2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs

Volume 1 : Ex Post and Ex Ante Report

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Steven D. Braithwait, Daniel G. Hansen, and

David Armstrong

Christensen Associates Energy Consulting, LLC
4610 University Ave., Suite 700
Madison, WI 53705
(608) 231-2266

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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 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 2008. Ex post hourly load impacts are estimated for each program and event, using regression analysis of hourly individual customer load, weather, and event data. Ex ante load impacts for 2009 through 2020 are simulated using load profiles and load impacts generated from the Program Year 2008 data, along with enrollment forecasts provided by the utilities.

Executive Summary

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E"). An ex post load impact analysis was performed for Program Year 2008 and an ex ante forecast was developed for 2009 through 2020. 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.

The scope of this evaluation covers 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.

The primary goals of this evaluation study were the following:

1. Assess the effectiveness of the aggregator programs;
2. Estimate the (*ex post*) load impacts for program year 2008;
3. Estimate *ex ante* load impacts for the programs for 2009 through 2020; and
4. Evaluate certain baseline issues.

ES.1 Program resources

CBP

The statewide CBP program is a tariff service that 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.

Each utility has about five or six aggregator agreements under CBP. Aggregators may offer products that differ by time of notification (*e.g.*, day-of or day-ahead) and length of event window. In 2008, PG&E and SDG&E each called one day-of and one day-ahead event, while SCE called twenty day-ahead events and two day-of events.

[1] Capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts.

AMP

Under AMP, aggregators enter bilateral contracts with PG&E, and 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. The baseline method uses the 3-in-10 method, except that for 2008, PG&E and three of five aggregators agreed to modify contracts to offer customers the option of an adjusted baseline, where the adjustment used data on pre-event usage on event days to adjust the baseline load. PG&E called five AMP events, all but one of them test or re-test events. All five aggregators were called simultaneously for only two of the events.

DRC

The terms of SCE's DRC are similar to those of its CBP program. Four aggregators offered a combination of three day-of contracts and two day-ahead contracts in 2008. SCE called twenty-one DRC events, three of which were day-of, and the remainder day-ahead.

Program enrollment

Tables ES.1 and ES.2 summarize 2008 program enrollment in terms of number of customer service accounts (SA IDs) and maximum demand, across all five aggregator programs at the three utilities.[2] Each program has attracted a large number of retail stores, while AMP has enrolled a large share of manufacturers, and DRC has enrolled hundreds of water utilities.

Table ES.1: Aggregator Program Enrollment (*Customer Accounts*)

	CBP			AMP	DRC
Industry type	PG&E	SCE	SDG&E	PG&E	SCE
1. Ag., Mining, Constr.	9	na	2	100	8
2. Manufacturing	25	19	49	172	59
3. Whole., Trans., Util.	73	12	15	93	825
4. Retail	317	563	173	105	358
5. Offices, hotels, services	180	39	54	113	89
6. Schools	47	na	5	39	22
7. Instit. & Govt.	104	5	54	19	34
8. Other/Unknown	11				
TOTAL	766	638	352	641	1,395

[2] 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.

Table ES.2: Aggregator Program Enrollment (*MW of Maximum Demand*)

Industry type	CBP			AMP	DRC
	PG&E	SCE	SDG&E	PG&E	SCE
1. Ag., Mining, Constr.	6.3	na	3.8	47.0	4.0
2. Manufacturing	29.1	9.5	29.4	217.7	42.9
3. Whole., Trans., Util.	19.3	6.7	8.4	77.4	254.4
4. Retail	88.5	164.5	44.2	56.7	159.6
5. Offices, hotels, services	46.1	9.5	11.3	90.4	35.4
6. Schools	32.1	na	6.9	30.1	34.0
7. Instit. & Govt.	11.8	0.9	6.8	12.6	7.4
8. Other/Unknown	1.2				
TOTAL	234.3	201.5	110.6	532.0	537.8

ES.2 Evaluation methodology

We developed direct estimates of total program-level load impacts for each program from the coefficients of individual customer regression equations. These equations were estimated over the summer months for 2008, using individual customer load 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.*, daily CDD)
- Event indicators—Event indicators 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 impacts on event days. In addition, the individual 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 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 – Ex Post Load Impacts

Table ES.3 summarizes estimates of average hourly ex post load impacts for PY 2008 for the three utilities' aggregator programs. These values represent the load impacts under the assumption that both typical *day-ahead* and *day-of* events are called.

Table ES.3: Summary of CBP, AMP and DRC Average Hourly Load Impacts (MW)

Program	PG&E	SCE	SDG&E	Total
CBP	22.2	15.5	16.4	54.1
AMP	64.9	-	-	64.9
DRC	-	34	-	34
Total	87.2	49.5	16.4	211.9

Analysis of the effect of TA/TI participation on load impacts for SDG&E's CBP program, SCE's CBP and DRC programs, and PG&E's AMP program produced some evidence that TA/TI participation increased the percent load impacts for the customers who obtained technical assistance and incentives. In many cases, however, the number of TA/TI participants was quite small, and participation occurred prior to any 2008 events, thus limiting the degree to which formal analyses, particularly of the "before/after" type, could be undertaken.

ES 4 Detailed study findings – Ex Ante Load Impacts

Forecasts of ex ante load impacts were developed for each program. Reference loads were simulated for all of the scenarios required by the Protocols using the load data available from the 2008 program year. Forecast percentage load impacts by industry group were derived from the ex post load impact estimates. The per-customer reference loads and load impacts were scaled according to enrollment forecasts created by the utilities.

Table ES.4 summarizes the forecast ex ante load impact by utility and program for 2012. That year was selected because the majority of the enrollment forecasts are unchanged after that date. Load impacts are forecast to increase for all but SCE's CBP program.

Table ES.4: Summary of Average Hourly Ex Ante Load Impacts (MW) for the Aggregator DR Programs in PY 2012

Program	PG&E	SCE	SDG&E	Total
CBP	43	13	27	83
AMP	159	-	-	159
DRC	-	117	-	117
Total	202	130	27	359

ES 5 Conclusions

The individual customer regression equations appeared to work well in providing the capability to develop both ex post and ex ante load impact estimates and providing the capability of summing across different customer types, to produce load impacts by industry type and local capacity area. They also provided information that could be used as the basis for estimating the incremental effect of TA/TI participation.

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), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E"). An ex post analysis was performed for Program Year 2008 and an ex ante forecast was developed for 2009 through 2020. 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 receive both *capacity credits* for monthly nominated load reductions, regardless of whether events are called, and *energy payments* based on measured load reductions during events.

The scope of this evaluation covers three price-responsive programs, including the state-wide Capacity Bidding Program (CPB), a tariff service operated by all three IOUs, Aggregator Managed Portfolio (AMP) operated by Pacific Gas and Electric (PG&E), and Demand Response Resource Contracts (DRC), operated by Southern California Edison (SCE). The latter two programs are implemented through bilateral contracts between utilities and the aggregators.

The primary goals of this evaluation study were the following:

1. Assess the effectiveness of the aggregator programs;
2. Estimate the (*ex post*) load impacts for program year 2008;
3. Estimate *ex ante* load impacts for the programs for 2009 through 2020; and
4. Evaluate certain baseline issues.

The first goal involved a *process evaluation* consisting of interviews with program and aggregator staff, and surveys of participating customers, with the objective of assessing how effectively the programs have been administered and developing information on customer awareness and response to the programs. Results of the process evaluation are presented in Volume 3 of this report.

The second goal involved estimating the *hourly load impacts* for each event, for each of the utilities' aggregator programs. 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).

The third goal involved combining the information on historical ex post load impacts with utility projections of program enrollment to produce *forecasts of load impacts through 2020* for each of the programs. Key issues involved the detail by which the ex ante load impact forecasts must be presented, including the number of customer types and sizes.

The last goal involved investigation of certain issues in measuring the *baseline loads* that are used to calculate aggregator load impacts for settlement purposes. Key issues included assessing the relative accuracy of baselines developed at the aggregator level compared to those developed by summing individual customer-level baselines; assessing the effect of adjusting the baseline for differences in morning consumption on event days and on days used in constructing the baseline; assessing the degree to which gaming was avoided for those customers who selected the adjusted baseline approach; and assessing several alternatives to the current highest 3-in-10 baseline, including adjusted 5-in-10 and adjusted 10-in-10 baselines. The baseline analysis is documented in Volume 2 of this report.

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 load. 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 is a tariff service that 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. 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 4-hour or 6-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. 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 as the difference between the baseline load and the observed aggregated load in that hour.

PG&E has six CBP aggregators, four of which offer day-ahead products and two of which offer both day-of and day-ahead products. SCE has six aggregator agreements, three of which offer day-of portfolios, two of which offer day-ahead portfolios, and one offers both. SDG&E has six CBP aggregators, four of which offer day-ahead products, one offers day-of products, and one offers both types.

AMP

PG&E has five AMP bilateral aggregator contracts. Four aggregators offer day-of products, while one offers day-ahead 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. The baseline method is the 3-in-10 method, except that for 2008, PG&E and three of five aggregators agreed to modify contracts to offer customers the option of an adjusted baseline. The adjustment used the ratio of usage in the four hours prior to the event to usage in the same hours for the ten weekdays used in the 3-in-10 baseline, where the objective was to produce more accurate baselines for weather-sensitive customers.

DRC

SCE has four DRC aggregators, which offered a combination of three day-of contracts and two day-ahead contracts in 2008. The terms of DRC are similar to those of SCE's CBP program.

2.2 Participant characteristics

In order to assess whether load impacts differ by customer type, the customers are categorized according to eight industry types. 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 summarizes the industry groups and the corresponding North American Industry Classification System (NAICS) codes.

Table 2.1: Industry Group Definition

	NAICS Codes
Agriculture, Mining, Construction	11, 21, 23
Manufacturing	31, 32, 33
Wholesale, transportation, utilities	22, 42, 48-49
Retail	44, 45
Offices, hotel, services	51-56, 62, 72
Schools	61
Institutions, government	71, 81, 92

The participant tables show the following factors for each industry group and overall:

- Number of customers
- Total maximum demand (kW), equal to the sum of customers' individual maximum demands
- Total demand during weekday non-event peak periods (kW)
- The share of peak demand
- Coincidence factor – the ratio of peak demand to maximum demand
- Average customer peak demand (kW).

CBP

Tables 2.2 through 2.4 show CBP enrollment by industry type for PG&E, SCE and SDG&E. The values illustrate that Retail stores make up a large share of CBP enrollees at each of the utilities, especially SCE. At PG&E and SDG&E, Manufacturing, and Offices, Hotels, Finance and Services are also important groups.

The first column in the tables represents the number of customer service accounts. The second column, labeled "Sum of Max kW," represents the sum of enrolled customers' individual maximum demand values. The third column, labeled "Sum of Peak kW," shows average demand during non-holiday summer weekday peak periods (hours ending 13-18) on non-event days. The fourth column indicates the share of peak kW by industry type. The fifth column shows the ratio of average peak demand to maximum demand (shown in column two), a measure of the coincidence of peak demand to maximum demand. These values vary substantially across industry types. They are generally lowest in industry groups 1 and 3, and highest in groups 4 and 5.

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

Industry type	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Coin. Factor	Ave. Size (Pk kW)
1. Ag., Mining, Constr.	9	6,254	4,084	3%	65%	434
2. Manufacturing	25	29,146	21,173	13%	73%	803
3. Whole., Trans., Util.	73	19,281	11,347	7%	59%	153
4. Retail	317	88,454	68,437	42%	77%	179
5. Offices, Hotels, Services	180	46,053	33,090	20%	72%	142
6. Schools	47	32,117	16,535	10%	51%	310
7. Instit. & Govt.	104	11,768	6,979	4%	59%	52
8. Other/Unknown	11	1,224	847	1%	69%	68
TOTAL	766	234,298	162,491		69%	180

Table 2.3: CBP Enrollment by Industry group – *SCE*

Industry type	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Coin. Factor	Ave. Size (kW)
1. Ag., Mining, Constr.	na	na	na	na	na	na
2. Manufacturing	19	9,509	5,772	4%	61%	304
3. Whole., Trans., Util.	12	6,650	3,512	2%	53%	293
4. Retail	563	164,522	127,368	84%	77%	226
5. Offices, hotels, services	39	9,500	6,839	5%	72%	175
6. Schools	na	na	na	na	na	na
7. Instit. & Govt.	5	878	703	0%	80%	141
TOTAL	641	201,541	151,462		75%	236

na = not available due to small cell count

Table 2.4: CBP Enrollment by Industry group – *SDG&E*

Industry type	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Coin. Factor	Ave. Size (kW)
1. Ag., Mining, Constr.	2	3,752	1,049	1%	28%	525
2. Manufacturing	49	29,357	16,730	22%	57%	341
3. Whole., Trans., Util.	15	8,363	3,235	4%	39%	216
4. Retail	173	44,215	36,175	48%	82%	209
5. Offices, hotels, services	54	11,300	8,520	11%	75%	158
6. Schools	5	6,877	4,062	5%	59%	812
7. Instit. & Govt.	54	6,779	4,921	7%	73%	91
TOTAL	352	110,642	74,692		68%	212

Tables 2.5 and 2.6 show CBP enrollment by CAISO Local Capacity Area (LCA) for PG&E and SCE.

Table 2.5: CBP Enrollment by Local Capacity Area – *PG&E*

Local Capacity Area	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Ave. Size (Pk kW)
1 Greater Bay Area	561	121,846	87,101	54%	126
2 Greater Fresno	20	13,545	7,458	5%	321
3 Humboldt	na	na	na	na	na
4 Kern	33	14,740	9,246	6%	263
5 Northern Coast	22	10,342	7,796	5%	301
6 Sierra	36	13,477	9,452	6%	214
7 Stockton	16	6,396	4,593	3%	244
8 Other	77	53,888	36,800	23%	445
Total	766	234,298	162,491		180

Table 2.6: CBP Enrollment by Local Capacity Area – *SCE*

LCA	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Ave. Size (kW)
LA_BASIN	488	150,810	114,435	76%	234
OUTSIDE LA	31	11,816	9,033	6%	291
Other	33	11,679	8,113	5%	246
VENTURA	89	27,237	19,882	13%	223
Total	641	201,541	151,462		236

AMP and DRC

Tables 2.7 through 2.10 show comparable enrollment information for PG&E's AMP program and SCE's DRC program. AMP has a large share of Manufacturing customers, while DRC has large shares in the Wholesale, Transportation and other Utilities, and Retail groups.

Table 2.7: AMP Enrollment by Industry group

Industry type	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Coin. Factor	Ave. Size (Pk kW)
1. Ag., Mining, Constr.	100	47,038	18,738	5%	40%	161
2. Manufacturing	172	217,742	149,167	43%	69%	803
3. Whole., Trans., Util.	93	77,396	43,713	13%	56%	450
4. Retail	105	56,682	42,499	12%	75%	321
5. Offices, Hotels, Services	113	90,449	63,749	19%	70%	443
6. Schools	39	30,085	17,487	5%	58%	387
7. Instit. & Govt.	19	12,562	8,859	3%	71%	396
TOTAL	641	531,953	344,212		65%	472

Table 2.8: AMP Enrollment by Local Capacity Area

Local Capacity Area	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Ave. Size (Pk kW)
1 Greater Bay Area	220	171,515	123,678	36%	456
2 Greater Fresno	125	77,803	44,171	13%	317
3 Humboldt	8	3,034	1,332	0%	160
4 Kern	16	22,297	13,496	4%	771
5 Northern Coast	52	26,949	15,673	5%	247
6 Sierra	40	19,359	11,570	3%	236
7 Stockton	22	16,989	9,943	3%	403
8 Other	158	194,007	124,350	36%	746
Total	641	531,953	344,212		472

Table 2.9: DRC Enrollment by Industry group

Industry type	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Coin. Factor	Ave. Size (kW)
1. Ag., Mining, Constr.	8	4,005	2,379	1%	59%	297
2. Manufacturing	59	42,879	26,267	8%	61%	445
3. Whole., Trans., Util.	825	254,444	135,034	42%	53%	164
4. Retail	358	159,626	110,084	34%	69%	307
5. Offices, hotels, services	89	35,413	22,503	7%	64%	253
6. Schools	22	34,026	23,376	7%	69%	1,063
7. Instit. & Govt.	34	7,400	3,223	1%	44%	95
TOTAL	1,395	537,792	322,867		60%	231

Table 2.10: DRC Enrollment by LCA

LCA	Count	Sum of Max kW	Sum of Peak kW	% of Peak kW	Ave. Size (kW)
LA_BASIN	1010	404,292	243,231	75%	241
OUTSIDE LA	245	67,824	40,966	13%	167
Other	69	32,597	18,898	6%	274
VENTURA	71	33,079	19,772	6%	278
Total	1,395	537,792	322,867		231

2.3 Program events

CBP

PG&E called two CBP event days in 2008, as shown in Table 2.11. One was a four-hour *day-of* event on June 20, and the other was a two-hour *day-ahead* test event on August 14. SCE called twenty-two events, two of which were day-of events, as shown in Table 2.12. The number of portfolios offered by the five CBP aggregators that were called varied somewhat by event, as did the hours called. The hours for the portfolio with the broadest window are shown in the "Hours" column. The hours common to each portfolio for each event are shown in the last column. SDG&E called a day-of and day-ahead event, as shown in Table 2.13.

Table 2.11: PG&E CBP Events – 2008

Date	Type	Event/Test	Hours
6/20/2008	DO	Event	HE 14-17
8/14/2008	DA	Test	HE 16-17

Table 2.12: SCE CBP Events – 2008

Event	Date	Type	Num. of Portfolios	Hours	Common Hours
1	07-Jul-08	DA	12	HE 13-17	14-17
2	08-Jul-08	DA	12	HE 13-17	14-17
3	09-Jul-08	DA	12	HE 14-17	14-17
4	10-Jul-08	DA	12	HE 14-17	14-17
5	14-Jul-08	DA	12	HE 14-17	14-17
6	05-Aug-08	DA	13	HE 14-17	14-17
7	06-Aug-08	DA	13	HE 14-17	14-17
8	07-Aug-08	DA	12	HE 15-17	15-17
9	11-Aug-08	DA	12	HE 16-17	16-17
10	12-Aug-08	DA	12	HE 16-17	16-17
11	27-Aug-08	DA	12	HE 15-16	15-16
12	28-Aug-08	DA	12	HE 15-17	15-17
13	29-Aug-08	DA	13	HE 14-17	14-17
14	03-Sep-08	DA	13	HE 15-17	15-17
15	04-Sep-08	DA	13	HE 15-17	15-17
16	05-Sep-08	DA	13	HE 15-17	15-17
17	26-Sep-08	DA	8	HE 16	16
18	01-Oct-08	DO	7	HE 17-18	17-18
19	06-Oct-08	DA	14	HE 14-18	14-17
20	13-Oct-08	DA	14	HE 13-19	15-18
21	20-Oct-08	DA	14	HE 13-19	15-18
22	23-Oct-08	DO	7	HE 15-17	15-17

Table 2.13: SDG&E CBP Events – 2008

Event	Date	Option	Hours
1	7/9/2008	DA4	HE 14-17
		DA6	HE 13-18
2	10/1/2008	DO4	HE 14-17
		DO6	HE 14-19

Tables 2.14 and 2.15 list the events for PG&E's AMP and SCE's DRC programs. Five AMP events were called, but the last one was not included in the analysis because only one aggregator, with only one nominated customer account, was called.

Table 2.14: AMP (PG&E) Events – 2008

Event	Date	Type	Event/Test	Hours
1	5/16/2008	DO/DA	Event/Test	HE 15-16, 14-17
2	7/9/2008	DO	Test[1]	HE 16-17
3	8/14/2008	DO/DA	Test	HE 16-17
4	9/5/2008	DO	Test[2]	HE 16-17
5	9/26/2008	DO	Test[3]	

[1] Four of five aggregators
[2] Two of five aggregators
[3] One of five aggregators

Table 2.15: DRC (SCE) Events – 2008

Event	Date	Type	Event/ Test	Num. of Agg.	Hours
1	3/25/2008	DO	Test	1	HE 15-16
2	7/8/2008	DO	Event	3	HE 17-18
3	7/9/2008	DA	Test	1	HE 14-17
4	7/10/2008	DA	Event	1	HE 14-17
5	7/14/2008	DA	Event	1	HE 14-17
6	8/5/2008	DA	Event	1	HE 14-17
7	8/6/2008	DA	Event	2	HE 14-17
8	8/7/2008	DA	Event	2	HE 15-17
9	8/11/2008	DA	Event	2	HE 16-17
10	8/12/2008	DA	Event	2	HE 16-17
11	8/27/2008	DA	Event	2	HE 16-17
12	8/28/2008	DA	Event	2	HE 16-17
13	8/29/2008	DA	Event	2	HE 14-17
14	9/3/2008	DA	Event	2	HE 15-17
15	9/4/2008	DA	Event	2	HE 15-17
16	9/5/2008	DA	Event	2	HE 15-17
17	9/26/2008	DA	Event	2	HE 16
18	10/6/2008	DA	Event	2	HE 14-17
19	10/13/2008	DA	Event	2	HE 15-18
20	10/20/2008	DA	Event	2	HE 14-17
21	11/7/2008	DO	Event	1	HE 13-14

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 2008, 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.*, daily CDD)
- Event indicators—Event indicators 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.[3] Finally, uncertainty-adjusted load impacts were calculated to illustrate the degree of statistical confidence that exists around the estimated load impacts.

3.1 Primary regression equation specifications

Ex post load impacts were estimated using customer-level hourly data from May through October. The primary model that was used is shown below.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{11} \sum_{i=1}^{24} (b_{Evt,i}^{DR} \times h_{i,t} \times DR_t) + b^{MornLoad} \times MornLoad_t + \sum_{i=1}^{24} (b_i^{CDD} \times h_{i,t} \times CDD_t) \\
&+ \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) \\
&+ \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + e_t
\end{aligned}
$$

In this equation, Q_t represents hourly demand for a customer; the *b*'s are estimated parameters; $h_{i,t}$ is a dummy variable for hour *i*; *DR* indicates that a particular day was called as an event; $MornLoad_t$ is the day's average load from hours 1 through 10; CDD_t is cooling degree days;[4] 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 the months of June through October; and e_t is the error term. The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for the level of load on a particular day. Because of the autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

Separate models were estimated for each customer. The 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.

3.2 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.

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[3] 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.

[4] Cooling degree days are defined as MAX[0, (maxT + minT) / 2 – 65], where maxT is the maximum daily temperature in degrees Fahrenheit and minT is the minimum daily temperature.

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 10^{th}, 30^{th}, 70^{th}, and 90^{th} percentile scenarios are generated from these distributions.

4. Detailed Study Findings

This section describes the results of our estimation of aggregate and per-customer event-day load impacts for each aggregator program and each utility. For each program, we begin by summarizing the load impacts estimated for 2008, using estimates of *average hourly load impacts* for each event, and, where relevant, for average or typical events. We then provide the formal tables required by the Protocols, including reference loads, observed loads, and load impacts by hour, and uncertainty-adjusted load impacts at different probability levels. Load impact results are also illustrated in figures. We also provide illustrative graphs of the observed aggregated program load on selected event-days and non-event days as a form of real-world confirmation of the estimated load impacts.

We begin with CBP at each of the three utilities, and then turn to AMP and DRC.

4.1 CBP

4.1.1 PG&E[5]

Program-level load impacts

Table 4.1 shows average hourly estimated load impacts by industry group for PG&E's two CBP events. The Retail industry group provided the largest share of load impacts on the day-of (DO) event, while the Manufacturing and Retail industry groups provided the largest share of day-ahead (DA) load impacts. Since one event was a day-of event (June 20), and the other was a day-ahead event (August 14), the total (average hourly) load impact potential of the program may be considered as the sum of the two values – *e.g.*, 8.3 MW per hour for the day-of program type and 21.8 MW per hour for the day-ahead program type, for a total of 30.1 MW per hour.

[5] No CBP customer accounts at PG&E participated in TA/TI in 2008, so no incremental impact analysis was undertaken.

Table 4.1: PG&E CBP Average Hourly Load Impacts, by Industry Group (kW)

Industry type	Evt 1 (DO) 20-Jun	Evt 2 (DA) 14-Aug
1. Ag., Mining, Constr.	0	94
2. Manufacturing	-11	5,822
3. Whole., Trans., Util.	1,716	1,243
4. Retail	4,117	5,950
5. Offices, Hotels, Services	172	510
6. Schools	216	2,037
7. Instit. & Govt.	0	320
8. Other/Unknown	0	44
TOTAL	6,211	16,020

Table 4.2 shows average hourly load impacts by LCA. The largest shares of the program's load impacts are in the Greater Bay Area and Other.

Table 4.2: PG&E CBP 2008 Average Hourly Load Impacts, by LCA (kW)

	Local Capacity Area	Evt 1 (DO) 20-Jun	Evt 2 (DA) 14-Aug
1	Greater Bay Area	1,952	6,974
2	Greater Fresno	323	952
3	Humboldt	0	12
4	Kern	1,289	837
5	Northern Coast	773	636
6	Sierra	862	790
7	Stockton	381	644
8	Other	630	5,173
	Total	6,211	16,020

SCAPP results

The 355 customers participating in the Small Customer Aggregator Pilot Program (SCAPP) produced an average hourly load impact of approximately 839 kW for the second event, in which their aggregator nominated load reductions. This estimate was obtained by adding up the estimated load impacts for each customer that was identified as a participant in SCAPP.

Hourly load impacts

Tables 4.3a and 4.3b show aggregate and per-customer (respectively) hourly reference load, observed load, and load impact values for PG&E's day-of CBP program type on the June 20, 2008 DO event. Hourly load impacts averaged about 21 percent of the reference load. The 10th and 90th percentile load impacts are estimated to lie about 7 percent below and above the estimated load impacts for the event. Figure 4.1 illustrates the loads and load impacts for the DO event, while Figure 4.2 illustrates the uncertainty-adjusted DO load impacts.

