2015 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: Ex-Post and Ex-Ante Load Impacts

CALMAC ID PGE0374

Public Report *Confidential Information is Redacted*

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Prepared for:

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April 1, 2016

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Abstract

This report documents the load impact evaluation of the aggregator-based demand response (DR) programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), for Program Year 2015 (PY2015).

As part of these programs, DR aggregators contract with the IOUs and with commercial, industrial, and agricultural customers to act on their behalf in all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a “portfolio” of individual service accounts, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Depending on their contractual arrangement with the IOU, aggregators can enroll and nominate customer service accounts in a mix of day-ahead (DA) and day-of (DO) triggered DR product types. The terms and conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU, and customers.

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

The primary goals of this evaluation study are the following:

- Estimate the ex-post load impacts for program year 2015.
- Estimate ex-ante load impacts for the programs for years 2016 through 2026.

Nominated customer service accounts in the DO versions of all of the programs exceeded those in the DA versions, and were generally higher for AMP than for CBP. Numbers of nominated customer service accounts[1] ranged from less than 100 service accounts for some CBP product types, to over 1,400 for AMP. The various programs and notice types were called from 16 to 61 times in 2015, including several CBP and AMP events that were called for various combinations of distribution-based geographical locations or Sub-Load Aggregation Points (Sub-LAPs). These local, or Sub-LAP, events might be called when the utility does not need the entire nominated load reduction, or in cases of localized distribution events.

Hourly ex-post load impacts were estimated for each program, notice type, and event during 2015, using regression analysis of individual customer-level hourly load, weather, and event data. Estimated load impacts were reported for each event, for all programs and product types (e.g., DA 1-4 hours and DO 2-6 hours). Load impacts for the average event day were also reported by industry type and CAISO local capacity area (LCA) where relevant.

Estimated aggregate load impacts for the typical CBP DA event were 15.9 MW for PG&E, 1.0 MW for SCE, and 7.8 for SDG&E. Load impacts for CBP with DO notice were 20.0 MW for PG&E, 16.4 MW for SCE, and 5.7 for SDG&E. The typical AMP aggregate load impacts were generally larger, with PG&E’s DO product averaging 96.9 MW and SCE’s DO products averaging [redacted]

Ex-ante load impact forecasts are developed by combining enrollment forecasts provided by the utilities, and per-customer load impacts generated from analysis of current and prior ex-post load impact estimates. The forecast numbers of nominated customer service accounts and aggregate load impacts generally follow patterns in the current year, except in cases of major anticipated changes. These include SCE anticipating that the Commission will not approve AMP contracts after 2017 and that there will be 450 additional CBP DO accounts beginning in 2018 as a result.

[1] PG&E refers to these as service agreements.

Executive Summary

This report documents the load impact evaluation of aggregator demand response (DR) programs offered by three investor-owned utilities (IOUs) in California: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

Aggregators are non-utility entities that contract with eligible, non-residential utility customers to act on their behalf in all aspects of the DR program, including the receipt of notices of DR events from the utility, the receipt of incentive payments, and the payment of penalties to the utility. Each aggregator forms a portfolio of individual customers who then participate as a group to provide load reduction during DR events.

The evaluation includes two price-responsive DR programs: the Capacity Bidding Program (CBP), which is operated by all three IOUs, and PG&E's and SCE's Aggregator Managed Portfolio (AMP) programs. The AMPs are utility-specific programs in which the utilities enter into bilateral contracts with individual aggregators. The aggregators then enroll customers under the terms of their own contracts to provide the load reduction capacity. The utilities are not directly involved in the contracts between the aggregators and the participating customers.

The primary goals of the 2015 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU.
- Estimate average monthly ex-ante load impacts for each product and IOU for 2016 through 2026.

Program Descriptions

In the following subsections we present a description of each program and the total number of accounts nominated for each program by IOU.

Capacity Bidding Program

The statewide CBP program provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, and the program notice option day-ahead (DA) or day-of (DO).[2] The program has two notification options: day-ahead (DA) and day-of (DO). Additional energy payments ($/kWh) are made to bundled[3] customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The aggregator's delivered monthly capacity incentive payment is adjusted based upon the aggregator's performance for the operating month. Delivered capacity determines performance. If an aggregator's delivered capacity is less than 50%, the aggregator is assessed a penalty. If no events are called, aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments. CBP events can be triggered when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater; the utility receives a market award of dispatch instruction from the California Independent System Operator (CAISO); or when the utility in its sole opinion, forecasts that generation or electric resources may not be adequate.

