specific load-impact regression models that accounted for each customer’s enrollment dates, and nomination and called status for each event. This method has several strong advantages (*e.g.*, properly accounting for bidding behavior, allowing the results to be summarized according to any observed customer characteristic without requiring the estimation of a new model, and the ability to screen customer-specific results for reasonableness). However, it does require the estimation of many models (*e.g.*, for hundreds of customers for each program). While we have largely automated the estimation process, the resulting number of equation results limits the extent to which each customer’s regression equation can be subjected to detailed examination due to time and resource constraints. In addition, in order to facilitate efficient post-processing of the results, it is important to use a uniform model structure across all of the customers in a program. That said, we have screened the estimated equations, particularly looking for large outliers, and have rejected a few load impact estimates when the underlying raw data suggest spurious results. Fortunately, in the case of the aggregator programs, we found very few cases of unusual patterns of estimated load impacts which might suggest spurious results. In fact, most all of the largest estimated load impact coefficients were estimated with high degrees of precision (*e.g.*, t-statistics in excess of 2).

7. Recommendations

One issue that arose during the ex ante evaluation suggests a possible improvement in linkage between the ex post and ex ante efforts. The issue dealt primarily with PG&E's enrollment forecast developed by The Brattle Group. Briefly, Brattle started the enrollment forecast for PG&E CBP from enrollment data provided by PG&E. However, their calculated percentage shares by industry group differed from those that we had developed in the ex post evaluation, and on which the per-customer reference load and load impacts were based. As described above, we had to go to some effort to sort out the program data on monthly enrollments and nominations. It appears to be a duplication of effort for Brattle to have to go through the same process to determine the starting point for their enrollment forecast. We recommend that in future evaluations we work more closely at the beginning of the enrollment forecasting process to ensure comparability of results and avoid duplication. Similar feedback might be appropriate for the enrollment forecasting process for the other two utilities as well.