Table 4.3a: Aggregate Hourly Load Impacts – *PG&E CBP DO Event (June 20)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	17,103	17,550	-446	73	-825	-601	-446	-291	-67
2	17,065	17,568	-503	71	-882	-658	-503	-348	-124
3	17,187	17,718	-531	70	-910	-686	-531	-375	-151
4	17,618	18,050	-431	68	-811	-587	-431	-276	-52
5	18,128	18,159	-31	67	-410	-186	-31	124	348
6	19,158	18,545	613	66	234	458	613	768	992
7	21,015	20,205	810	67	430	654	810	965	1,189
8	21,947	21,554	393	72	14	238	393	548	772
9	24,494	24,260	234	77	-145	79	234	390	614
10	25,065	25,062	3	83	-377	-153	3	158	382
11	26,113	26,157	-43	87	-423	-199	-43	112	336
12	26,973	27,197	-225	91	-604	-380	-225	-69	155
13	27,706	25,459	2,247	94	1,868	2,092	2,247	2,402	2,626
14	28,302	22,464	5,838	96	5,459	5,683	5,838	5,993	6,217
15	28,832	22,568	6,263	98	5,884	6,108	6,263	6,419	6,643
16	28,928	22,363	6,565	100	6,185	6,410	6,565	6,720	6,944
17	28,724	22,548	6,176	101	5,797	6,021	6,176	6,332	6,556
18	27,942	25,377	2,565	100	2,186	2,410	2,565	2,720	2,944
19	27,313	26,591	722	98	343	567	722	877	1,101
20	26,419	25,831	588	95	209	433	588	743	967
21	25,971	25,807	163	91	-216	8	163	319	543
22	24,788	24,640	147	86	-232	-8	147	302	526
23	21,007	20,417	590	83	211	435	590	745	969
24	17,968	17,369	599	80	220	444	599	754	978
	Reference Energy Use (kWh)	Estimated 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	565,767	533,459	32,307	261.3	n/a	n/a	n/a	n/a	n/a

Table 4.4b: Per Customer Hourly Load Impacts – *PG&E CBP DO Event (June 20)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	241	247	-6	73	-12	-8	-6	-4	-1
2	240	247	-7	71	-12	-9	-7	-5	-2
3	242	250	-7	70	-13	-10	-7	-5	-2
4	248	254	-6	68	-11	-8	-6	-4	-1
5	255	256	0	67	-6	-3	0	2	5
6	270	261	9	66	3	6	9	11	14
7	296	285	11	67	6	9	11	14	17
8	309	304	6	72	0	3	6	8	11
9	345	342	3	77	-2	1	3	5	9
10	353	353	0	83	-5	-2	0	2	5
11	368	368	-1	87	-6	-3	-1	2	5
12	380	383	-3	91	-9	-5	-3	-1	2
13	390	359	32	94	26	29	32	34	37
14	399	316	82	96	77	80	82	84	88
15	406	318	88	98	83	86	88	90	94
16	407	315	92	100	87	90	92	95	98
17	405	318	87	101	82	85	87	89	92
18	394	357	36	100	31	34	36	38	41
19	385	375	10	98	5	8	10	12	16
20	372	364	8	95	3	6	8	10	14
21	366	363	2	91	-3	0	2	4	8
22	349	347	2	86	-3	0	2	4	7
23	296	288	8	83	3	6	8	10	14
24	253	245	8	80	3	6	8	11	14
	Reference Energy Use (kWh)	Estimated 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	7,969	7,514	455	261.3	n/a	n/a	n/a	n/a	n/a

Figure 4.1: Hourly Loads and Load Impacts – *PG&E CBP DO Event (June 20)*

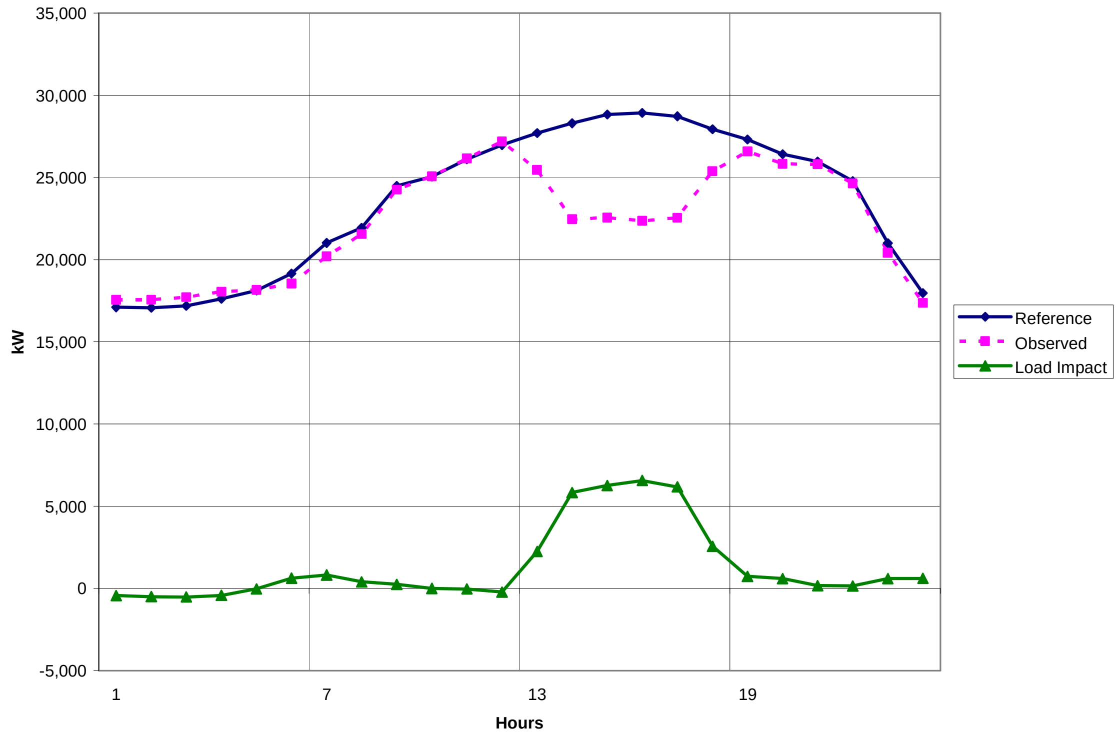
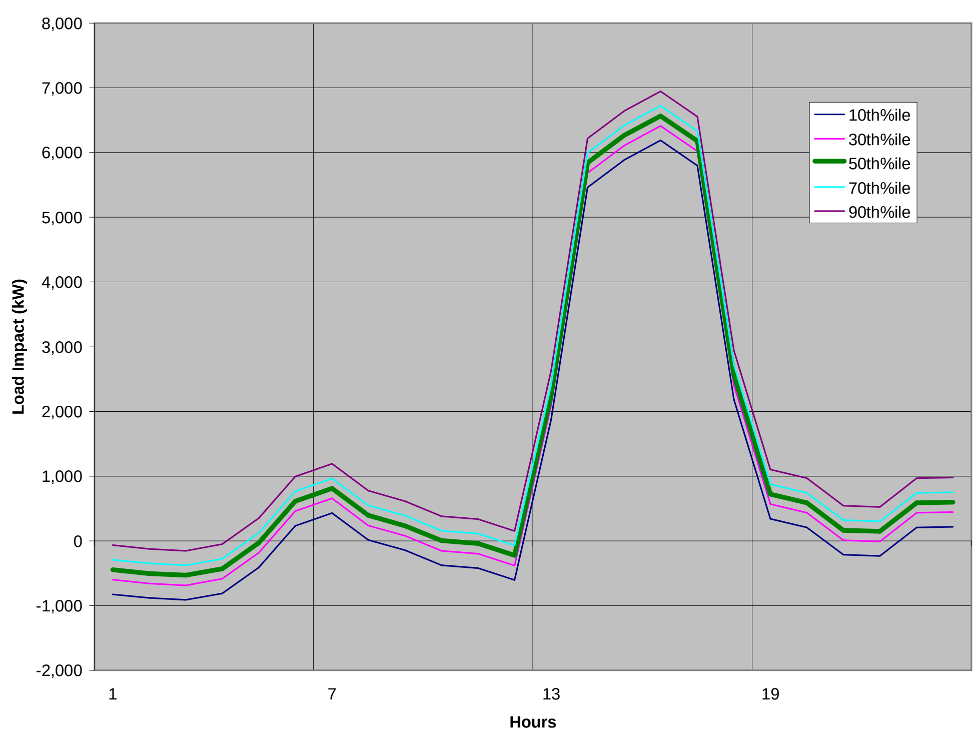


Figure 4.2: Uncertainty-Adjusted Load Impacts – *PG&E CBP DO Event (June 20)*



Tables 4.4a and 4.4b show aggregate and per customer (respectively) hourly loads and load impacts for the August 14 day-ahead CBP event. Estimated load impacts in hours 16 and 17 are approximately 17 percent of the reference load. The 10th and 90th percentile load impacts are estimated to lie about 11 percent below and above the estimated load impacts for the event.

Table 4.5a: Aggregate Hourly Load Impacts – *PG&E CBP DA Event (August 14)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	64,644	65,103	-459	69	-2,049	-1,110	-459	192	1,132
2	63,271	63,226	45	67	-1,545	-606	45	696	1,636
3	62,258	61,648	609	66	-981	-42	609	1,260	2,200
4	62,001	62,388	-387	65	-1,978	-1,038	-387	264	1,203
5	63,577	64,995	-1,418	64	-3,008	-2,069	-1,418	-767	173
6	67,530	68,830	-1,299	63	-2,890	-1,950	-1,299	-649	291
7	78,152	78,825	-673	63	-2,263	-1,324	-673	-22	918
8	83,052	82,634	418	64	-1,173	-233	418	1,069	2,008
9	89,269	87,723	1,546	67	-44	895	1,546	2,197	3,137
10	94,685	92,492	2,194	70	603	1,543	2,194	2,845	3,784
11	98,697	97,433	1,265	74	-326	614	1,265	1,916	2,855
12	100,637	99,984	653	78	-938	2	653	1,304	2,244
13	99,765	99,023	742	81	-848	91	742	1,393	2,333
14	101,258	101,107	152	84	-1,439	-499	152	803	1,742
15	101,688	98,107	3,581	85	1,990	2,930	3,581	4,232	5,171
16	100,265	83,971	16,294	87	14,704	15,644	16,294	16,945	17,885
17	97,207	81,316	15,891	86	14,300	15,240	15,891	16,542	17,481
18	91,959	85,612	6,346	85	4,756	5,696	6,346	6,997	7,937
19	87,491	83,566	3,925	83	2,334	3,274	3,925	4,576	5,516
20	87,030	82,823	4,207	79	2,616	3,556	4,207	4,858	5,798
21	87,093	87,040	53	75	-1,538	-598	53	703	1,643
22	80,405	83,243	-2,839	72	-4,429	-3,490	-2,839	-2,188	-1,248
23	72,258	72,222	35	70	-1,555	-616	35	686	1,626
24	67,315	66,392	924	69	-667	273	924	1,575	2,514
	Reference Energy Use (kWh)	Estimated 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	2,001,509	1,949,703	51,806	73.7	n/a	n/a	n/a	n/a	n/a

Table 4.6b: Per Customer Hourly Load Impacts – *PG&E CBP DA Event (August 14)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	117	118	-1	69	-4	-2	-1	0	2
2	114	114	0	67	-3	-1	0	1	3
3	113	111	1	66	-2	0	1	2	4
4	112	113	-1	65	-4	-2	-1	0	2
5	115	118	-3	64	-5	-4	-3	-1	0
6	122	124	-2	63	-5	-4	-2	-1	1
7	141	143	-1	63	-4	-2	-1	0	2
8	150	149	1	64	-2	0	1	2	4
9	161	159	3	67	0	2	3	4	6
10	171	167	4	70	1	3	4	5	7
11	178	176	2	74	-1	1	2	3	5
12	182	181	1	78	-2	0	1	2	4
13	180	179	1	81	-2	0	1	3	4
14	183	183	0	84	-3	-1	0	1	3
15	184	177	6	85	4	5	6	8	9
16	181	152	29	87	27	28	29	31	32
17	176	147	29	86	26	28	29	30	32
18	166	155	11	85	9	10	11	13	14
19	158	151	7	83	4	6	7	8	10
20	157	150	8	79	5	6	8	9	10
21	157	157	0	75	-3	-1	0	1	3
22	145	151	-5	72	-8	-6	-5	-4	-2
23	131	131	0	70	-3	-1	0	1	3
24	122	120	2	69	-1	0	2	3	5
	Reference Energy Use (kWh)	Estimated 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	3,619	3,526	94	73.7	n/a	n/a	n/a	n/a	n/a

Figure 4.3 illustrates the loads and load impacts, while Figure 4.4 shows the uncertainty-adjusted load impacts.

Figure 4.3: Hourly Loads and Load Impacts – *PG&E CBP DA Event (August 14)*

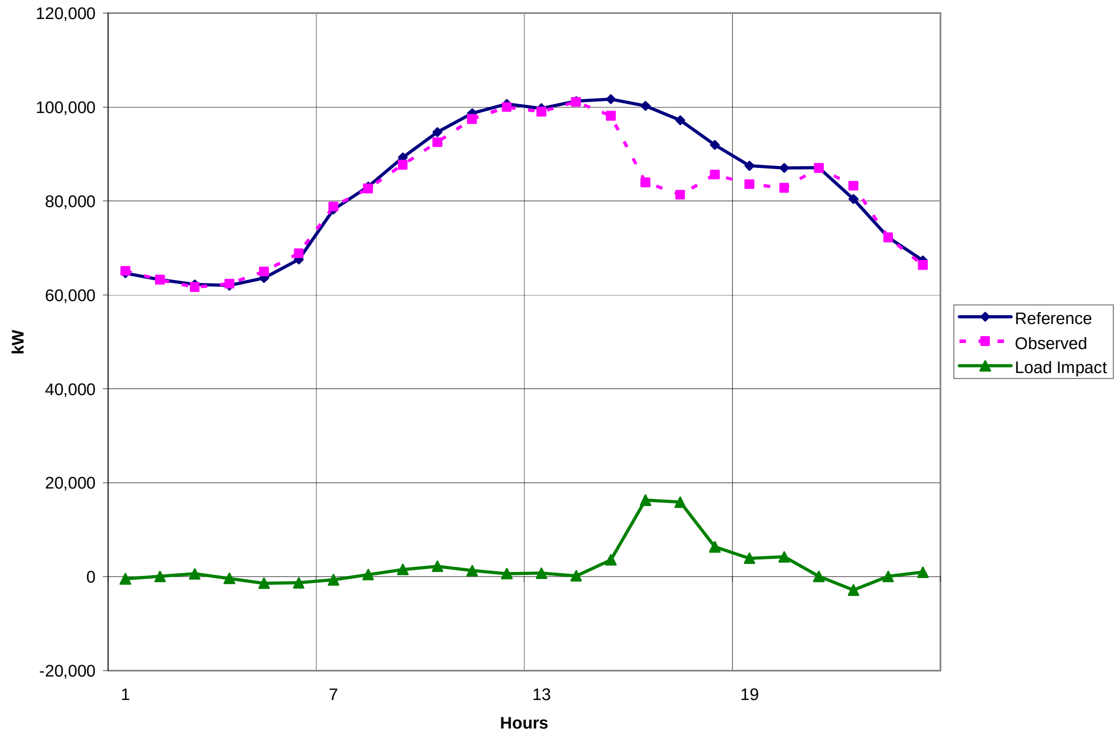
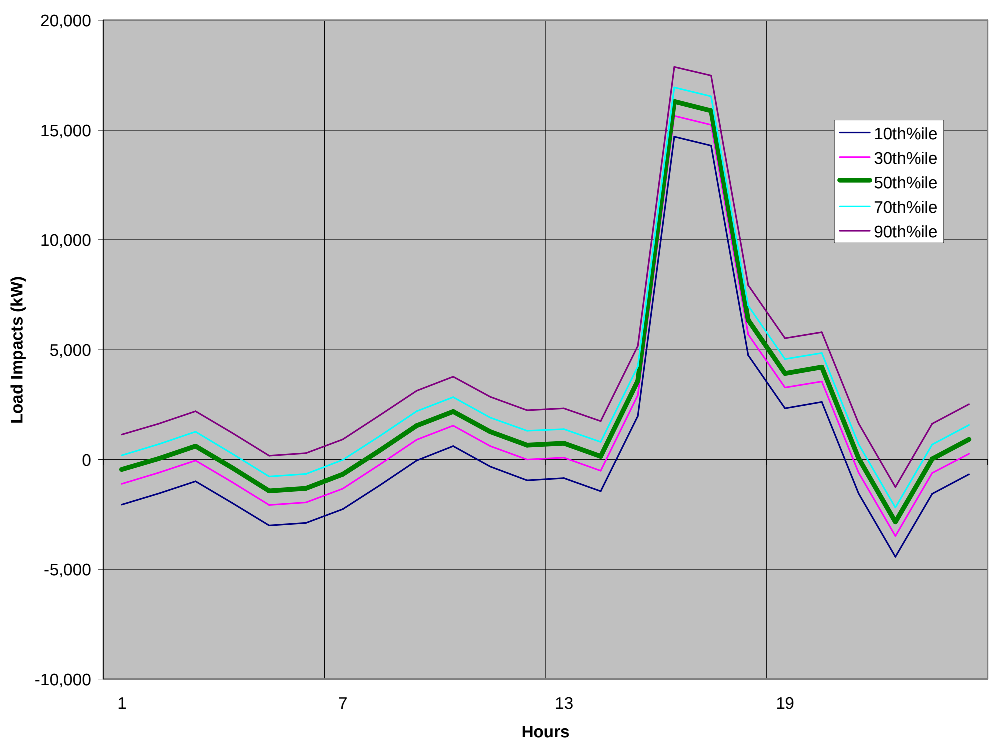


Figure 4.4: Uncertainty-Adjusted Load Impacts – *PG&E CBP DA Event (August 14)*



Observed event-day loads
As confirmation of the estimated overall program load impacts, Figures 4.5 and 4.6 show the total nominated load for PG&E's CBP customers, for the June 20 and August 14 events, and for nearby days. Note that the load levels indicated in these figures differ from the levels in both of the previous sets of figures. This is so because the observed loads include all customers nominated in any month, in both program types (DA and DO). The load reductions during the events show clearly. The estimated load reductions of approximately 6.2 MW for the first event, and 16 MW for the second are consistent with the loads in the figures.

Figure 4.5: PG&E Total Nominated CBP Load, *June 20 Event*

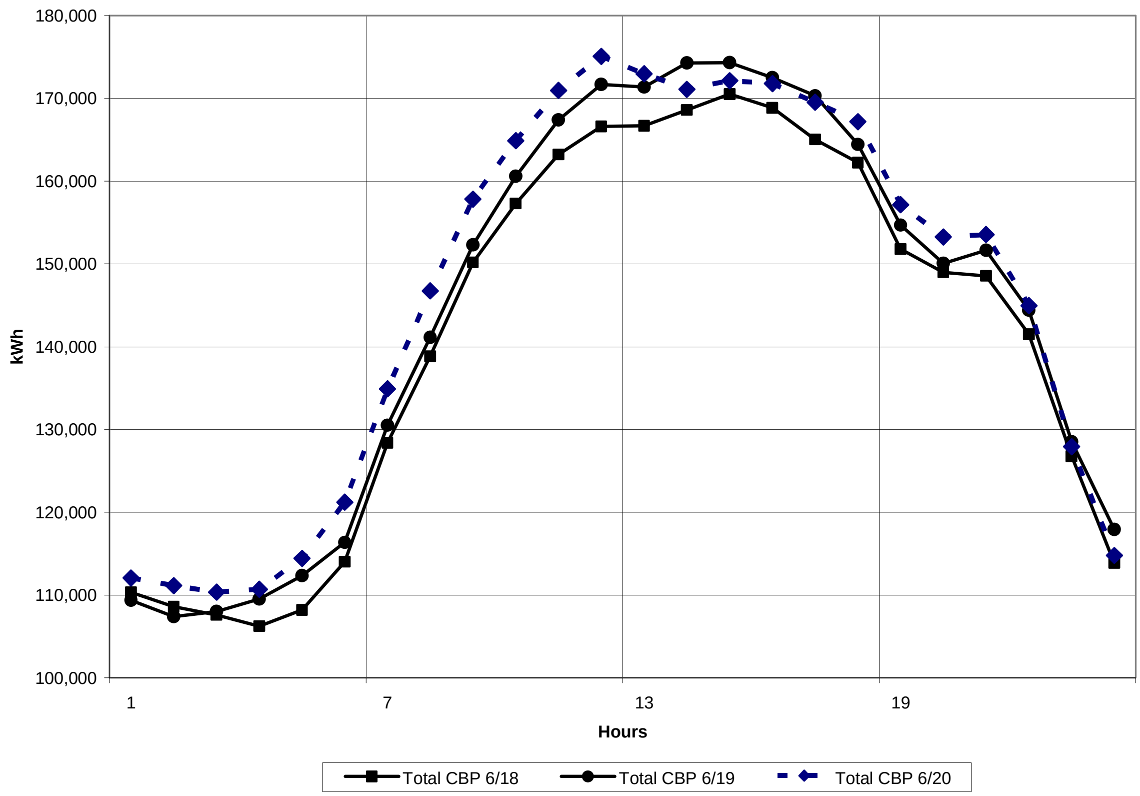
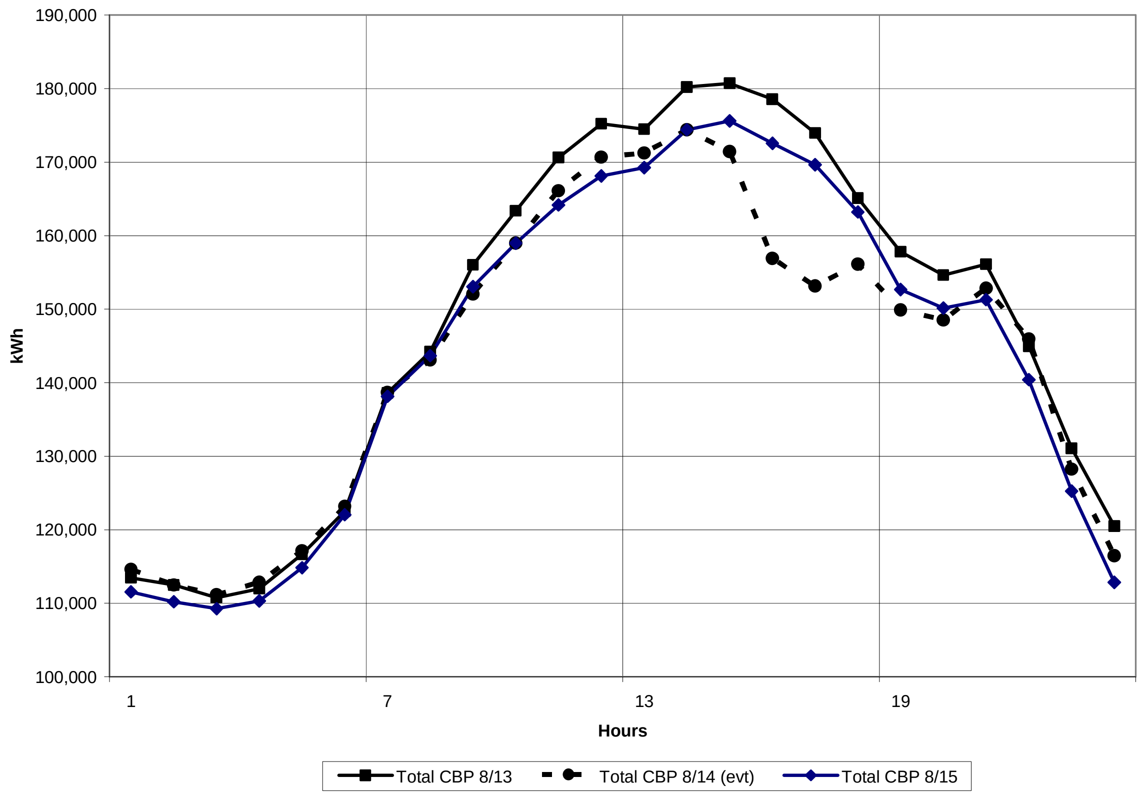


Figure 4.6: PG&E Total Nominated CBP Load, *August 14 Event*



4.1.2 SCE

Summary load impacts

Table 4.5 shows average hourly estimated load impacts for each of SCE's CBP events. The load impacts for the day-ahead events are remarkably consistent across events, at approximately 11 MW, with the magnitude of the impacts growing through the summer as enrollment increased. Table 4.6 shows the breakdown of load impacts by industry type for the average day-ahead and day-of event. The retail industry group provided the largest shares of the load impacts. Table 4.7 shows the breakdown of load impacts by CAISO LCA for the average day-ahead and day-of event. The bulk of the load impacts were in the LA Basin LCA. The total load impact potential of the program may be considered as the sum of the load impacts for the DA and DO programs, or approximately 4.3 MW for the day-of program type and 11.1 MW for the day-ahead program type, for a total of 15.4 MW.

Table 4.7: CBP Average Hourly Load Impacts by Event (kW) – SCE

Event	Date	Type	Load Impact
1	07-Jul-08	DA	9,808
2	08-Jul-08	DA	11,627
3	09-Jul-08	DA	12,431
4	10-Jul-08	DA	11,405
5	14-Jul-08	DA	11,817
6	05-Aug-08	DA	10,931
7	06-Aug-08	DA	11,262
8	07-Aug-08	DA	11,324
9	11-Aug-08	DA	10,833
10	12-Aug-08	DA	10,661
11	27-Aug-08	DA	11,708
12	28-Aug-08	DA	11,636
13	29-Aug-08	DA	10,378
14	03-Sep-08	DA	10,022
15	04-Sep-08	DA	10,770
16	05-Sep-08	DA	10,067
17	26-Sep-08	DA (1 hr, 1/2 Agg.)	1,451
18	01-Oct-08	**DO**	4,876
19	06-Oct-08	DA	9,361
20	13-Oct-08	DA	13,811
21	20-Oct-08	DA	11,390
22	23-Oct-08	**DO**	3,810
		Ave. DA	11,118
		Ave. DO	4,343

Table 4.8: CBP Average Hourly Load Impacts by Industry Type – SCE

Industry Type	Ave. DA	Ave. DO
1. Ag., Mining, Constr.	37	0
2. Manufacturing	382	0
3. Whole., Trans., Util.	116	-2
4. Retail	10,578	3,477
5. Offices, hotels, services	5	868
6. Schools	0	0
7. Instit. & Govt.	1	0
Total	11,118	4,343

Table 4.9: CBP Average Hourly Load Impacts by LCA – SCE

LCA	Ave. DA	Ave. DO
LA_BASIN	8,225	3,325
OUTSIDE LA	841	507
Unknown	639	234
VENTURA	1,413	277
Total	11,118	4,343

Hourly load impacts

Tables 4.8a and 4.8b show aggregate and per customer (respectively) hourly reference load, observed load, and load impact values for the average SCE CBP event, where the average event is defined as the sum of the averages of the twenty DA events and the two DO events (since both types of events may be called on the same day). Hourly load impacts averaged 12 to 15 percent of the total reference load of the two program types for the overlapping hours 15-17. The 10th and 90th percentile load impacts are estimated to lie about 5 percent below and above the estimated load impacts for the average event. Figure 4.7 illustrates the loads and load impacts for the average event, while Figure 4.8 illustrates the uncertainty-adjusted load impacts.