Participating aggregators may adjust their nominations each month, as well as their choice of available notice-type and event-duration option (e.g., DA or DO event notice, and 1 to 4, 2 to 6, or 4 to 8 hour maximum event durations). For PG&E and SDG&E, CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m.,

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[2] Participants may be individual customers or aggregators, but most of them are aggregators. An individual customer may be self-aggregated, acting as its own aggregator.
[3] The program is also open to Direct Access (DA) and Community Choice Aggregation (CCA) customers. SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.

with a maximum of 30 event hours per month for PG&E, and maximum of 44 event hours per month for SDG&E. For SCE, CBP events may be called on any non-holiday weekday of the entire year, between the hours of 11 a.m. and 7 p.m., with a maximum of 30 event hours per month. SDG&E added a 30-minute notice option to the program in 2015 however no customers were nominated for this option. CBP is open to all commercial customers enrolled on a TOU rate.

Customers enrolled in CBP may participate in another DR program, so long as it is an energy-only program (e.g. cannot have a capacity payment component) and does not have the same notification type (i.e., day-ahead or day-of).

Aggregator Managed Portfolio

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

PG&E

In PY 2015, PG&E had AMP contracts with three aggregators. All three offered DO contracts only. Each aggregator may call up to 80 hours of events each year between the hours of 11 a.m. and 7 p.m., including test events. AMP events may be triggered when the utility expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or the utility, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. In 2015, PG&E dispatched a few localized events in which only some Sub-Load Aggregation Points (Sub-LAPs) were called. Customers who participate in AMP with DO notice are allowed to dually enroll in PG&E's Demand Bidding Program (DBP) or Peak Day Pricing (PDP). The settlement baselines are based on the aggregate 10-in-10 method, with an optional day-of adjustment.

SCE

On December 22, 2014, the CPUC issued Resolution E-4695 approving two AMP contracts for SCE for 2015-2016. Both contracts are DO contracts, each with various operating months ([redacted]) and different event windows ([redacted]). Aggregators have the ability to move between SCE's AMP and CBP programs. The total unadjusted DR resource capacity for 2015 is [redacted]. The AMP contracts provide Aggregators the option to adjust their contract commitments annually (+/-10%) and monthly (+/-5%). Customers participating in SCE's AMP may dually enroll in SCE's OBMC, RTP, DBP, and Critical Peak Pricing (CPP) programs. Settlement baselines are based on individual 10-in-10 baselines, with an optional day-of adjustment (DOA) of up to 40 percent.

Program Nominations

In Table E-1, we present the total number of nominated accounts for the average event day in 2015 by program, notice type, and utility.[4] Statewide, a total of 1,839 accounts participated in CBP, and [redacted] accounts participated in AMP.

[4]An average event day is calculated as the average of all HE16 – HE19 system level events. Because different accounts are called on different days, we calculate the average number of customers to include every responding account on any day included in the average. Because of this, the average number of accounts for an average day will be higher than a simple average of total accounts across each event.

Table E-1 Summary of Nominated Accounts by Notice Type, Average Event Day

Program	Utility	Nominated Accounts	
		Day-Ahead	Day-Of
CBP	PG&E	200	569
	SCE	55[5]	670
	SDG&E	122	223
	Total	**377**	**1,462**
AMP	PG&E	-	1,417
	SCE	-	[redacted]
	Total	**-**	[redacted]

Evaluation Methods

AEG used customer-specific regression models as the primary evaluation method for both the ex-post and ex-ante analysis. Customer-specific regressions allow for almost unlimited granularity in the results, and can readily be used to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects. The approach also allows for a consistent technique to be applied across the three IOUs and multiple aggregator programs with minimal incremental effort. Because the CBP and AMP events are called only on isolated days over the course of the program year, while both participants and non-participants face identical TOU rates on all other days, a regression model is well-suited to estimating the effect of events relative to usage on non-event days.

The regression models capture variation in hourly customer loads as a function of several primary factors:

- Weather, using hourly weather variables such as cooling and heating degree days.
- Seasonal patterns, such as month of year, day of week, and interactions between seasonal and other variables.
- Events, including CBP and AMP event days and events called in other DR programs across the three IOUs.
- Daily fluctuations in load unrelated to other variables captured by a morning load adjustment.

Once we developed a set of customer-specific regression models to estimate the ex-post impacts, those same models were then used to predict the ex-ante impacts under the CAISO, and IOU 1-in-2 and 1-in-10 weather scenarios.

Results

2015 Events

Table E-2 shows the number of events by notification type, program, and utility for the PY2015 evaluation period.[6] PG&E had 16 CBP DA events, 18 CBP DO events, and 18 AMP DO events. SCE had the most events of the three IOUs, with 61 CBP DA events, 42 CBP DO events, and 10 AMP DO events. SDG&E also had a considerable number of events, with 42 events for the CBP DA product, and 24 for the CBP DO product.

[5] Counts for SCE represent average summer events.
[6] The PY2015 evaluation period is May 1 through Oct. 31, 2015 for PG&E and SDG&E, and is Nov. 1, 2014 – Oct. 31, 2015 for SCE.

Table E-2 Summary of PY2015 Events by Notice Type

Program	Utility	Number of Events by Notice Type Day-Ahead	Day-Of
CBP	PG&E	16	18
	SCE	61	42
	SDG&E	42	24
AMP	PG&E	-	18
	SCE	-	10

2015 Ex-Post Impacts

Table E-3 summarizes the 2015 ex-post load impacts and nominated capacity by notification type, program, and utility. The SCE DA CBP product had the smallest per-customer impact and aggregate impact across the three utilities. The impacts for both PG&E and SDG&E in the DA CBP product are larger, with per-customer impacts ranging from 62.8 to 79.7 kW and total aggregate MW impacts of 15.9 and 7.7, respectively. The DO CBP programs are relatively comparable across utilities, especially from a per-customer impact perspective, although PG&E shows the largest per-customer and total aggregate impacts, at 35.2 kW and 20.0 MW, respectively. Of the two AMP programs, PG&E has just slightly higher impacts, at 68.4 kW per-customer and 96.9 MW in the aggregate.

Table E-3 Summary of PY2015 Ex-Post Impacts and Nominated Capacity

		Day-Ahead			Day-Of		
Program	Utility	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
CBP	PG&E	79.7	15.9	23.7	35.2	20.0	23.9
	SCE	18.6	1.0	2.2	24.5	16.4	25.7
	SDG&E	62.8	7.7	7.6	25.6	5.7	6.8
AMP	PG&E	-	-	-	68.4	96.9	120.4
	SCE	-	-	-	[redacted]		

Enrollment Forecast

Table E-4 summarizes the enrollment forecast by program, utility, notification type, and year during the month of August. PG&E and SDG&E forecast constant enrollment across the 2016-2026 horizon for all products.[7] SCE forecasts an increase in service accounts for the CBP DO product after 2017 and no AMP accounts after 2017.[8]

[7] While PG&E has proposed closing AMP in its 2017 DR Transition Filing, the filing has not been approved by the California Public Utilities Commission as of March 2016. In the absence of a CPUC decision, the program is assumed to continue for the forecast horizon for the purpose of this evaluation.

[8] The fate of AMP contracts for 2018 and beyond is unknown. Therefore, SCE assumes Commission will not approve AMP contracts for 2018-2026. If there are no contracts for 2018-2026, then SCE anticipates some Aggregators will participate in other programs such as CBP and DR Auction Mechanism (DRAM). As a result, beginning in 2018, SCE estimates 450 additional accounts to participate in CBP DO as a result of elimination of AMP. This too remains constant through 2026 assuming DRAM will exist beyond 2017.

Table E-4 2016-2026 Enrollment Forecast, During Month of August

			Number of Service Accounts		
Program	**Utility**	**Notice**	**2016**	**2017**	**2018-2026 (Each Year)**
CBP	PG&E	DA	175	175	175
		DO	609	609	609
	SCE	DA	30	30	30
		DO	814	814	1,264
	SDG&E	DA	122	122	122
		DO	220	220	220
AMP	PG&E	DO	1,459	1,459	1,459
	SCE	DO	[redacted]		

Ex-Ante Impacts

Table E-5 summarizes the aggregate load impact forecasts for an August peak day by program and utility for each weather scenario. Collectively, the greatest impacts are expected to be for AMP DO, followed by CBP DO, and then CBP DA. In total, across all programs and all IOUs, the AMP and CBP programs are expected to provide approximately 266 MW of DR capacity in 2016.

Table E-5 Summary of Average Event-Hour Ex-Ante Impacts, August Peak Day

			Aggregate Impact (MW)			
			Utility Peak		CAISO Peak	
Program	**Utility**	**Notice**	**1-in-2**	**1-in-10**	**1-in-2**	**1-in-10**
CBP	PG&E	DA	21.16	21.16	20.97	20.97
		DO	17.09	17.09	16.80	16.80
	SCE	DA	1.24	1.24	1.24	1.24
		DO	30.24	30.24	30.24	30.24
	SDG&E	DA	7.67	7.67	7.66	7.66
		DO	4.55	4.55	4.54	4.54
AMP	PG&E	DO	80.38	80.38	81.55	81.55
	SCE	DO	93.68	93.68	93.68	93.68

Recommendations

AEG's recommendations for the PY2016 CBP and AMP program operations and the evaluation of load impacts are as follows:

- **Continue to offer AutoDR Enablement:** This evaluation was able to show incrementally higher impacts for AutoDR enabled customers. Therefore AEG recommends that the IOUs continue to encourage participants to adopt automated response technology. However, the actual ex-post impacts achieved by AutoDR participants are generally lower than the total kW indicated by the load shed test results. This suggests that these customers have the potential to provide incrementally more impacts.