Table 4.10a: Aggregate Hourly Load Impacts – *SCE CBP Typical DA and DO Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	49,795	50,088	-293	70	-975	-572	-293	-13	390
2	48,061	48,663	-602	69	-1,285	-882	-602	-322	81
3	47,265	47,896	-632	68	-1,315	-911	-632	-352	51
4	48,308	48,698	-390	67	-1,073	-669	-390	-110	294
5	55,189	55,636	-447	66	-1,130	-726	-447	-167	236
6	61,391	62,347	-956	66	-1,639	-1,235	-956	-676	-272
7	74,290	76,591	-2,301	65	-2,984	-2,580	-2,301	-2,021	-1,617
8	74,512	74,749	-237	66	-920	-516	-237	43	446
9	76,234	76,643	-410	70	-1,093	-689	-410	-130	273
10	81,144	81,486	-342	75	-1,025	-621	-342	-62	341
11	85,470	85,689	-218	80	-901	-498	-218	61	465
12	88,493	89,160	-666	83	-1,350	-946	-666	-387	17
13	91,007	90,562	445	86	-238	165	445	724	1,128
14	92,826	87,081	5,745	87	5,062	5,466	5,745	6,025	6,428
15	93,724	81,959	11,765	88	11,082	11,485	11,765	12,044	12,448
16	93,941	80,674	13,267	88	12,584	12,987	13,267	13,546	13,950
17	94,198	80,055	14,144	87	13,461	13,864	14,144	14,423	14,827
18	93,890	88,246	5,643	85	4,960	5,364	5,643	5,923	6,327
19	94,086	94,360	-273	81	-956	-553	-273	6	410
20	94,311	95,204	-893	78	-1,576	-1,172	-893	-613	-209
21	94,074	93,744	331	75	-352	51	331	610	1,014
22	85,736	86,351	-615	73	-1,299	-895	-615	-336	68
23	67,980	67,873	108	71	-576	-172	108	387	791
24	57,474	57,330	145	70	-539	-135	145	424	828
	Reference Energy Use (kWh)	Estimated 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	1,843,400	1,801,082	42,318	92.0	n/a	n/a	n/a	n/a	n/a

Table 4.11b: Per Customer Hourly Load Impacts – *SCE CBP Typical DA and DO Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	151	152	-1	70	-3	-2	-1	0	1
2	146	148	-2	69	-4	-3	-2	-1	0
3	144	145	-2	68	-4	-3	-2	-1	0
4	147	148	-1	67	-3	-2	-1	0	1
5	168	169	-1	66	-3	-2	-1	-1	1
6	186	189	-3	66	-5	-4	-3	-2	-1
7	226	233	-7	65	-9	-8	-7	-6	-5
8	226	227	-1	66	-3	-2	-1	0	1
9	232	233	-1	70	-3	-2	-1	0	1
10	246	247	-1	75	-3	-2	-1	0	1
11	260	260	-1	80	-3	-2	-1	0	1
12	269	271	-2	83	-4	-3	-2	-1	0
13	276	275	1	86	-1	1	1	2	3
14	282	264	17	87	15	17	17	18	20
15	285	249	36	88	34	35	36	37	38
16	285	245	40	88	38	39	40	41	42
17	286	243	43	87	41	42	43	44	45
18	285	268	17	85	15	16	17	18	19
19	286	287	-1	81	-3	-2	-1	0	1
20	286	289	-3	78	-5	-4	-3	-2	-1
21	286	285	1	75	-1	0	1	2	3
22	260	262	-2	73	-4	-3	-2	-1	0
23	206	206	0	71	-2	-1	0	1	2
24	175	174	0	70	-2	0	0	1	3
	Reference Energy Use (kWh)	Estimated 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	5,598	5,470	129	92.0	n/a	n/a	n/a	n/a	n/a

Figure 4.7: Hourly Loads and Load Impacts – *SCE CBP Typical DA and DO Event*

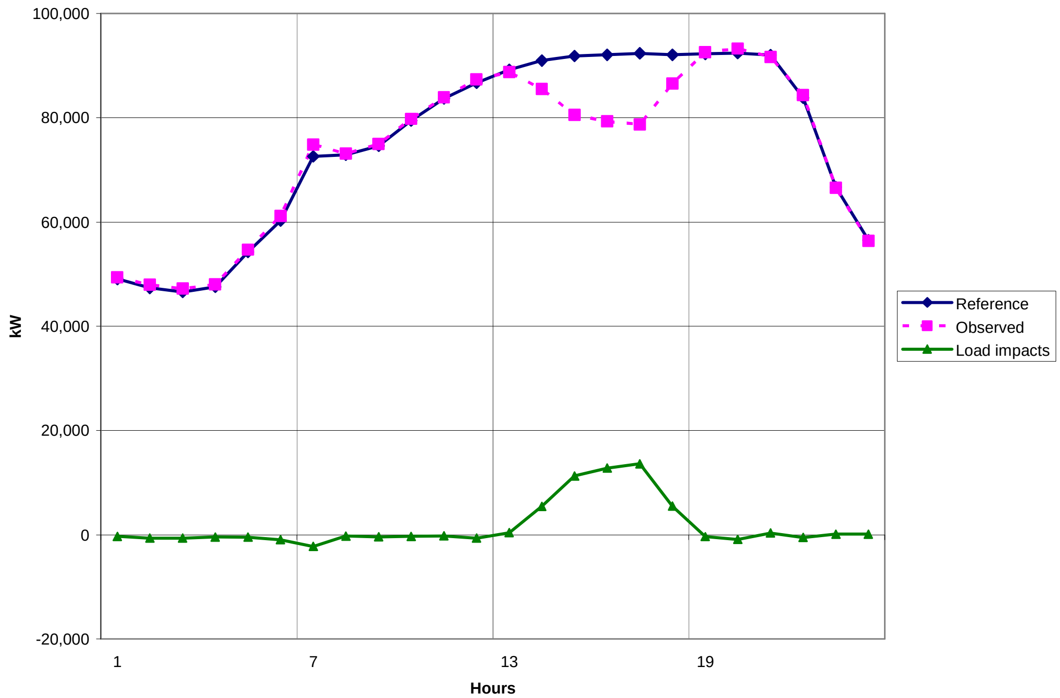
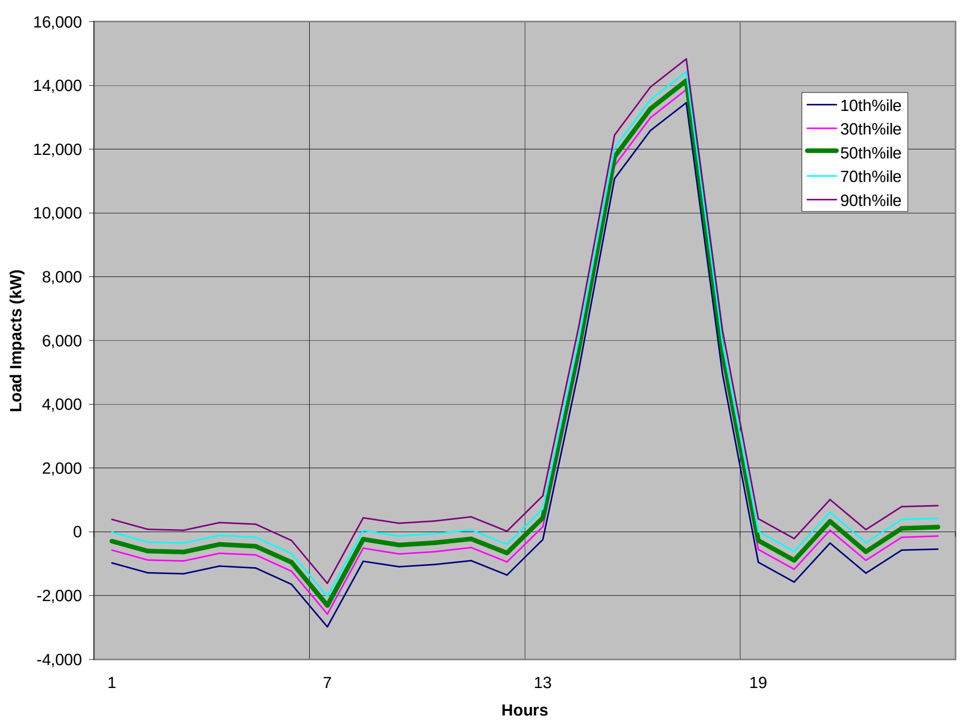


Figure 4.8: Uncertainty-Adjusted Load Impacts – SCE CBP Typical DA and DO *Event*



Observed event-day loads
As confirmation of the estimated overall program load impacts, Figure 4.9 shows the total load for all of SCE's CBP customers, for average non-October DA events, along with typical non-event days (the loads during the October events were generally lower than during the earlier events). The load reductions during the events show clearly, including the effect of different event windows (*e.g.*, hours 14-17, and 15-17). Figure 4.10 illustrates the two October DO events.

Figure 4.9: SCE CBP Average *Day-Ahead* Event Days

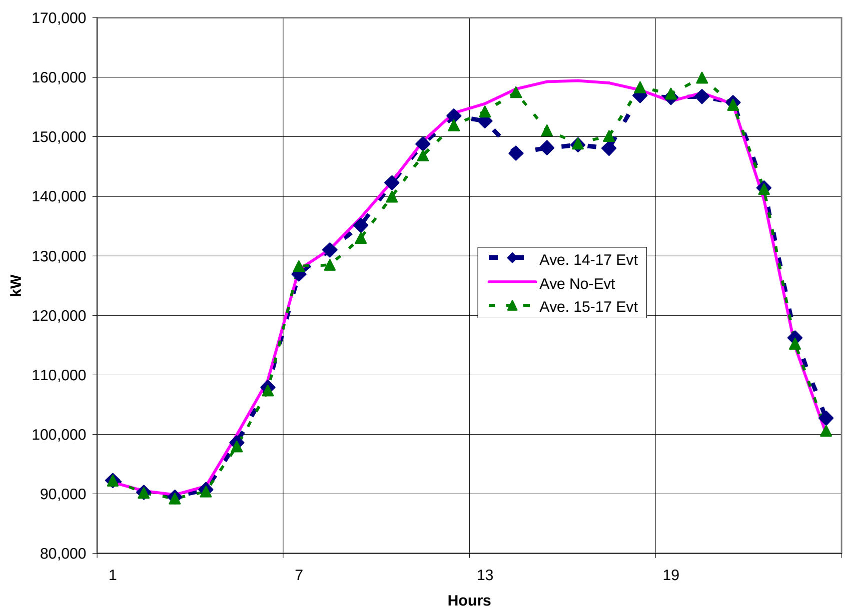
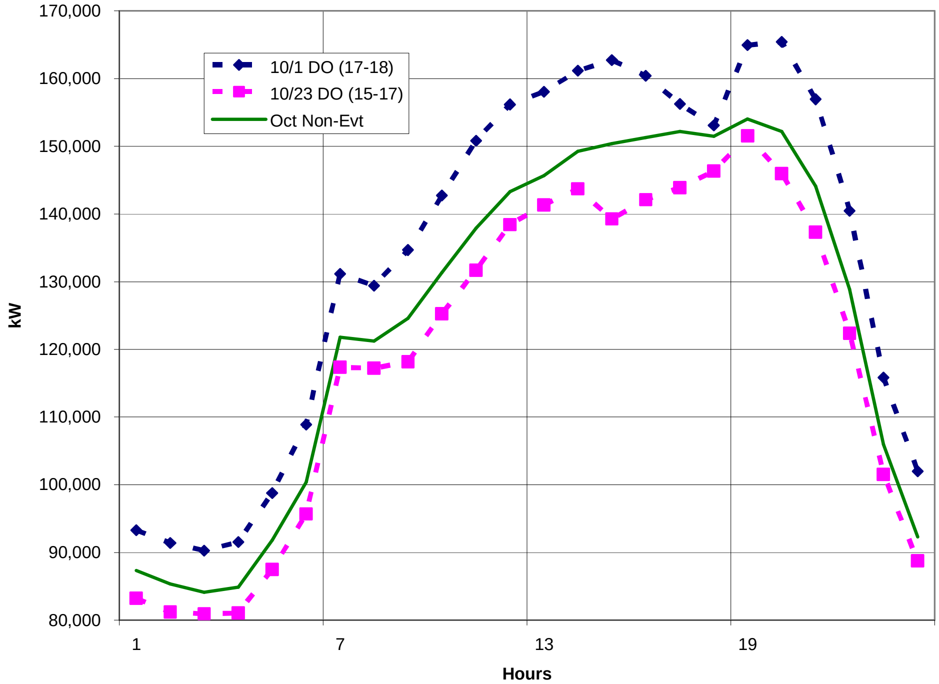


Figure 4.10: SCE CBP October *Day-Of* Event Days



TA/TI Effects

TA/TI participants in CBP at SCE included 56 enrollees in the DO program type, approximately evenly split between industry types 4 and 5. Both included multiple sites of a single customer, one a retail store and the other a service establishment. We conducted a preliminary regression analysis of the average percent load impact of each customer as a function of variables such as industry type, size, TA/TI participation, and the latter two variables interacted. No direct effect of TA/TI participation on percent load impact could be found. However, the interacted term was modestly significant, indicating that the percent load impact of TA/TI customers increased with size, compared to all customers.

Table 4.9 summarizes differences in percent load impacts for the two involved industry types, by size categories, for the TA/TI participants and all other DO enrollees (Non) who were called for an event. For the retail stores (industry 4), the percent LI for non-TA/TI customers (sixth column) indicates a declining pattern of percent impacts as the size categories increase. In contrast, the two industry 4 TA/TI size categories showed increased percent load impacts. For industry 5, the TA/TI participants show larger percentage load impacts than the non-participants, but the numbers of customers are small. In all, the results are suggestive, but not definitive, of TA/TI participation resulting in larger load impacts.

Table 4.12: SCE CBP TA/TI Effects

	Customers				Percent Load Impact			
	Industry 4		Industry 5		Industry 4		Industry 5	
Max kW	TA/TI	Non	TA/TI	Non	TA/TI	Non	TA/TI	Non
<100	19	52	0	0	20%	26%		
100-200	8	10	6	2	27%	25%	17%	10%
200-500	0	24	23	1		10%	17%	9%
>500	0	28	0	0		6%		
All	27	114	29	3	24%	17%	16%	10%

4.1.3 SDG&E

Summary load impacts

Table 4.10 summarizes estimated ex post load impacts by industry type and in total for SDG&E's two CBP events. The manufacturing and retail industry groups provided the largest shares of the DA load impacts, while wholesale & utilities and retail provided the bulk of the DO load impacts. If the day-ahead and day-of program types were called on the same day, the implied load impact would be the sum of the two total values, or approximately 16.4 MW.

Table 4.13: SDG&E CBP 2008 Average hourly Load Impacts (kW)

Industry type	Day-ahead 9-Jul	Day-of 1-Oct
1. Ag., Mining, Constr.	455	0
2. Manufacturing	6,336	0
3. Whole., Trans., Util.	148	2,342
4. Retail	2,538	2,752
5. Offices, hotels, services	67	276
6. Schools	368	0
7. Instit. & Govt.	373	791
TOTAL	10,285	6,160

TA/TI impacts

Table 4.11 provides an indication of the effect of TI participation on SDG&E's CBP load impacts. All of the TI applications were completed by one aggregator, who nominated *day-of* load reductions. The last column shows the percentage of that aggregator's TI-participating customers in the three industry types that included TI participants. The values in the first two columns represent (load-weighted) average percentage hourly load impacts (relative to estimated reference loads) for the October day-of event, for Non-TI and TI customers. The next column shows overall load-weighted percentage load impacts for *all* CBP customers in the indicated industry types. The percentage load impacts for TI participants are substantially larger than those for non-participants in each case.

Table 4.14: Average Hourly Percent Load Impacts per Customer,
by TI Participation

Industry type	Non-TI	TI	Overall	% of Cust. in TI
4. Retail	27%	37%	30%	20%
5. Offices, hotels, services	6%	40%	12%	24%
7. Instit. & Govt.	15%	26%	24%	46%
All	22%	32%	26%	

Hourly load impacts

Tables 4.12a and 4.12b show aggregate and per customer (respectively) hourly reference load, observed load, and load impact values for SDG&E's day-ahead CBP program type on the July 9, 2008 DA event, which was called for hours 14-17 for DA4 contracts, and hours 13-18 for DA6 contracts. Hourly load impacts averaged about 30 to 40 percent of the reference load during the overlapping hours 14-17. The 10th and 90th percentile load impacts are estimated to range from 15 to 23 percent below and above the estimated load impacts for the event. Figure 4.11 illustrates the loads and load impacts for the DA event, while Figure 4.12 illustrates the uncertainty-adjusted DA load impacts.

Table 4.15a: Aggregate Hourly Load Impacts – *SDG&E CBP DA Event (July 9)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	20,703	21,995	-1,292	64	-3,181	-2,065	-1,292	-519	597
2	20,175	21,740	-1,565	64	-3,454	-2,338	-1,565	-792	324
3	19,712	21,202	-1,490	63	-3,379	-2,263	-1,490	-717	399
4	19,604	20,796	-1,192	63	-3,081	-1,965	-1,192	-419	697
5	20,636	21,807	-1,171	63	-3,060	-1,944	-1,171	-398	718
6	22,702	23,824	-1,122	63	-3,011	-1,895	-1,122	-349	767
7	27,874	29,801	-1,927	63	-3,816	-2,700	-1,927	-1,154	-38
8	30,602	29,058	1,544	65	-345	771	1,544	2,317	3,433
9	31,166	28,022	3,144	67	1,255	2,371	3,144	3,917	5,033
10	32,362	32,241	121	65	-1,768	-652	121	894	2,010
11	33,221	33,641	-421	69	-2,310	-1,194	-421	352	1,468
12	33,151	34,984	-1,833	70	-3,722	-2,606	-1,833	-1,060	56
13	33,573	29,300	4,273	72	2,384	3,500	4,273	5,046	6,162
14	34,195	21,325	12,870	70	10,981	12,097	12,870	13,643	14,759
15	32,204	21,826	10,378	71	8,489	9,605	10,378	11,151	12,267
16	31,124	21,574	9,550	70	7,661	8,777	9,550	10,323	11,439
17	30,340	21,995	8,345	68	6,456	7,572	8,345	9,118	10,234
18	30,068	24,425	5,643	67	3,754	4,870	5,643	6,416	7,532
19	29,052	26,950	2,102	66	213	1,329	2,102	2,875	3,991
20	28,268	26,305	1,963	64	74	1,190	1,963	2,736	3,852
21	28,639	27,501	1,138	65	-751	365	1,138	1,911	3,027
22	27,404	26,617	787	65	-1,102	14	787	1,560	2,676
23	23,758	23,712	47	65	-1,843	-726	47	820	1,936
24	21,846	22,446	-600	64	-2,489	-1,373	-600	173	1,289
	Reference Energy Use (kWh)	**Estimated 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	662,378	613,085	49,293	0.0	n/a	n/a	n/a	n/a	n/a

Table 4.16b: Per Customer Hourly Load Impacts – *SDG&E CBP DA Event (July 9)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	216	229	-13	64	-33	-22	-13	-5	6
2	210	226	-16	64	-36	-24	-16	-8	3
3	205	221	-16	63	-35	-24	-16	-7	4
4	204	217	-12	63	-32	-20	-12	-4	7
5	215	227	-12	63	-32	-20	-12	-4	7
6	236	248	-12	63	-31	-20	-12	-4	8
7	290	310	-20	63	-40	-28	-20	-12	0
8	319	303	16	65	-4	8	16	24	36
9	325	292	33	67	13	25	33	41	52
10	337	336	1	65	-18	-7	1	9	21
11	346	350	-4	69	-24	-12	-4	4	15
12	345	364	-19	70	-39	-27	-19	-11	1
13	350	305	45	72	25	36	45	53	64
14	356	222	134	70	114	126	134	142	154
15	335	227	108	71	88	100	108	116	128
16	324	225	99	70	80	91	99	108	119
17	316	229	87	68	67	79	87	95	107
18	313	254	59	67	39	51	59	67	78
19	303	281	22	66	2	14	22	30	42
20	294	274	20	64	1	12	20	29	40
21	298	286	12	65	-8	4	12	20	32
22	285	277	8	65	-11	0	8	16	28
23	247	247	0	65	-19	-8	0	9	20
24	228	234	-6	64	-26	-14	-6	2	13
	Reference Energy Use (kWh)	Estimated 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	6,900	6,386	513	0.0	n/a	n/a	n/a	n/a	n/a

Figure 4.11: Hourly Loads and Load Impacts – *SDG&E CBP DA Event (July 9)*

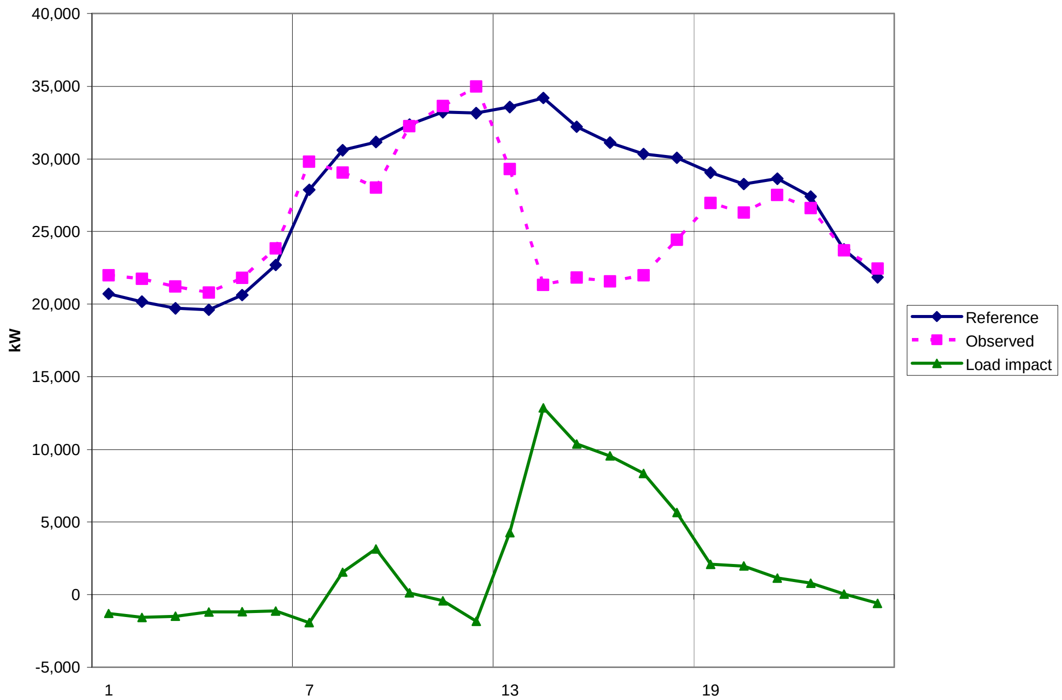
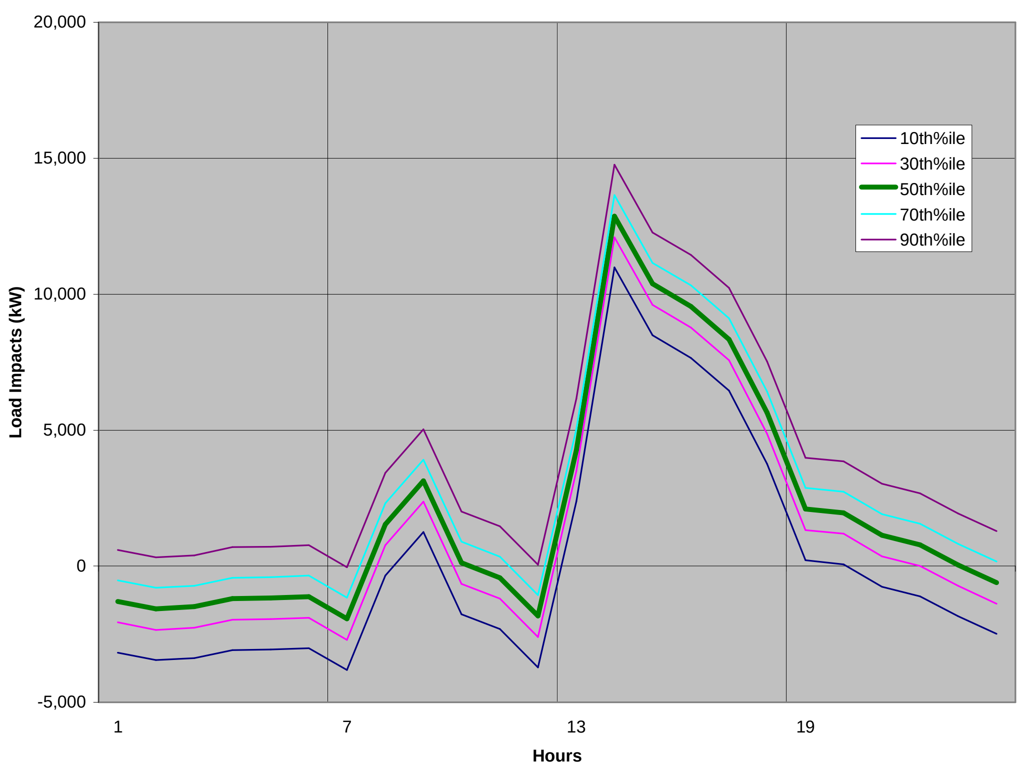


Figure 4.12: Uncertainty-Adjusted Load Impacts – *SDG&E CBP DA Event (July 9)*



Tables 4.13a and 4.13b show aggregate and per customer (respectively) hourly load and load impact values for SDG&E's day-of CBP program type on the October 1, 2008 DO event, which was called for hours 14-17 for DO4 contracts, and hours 14-19 for DO6 contracts. Hourly load impacts ranged from 28 to 34 percent of the reference load during the overlapping hours 14-17. The 10th and 90th percentile load impacts are estimated to range from 9 to 12 percent below and above the estimated load impacts for the event. Figure 4.13 illustrates the loads and load impacts for the DO event, while Figure 4.14 illustrates the uncertainty-adjusted DO load impacts.

Table 4.17a: Aggregate Hourly Load Impacts – *SDG&E DO CBP Event (Oct. 1)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	11,299	11,546	-248	73	-892	-511	-248	16	397
2	11,164	11,250	-86	72	-730	-350	-86	177	558
3	11,057	11,467	-411	72	-1,055	-674	-411	-147	233
4	11,473	11,588	-115	70	-759	-379	-115	148	529
5	12,347	12,603	-256	69	-900	-519	-256	8	388
6	13,451	13,640	-189	70	-833	-453	-189	74	455
7	14,412	14,374	38	70	-606	-225	38	302	683
8	15,049	15,177	-127	77	-772	-391	-127	136	517
9	17,401	17,968	-566	81	-1,210	-830	-566	-303	78
10	19,328	19,768	-440	87	-1,084	-703	-440	-176	204
11	20,351	21,551	-1,200	90	-1,844	-1,464	-1,200	-937	-556
12	20,844	22,251	-1,407	90	-2,051	-1,671	-1,407	-1,144	-763
13	20,442	21,121	-680	91	-1,324	-943	-680	-416	-35
14	19,604	14,051	5,553	90	4,909	5,289	5,553	5,817	6,197
15	19,610	14,159	5,451	89	4,807	5,187	5,451	5,714	6,095
16	20,216	13,847	6,369	88	5,725	6,106	6,369	6,633	7,014
17	21,246	14,113	7,132	85	6,488	6,869	7,132	7,396	7,776
18	20,678	16,673	4,005	82	3,361	3,741	4,005	4,269	4,649
19	19,922	16,813	3,109	79	2,465	2,845	3,109	3,372	3,753
20	19,200	17,396	1,804	77	1,160	1,540	1,804	2,067	2,448
21	18,833	17,801	1,032	75	388	769	1,032	1,296	1,676
22	17,747	18,299	-552	74	-1,196	-816	-552	-288	92
23	14,824	15,293	-469	73	-1,113	-733	-469	-206	175
24	12,455	12,250	205	72	-439	-58	205	469	849
	Reference Energy Use (kWh)	Estimated 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	402,952	374,999	27,953	131.9	n/a	n/a	n/a	n/a	n/a

Table 4.18b: Per Customer Hourly Load Impacts – *SDG&E DO CBP Event (Oct. 1)*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	82	84	-2	73	-7	-4	-2	0	3
2	81	82	-1	72	-5	-3	-1	1	4
3	81	84	-3	72	-8	-5	-3	-1	2
4	84	85	-1	70	-6	-3	-1	1	4
5	90	92	-2	69	-7	-4	-2	0	3
6	98	100	-1	70	-6	-3	-1	1	3
7	105	105	0	70	-4	-2	0	2	5
8	110	111	-1	77	-6	-3	-1	1	4
9	127	131	-4	81	-9	-6	-4	-2	1
10	141	144	-3	87	-8	-5	-3	-1	1
11	149	157	-9	90	-13	-11	-9	-7	-4
12	152	162	-10	90	-15	-12	-10	-8	-6
13	149	154	-5	91	-10	-7	-5	-3	0
14	143	103	41	90	36	39	41	42	45
15	143	103	40	89	35	38	40	42	44
16	148	101	46	88	42	45	46	48	51
17	155	103	52	85	47	50	52	54	57
18	151	122	29	82	25	27	29	31	34
19	145	123	23	79	18	21	23	25	27
20	140	127	13	77	8	11	13	15	18
21	137	130	8	75	3	6	8	9	12
22	130	134	-4	74	-9	-6	-4	-2	1
23	108	112	-3	73	-8	-5	-3	-2	1
24	91	89	1	72	-3	0	1	3	6
	Reference Energy Use (kWh)	Estimated 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	2,941	2,737	204	131.9	n/a	n/a	n/a	n/a	n/a

Figure 4.13: Hourly Loads and Load Impacts – *SDG&E DO CBP Event (Oct. 1)*

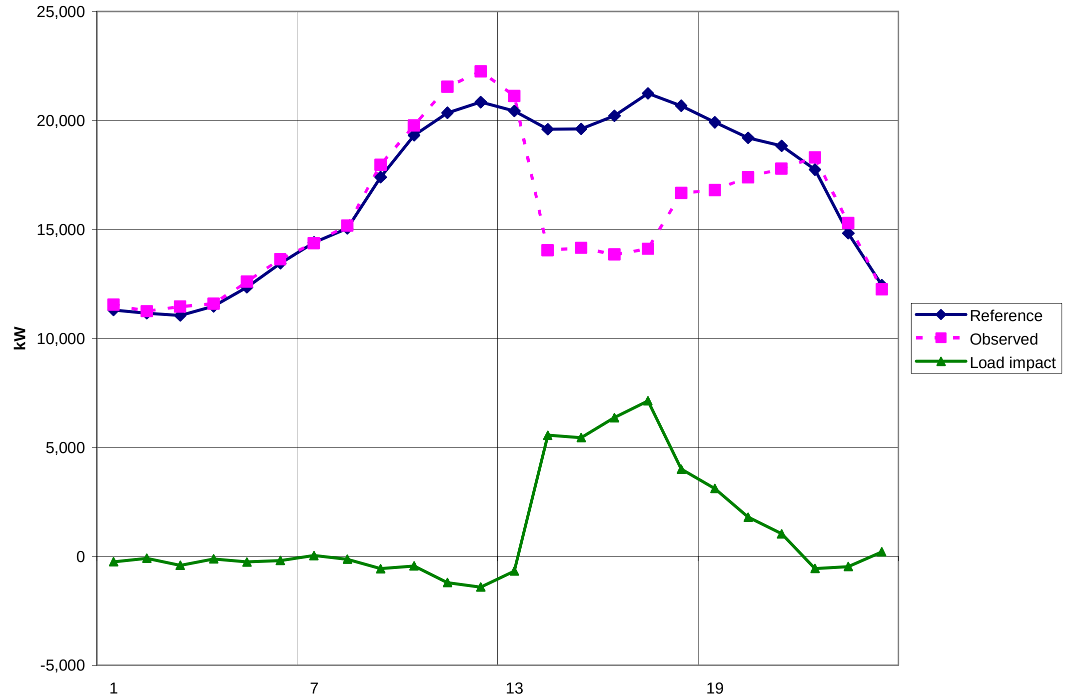
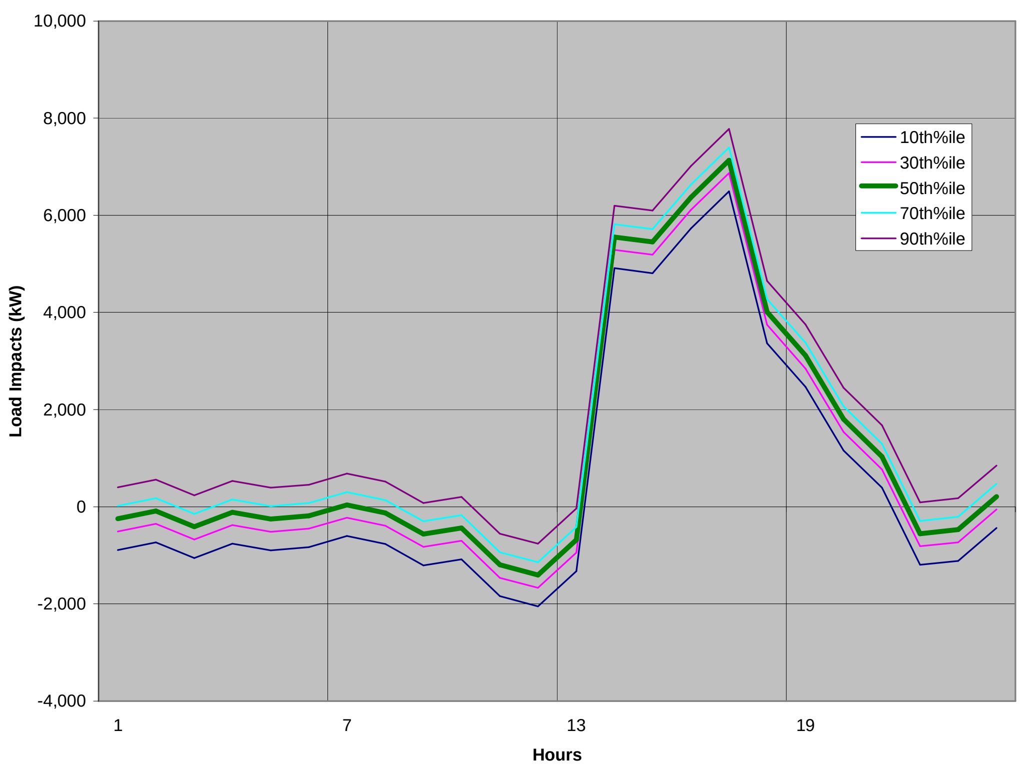


Figure 4.14: Uncertainty-Adjusted Load Impacts – *SDG&E DO CBP Event (Oct. 1)*



Observed event-day loads

As confirmation of the estimated overall program load impacts, Figure 4.15 shows the total load for the customers nominated for day-ahead events in July, for the week of the July 9 DA event. The load reduction during the event shows clearly, though the load variability during the event period on the other non-event days of the week is suggestive of the uncertainty in establishing baseline loads and estimating load impacts. The estimated load reduction of approximately 10,300 kW is certainly consistent with the loads in the figure. Figure 4.16 shows the total nominated day-of load for the October 1 DO event, as well as the load for several surrounding days. The estimated load impact of approximately 6 MW is consistent with the load reduction shown in the figure.

Figure 4.15: SDG&E July 9 Day-Ahead Event

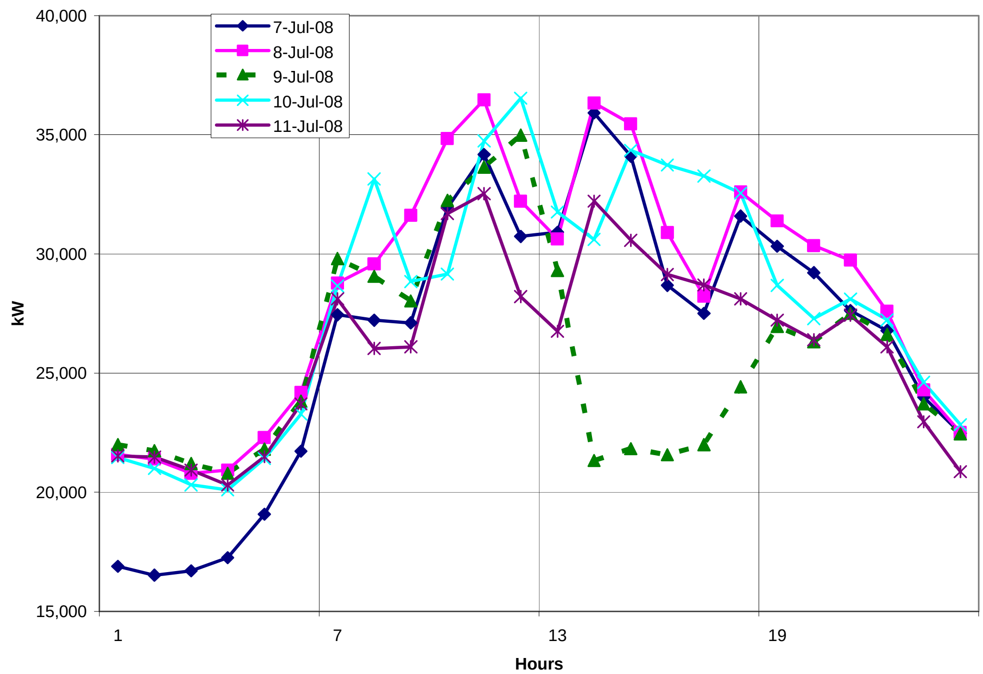
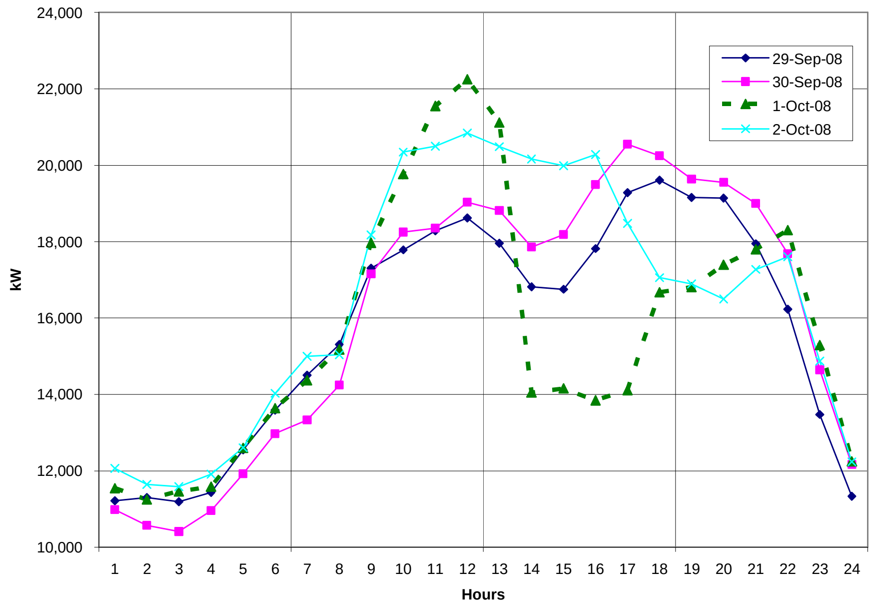


Figure 4.16: SDG&E October 1 Day-Of Event



4.2 AMP (PG&E)

Tables 4.14 and 4.15 report estimated average hourly load impacts for the first four AMP events, by industry type and local capacity area, on the basis of the load impacts estimated in the individual customer regressions. Referring back to Table 2.14, which shows the AMP events, the first and third events involved all of the aggregators, though the number of nominated customers expanded considerably between May and August. Four of the aggregators were called on the second event, and only two on the fourth event. The total average hourly load impacts in the last row of the table reflect those differences, with the largest load impact occurring on Event 3.

Table 4.19: Average Hourly Load Impacts (kW) by Industry Group – *PG&E AMP*

Industry type	Event 1 (DO/DA) 16-May	Event 2 (DO) 9-Jul	Event 3 (DO/DA) 14-Aug	Event 4 (DO) 5-Sep
1. Ag., Mining, Constr.	2,445	3,589	5,085	1,902
2. Manufacturing	22,813	11,635	30,933	9,924
3. Whole., Trans., Util.	13,004	17,417	21,509	15,001
4. Retail	4,080	7,893	6,192	1,899
5. Offices, hotels, services	3,065	2,821	7,409	2,027
6. Schools	927	842	1,672	-967
7. Instit. & Govt.	3,986	273	6,772	-106
TOTAL	50,319	44,470	79,571	29,679

Table 4.20: Average Hourly Load Impacts (kW) by LCA – *PG&E AMP*

Local Capacity Area	Event 1 (DO/DA) 16-May	Event 2 (DO) 9-Jul	Event 3 (DO/DA) 14-Aug	Event 4 (DO) 5-Sep
1 Greater Bay Area	8,605	8,191	12,718	4,832
2 Greater Fresno	9,528	8,476	16,843	4,553
3 Humboldt	0	0	873	118
4 Kern	1,091	750	1,388	1,665
5 Northern Coast	1,700	1,585	4,243	408
6 Sierra	972	705	1,743	477
7 Stockton	1,535	1,024	3,199	-129
8 Other	26,887	23,739	38,564	17,756
Total	50,319	44,470	79,571	29,679

Hourly load impacts
Tables 4.16a and 4.16b show aggregate and per customer (respectively) hourly load and load impact values for the average PG&E AMP event, which for comparability was defined as the average of events 1 and 3, for which all DA and DO aggregators were called. The primary overlapping event hours were 16-17, although one aggregator was called for hours 14-17 on the first event. Hourly load impacts were 25 percent of the reference load during the overlapping hours. The 10^{th} and 90^{th} percentile load impacts are estimated to lie about 5 percent below and above the estimated average load impacts. Figure 4.17 illustrates the average loads and load impacts, while Figure 4.18 illustrates the uncertainty-adjusted load impacts.

Table 4.21a: Aggregate Hourly Load Impacts – *PG&E Average DA and DO AMP Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	182,379	183,306	-927	76	-3,901	-2,144	-927	290	2,047
2	179,171	179,828	-658	75	-3,631	-1,874	-658	559	2,316
3	176,675	177,012	-337	73	-3,310	-1,554	-337	880	2,637
4	175,534	176,239	-705	72	-3,679	-1,922	-705	512	2,269
5	176,365	177,823	-1,458	70	-4,432	-2,675	-1,458	-241	1,516
6	185,996	188,395	-2,399	69	-5,373	-3,616	-2,399	-1,183	574
7	203,018	204,628	-1,610	69	-4,584	-2,827	-1,610	-393	1,364
8	218,160	218,416	-256	71	-3,230	-1,473	-256	961	2,718
9	229,379	228,682	696	75	-2,278	-521	696	1,913	3,670
10	238,446	238,195	251	80	-2,723	-966	251	1,468	3,225
11	248,785	246,478	2,307	84	-667	1,090	2,307	3,524	5,281
12	254,684	251,283	3,401	88	427	2,184	3,401	4,618	6,375
13	254,601	247,528	7,073	91	4,099	5,856	7,073	8,290	10,047
14	258,785	242,139	16,646	93	13,672	15,429	16,646	17,863	19,620
15	257,085	223,581	33,504	95	30,530	32,287	33,504	34,721	36,478
16	252,984	188,118	64,866	96	61,892	63,649	64,866	66,083	67,840
17	249,112	190,288	58,825	96	55,851	57,608	58,825	60,042	61,798
18	243,105	218,410	24,695	95	21,721	23,478	24,695	25,912	27,669
19	236,132	226,351	9,781	93	6,807	8,564	9,781	10,997	12,754
20	228,826	219,812	9,014	89	6,041	7,798	9,014	10,231	11,988
21	221,003	214,715	6,289	85	3,315	5,072	6,289	7,506	9,263
22	210,090	205,024	5,066	82	2,093	3,849	5,066	6,283	8,040
23	198,486	193,093	5,393	79	2,419	4,176	5,393	6,609	8,366
24	188,290	183,812	4,477	78	1,503	3,260	4,477	5,694	7,451
	Reference Energy Use (kWh)	Estimated 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	5,267,089	5,023,155	243,934	199.8	n/a	n/a	n/a	n/a	n/a

Table 4.22b: Per Customer Hourly Load Impacts – *PG&E Average DA and DO AMP Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	493	495	-3	76	-11	-6	-3	1	6
2	484	486	-2	75	-10	-5	-2	2	6
3	478	478	-1	73	-9	-4	-1	2	7
4	474	476	-2	72	-10	-5	-2	1	6
5	477	481	-4	70	-12	-7	-4	-1	4
6	503	509	-6	69	-15	-10	-6	-3	2
7	549	553	-4	69	-12	-8	-4	-1	4
8	590	590	-1	71	-9	-4	-1	3	7
9	620	618	2	75	-6	-1	2	5	10
10	644	644	1	80	-7	-3	1	4	9
11	672	666	6	84	-2	3	6	10	14
12	688	679	9	88	1	6	9	12	17
13	688	669	19	91	11	16	19	22	27
14	699	654	45	93	37	42	45	48	53
15	695	604	91	95	83	87	91	94	99
16	684	508	175	96	167	172	175	179	183
17	673	514	159	96	151	156	159	162	167
18	657	590	67	95	59	63	67	70	75
19	638	612	26	93	18	23	26	30	34
20	618	594	24	89	16	21	24	28	32
21	597	580	17	85	9	14	17	20	25
22	568	554	14	82	6	10	14	17	22
23	536	522	15	79	7	11	15	18	23
24	509	497	12	78	4	9	12	15	20
	Reference Energy Use (kWh)	Estimated 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	14,235	13,576	659	199.8	n/a	n/a	n/a	n/a	n/a

Figure 4.17: Hourly Loads and Load Impacts – *PG&E Average DA & DO AMP Event*

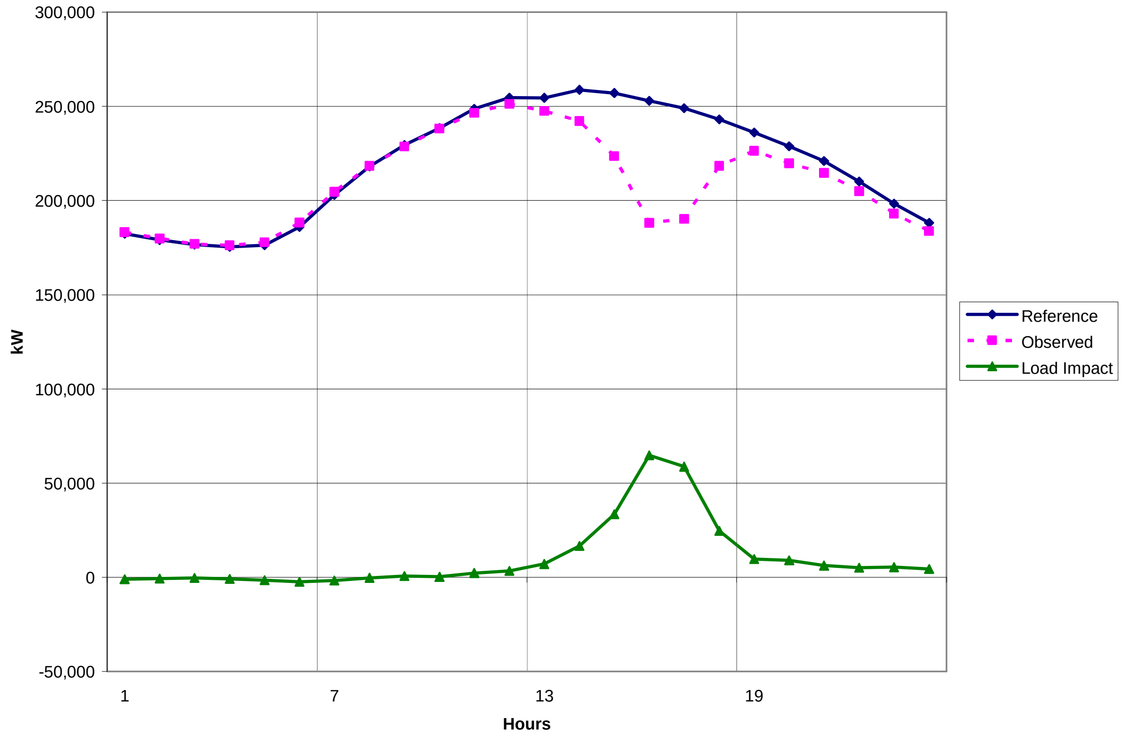
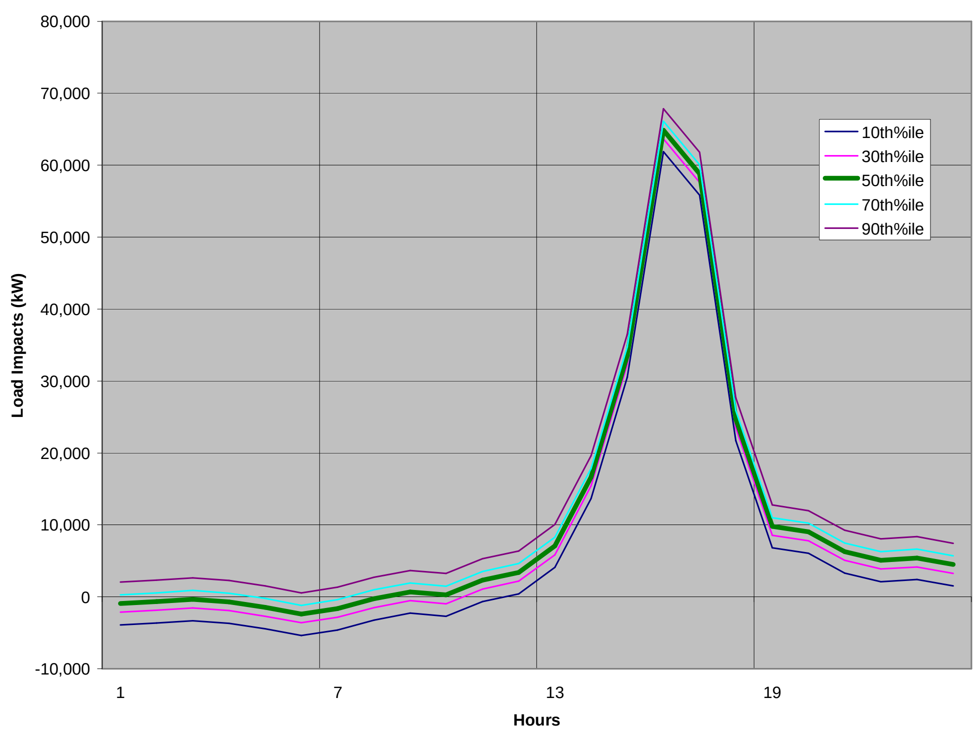
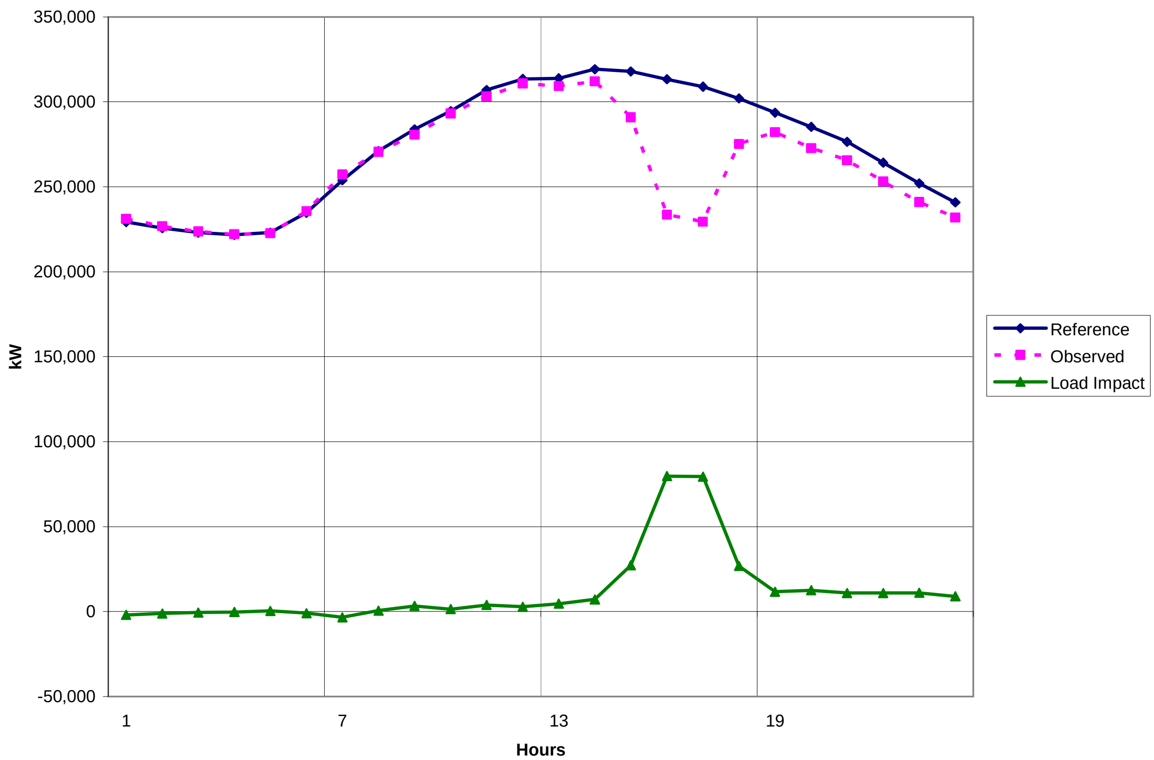


Figure 4.18: Uncertainty-Adjusted Load Impacts – *PG&E Average DA & DO AMP Event*



To illustrate the load impact potential by the middle of the summer, Figure 4-19 shows the reference and observed loads, and load impacts on the August 14 event 3, in which load reductions reached nearly 80 MW. These loads reached a higher level than those shown for the average event, because more customers were nominated for August than earlier in the summer.

Figure 4.19: Hourly Loads and Load Impacts – *PG&E AMP Event 3 (Aug. 14)*



TA/TI impacts

Approximately 35 AMP customer accounts participated in the TA/TI program and received payments prior to the August 14 event. Twenty-eight of those were different establishments of the same "big-box" retail customer. A similar number of stores from that company were enrolled in AMP but did not participate in TA/TI. We conducted two sets of analyses of those retail accounts. First, we compared the average percent load reduction on the August 14 event for the two groups of stores. The load-weighted average hourly load reduction for the 28 retail stores that *did not* participate in TA/TI was 17 percent (this compares to 15 percent load reductions for *all* AMP service accounts in industry group 4, which includes retail stores). In comparison, the average load reduction of the 28 retail stores that participated in TA/TI was 26 percent, or about 9 percentage points greater than the comparable stores which did not participate in TA/TI.

Second, since the TA/TI completion dates for all of the 28 retail stores were in July, between the first and third AMP events, we compared the average percent load reduction of the TA/TI participants for those two events, thus treating them as pre-TA/TI and post-

TA/TI events. The average load reduction for the first event, in May, was 15 percent, for the same set of customers whose August load reduction was 26 percent, as noted above. These results, while applying to a relatively small sample of customers, are consistent with a substantially greater load response capability after participation in TA/TI.[6] For completeness, the percentage load reductions for the remaining TA/TI participants, who were spread across industry groups 1, 2 and 6, were the following:

- Industry 1 – 62 percent (one account), compared to a load-weighted average of 39 percent for all non-TA/TI accounts,
- Industry 2 – 29 percent (4 accounts), compared to a load-weighted average of 24 percent for all non-TA/TI accounts, and
- Industry 6 – 24 percent (2 accounts), compared to a load-weighted average of 11 percent for all non-TA/TI accounts.

Observed event-day loads

Figures 4.20 and 4.21 show observed loads for the first and third AMP event days, as well as for several comparable non-event days. The first figure suggests load impacts in the range of 50 MW, while the second figure indicates load reductions of at least 70 MW, both of which are consistent with the estimated average hourly load impacts reported in Table 4.14.[7]

[6] Note that we had no information on the actual technologies installed through TA/TI, nor did we have information on any technologies that might have been installed in the non-TA/TI stores.

[7] The line labeled *adjusted baseline* was constructed using the *shape* of the August 21 load profile, with a morning adjustment to bring the load down to the actual August 14 level.

Figure 4.20: AMP Total Load – *May 16 Event* and June 20 Non-event

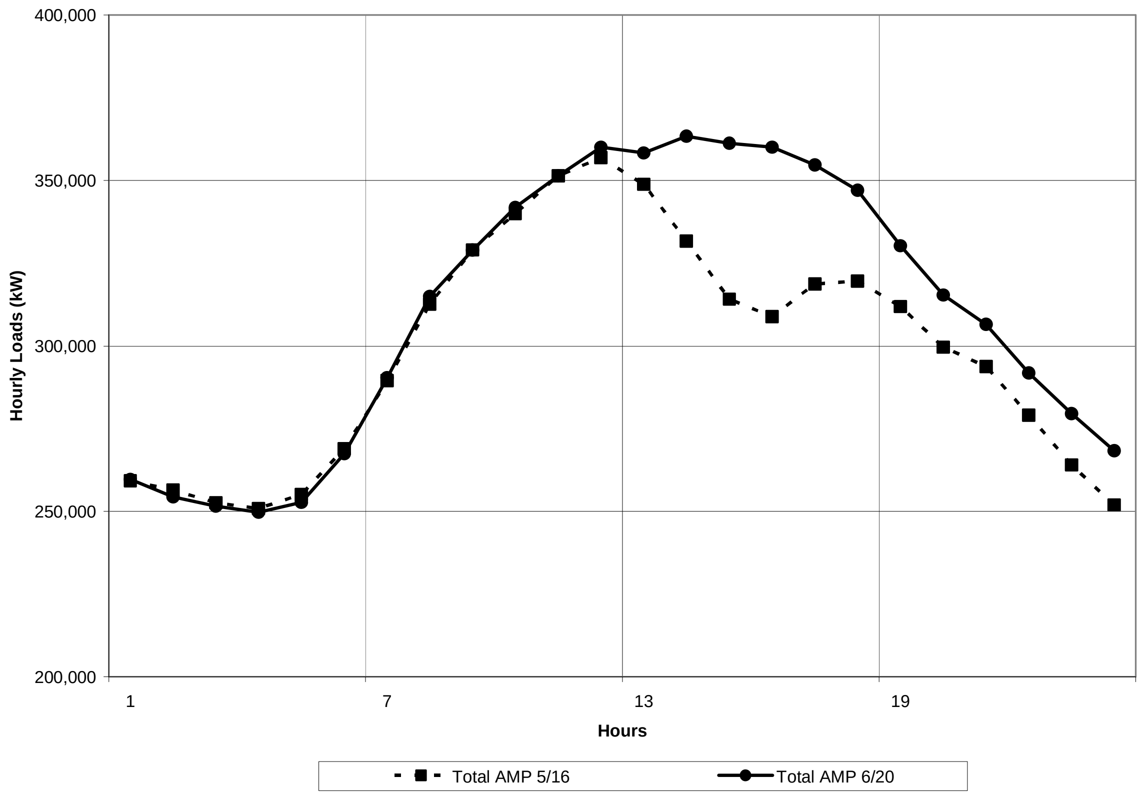
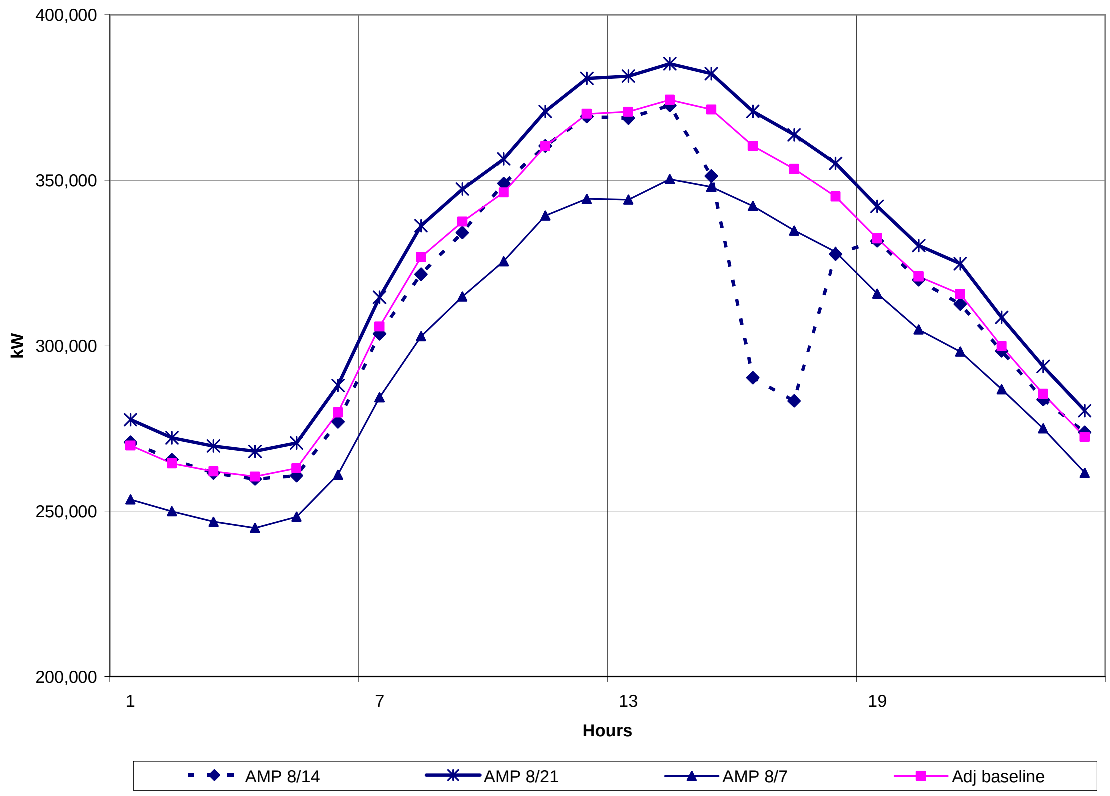


Figure 4.21: AMP Total Load – *August 14 Event*



4.3 DRC (SCE)

Table 4.17 shows average hourly estimated load impacts for each of SCE's DRC events. Typical load impacts for the day-ahead events range from a few hundred kW to 2,300 kW. The estimated day-of load impacts were nearly 33 MW for the July 8 event in which all aggregators were called, and 27.1 MW for the late November 7 event, for which one large aggregator was called. Table 4.18 shows the breakdown of load impacts by industry type for the average day-ahead event (across all events in which two aggregators were called) and the day-of event for July 8, in which all aggregators were called. Table 4.19 shows the breakdown of load impacts by CAISO LCA for the average day-ahead and day-of event. The bulk of the load impacts were in the LA Basin LCA. The total load impact potential of the program may be considered as the sum of the load impacts for the DA and DO programs, or approximately 33 MW for the day-of program type and 1.1 MW for the day-ahead program type, for a total of about 34 MW.