Rationale: The evaluation identified an incremental per customer impacts of 9 kW, on average, which is approximately a 25% increase over a similar non-enabled load impact.

- **Compare Reference Load and Estimated Observed Load:** AEG recommends using difference between the reference load and the estimated observed load in both the hourly load profiles and to estimate the impacts for the programs.

Rationale: The current approach, creating the estimated reference load by adding back the impacts, can have unintended impacts on the shape of the reference load in specific cases.

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Introduction

Background

This report documents the load impact evaluation of aggregator demand response (DR) programs offered by three investor-owned utilities (IOUs) in California: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

Aggregators are non-utility entities that contract with eligible, non-residential utility customers to act on their behalf in all aspects of the DR program, including the receipt of notices of DR events from the utility, the receipt of incentive payments, and the payment of penalties to the utility. Each aggregator forms a portfolio of individual customers who then participate as a single resource to provide load reduction during DR events. Aggregators, depending on their contractual arrangement with the IOU, can enroll and nominate customer service accounts in a mix of day-ahead (DA) and day-of (DO) triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator, and the IOU and its customers.

The evaluation includes two price-responsive DR programs:

- The statewide Capacity Bidding Program (CBP), which is operated by all three IOUs.
- PG&E's and SCE's Aggregator Managed Portfolio (AMP) programs, which are utility-specific programs where the utilities enter into bilateral contracts with individual third-party aggregators.

Research Objectives

The key objectives of this study are to estimate both ex-post and ex-ante impacts for the DR aggregator managed programs. More specifically:

1. Ex-post impacts are provided for each hour of each event day and for the average event day for all CBP and AMP programs. These results are presented separately for each notification type. They are also provided for the average customer, for all customers in aggregate, for each local capacity area (LCA), and for the service territory as a whole.
2. Ex-ante impacts are presented for each year over a 10-year time horizon based on both 1-in-2 and 1-in-10 weather conditions. The impacts are presented for all hours in which the program is available for the average customer, all customers in aggregate, each LCA, and the service territory as a whole. For resource adequacy, events are assumed to occur between 1pm and 6pm from April to October and from 4pm to 9pm for all other months. In addition, results are provided for a typical event day, the monthly system peak day, each LCA, and the service territory.

Report Organization

The remainder of this report is organized into the following sections:

- Section 2 describes the CBP and AMP programs as they are implemented by each IOU. The section also presents information regarding the total number of accounts nominated in each program, at each utility, by industry.
- Section 3 describes the methods used to estimate the ex-post and ex-ante impacts for the 2015 program year.
- Section 4 presents the ex-post impact evaluation results.

- Section 5 presents the ex-ante impact results.
- Section 6 discusses the methods used to ensure robust and unbiased results.
- Section 7 presents key findings and recommendations.

Program Descriptions and Resources

This section describes the CBP and AMP programs as they are implemented by each IOU. We also present information regarding the total number of accounts nominated in each program, at each utility, by industry.

Capacity Bidding Program

The statewide CBP program provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, and the program notice option (DA or DO).[9] The program has two options Capacity Bidding Program day-ahead (CBP DA) and Capacity Bidding Program day-of (CBP DO). Additional energy payments ($/kWh) are made to bundled[10] customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The aggregator's delivered monthly capacity incentive payment is adjusted based upon the aggregator's performance for the operating month. Delivered capacity determines performance. If an aggregator's delivered capacity is less than 50%, the aggregator is assessed a penalty. If no events are called, aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments. CBP events can be triggered when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater; the utility receives a market award of dispatch instruction from the CAISO; or when the utility in its sole opinion, forecasts that generation or electric resources may not be adequate.

Participating aggregators may adjust their nominations each month, as well as their choice of available notice-type and event-duration options (e.g., DA or DO event notice, and 1-to-4, 2-to-6, or 4-to-8 hour maximum event durations). For PG&E and SDG&E, CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m., with a maximum of 30 event hours per month for PG&E, and a maximum of 44 event hours per month for SDG&E. For SCE, CBP events may be called on any non-holiday weekday of the entire year, between the hours of 11 a.m. and 7 p.m., with a maximum of 30 event hours per month. SDG&E added 30-minute notice product to the program in 2015. CBP is open all commercial customers on a time of use rate.