Table 4.23: DRC Average Hourly Load Impacts by Event (kW)

Event	Date	Type	Event/ Test	Num. of Agg.	Hours	Load Impact
1	3/25/2008	DO	Test	1	HE 15-16	7,608
2	7/8/2008	DO	Event	3	HE 17-18	32,875
3	7/9/2008	DA	Test	1	HE 14-17	140
4	7/10/2008	DA	Event	1	HE 14-17	149
5	7/14/2008	DA	Event	1	HE 14-17	522
6	8/5/2008	DA	Event	1	HE 14-17	1,155
7	8/6/2008	DA	Event	2	HE 14-17	2,326
8	8/7/2008	DA	Event	2	HE 15-17	2,260
9	8/11/2008	DA	Event	2	HE 16-17	1,492
10	8/12/2008	DA	Event	2	HE 16-17	1,330
11	8/27/2008	DA	Event	2	HE 16-17	1,375
12	8/28/2008	DA	Event	2	HE 16-17	1,384
13	8/29/2008	DA	Event	2	HE 14-17	608
14	9/3/2008	DA	Event	2	HE 15-17	920
15	9/4/2008	DA	Event	2	HE 15-17	657
16	9/5/2008	DA	Event	2	HE 15-17	963
17	9/26/2008	DA	Event	2	HE 16	620
18	10/6/2008	DA	Event	2	HE 14-17	-519
19	10/13/2008	DA	Event	2	HE 15-18	838
20	10/20/2008	DA	Event	2	HE 14-17	1,364
21	11/7/2008	DO	Event	1	HE 13-14	27,101

Table 4.24: Average Hourly Load Impacts (kW) for Typical Event, by Industry Group – *SCE DRC*

Industry Type	Ave. DA	Ave. DO
1. Ag., Mining, Constr.	0	1,117
2. Manufacturing	65	3,746
3. Whole., Trans., Util.	98	16,689
4. Retail	991	4,436
5. Offices, hotels, services	0	2,887
6. Schools	0	3,728
7. Instit. & Govt.	0	271
Total	1,154	32,875

Table 4.25: Average Hourly Load Impacts (kW) for Typical Event, by LCA – *DRC*

LCA	Ave. DA	Ave. DO
LA_BASIN	702	25,803
OUTSIDE LA	52	2,044
Other	40	2,422
VENTURA	360	2,606
Total	1,154	32,875

Hourly load impacts

Tables 4.20a and 4.20b show aggregate and per customer (respectively) hourly reference load, observed load, and load impact values for the average SCE DRC event, where the average event is defined as the sum of the averages of the typical DA events for which both aggregators were called (events 7 through 20), and the second DO event (July 8), for which all three aggregators were called (since both types of events may be called on the same day). Hourly load impacts were about 21 percent of the reference load in hours 17-18 which were the hours of the DO event. The 10th and 90th percentile load impacts in those hours are estimated to lie about 7 percent below and above the estimated load impacts for the average event. Figure 4.22 illustrates the loads and load impacts for the average event, while Figure 4.23 illustrates the uncertainty-adjusted load impacts. The bulk of the DRC load impacts come from the DO contracts. This is shown in the summary of average hourly load impacts in Table 4.17 above, and illustrated in Figure 4.24 below, which shows loads and load impacts for a typical DA event (August 27), for which the average load impact was 1.4 MW.

Table 4.26a: Aggregate Hourly Load Impacts – *Typical SCE DRC DA & DO Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	125,739	124,831	908	67	-1,455	-59	908	1,875	3,271
2	122,632	121,997	635	66	-1,728	-332	635	1,602	2,999
3	119,907	120,290	-383	66	-2,747	-1,350	-383	584	1,980
4	118,899	120,262	-1,364	65	-3,727	-2,331	-1,364	-397	1,000
5	120,211	122,442	-2,231	65	-4,595	-3,198	-2,231	-1,264	132
6	124,702	127,582	-2,879	64	-5,243	-3,846	-2,879	-1,912	-516
7	134,629	137,291	-2,662	64	-5,025	-3,629	-2,662	-1,695	-298
8	142,663	144,665	-2,002	66	-4,366	-2,969	-2,002	-1,035	361
9	152,074	152,811	-736	70	-3,100	-1,704	-736	231	1,627
10	156,400	158,095	-1,695	74	-4,059	-2,662	-1,695	-728	668
11	163,248	156,543	6,705	78	4,341	5,738	6,705	7,672	9,068
12	163,493	165,529	-2,036	81	-4,400	-3,003	-2,036	-1,069	327
13	160,743	162,985	-2,241	83	-4,605	-3,209	-2,241	-1,274	122
14	161,601	162,151	-550	84	-2,914	-1,517	-550	417	1,813
15	161,385	162,264	-879	84	-3,242	-1,846	-879	88	1,484
16	159,945	151,992	7,953	84	5,590	6,986	7,953	8,921	10,317
17	158,136	124,795	33,341	82	30,978	32,374	33,341	34,308	35,705
18	155,019	121,350	33,669	80	31,306	32,702	33,669	34,636	36,033
19	155,551	139,243	16,307	78	13,944	15,340	16,307	17,274	18,670
20	157,003	150,457	6,546	75	4,182	5,579	6,546	7,513	8,909
21	157,580	155,742	1,838	72	-525	871	1,838	2,805	4,202
22	150,410	150,263	146	70	-2,217	-821	146	1,114	2,510
23	136,634	134,812	1,823	69	-541	856	1,823	2,790	4,186
24	130,579	129,379	1,200	68	-1,163	233	1,200	2,167	3,563
	Reference Energy Use (kWh)	Estimated 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	3,489,183	3,397,771	91,412	57.4	n/a	n/a	n/a	n/a	n/a

Table 4.27b: Per Customer Hourly Load Impacts – *Typical SCE DRC DA & DO Event*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	274	272	2	67	-3	0	2	4	7
2	267	266	1	66	-4	-1	1	3	7
3	261	262	-1	66	-6	-3	-1	1	4
4	259	262	-3	65	-8	-5	-3	-1	2
5	262	267	-5	65	-10	-7	-5	-3	0
6	272	278	-6	64	-11	-8	-6	-4	-1
7	293	299	-6	64	-11	-8	-6	-4	-1
8	311	315	-4	66	-10	-6	-4	-2	1
9	331	333	-2	70	-7	-4	-2	1	4
10	341	344	-4	74	-9	-6	-4	-2	1
11	356	341	15	78	9	12	15	17	20
12	356	361	-4	81	-10	-7	-4	-2	1
13	350	355	-5	83	-10	-7	-5	-3	0
14	352	353	-1	84	-6	-3	-1	1	4
15	352	353	-2	84	-7	-4	-2	0	3
16	348	331	17	84	12	15	17	19	22
17	344	272	73	82	67	71	73	75	78
18	338	264	73	80	68	71	73	75	78
19	339	303	36	78	30	33	36	38	41
20	342	328	14	75	9	12	14	16	19
21	343	339	4	72	-1	2	4	6	9
22	328	327	0	70	-5	-2	0	2	5
23	298	294	4	69	-1	2	4	6	9
24	284	282	3	68	-3	1	3	5	8
	Reference Energy Use (kWh)	Estimated 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	7,600	7,401	199	57.4	n/a	n/a	n/a	n/a	n/a

Figure 4.22: Hourly Loads and Load Impacts – *Typical SCE DRC DA & DO Event*

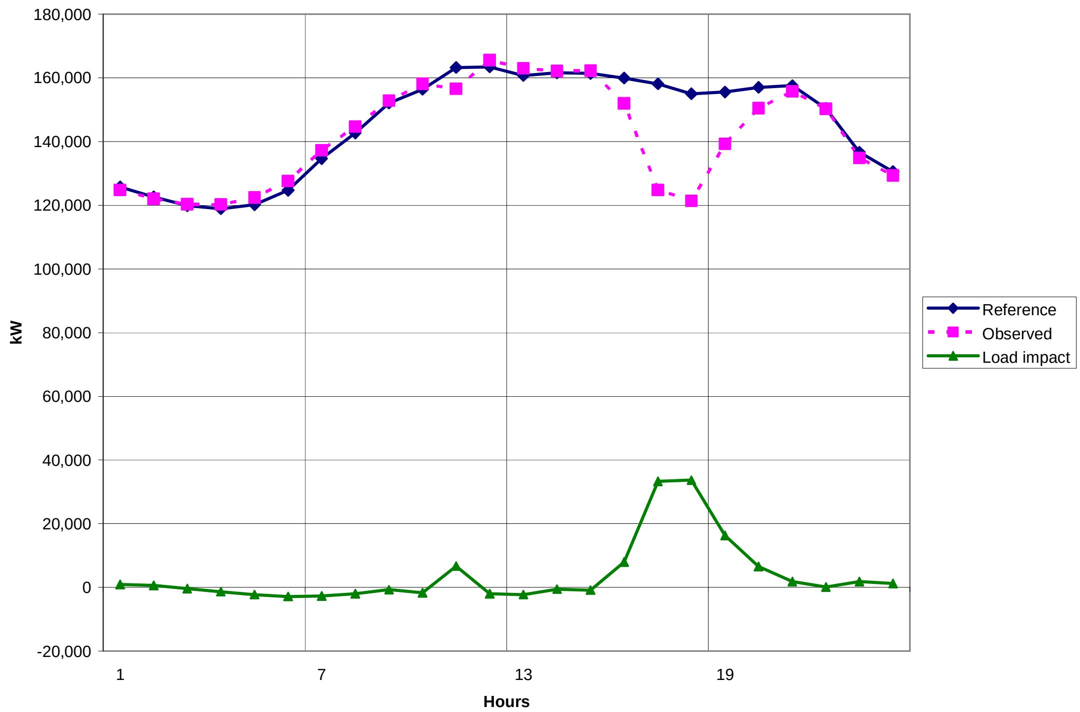


Figure 4.23: Uncertainty-Adjusted Load Impacts – *Typical SCE DRC DA & DO Event*

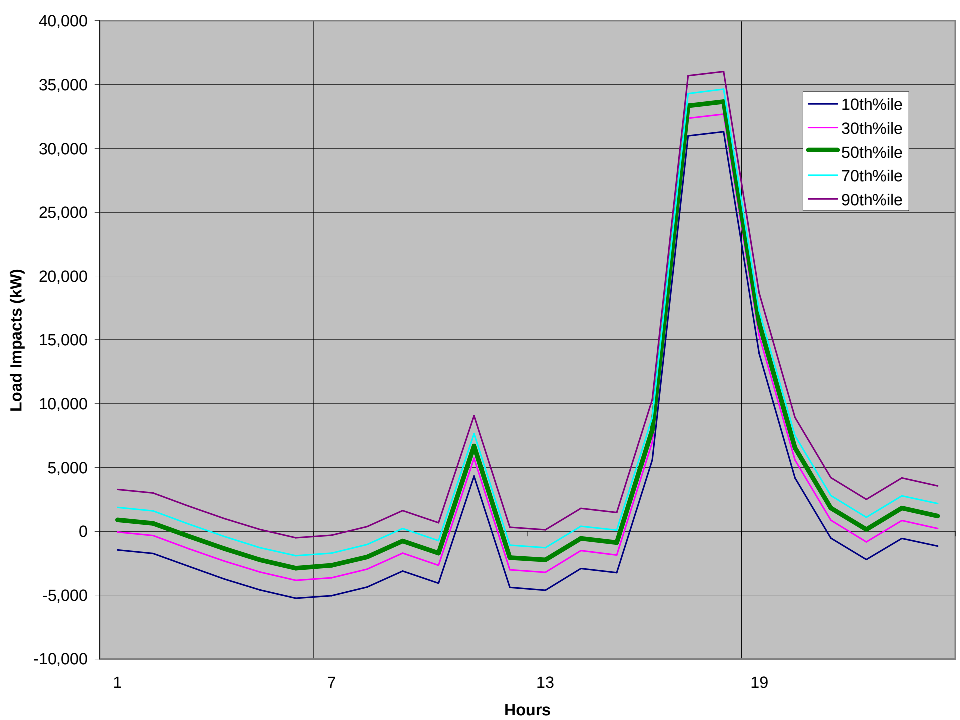
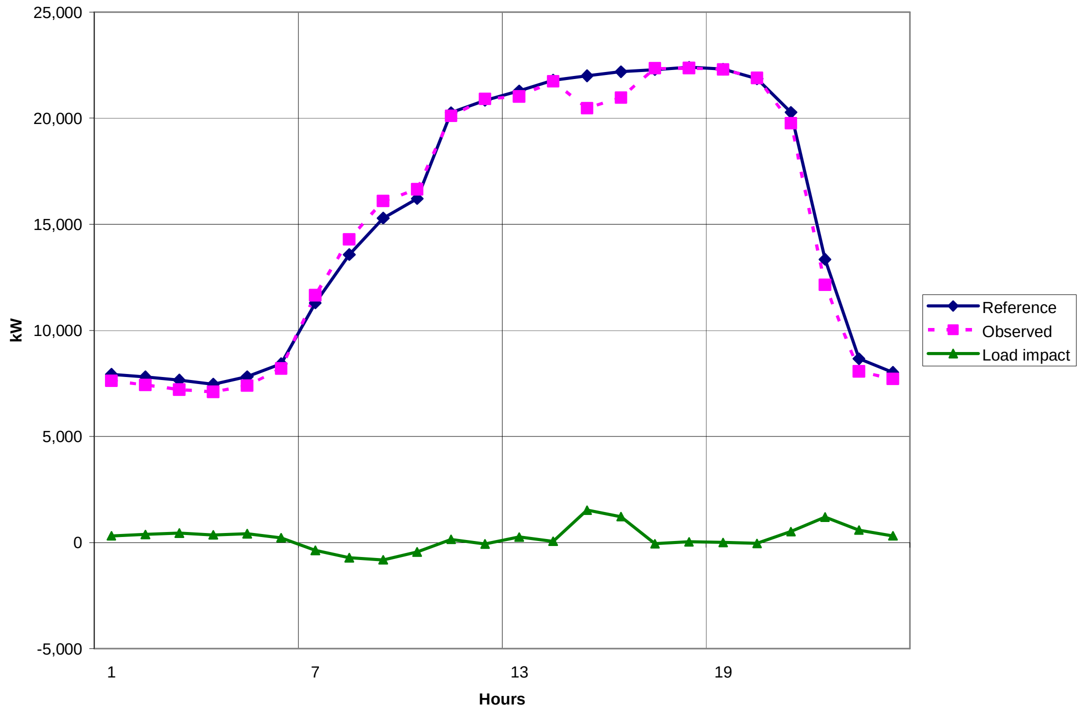


Figure 4.24: DRC Load Impacts – *August 27 DA Event Day*



TA/TI impacts
Only four DRC enrollees participated in TA/TI prior to events in which they were called (several others participated later in 2008). Thus, no formal analysis is warranted. Three of the participants were water utilities, which tend to be very responsive in any case. The three averaged greater than 50 percent load reductions, compared to 36 percent for all other industry group 3 customers. The other participant was a hotel that achieved 13 percent load impacts, which is in line with other industry group 5 customers.

Observed event-day loads
As confirmation of the estimated overall program load impacts, Figure 4.25 shows the total DRC load for the average DA events, and for a comparable set of non-event days. Figure 4.26 shows the total DRC load on the July 8 DO event, in which all three DO aggregators were called.

Figure 4.25: SCE DRC Average of Day-Ahead Events 7 - 17

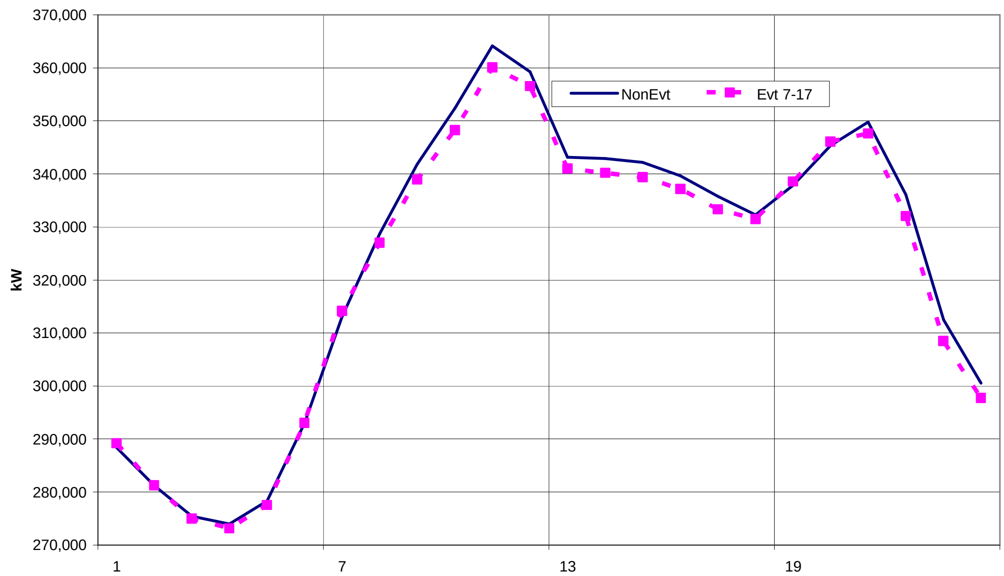
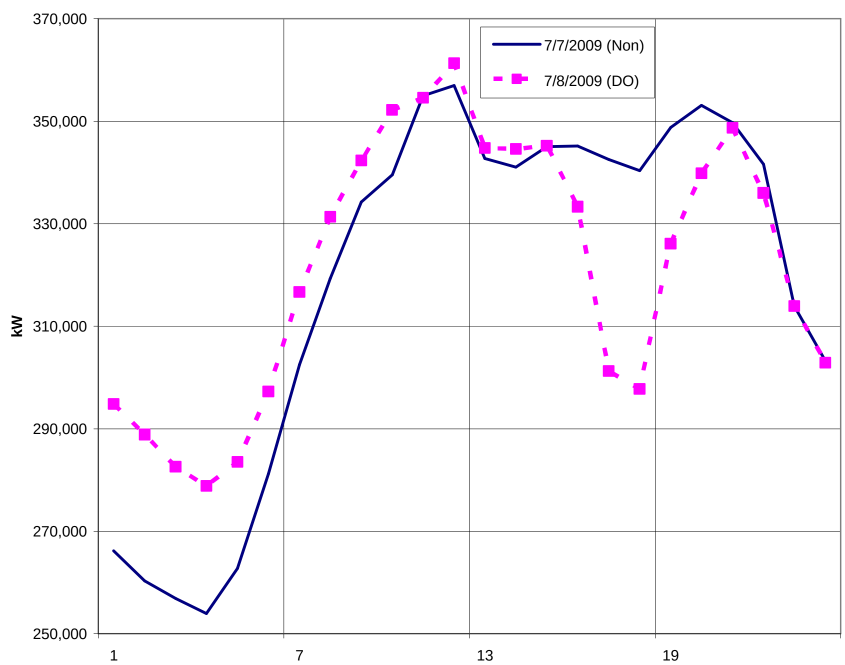


Figure 4.26: SCE DRC Day-Of Event – *July 8, 2008*



5. Ex Ante Load Impacts

This section documents the preparation of ex ante forecasts for 2009 to 2020 of reference loads and load impacts 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 DRC for SCE. The forecasts of load impacts were developed in two primary stages. First, estimates of reference loads and percentage load impacts were developed based on the ex post load impact evaluations of historical data on events in 2008 that was described in the previous sections. Second, the simulated reference loads and load impacts were combined with forecasts of program enrollment to develop forecasts of load impacts. Separate forecasts were developed by *customer size*, *industry type* (according to NAICS or SIC codes), and CAISO *Local Capacity Area*, as well as by the event day-types described in Section 5.1 below. For PG&E, enrollment forecasts were provided through a separate contract with The Brattle Group. SCE and SDG&E provided the 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 must be reported by the following factors (in addition to the customer size, customer type and LCA factors 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

Customer accounts were assigned to one of three size groups, 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;[8]
- Medium – maximum demand between 20 and 200 kW;
- Large – maximum demand greater than 200 kW.

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

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 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. Simulate reference loads by cell
3. Calculate forecast percentage load impacts by cell
4. Apply percentage load impacts to the reference loads
5. Scale the reference loads using enrollment forecasts

Each of these steps is described below.

Define data sources
No major design changes are planned for any of the aggregator programs. Because of this, there is a close link between the results of the ex post analyses conducted for the 2008 program year and the ex ante load impacts. That is, the historical customer loads serve as the source of the ex ante reference loads and the historical percentage load impacts serve as the source of the ex ante load impacts. There is no need to convert historical load impacts to price elasticities because the price signal is not expected to change. This contrasts with our CPP/PDP ex ante load impact study, in which elasticity estimates were developed to account for significant changes in event day prices in the forecast period.

Simulate reference loads
For each program, we estimated regression equations for each customer account, using data for 2008. The purpose of these equations was to simulate reference loads by customer type for the various scenarios required by the Protocols (*e.g.*, the typical event day in a 1-in-2 weather year).

These equations were similar in design to the ex post load impact equations described in Section 3.1. There was one primary difference between the ex post and ex ante regression models: the ex ante models excluded the morning-usage variable. While this variable is useful for increasing accuracy in estimating ex post load impacts for particular events, it complicates the use of the equations in ex ante simulation. That is, it requires one to separately simulate the level of the morning load.

The definitions of the 1-in-2 and 1-in-10 weather years differed by utility, as shown in Table 5.1. For SDG&E, the year shown was used to generate the typical event days. Unlike SCE and PG&E, SDG&E selected from different years to develop its scenarios of peak load days by month.

Table 5.1: Weather Year Definitions by Utility

Utility	1-in-2 Weather Year	1-in-10 Weather Year
PG&E	2004	2003
SCE	2002	1998
SDG&E	2004*	2007*

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. These correspond to the reporting levels required in the Protocols. This method is feasible because SCE did not provide enrollments by cell (*i.e.*, combinations of industry groups and LCAs) for these programs. Specifically, SCE specified that CBP enrollments would increase 5 percent per year through 2012; and SCE forecast DRC enrollments by aggregator and notice level (day ahead and day of).

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. Differences in the load profiles across LCAs were 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.

For SDG&E's CBP program, we developed per-customer load profiles for by industry group, notice level and hours of availability (*e.g.*, manufacturing customers called with day-ahead notice for a four-hour event window). This method conformed to the enrollment forecast provided by SDG&E, which specified the number of enrolled customers within each group.

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, as implemented in 2008, differ somewhat from those of some of the other DR programs, in that many of the events called differed in terms of program type (*e.g.*, day-ahead or day-of), event length (*e.g.*, as short as one hour, to as long as 6 hours, depending in part on the aggregator contracts), and the particular hours called. As a result, in many cases there was no obvious definition of a "typical" event in 2008. However, a definition of a typical event was needed for the ex ante forecast period that would allow us to forecast the load impact that would occur if all nominated customers were called on the same day. The following

procedures were used to define typical events 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 2008. For the PG&E and SDG&E CBP programs, only two events were called – one day-ahead event and one day-of event. To simulate an event in which both program types are simultaneously called, the load impacts for a typical event were defined as the sum of the load impacts for the two program-types. For the SCE CBP program, the load impacts for a typical event were defined as the sum of the average DA event (the average across all but the 1-hour September 26 event for which not all aggregators were called) and the average DO event. A similar definition applied for SCE's DRC program, for which the average DA event was defined across all events in which both aggregators were called, and the typical DO event was the one event in which all three aggregators were called. Finally, for PG&E's AMP program, a typical event was defined as the average of the two events in which *both* the DA and DO program types were called.

- *Forecast period*. Although events of many different hours were called in 2008 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 14-17. For SCE and SDG&E, we specified an eight-hour event, from hours-ending 12 to 19 to cover the entire window for which an event may be called.

The percentage load impacts were developed separately for each industry group (or, for SDG&E, for each industry group, notice level and event duration) and were based on the 2008 ex post load impact estimates. We estimated the percentage load impacts during event and non-event hours, with the *enrolled* reference load serving as the denominator. The use of enrolled loads in place of loads of customers who submit bids embeds the assumption that future nomination patterns match historical patterns. In addition, because The Brattle Group and SDG&E provided forecasts of enrollments but not of nominations, our results needed to be expressed on a per enrolled customer basis.

For PG&E, load impacts were differentiated by event hours, hours adjacent to the event hours, and all other non-event hours. These load impacts were estimated in the ex ante regression models, with the event-hour variables modified to reflect these groupings (versus the hourly impacts used in the ex post models). For SCE and SDG&E, the load impacts were differentiated by event hours and non-event hours and were developed directly from the ex post load impact estimates.

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

Apply forecast enrollment to produce program-level load impacts. For PG&E's program, The Brattle Group produced load impacts by industry group, LCA, and at the program level by applying the database created in the previous step to the enrollment forecasts. 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.

For SCE, we simply scaled the results for all levels of reporting using ratios specific to each program. For CBP, the results were increased by 5 percent per year through 2012 and held constant for the remainder of the forecast years. Table 5.2 summarizes the scaling factors used for DRC. The scaling factors are the ratio of the forecast year's contract MW to the contract MW on August 1, 2008. Customers with day-ahead and day-of notice are separately scaled.

Table 5.2: SCE DR Contracts Enrollment Assumptions

Year	Day-Ahead		Day-Of	
	Contract MW	Scaling Factor	Contract MW	Scaling Factor
8/1/2008	6		57.5	
2009	24	4.0	95.0	1.7
2010	54	9.0	130.0	2.3
2011	63	10.5	180.0	3.1
2012 and beyond	45	7.5	190.0	3.3

For SDG&E's CBP program, the process of creating the program-level load impacts was similar to the one used for PG&E's programs, in that per-customer reference loads and load impacts were scaled to aggregated levels (program or industry group level) using a forecast of the number of enrolled customers in each customer group. SDG&E provided the enrollment forecast, which consisted of the monthly number of customers in each group.

5.3 Detailed Findings

This section summarizes the enrollment forecasts, percentage load impacts, and resulting reference loads and load impacts from the ex ante evaluation.

5.3.1 Enrollment Forecasts

The enrollment forecasts provided by PG&E (as performed by The Brattle Group), SCE and SDG&E for their CBP programs are illustrated in Figures 5.1 through 5.3. SCE assumes a 5 percent growth rate in enrollment through 2012, with enrollments constant for the remainder of the forecast period. SDG&E anticipates growth until 2011, with steady enrollment after that date.

Figure 5.1: Enrollment Forecasts – PG&E CBP

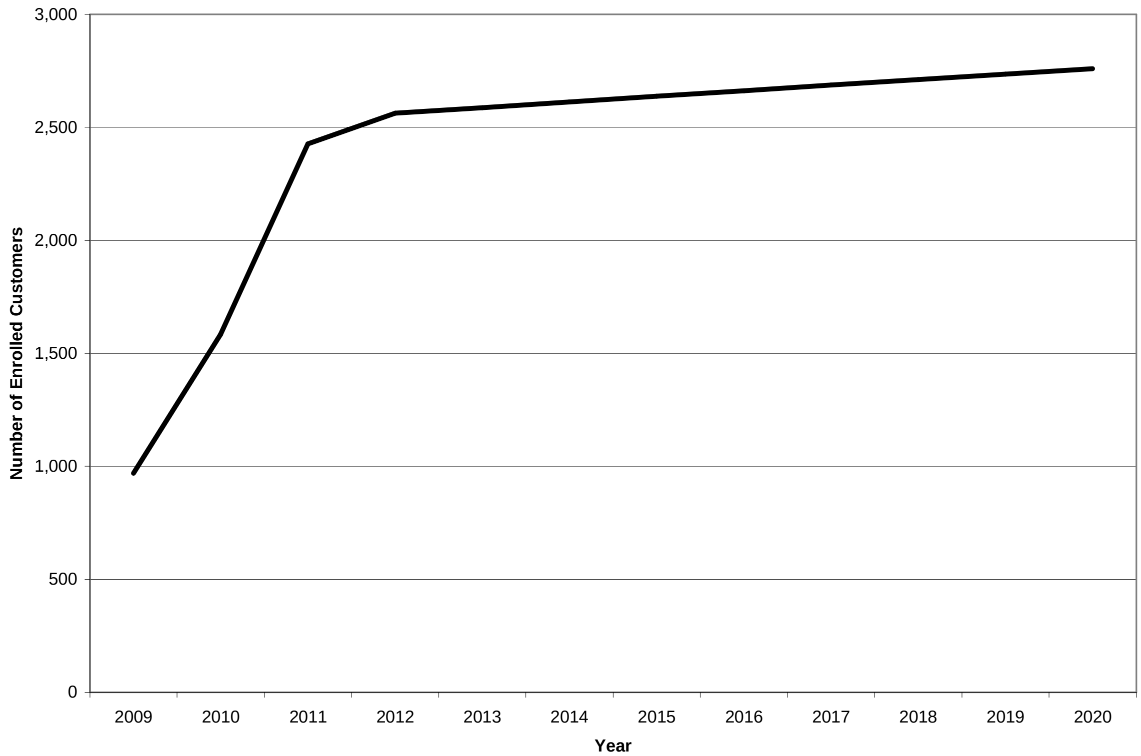


Figure 5.2: Enrollment Forecasts – SCE CBP

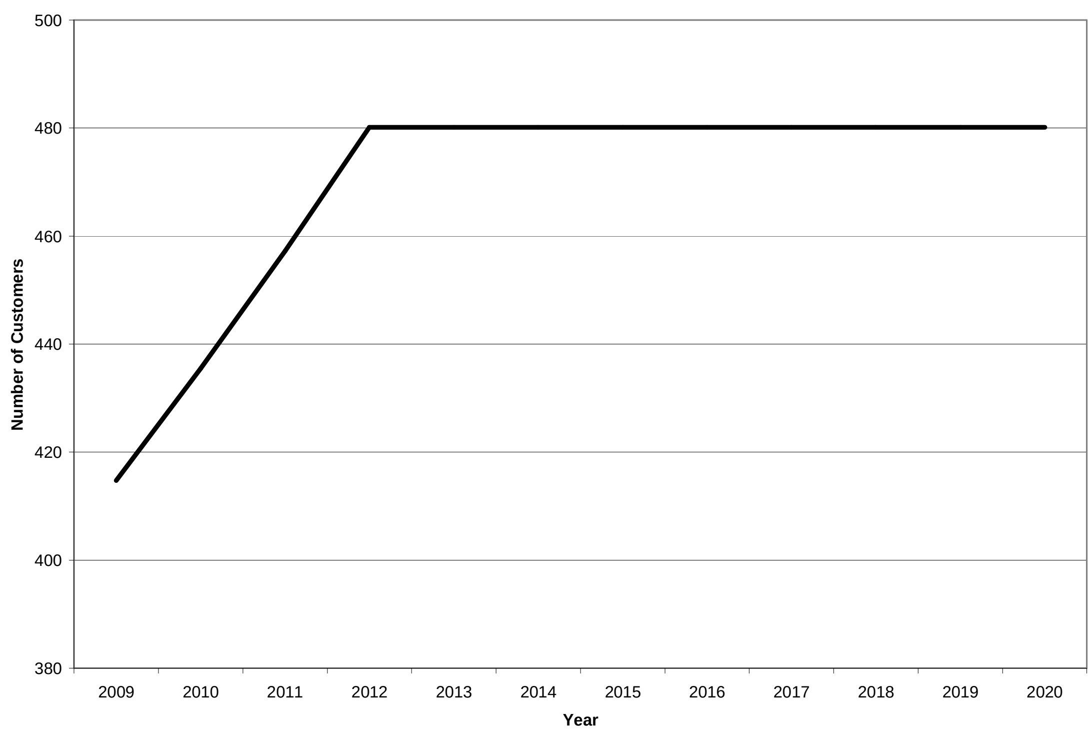


Figure 5.3: Enrollment Forecasts – SDG&E CBP

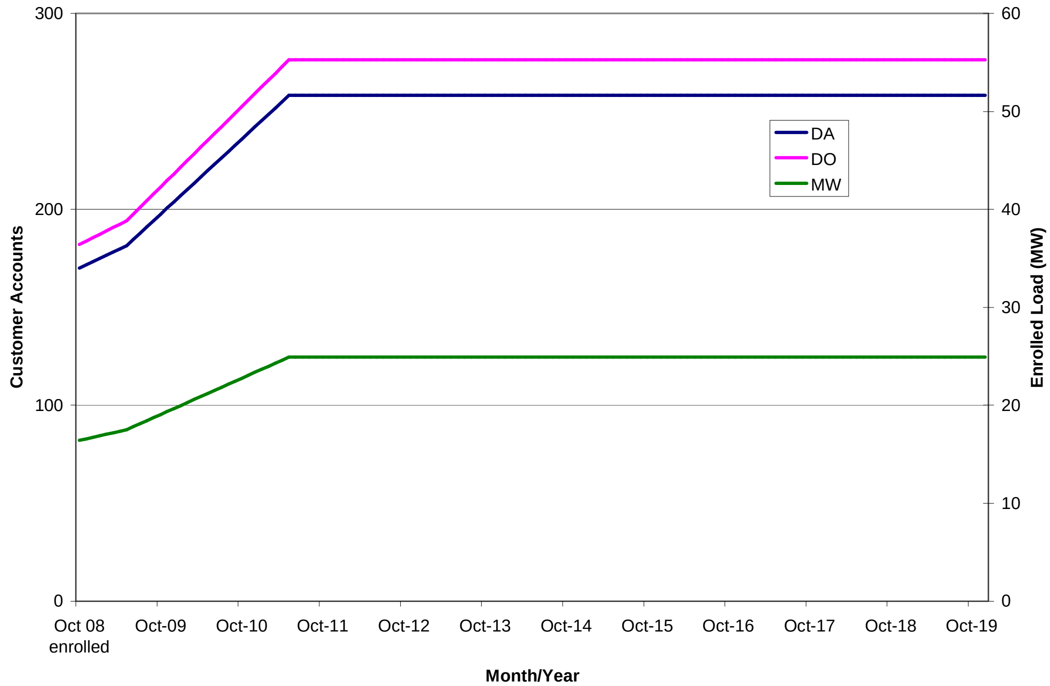


Figure 5.4 summarizes SCE's DRC contract load amounts by DA and DO program types for 2008 and the expected contract amounts through 2012. We scaled the DRC reference loads to correspond to the expected growth in contract amounts over that period.

Figure 5.5 summarizes PG&E's AMP enrollment forecast. Enrollments are expected to increase from 749 customers in May 2009 to 2,311 by May 2011, at which point the number of enrolled customers remains constant through 2020.

Figure 5.4: Expected Contract Amounts – SCE DRC

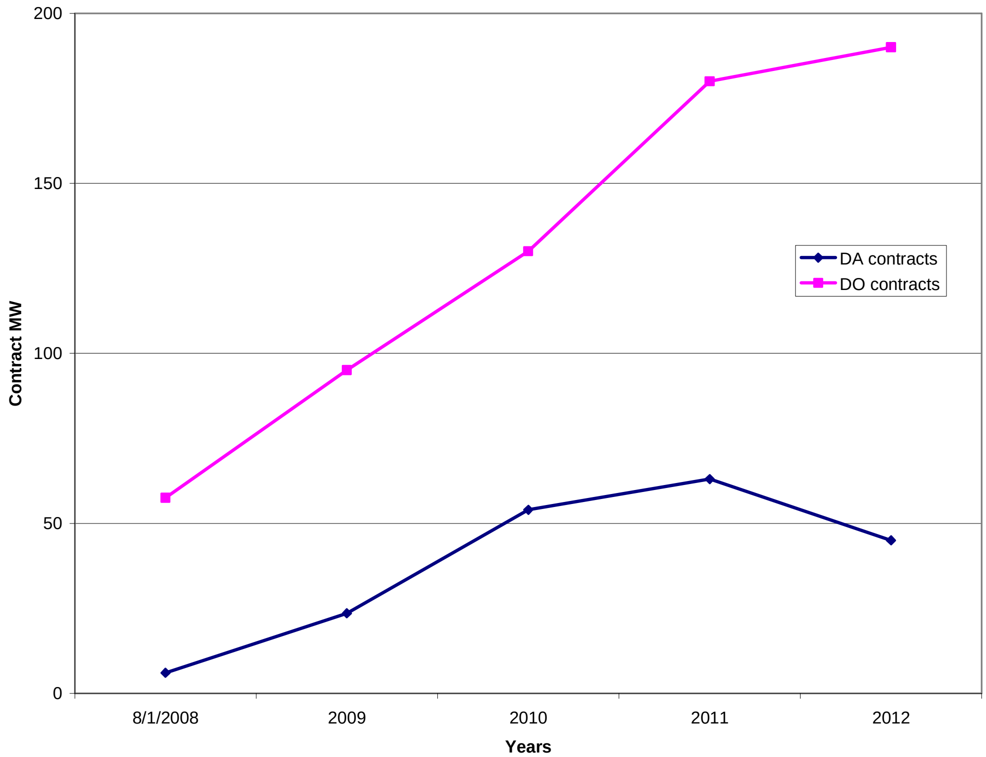
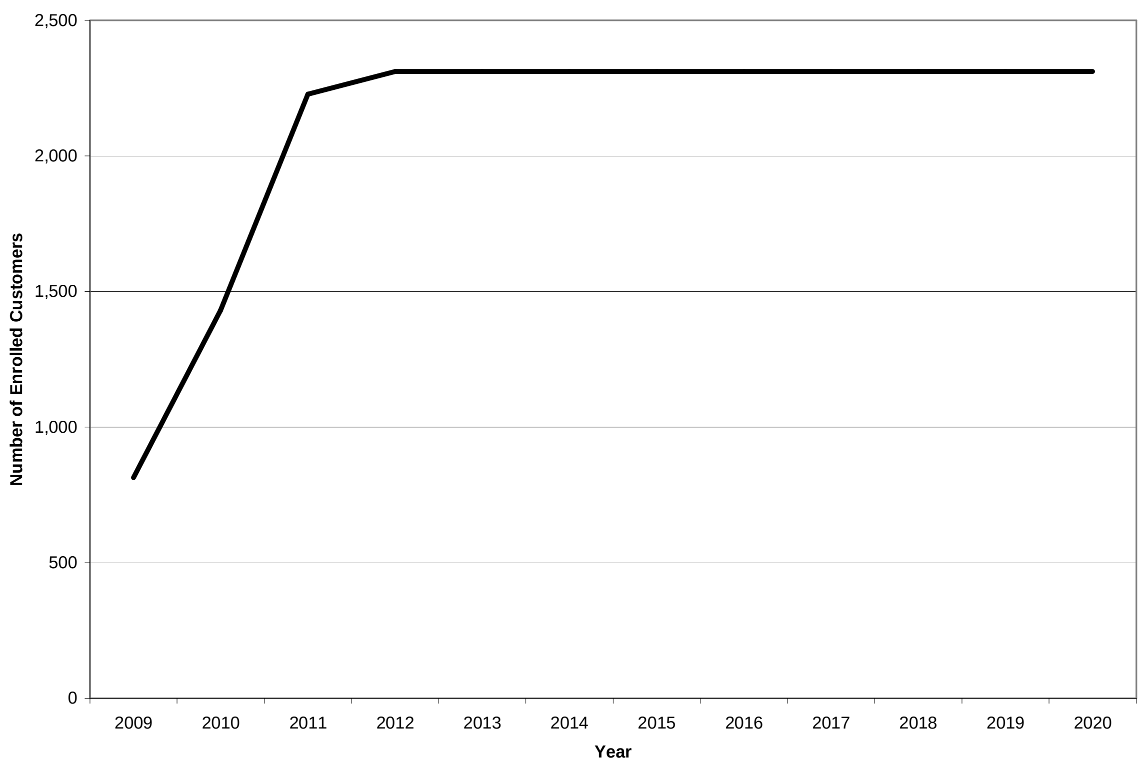


Figure 5.5: Enrollment Forecasts – PG&E AMP



5.3.2 Reference Loads and Load Impacts

For each utility and program, we provide the following summary information:

1. A figure showing the hourly reference load, event-day load, and load impacts for the typical event day in a 1-in-2 weather year;
2. A pie chart showing the share of load impacts by LCA (except for SDG&E);
3. A pie chart showing the share of load impacts by industry group;
4. Average event-hour load impacts by year; and
5. Average event-hour load impacts by peak month day.

Together, these figures provide a good indication of the variability in the forecast load impacts according to the variations produced according to the Protocol's requirements. The tables required by the Protocols are provided in the Appendix.

PG&E CBP

Figure PG&E CBP 1 shows the August 2012 forecast load impacts for a typical event day in a 1-in-2 weather year.[9] Event-hour load impacts range from 41.6 MW to 44.4 MW, which represent approximately 7.7 percent of the enrolled reference load.

Figures PG&E CBP 2 and 3 show how the load impacts are distributed by LCA and industry group. Nearly half of the load impacts come from customers in the Greater Bay Area LCA; and Retail and Manufacturing customer types account for the largest shares of load impacts, at 48 percent and 23 percent of the total respectively.

Figure PG&E CBP 4 illustrates the average hourly 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 enrollments shown in Figure 5.1, with impacts rapidly increasing to approximately 42 MW in 2011, after which there are modest increases.

[9] For this program, program-level impacts and portfolio-level impacts are the same.

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

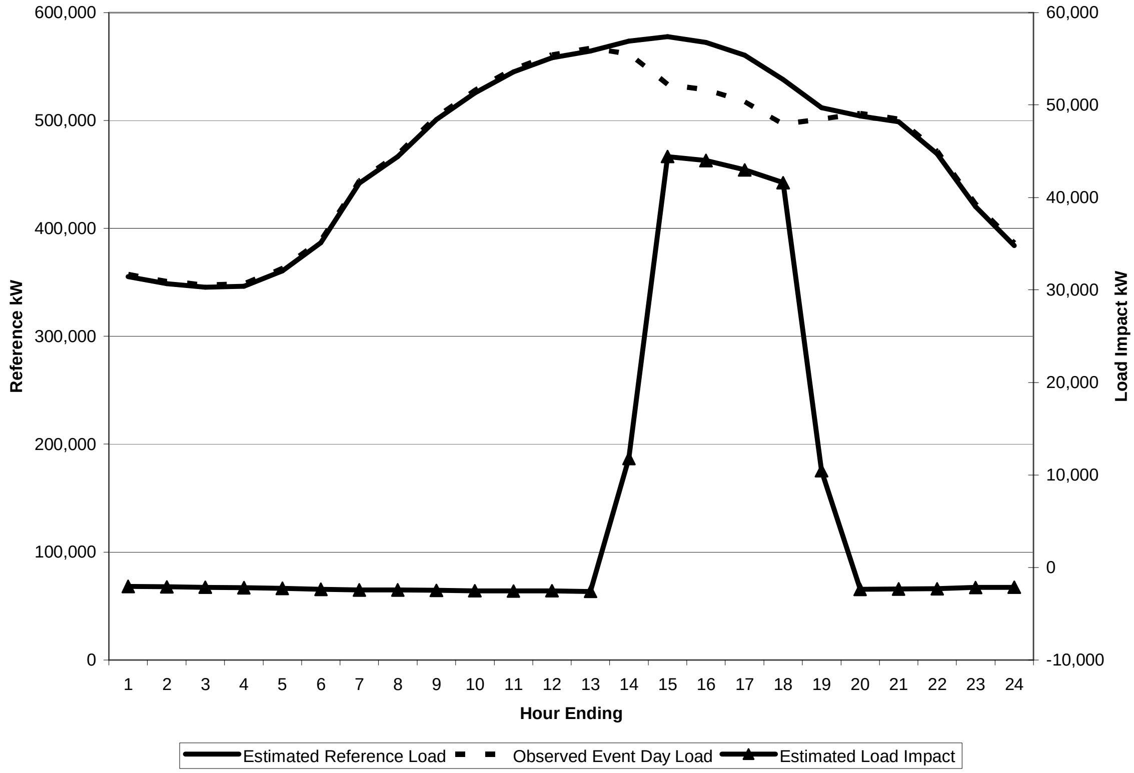


Figure PG&E CBP 2: Share of Load Impacts by LCA for the August 2012 Peak Day in a 1-in-2 Weather Year

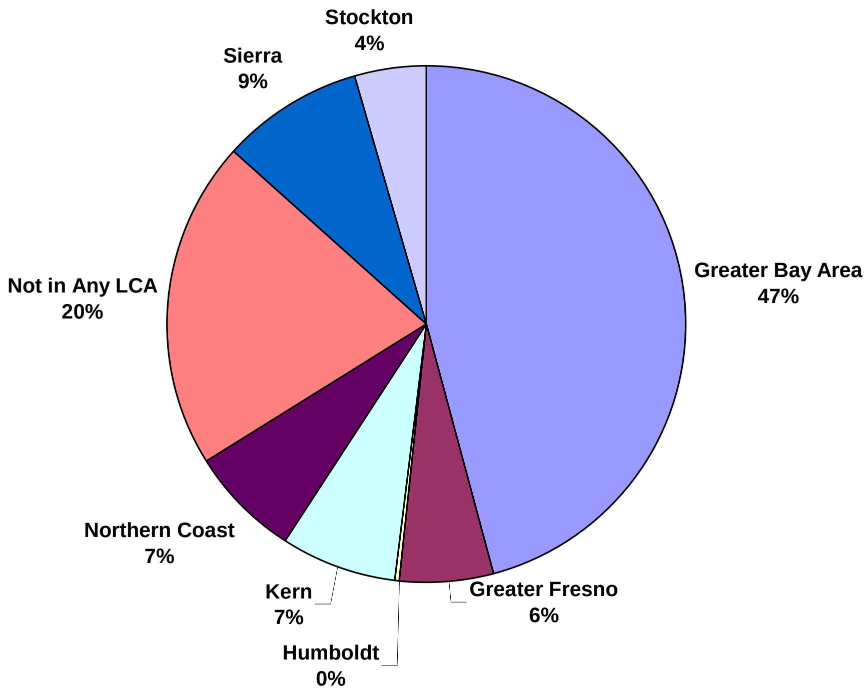


Figure PG&E CBP 3: Share of Load Impacts by Industry Group for the August 2012 Peak Day in a 1-in-2 Weather Year

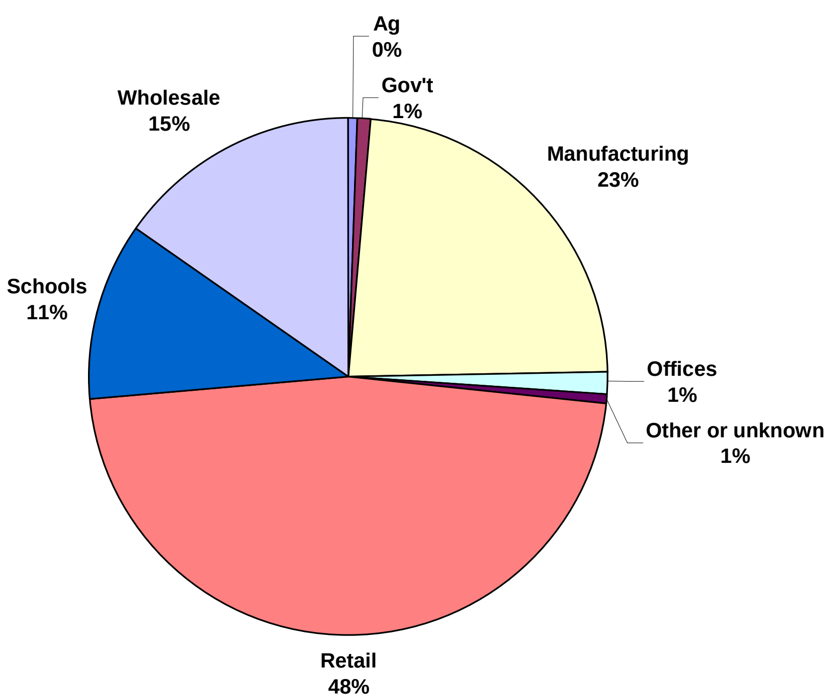
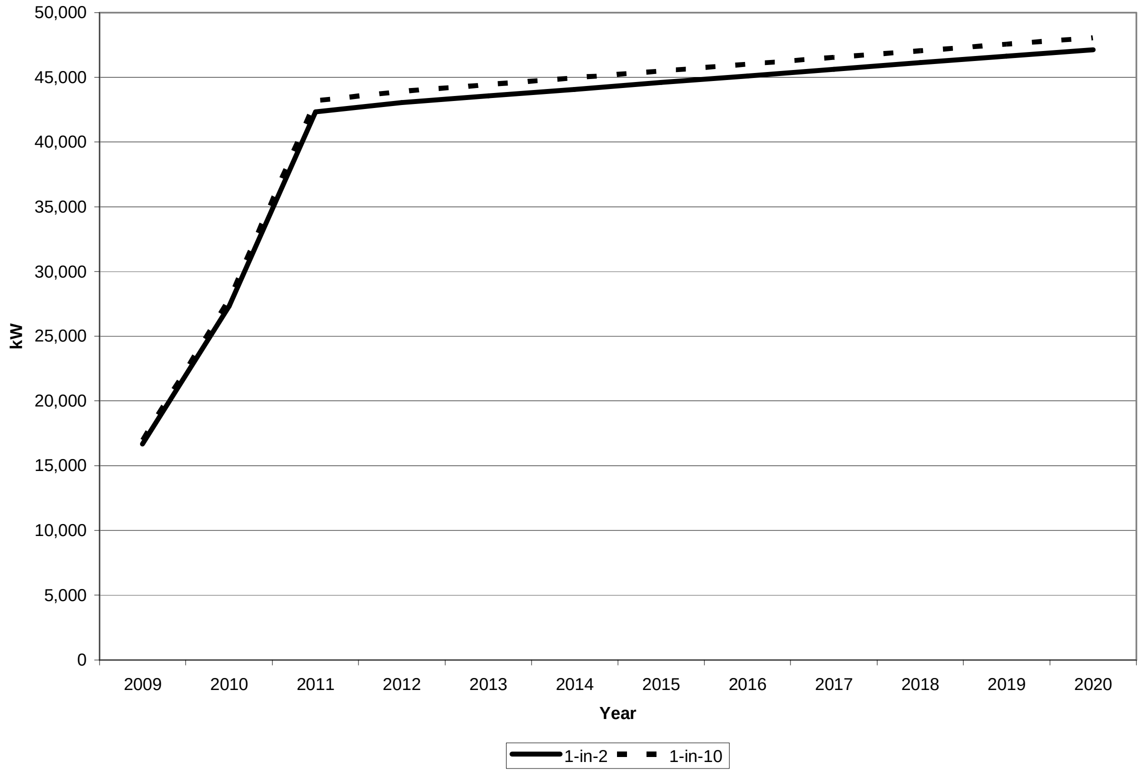


Figure PG&E CBP 4: Load Impacts by Year for the August Peak Day in 1-in-2 and 1-in-10 Weather Years



SCE CBP

Figure SCE CBP 1 shows the forecast load impacts for a typical event day in a 1-in-2 weather year. The values in the figure apply to the years 2012 through 2020, as SCE's forecast enrollment does not change after 2012. Event-hour load impacts range from 12.8 MW to 13.4 MW, which is approximately 10.9 percent of the enrolled reference load. Non-event hour load impacts average an increase of 0.5 MW, or 0.6 percent of the reference load in those hours.

Figures SCE CBP 2 and 3 show how the load impacts are distributed by LCA and industry group. Seventy-four percent of the load impacts come from customers in the LA Basin LCA; and ninety percent of the load impacts are from retail customers.

Figure SCE CBP 4 illustrates the average hourly load impact across years for the typical event day in both 1-in-2 and 1-in-10 weather years. As with the enrollment forecasts, the level of load impacts does not change after 2012, when the load impact is approximately 13.2 MW in a 1-in-2 weather year and 13.6 MW in a 1-in-10 weather year.

Figure SCE CBP 5 illustrates the load impact across monthly peak days of a 1-in-2 weather year. Little variation exists across the months, with a minimum load impact of 12.1 MW in May and a maximum load impact of 13.4 MW in July.