Customer service accounts enrolled in CBP may participate in another DR program, so long as it is an energy-only program (i.e., cannot have a capacity payment component) and does not have the same notification type (i.e., day-ahead or day-of). In 2015, SCE completed the integration its CBP portfolio into the CAISO wholesale energy market on July 23, 2015 and considers the CBP program to be effectively integrated into the CAISO market for the purposes of DR program dispatch. Approximately 72% of the MW capacity of the CBP portfolio was not integrated due to operational constraints such as resource minimum registration sizes and CAISO rules that result in a program being integrated as a large number of resources. However, the non-integrated portion is effectively linked with the integrated resources, such that dispatch of the resource is controlled by CAISO market awards. Thus a CAISO award of any integrated resource results in SCE's dispatch of all customers in the corresponding Load Control Group (LCG). One exception to the above is the CBP Day Ahead 2-6 program, which is too small to have any resources registered in the CAISO market. However, SCE dispatched CBP DA 2-6 LCGs along with the corresponding CBP DA 1-4 LCGs based on the CAISO awards for the integrated CBP DA 1-4 Proxy Demand Resources (PDRs).

[9] The vast majority of the participants are third-party aggregators, while some customers are self-aggregated and act as their own aggregator.

[10] The program is also open to Direct Access (DA) and Community Choice Aggregation (CCA) customers, but the IOUs do not provide *energy* payments for the load reduction of the DA and CCA customers. SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.

Table 2-1 presents the industry-type definitions and corresponding NAICS codes. There are eight categories of industries.

Table 2-1 Industry Type Definitions

Industry Type	NAICS Codes
1. Agriculture, Mining & Construction	11, 21, 23
2. Manufacturing	31-33
3. Wholesale, Transport, Other Utilities	22, 42, 48-49
4. Retail Stores	44-45
5. Offices, Hotels, Health, Services	51-56, 62, 72
6. Schools	61
7. Entertainment, Other Services, Gov't	71, 81, 92
8. Other / Unknown	NA

Table 2-2 on the following page presents the number of service accounts that were nominated during CBP events at each utility in 2015, by notification type and industry group. The table also includes their maximum coincident demand.[11] Since nominations vary by month, we use the number of nominated service accounts for the average summer event day to reflect the typical number of program participants.

Aggregators participated and nominated a larger number of service accounts in the day-of notice option, compared to the day-ahead option, at all three utilities. Retail stores make up a large share of CBP DO nominated customer service accounts at each of the utilities, as well as CBP DA at PG&E and SCE. Approximately half of SDG&E's DA product consists of customer service accounts in the "Offices, Hotels, Health, and Services" industry type.

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

Table 2-2 CBP Nominated Service Accounts, by Utility and Industry Group (2015)

Utility	Industry Type	Day-Ahead Accounts	Day-Ahead Sum of Max Demand (MW)	Day-Of Accounts	Day-Of Sum of Max Demand (MW)
PG&E	1. Agriculture, Mining & Construction	[redacted]	[redacted]	24	2.72
	2. Manufacturing	52	78.16	29	27.88
	3. Wholesale, Transport, Other Utilities	23	13.19	[redacted]	[redacted]
	4. Retail Stores	56	8.36	429	98.82
	5. Offices, Hotels, Health, Services	30	35.01	61	35.94
	6. Schools	[redacted]	[redacted]	[redacted]	[redacted]
	7. Entertainment, Other Services, Gov't	[redacted]	[redacted]	[redacted]	[redacted]
	8. Other / Unknown	[redacted]	[redacted]	[redacted]	[redacted]
	Total	**200**	**157.74**	**569**	**173.90**
SCE	1. Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]
	2. Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]
	3. Wholesale, Transport, Other Utilities	[redacted]	[redacted]	43	30.74
	4. Retail Stores	22	57.83	526	179.43
	5. Offices, Hotels, Health, Services	[redacted]	[redacted]	78	47.69
	6. Schools	[redacted]	[redacted]	[redacted]	[redacted]
	7. Entertainment, Other Services, Gov't	[redacted]	[redacted]	[redacted]	[redacted]
	8. Other / Unknown	-	-	-	-
	Total	**55**	**106.17**	**670**	**301.23**
SDG&E	1. Agriculture, Mining & Construction	-	-	[redacted]	[redacted]
	2. Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]
	3. Wholesale, Transport, Other Utilities	[redacted]	[redacted]	-	-
	4. Retail Stores	[redacted]	[redacted]	201	62.13
	5. Offices, Hotels, Health, Services	69	24.40	[redacted]	[redacted]
	6. Schools	27	6.70	-	-
	7. Entertainment, Other Services, Gov't	[redacted]	[redacted]	[redacted]	[redacted]
	8. Other / Unknown	-	-	[redacted]	[redacted]
	Total	**122**	**56.89**	**223**	**77.79**