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

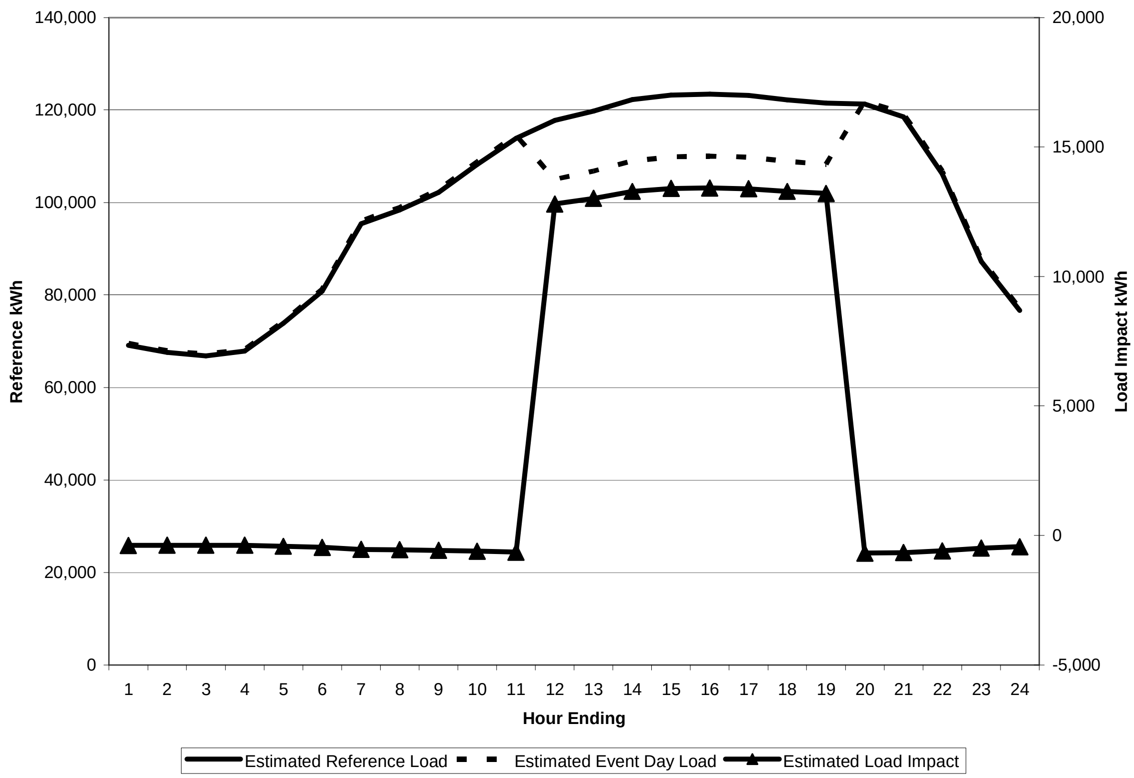


Figure SCE CBP 2: Share of Load Impacts by LCA for the Typical Event Day in a 1-in-2 Weather Year for 2012 and Beyond

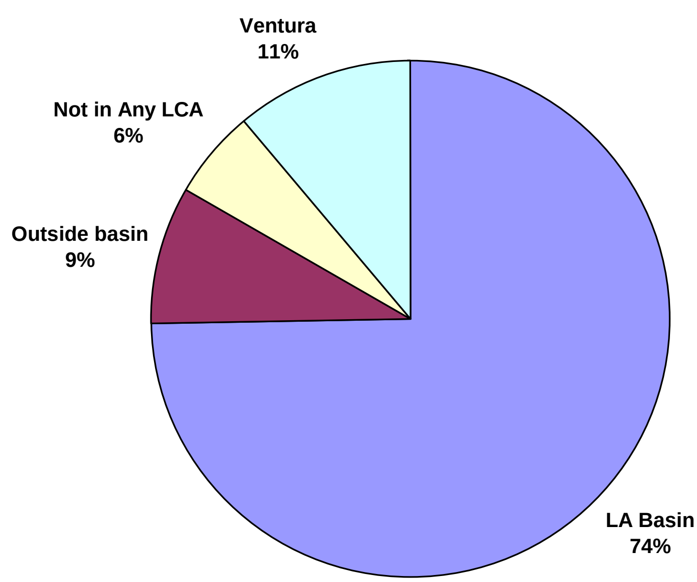


Figure SCE CBP 3: Share of Load Impacts by Industry Group for the Typical Event Day in a 1-in-2 Weather Year for 2012 and Beyond

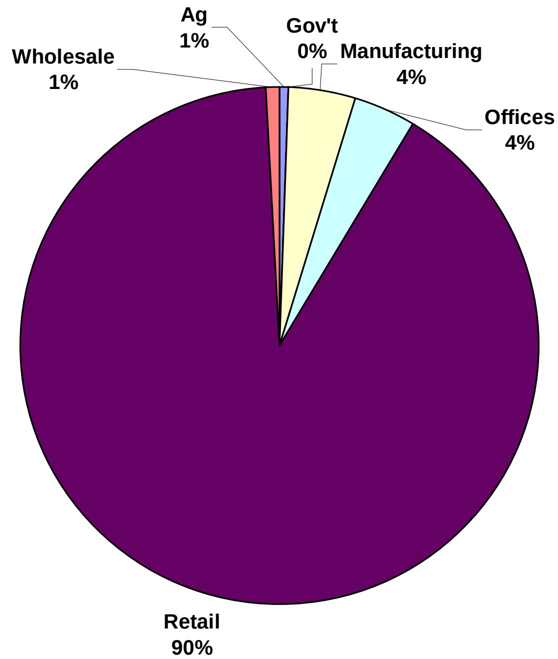


Figure SCE CBP 4: Average Event-Hour Load Impacts by Forecast Year and Weather Scenario for the Typical Event Day

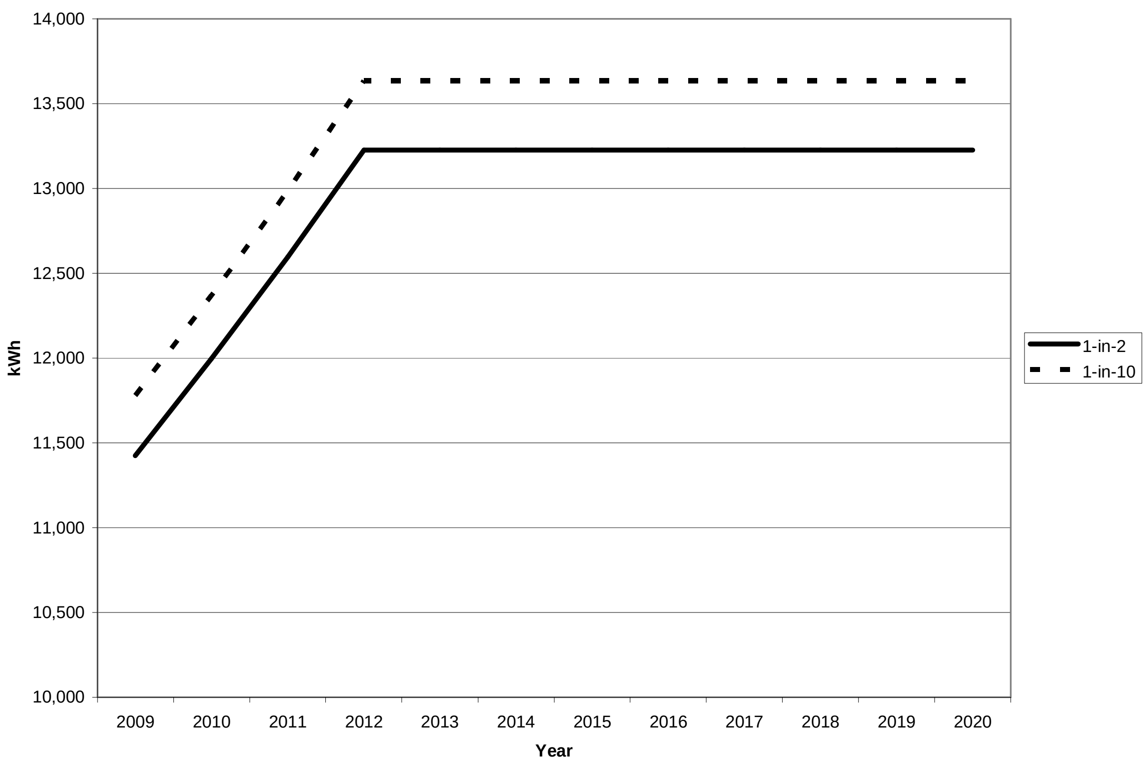
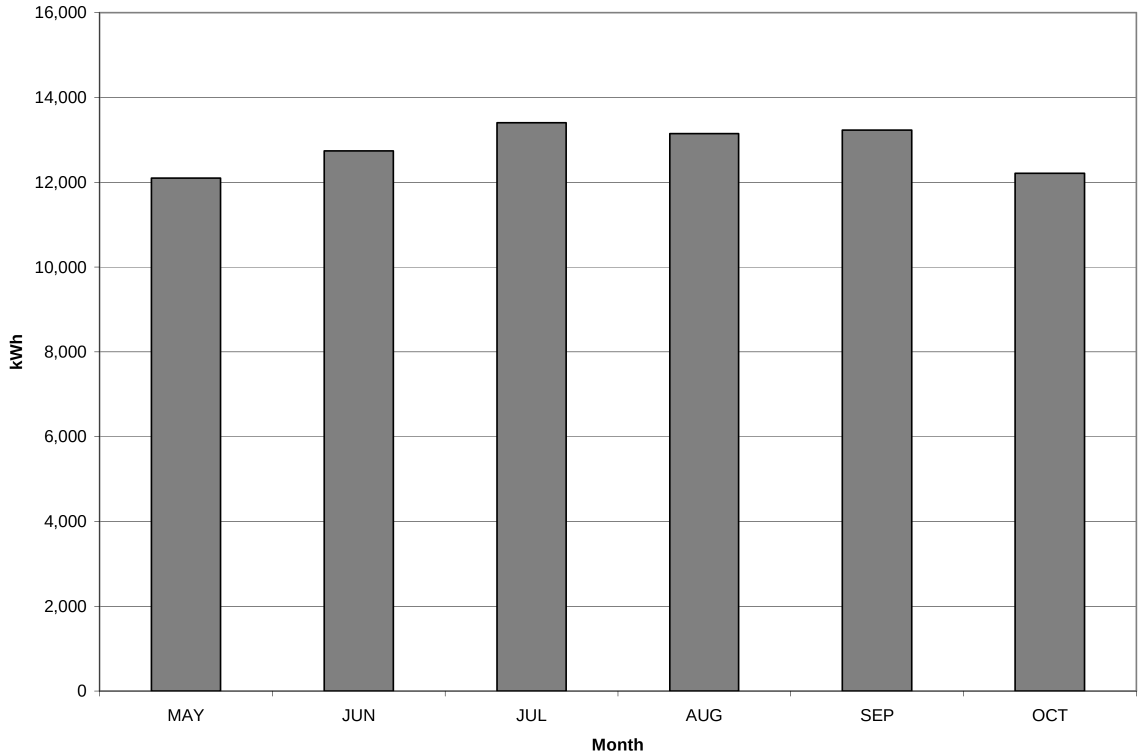


Figure SCE CBP 5: Average Event-Hour Load Impacts by Month for each Peak Load Day in a 1-in-2 Weather Year for 2012 and Beyond



SDG&E CBP

Figure SDG&E CBP 1 shows the forecast load impacts for a typical event day in a 1-in-2 weather year at the program level. The values in the figure apply to the years 2011 through 2020, as SDG&E's forecast enrollment does not change after 2011. Event-hour load impacts range from 26.6 MW to 28.8 MW, which is approximately 24 percent of the enrolled reference load. Non-event hour load impacts average an increase of 0.3 MW, or 0.3 percent of the reference load in those hours.

Figure SDG&E CBP 2 shows the same scenario as in Figure SDG&E CBP 1, but for the portfolio-level impacts. Overlap between CBP and CPP enrollment causes a small reduction in CBP load impacts for the portfolio analysis. The portfolio-level load impacts are 1.7 to 2.6 MW lower than the program-level load impacts.

Figure SDG&E CBP 3 shows how the load impacts are distributed by industry group. Retail customers account for the largest share of the load impacts at 43 percent of the total, with manufacturing customers accounting for the second-largest share (29 percent).

Figure SDG&E CBP 4 illustrates the average hourly load impact across years for the typical event day in both 1-in-2 and 1-in-10 weather years. As with the enrollment forecasts, the level of load impacts does not change after 2011, when the load impact is approximately 27.4 MW in a 1-in-2 weather year and 27.8 MW in a 1-in-10 weather year.

Figure SDG&E CBP 5 illustrates the load impact across monthly peak days of a 1-in-2 weather year. The loads impacts are highest in September, at 28.1 MW, and lowest in May, at 24.0 MW.

Figure SDG&E CBP 1: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2011 and Beyond, Program Level

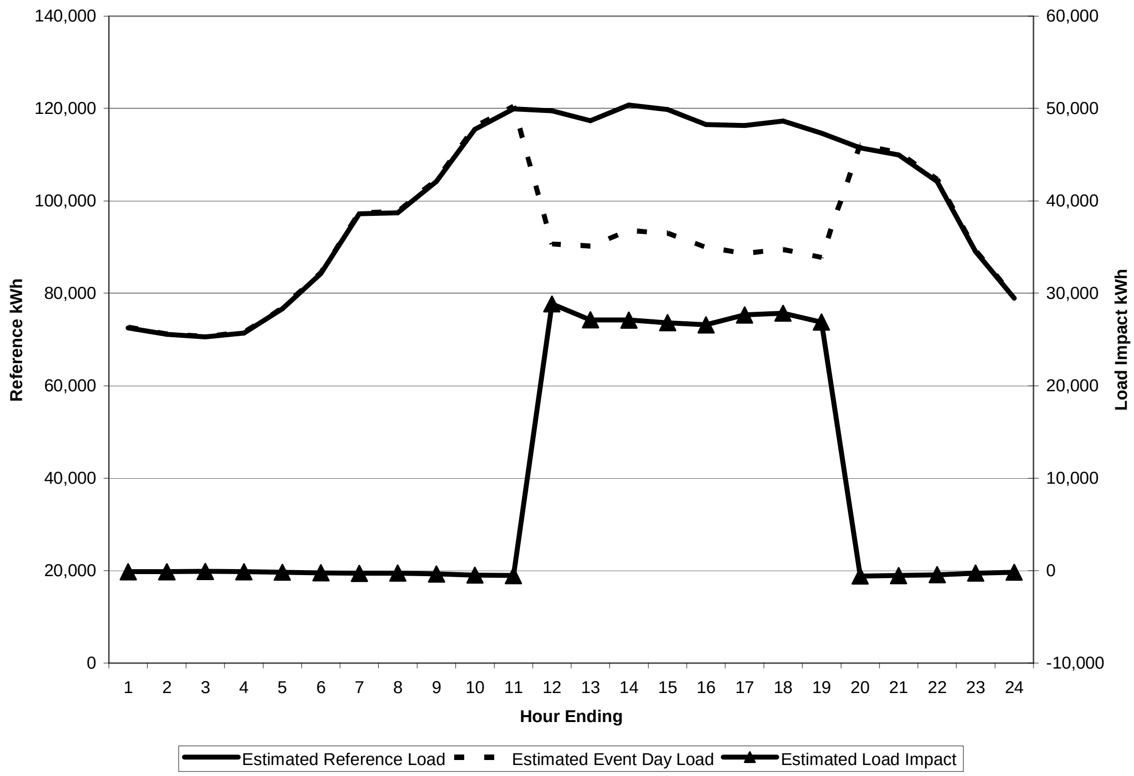


Figure SDG&E CBP 2: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2011 and Beyond, Portfolio Level

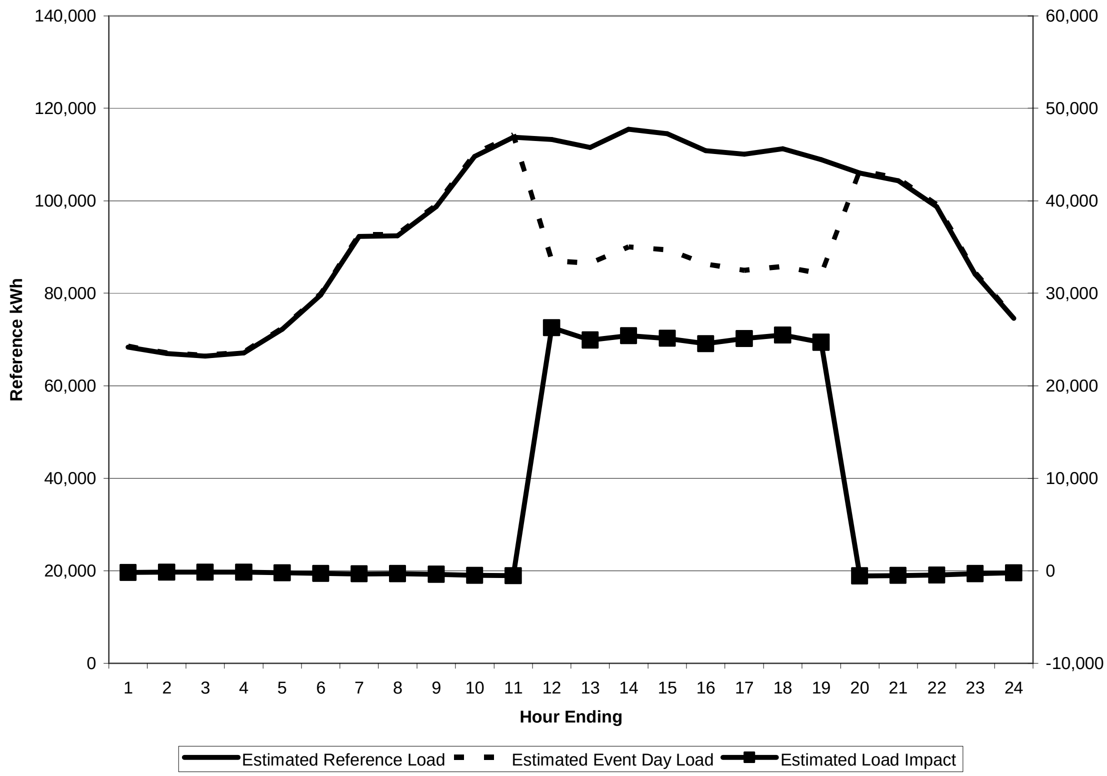


Figure SDG&E CBP 3: Share of Load Impacts by Industry Group for the Typical Event Day in a 1-in-2 Weather Year for 2011 and Beyond

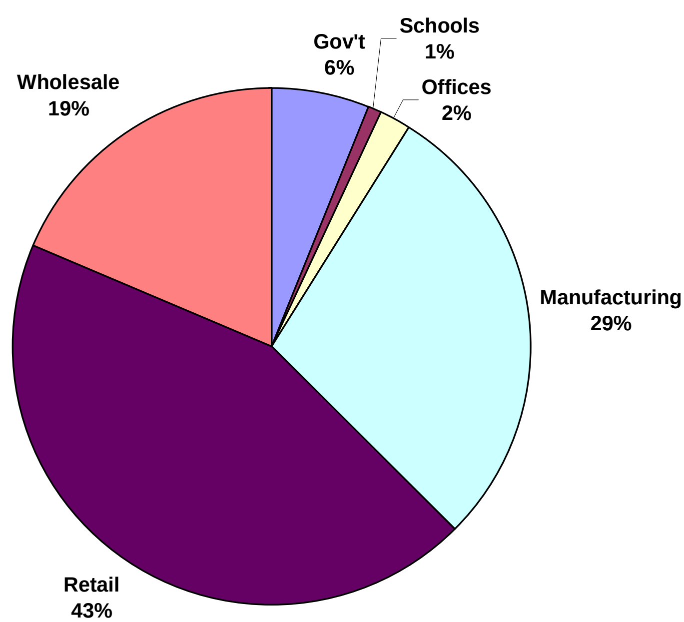


Figure SDG&E CBP 4: Average Event-Hour Load Impacts by Forecast Year and Weather Scenario for the Typical Event Day

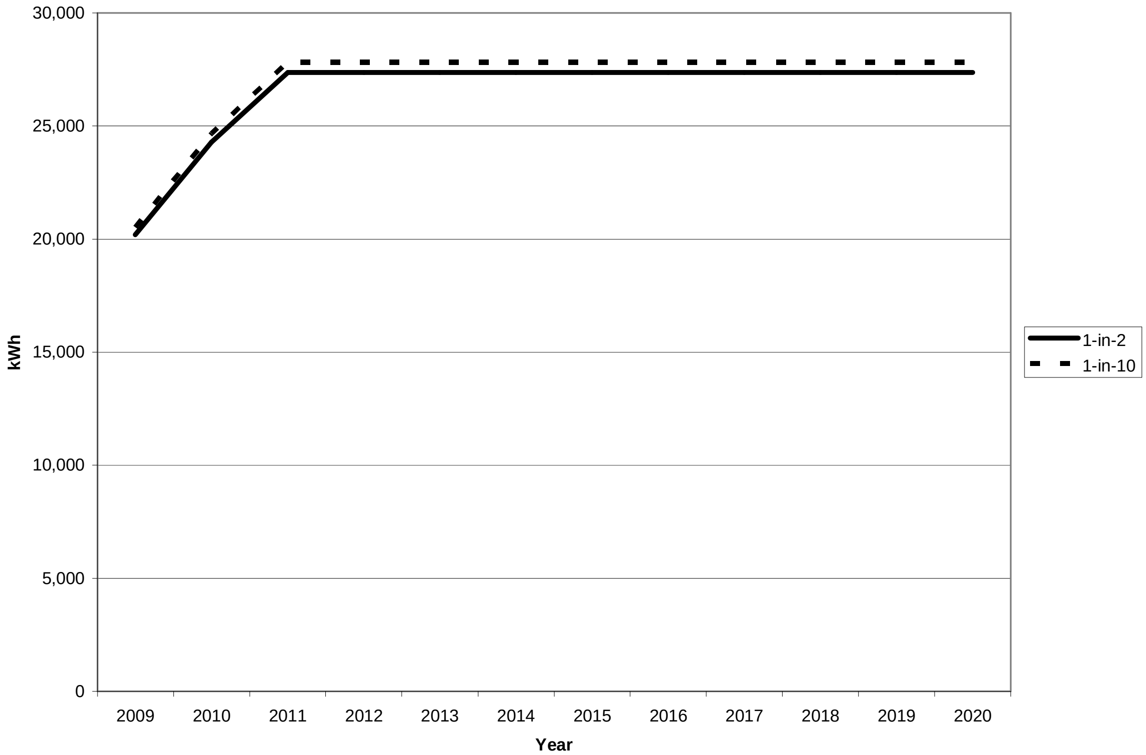
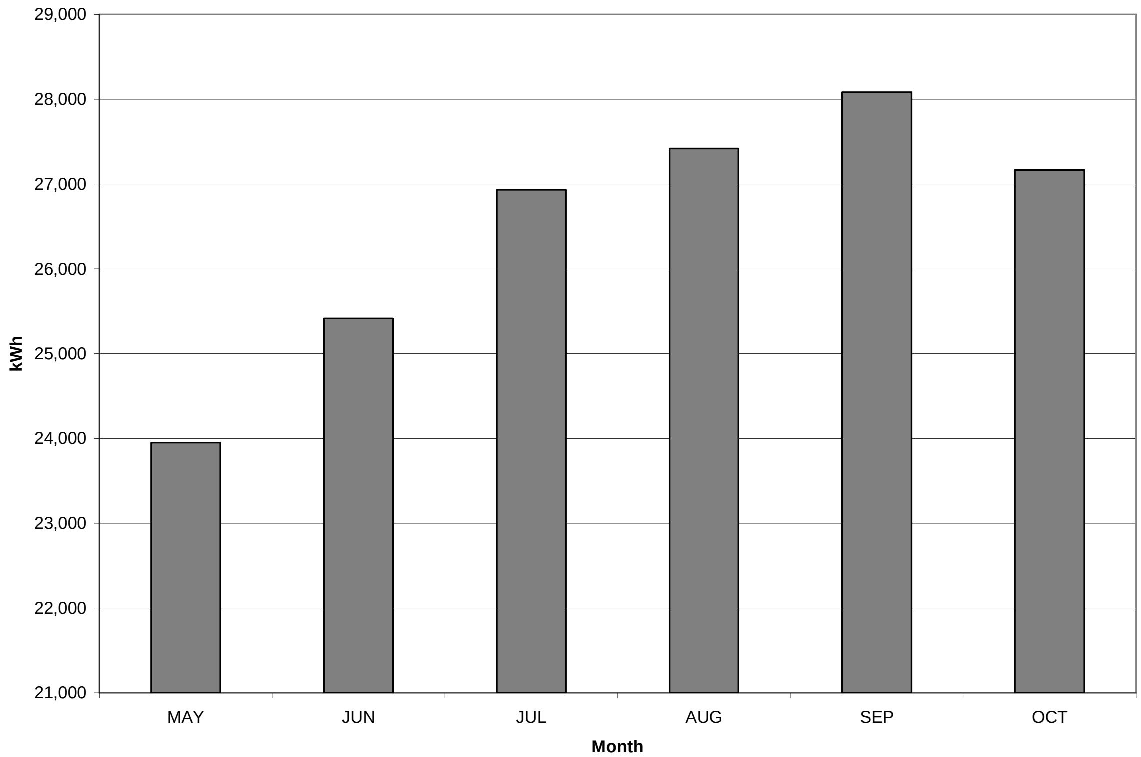


Figure SDG&E CBP 5: Average Event-Hour Load Impacts by Month for each Peak Load Day in a 1-in-2 Weather Year for 2011 and Beyond



PG&E AMP

Figure PG&E AMP 1 shows the August 2012 forecast load impacts for a typical event day in a 1-in-2 weather year.[10] Event-hour load impacts range from 154.5 MW to 163.7 MW, which represent approximately 12 percent of the enrolled reference load.

Figures PG&E AMP 2 and 3 show how the load impacts are distributed by LCA and industry group. Customers in the Greater Bay Area, Greater Fresno, and not in an LCA together combine to account for 75 percent of the load impacts. Manufacturing customers account for 40 percent of the load impacts, with Wholesale customers constituting the next largest group, with 27 percent of the load impacts.

Figure PG&E AMP 4 illustrates the average hourly load impact across years for the August peak day in a 1-in-2 weather year. The load impacts in this figure mirror the enrollment forecast, with impacts increasing in 2010 and 2011 and then remaining constant at 159 MW.

[10] For this program, program-level impacts and portfolio-level impacts are the same.

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

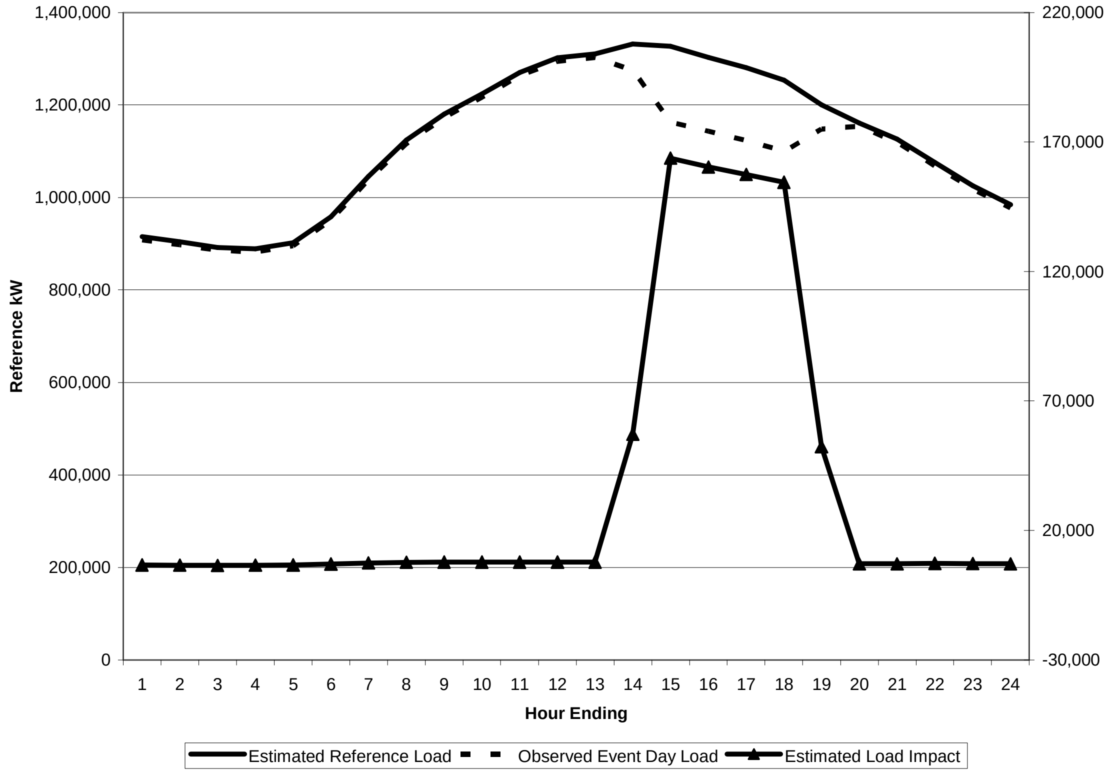


Figure PG&E AMP 2: Share of Load Impacts by LCA for the August 2012 Peak Day in a 1-in-2 Weather Year

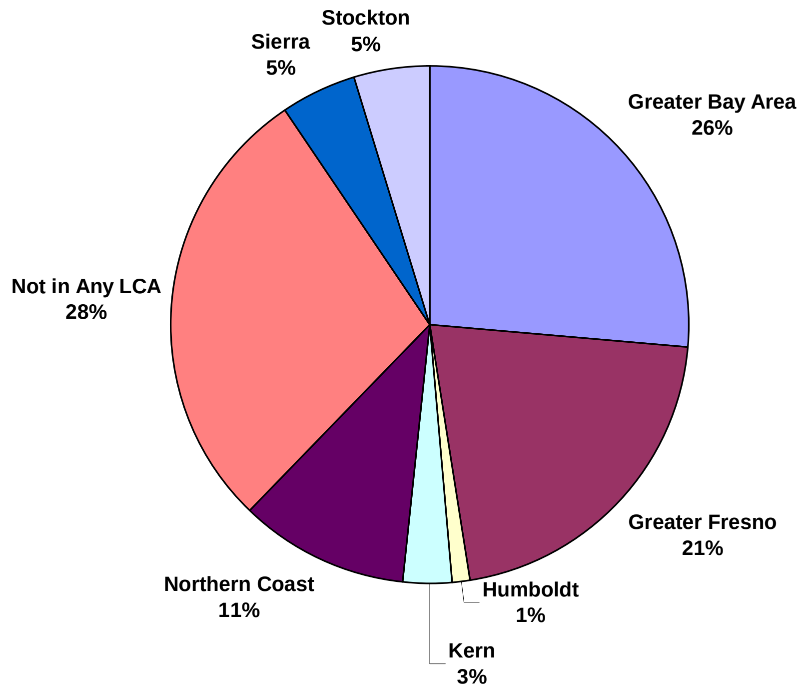


Figure PG&E AMP 3: Share of Load Impacts by Industry Group for the August 2012 Peak Day in a 1-in-2 Weather Year