Aggregator Managed Portfolio

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

PG&E's AMP

In 2015, PG&E had AMP contracts with three aggregators. All three offered DO contracts only. Each aggregator may call up to 76 hours of events each year between the hours of 11 a.m. and 7 p.m., including test events. AMP events may be triggered when the utility expects the dispatch of electric supply resources with implied heat rates of 15,000 BTU/kWh or greater, and/or the utility, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system. In 2015, PG&E dispatched a few localized events for which only some Sub-Load Aggregation Points (Sub-LAPs) were called. These events are described in Section 4.

Customers who participate in AMP with DO notice are allowed to dually enroll in PG&E's Demand Bidding Program (DBP) or Peak Day Pricing (PDP). The settlement baselines are based on the aggregate 10-in-10 method, with an optional day-of adjustment.

Table 2-3 shows the number of customer service accounts nominated for the typical PG&E AMP DO event, by industry type, along with their coincident maximum demand. Since nominations vary by month, the number of nominated service accounts for the average summer event day here reflects the typical number of program participants. The aggregators nominated over 1,400 service accounts across the DO notice type in 2015. More than half of those nominated were in the Agriculture, Mining & Construction or Retail Store industry types, while the balance of nominations were spread over the remaining industry types. Schools accounted for the smallest number of nominations.

Table 2-3 PG&E AMP Nominated Accounts by Industry Group (2015)

Utility	Industry Type	DO Accounts	Sum of Max Demand (MW)
PG&E	1. Agriculture, Mining & Construction	578	142.11
	2. Manufacturing	112	175.41
	3. Wholesale, Transport, Other Utilities	141	116.30
	4. Retail Stores	328	80.77
	5. Offices, Hotels, Health, Services	188	141.07
	6. Schools	[redacted]	
	7. Entertainment, Other Services, Gov't	53	18.16
	8. Other, Unknown	[redacted]	
	Total	**1,417**	**701.60**

SCE's AMP

On December 22, 2014, the CPUC issued Resolution E-4695 approving two AMP contracts for SCE for 2015-2016. Both contracts are DO contracts, each with various operating months ([redacted]) and different event windows ([redacted]). Aggregators have the ability to move between SCE's AMP and CBP programs. The total unadjusted DR resource capacity for 2015 is [redacted]. The AMP contracts provide Aggregators the option to adjust their contract commitments annually (+/-10%) and monthly (+/-5%). Customers participating in SCE's AMP may dually enroll in SCE's Optional Binding Mandatory Curtailment (OBMC), Real-Time Pricing (RTP), Demand Bidding Program (DBP), and Critical Peak Pricing (CPP) programs. Settlement baselines are based on individual 10-in-10 baselines, with an optional day-of adjustment (DOA) of up to 40 percent. In 2015, SCE completed the integration its AMP portfolio into the CAISO wholesale energy market on July 23, 2015 and considers the AMP program to be effectively integrated into the CAISO market for the purposes of DR program dispatch. Approximately 25% of the MW capacity of the AMP portfolio was not integrated due to operational constraints such as resource minimum registration sizes and CAISO rules that result in a program being integrated as a large number of resources. However, the non-integrated portion is effectively linked with the integrated resources, such that dispatch of the resource is controlled by CAISO market awards. Thus a CAISO award of any integrated resource results in SCE's dispatch of all customers in the corresponding Load Control Group (LCG).

In Table 2-4 we present the nominated accounts by industry. The number of accounts in this table and the sum of maximum demand reflect the total number of customers, as opposed to values for an average event day. Nominated customer service accounts for AMP DO are spread over several industry types, with most in Wholesale, Transport, and Other Utilities and Retail stores.

Table 2-4 SCE AMP Nominated Accounts by Industry Group (2015)

Utility	Industry Type	DO Accounts	Sum of Max Demand (MW)
SCE	1. Agriculture, Mining & Construction	[redacted]	[redacted]
	2. Manufacturing	[redacted]	[redacted]
	3. Wholesale, Transport, Other Utilities	[redacted]	[redacted]
	4. Retail Stores	[redacted]	[redacted]
	5. Offices, Hotels, Health, Services	[redacted]	[redacted]
	6. Schools	[redacted]	[redacted]
	7. Entertainment, Other Services, Gov't	[redacted]	[redacted]
	Total	[redacted]	[redacted]

Study Methods

This section presents the methods used to estimate the ex-post and ex-ante impacts for the DR aggregator programs for the three IOUs.

Overview

AEG used customer-specific regression models as the primary evaluation method for both the ex-post and ex-ante analysis. Customer-specific regressions allow for almost unlimited granularity in the results, and can be used readily to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects. The approach also allows for a consistent technique to be applied across the three IOUs and multiple aggregator programs with minimal incremental effort. Because the CBP and AMP events are called only on isolated days over the course of the program year, and because both participants and non-participants face identical TOU rates on all other days, a regression model is well-suited to estimating the effect of events relative to usage on non-event days.

The regression models capture variation in hourly customer loads as a function of several primary factors including:

- Weather, specifically hourly weather variables such as cooling and heating degree days.
- Seasonal patterns, such as month of year, day of week, and interactions between seasonal and other variables.
- Events, including CBP and AMP event days and events called in other DR programs across the three IOUs.
- Daily fluctuations in load unrelated to other variables captured by a morning load adjustment.

Once we developed a set of customers specific regression models to estimate the ex-post impacts, those same models were then used to predict the ex-ante impacts under the CAISO, and IOU 1-in-2 and 1-in-10 weather scenarios.

Ex-Post Impact Analysis

The program year 2015 ex-post analysis was designed specifically to meet each of the following goals:

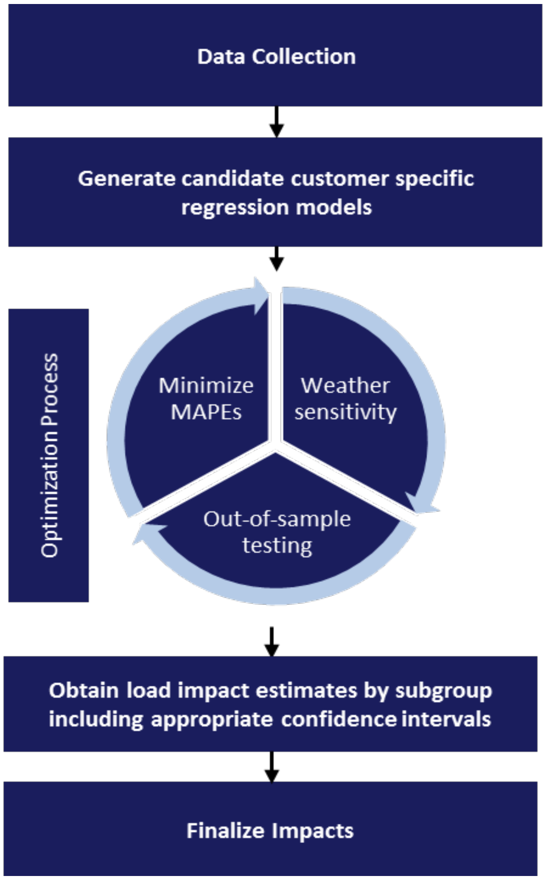
1. To develop hourly and daily load impact estimates for each event in the 2015 program year.
2. To provide these estimates by various segments: IOU, program, LCA, industry group, Automated Demand Response (Auto-DR) and TA&TI participation, and notification type.
3. To estimate the distribution of load impacts by customer segment for the average event.

AEG used customer-specific regressions to estimate the load impact for each customer on each event day. Because AMP and CBP are implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling and analysis. However, the same basic methodology was employed across all three IOUs in order to balance consistency of results with modification to account for differences in implementation and rate design. Given the goals of the project and the potential differences across service territories, customer-specific regressions offered the most flexible, consistent, and appropriate solution for several reasons:

- The individual customer impacts can simply be added together to estimate impacts at any level including, but not limited to, utility, program, aggregator, LCA, NAICS, or notification type.
- They can be easily used to control for variation in load due to weather conditions, geography, and time-related variables (day of week, month, hour, etc.).
- Because impacts are estimated for each customer separately, they also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
- Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to capture differences between customers; therefore, they are better able to model changes in energy usage than an aggregated model.
- Because the events are called only on isolated days over the course of the program year, and on all other days the participants and non-participants face similar TOU rates, the data conforms nicely to what researchers often call a repeated-measures design. This simply means that all participants are subjected to the treatment at the same time, repeatedly over the course of the study. In this case, the control can be defined as an absence of the treatment, or the non-event days.[12]

It is not practical to develop models individually for more than 5,000 participants, therefore AEG used a candidate model optimization process to select the best model for each participant. Figure 3-1 illustrates a high-level overview of the approach AEG used to develop ex-post impacts. The subsections that follow describe the process in more detail.