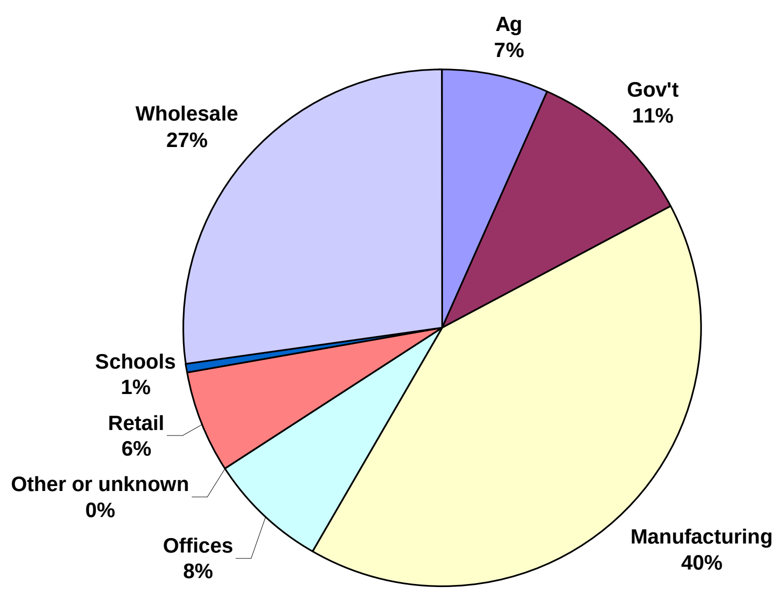
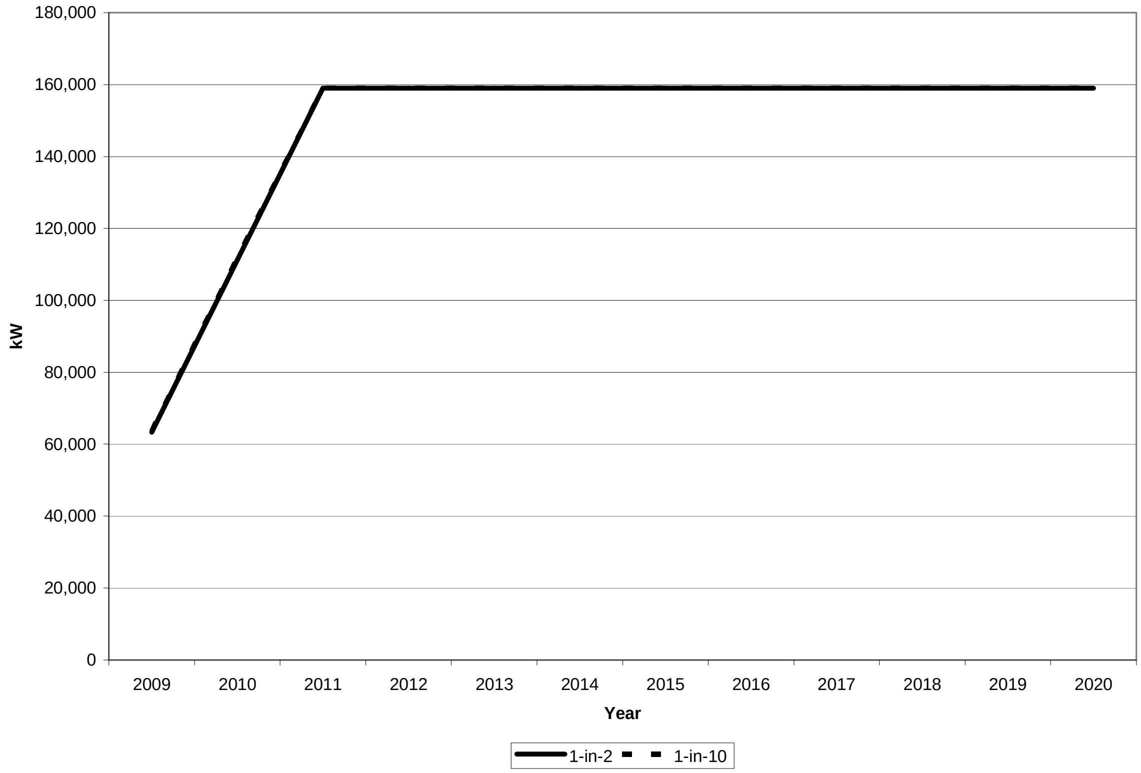


Figure PG&E AMP 4: Average Event-Hour Load Impacts by Forecast Year and Weather Scenario for the August Peak Day



SCE DRC

Figure SCE DRC 1 shows the forecast load impacts for a typical event day in a 1-in-2 weather year. The values in the figure apply to the years 2012 through 2020, as SCE's forecast enrollment does not change after 2012. Event-hour load impacts range from 114.3 MW to 119.8 MW, which is approximately 13 percent of the enrolled reference load. Non-event hour load impacts average 0.4 MW, or 0.05 percent of the reference load in those hours.

Figures SCE DRC 2 and 3 show how the load impacts are distributed by LCA and industry group. Seventy-seven percent of the load impacts come from customers in the LA Basin LCA. Wholesale customers account for 42 percent of the load impacts, with retail stores being the next largest group at 21 percent.

Figure SCE DRC 4 illustrates the average hourly load impact across years for the typical event day in both 1-in-2 and 1-in-10 weather years. As with the enrollment forecasts, the level of load impacts does not change after 2012, when the load impact is approximately 116.9 MW in a 1-in-2 weather year and 120.0 MW in a 1-in-10 weather year.

Figure SCE DRC 5 illustrates the load impact across monthly peak days of a 1-in-2 weather year. Load impacts are lowest in October (at 108.6 MW) and highest in July (at 118.4 MW).

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

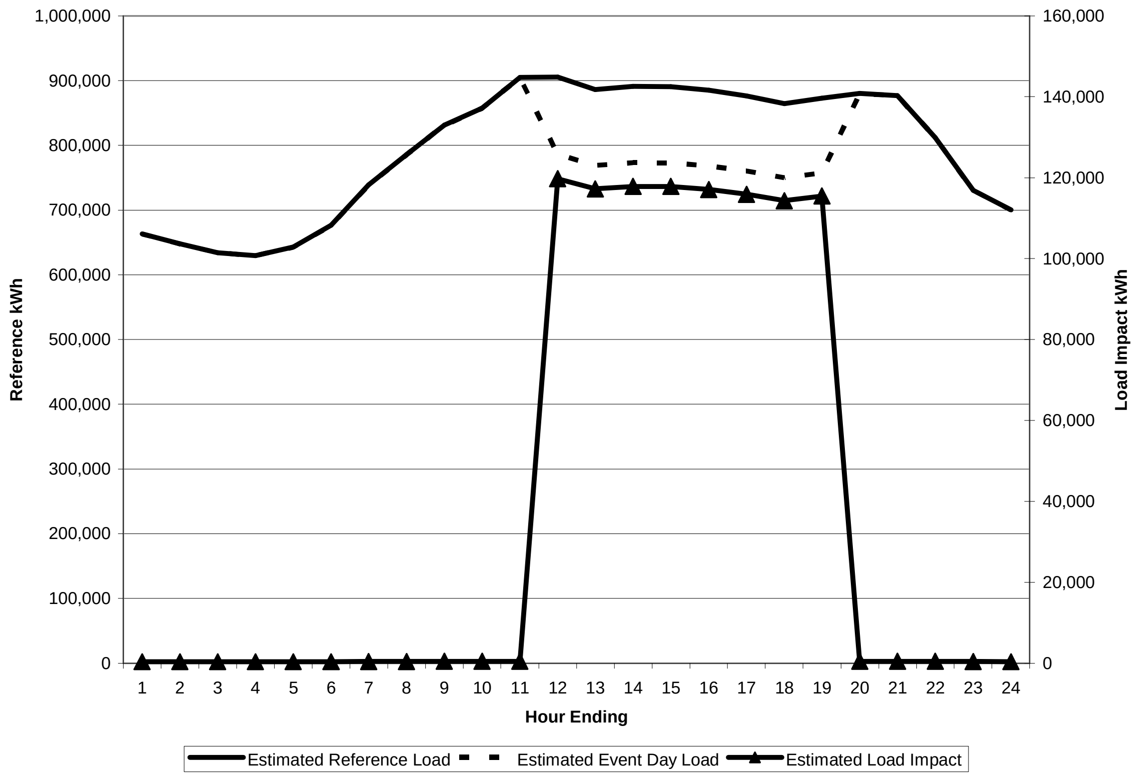


Figure SCE DRC 2: Share of Load Impacts by LCA for the Typical Event Day in a 1-in-2 Weather Year for 2012 and Beyond

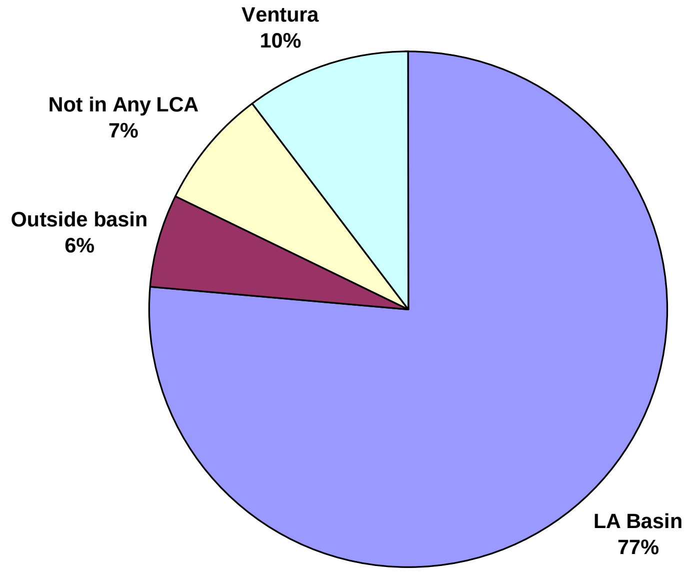


Figure SCE DRC 3: Share of Load Impacts by Industry Group for the Typical Event Day in a 1-in-2 Weather Year for 2012 and Beyond

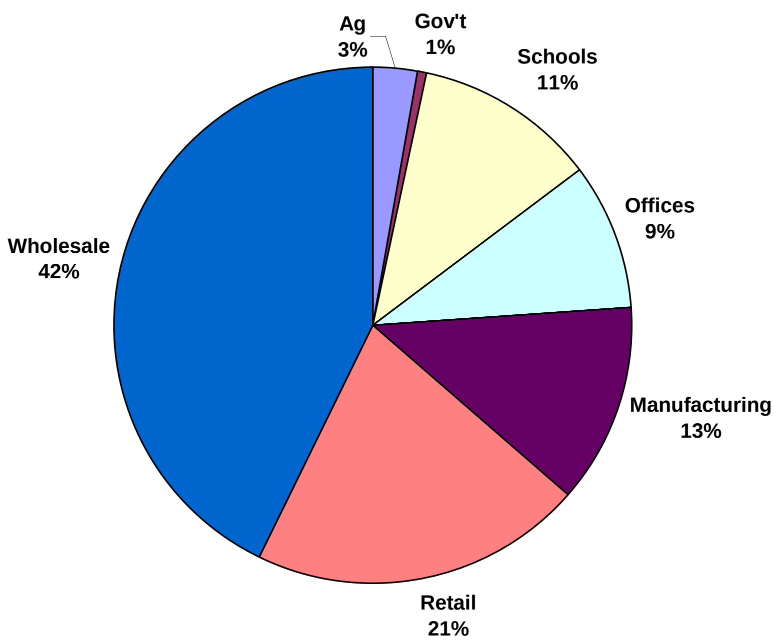


Figure SCE DRC 4: Average Event-Hour Load Impacts by Forecast Year and Weather Scenario for the Typical Event Day

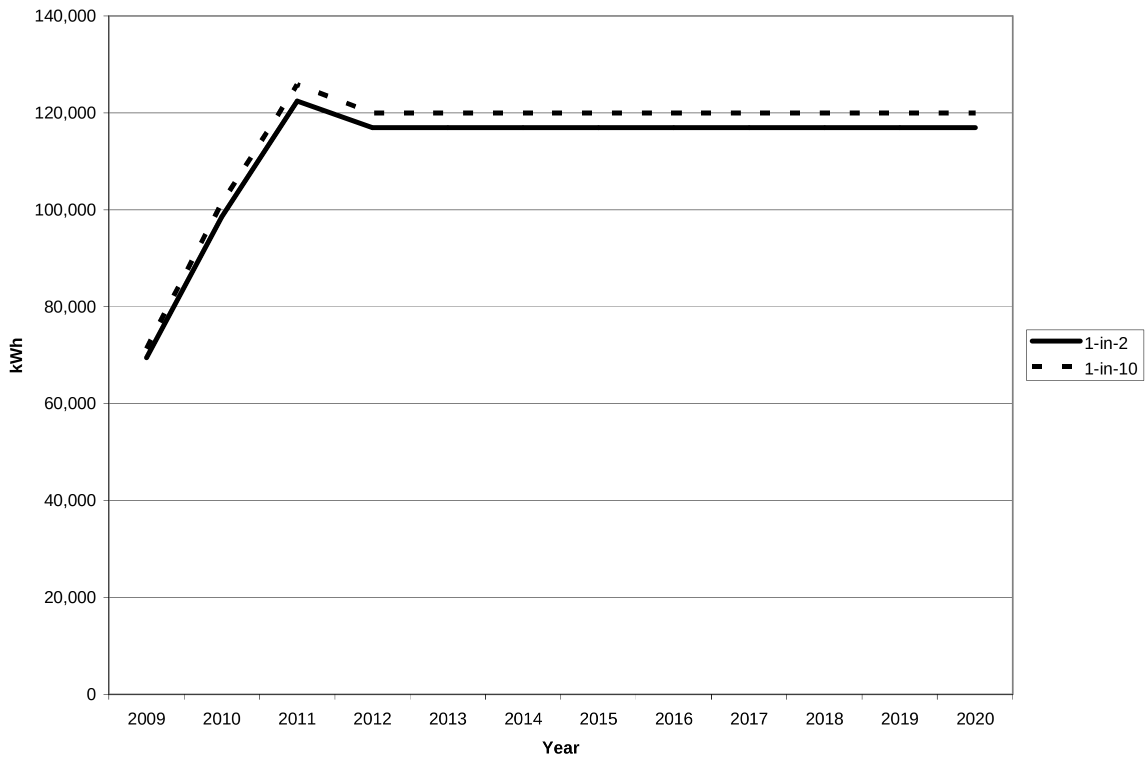
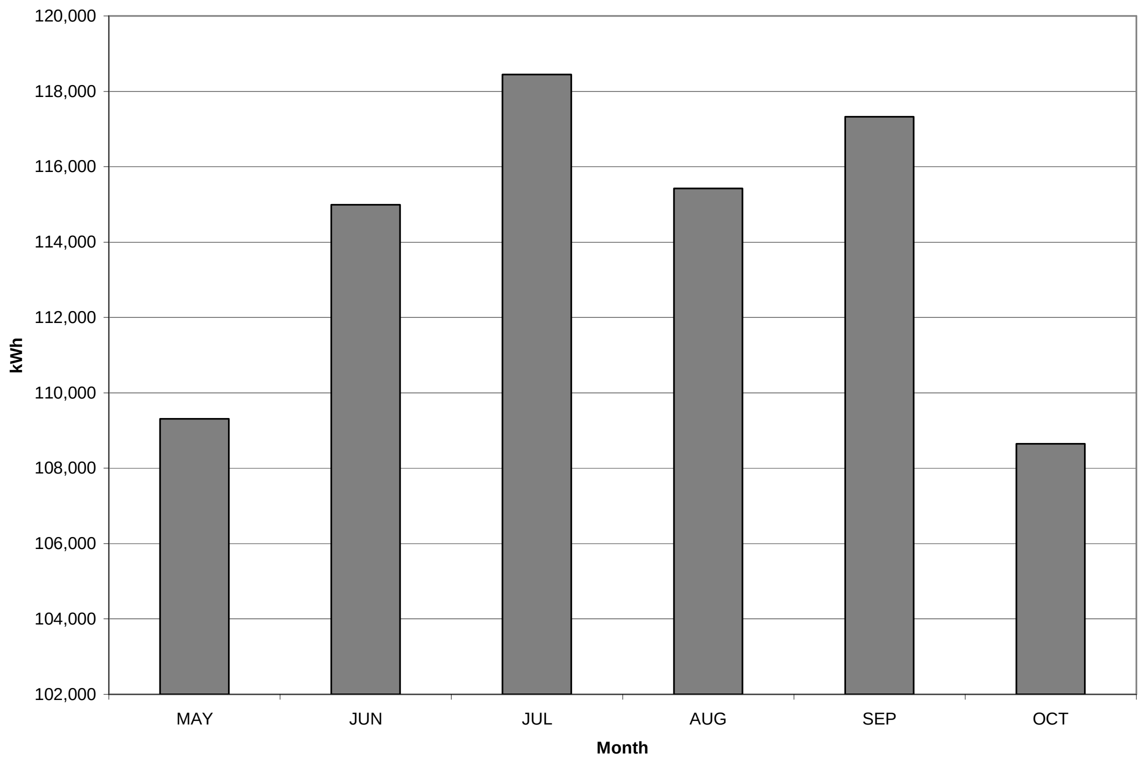


Figure SCE DRC 5: Average Event-Hour Load Impacts by Month for each Peak Load Day in a 1-in-2 Weather Year for 2012 and Beyond



5.4 Sensitivity Analysis for TA/TI and AutoDR

PG&E provided high, medium, and low funding scenarios for TA/TI and AutoDR that were used to develop a sensitivity analysis of the potential incremental effects of the programs on the level of load impacts. PG&E provided us with a forecast of the annual funding level for each program. For AMP, TA/TI funding ends in 2012 and no AutoDR funding is provided in any forecast year. For CBP, TA/TI funding exists in all years, while AutoDR funding commences in 2010.

PG&E provided assumptions regarding the cost per kW of load reduction from each program. For TA/TI, this cost is $275 per kW, while the cost is $300 per kW for AutoDR.

Table 5.3 contains the annual increase in AMP load impacts by program and funding scenario. These values are illustrated in Figure 5.6. Parallel results for CBP are shown in Table 5.4 and Figure 5.7.

Notice that the level of the added load response does not change for AMP after 2011, which is the last year of program funding. For CBP, the incremental load impacts are high relative to the size of the program. For example, assuming that the average customer is 225 kW in size and experiences a 7 percentage point increase in load impacts due to TA/TI or AutoDR, the medium scenario incremental load impacts imply that over 70 percent of the customers are enrolled in one of the programs. This may therefore be regarded as an optimistic forecast.

Table 5.3: Annual Increase in AMP Load Impacts from TA/TI and AutoDR by Year and Funding Scenario (kW)

Year	TA/TI			AutoDR		
	High	Medium	Low	High	Medium	Low
2009	2,850	2,565	2,280	0	0	0
2010	5,100	4,590	2,912	0	0	0
2011	8,789	7,910	4,363	0	0	0
2012	8,789	7,910	4,363	0	0	0
2013	8,789	7,910	4,363	0	0	0
2014	8,789	7,910	4,363	0	0	0
2015	8,789	7,910	4,363	0	0	0
2016	8,789	7,910	4,363	0	0	0
2017	8,789	7,910	4,363	0	0	0
2018	8,789	7,910	4,363	0	0	0
2019	8,789	7,910	4,363	0	0	0
2020	8,789	7,910	4,363	0	0	0

Table 5.4: Annual Increase in CBP Load Impacts from TA/TI and AutoDR by Year and Funding Scenario (kW)

Year	TA/TI			AutoDR		
	High	Medium	Low	High	Medium	Low
2009	832	749	665	0	0	0
2010	4,468	4,021	2,814	2,977	2,680	2,382
2011	11,899	10,709	9,200	11,741	10,567	9,392
2012	12,655	11,360	9,752	12,494	11,215	9,943
2013	13,492	12,080	10,363	13,301	11,909	10,532
2014	14,411	12,872	11,034	14,173	12,660	11,169
2015	15,199	13,521	11,560	14,961	13,310	11,695
2016	16,042	14,215	12,122	15,781	13,984	12,241
2017	16,978	14,986	12,746	16,680	14,725	12,841
2018	17,782	15,618	13,236	17,494	15,366	13,337
2019	18,635	16,291	13,755	18,333	16,027	13,848
2020	19,576	17,032	14,328	19,249	16,748	14,405

Figure 5.6: Annual Increase in AMP Load Impacts from TA/TI and AutoDR by Year and Funding Scenario (kW)

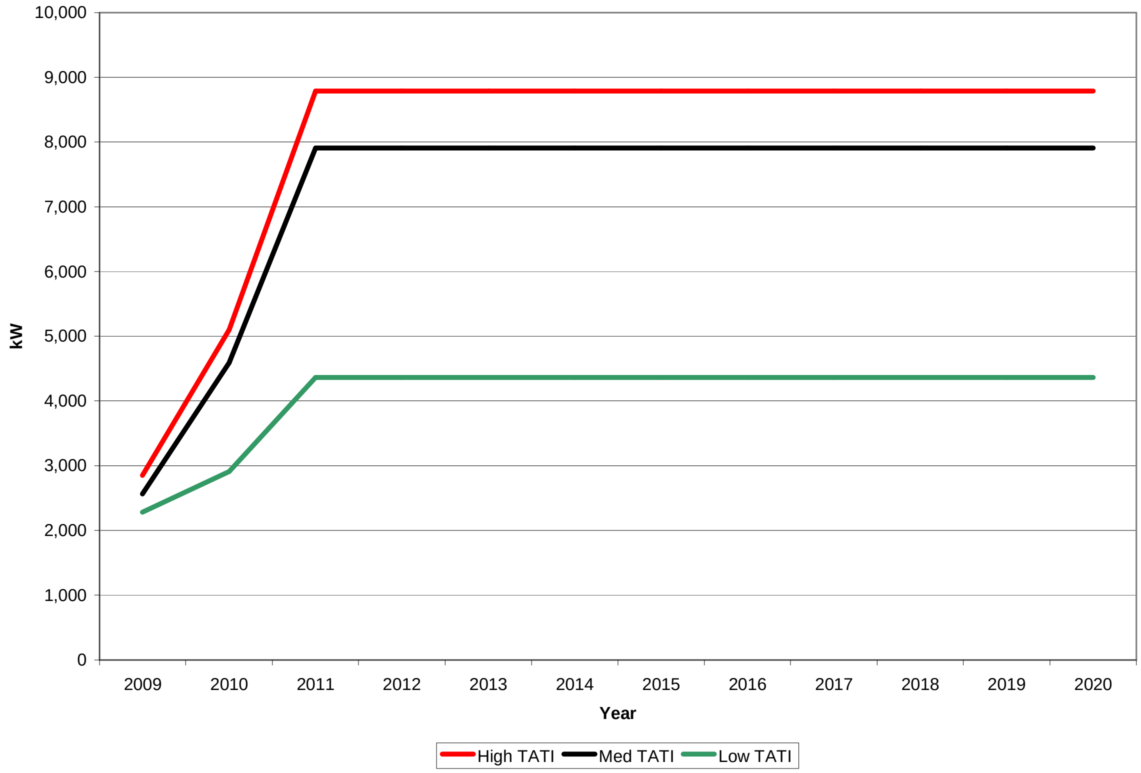
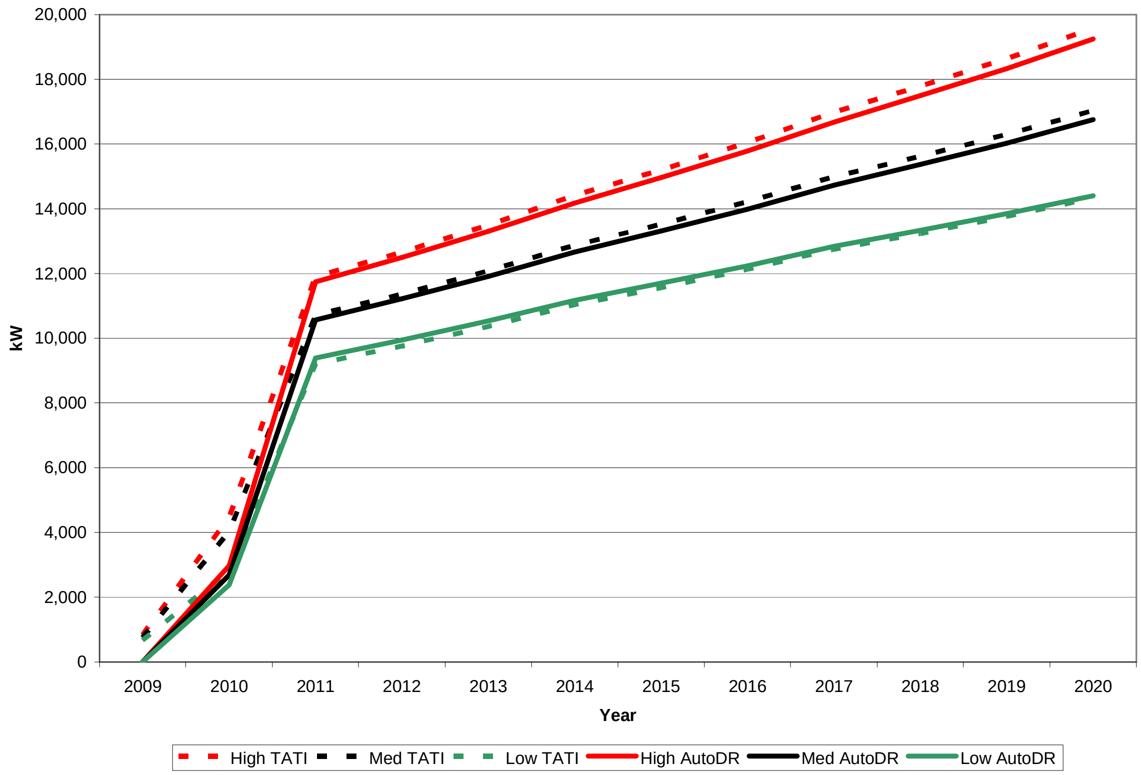


Figure 5.7: Annual Increase in CBP Load Impacts from TA/TI and AutoDR by Year and Funding Scenario (kW)



6. Validity Assessment

In previous ex post load impact evaluations, we have often used group-level data and regression models to examine load impacts. This method had the advantage of limiting the analysis to estimating a manageable number of models, but has the disadvantage of not easily accounting for changing enrollment over the summer and calculating the distribution of load impacts across factors such as industry types and local capacity areas. In addition, the aggregator programs are complicated by changing nominations across months, and different aggregators and enrollees being called on different events.

In this study, we estimated customer-specific regression models that accounted for each customer's enrollment dates, and nomination and called status for each event. While this method has some significant advantages (properly accounting for nominating behavior and allowing the results to be summarized according to any observed customer characteristic without requiring the estimation of a new model), it does require that many models (*e.g.*, for hundreds of customers for each program) are estimated. This prevents a detailed examination of each customer's regression model. In addition, in order to facilitate post-processing the results, it is important to use a uniform model structure across all of the customers in a program.

Therefore, our primary concern with respect to the validity of the findings is regarding the appropriateness of the model specification that is used for all customers. That is, we believe that the most significant issue in an ex post analysis of load impacts is the risk of omitted variable bias. Invariably, loads levels change from day to day, or week to week for reasons that cannot be easily known to the analyst. For example, it is not uncommon for manufacturing customers to shut down or significantly reduce operations for one to two weeks as some arbitrary time. Such activity can bias the estimates for the other included variables if variables are not included to explicitly account for such a “shut down”. It is possible that with more time and resources, we could have discovered a model specification that better accounted for such factors that affect load, which may lead to improved estimates of load response. That said, the estimates contained in this study appear to be reasonable, particularly when compared to simple graphs of non-event day loads, giving us no reason to believe that any serious bias exists in the overall findings.

7. Summary

Table 7.1 summarizes the average hourly load impacts that were estimated for PY 2008 for the aggregator programs of the three utilities. The values shown represent the sum of the load impacts from the day-ahead and day-of portfolios of each program, thus illustrating each program’s likely load reduction when both portfolios are called.

Table 7.2 summarizes the forecast ex ante load impact by utility and program. The year 2012 was selected because the majority of the enrollment forecasts are unchanged after that date. Load impacts are forecast to increase for all but one program.

Table 7.1: Summary of Average Hourly Ex Post Load Impacts (MW) for the Aggregator DR Programs in PY 2008

Program	PG&E	SCE	SDG&E	Total
CBP	22.2	15.5	16.4	54.1
AMP	64.9	-	-	64.9
DRC	-	34	-	34
Total	87.2	49.5	16.4	211.9

Table 7.2: Summary of Average Hourly Ex Ante Load Impacts (MW) for the Aggregator DR Programs in PY 2012

Program	PG&E	SCE	SDG&E	Total
CBP	43	13	27	83
AMP	159	-	-	159
DRC	-	117	-	117
Total	202	130	27	359