Figure 3-1 Ex-Post Analysis Approach



[12] Because of increased event frequency in some of the IOUs we used two years of data to ensure that enough similar non-event days were available.

Develop Candidate Customer-Specific Regression Models

After collecting the data required for the evaluation, the next step was to develop a set of candidate models. In general, we think of regression models as being made up of building blocks, which are in turn made up of one or more explanatory variables. These different sets of variables can be combined in different ways to represent different types of customers. The blocks can be generally categorized into either “baseline” variables or “impact” variables and could be made up of a single variable (e.g., cooling degree hours, CDH), or a group of variables (e.g., days of the week). The baseline portion of the model explains variation in usage unrelated to DR events while the impact portion explains the variation in usage related to a DR event.[13]

In Table 3-1 below we present the different explanatory variables that we used to create approximately 35 different candidate models for the CBP and AMP participants.

Table 3-1 Explanatory Variables Included in Candidate Regression Models

Variable Name	Variable Description
	Baseline Variables
$Weather_{i,d}$	Weather related variables including average daily temperature, multiple cooling degree hour (CDH) terms with base values of 75, 70, and 65 depending on service territory, and lagged versions of various weather related variables
$Month_{i,d}$	A series of indicator variables for each month
$DayOfWeek_{i,d}$	A series of indicator variables for each day of the week
$Year_{i,d}$	An indicator for the year 2015[14]
$OtherEvt_{i,d}$	Equals one on event days of other demand response programs in which the customer is enrolled
$MornLoad_{i,d}$	The average of each day’s load in hours 5 a.m. through 10 a.m.
	Impact Variables
$P_{t,d}$	An indicator variable for aggregator program event days
$P * Weather_{t,d}$	An indicator variable for aggregator program event days interacted with weather terms
$P * Year_{i,d}$	An indicator variable for aggregator program event days interacted with the year 2015
$P*NonTypEvent_{i,d}$	An indicator variable for aggregator program event days interacted with an indicator for non-typical event windows (outside of HE 16-19)

With the different variables presented above, sets of candidate models were created that represent a wide variety of customers and their impacts. Each IOU has customized sets of candidate models, but in general, the candidate models fit into two basic categories with a total of approximately 25 weather sensitive models and 10 non-weather sensitive models:

- Weather-sensitive models include weather effects and calendar effects. These models are less likely to require a morning load adjustment due to much of the variation in load on a day-to-day basis being captured by weather terms.
- Non-weather sensitive models include the morning load adjustment and calendar effects.

Optimization Process

After developing a set of candidate models, a single “best” model was selected for each customer. The final model was selected to minimize error and bias through a series of out-of-sample tests and MAPE (mean absolute percentage error) and MPE (mean percentage error) comparisons. [15]

[13] Any unexplained variation will end up in the error term.
[14] Because a large number of events were called in 2015, which was also a relatively mild year, we included data from 2014 to ensure that we would have enough event-like days. Therefore we also included a “year” indictor variable in the models.
[15] For more information on the model out-of-sample tests and MAPE results see Section 6, Model Validity.

Below are examples of two final models, one for a weather sensitive customer and one for a non-weather sensitive customer. For both types of models, the model specification is identical for each hour of the day.

Simple weather sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + Month_{i,d} + Weather_{i,d} + P_{i,d} + (P_{i,d} * Weather_{i,d}) + \varepsilon_{it} \quad (3.1)$$

where:

$kwh_{i,d}$ is the customer's consumption in hour i, on day d.

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d.

and, all other terms are defined in Table 3-1 above.

Simple non-weather sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + MornLoad_{i,d} + DayofWeek_{i,d} + P_{i,d} + \varepsilon_{it} \quad (3.2)$$

where:

$kwh_{i,d}$ is the customer's consumption in hour i, on day d.

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d.

and, all other terms are defined in Table 3-1 above.

The "best" model selected is for each customer to calculate the customer-specific impact as follows:

1. We obtained the actual and predicted load on each hour and day based on the best model specification for each customer.
2. We used the estimated coefficients and the baseline portion of the model to predict what this customer would have used on each day and hour if there had been no events. We call this prediction the reference load.
3. We calculated the difference between the reference load (the estimate based on the baseline variables) and the predicted load (the estimate based on the baseline + impacts variables) on each event day. This difference represents our estimated load impact.
4. In order to show the observed load (and avoid confusion associated with the predicted actual) we re-estimated the reference load as the sum of the observed load and the load impact.

Obtain Load Impacts and Confidence Intervals by Subgroup

Because we estimated an impact for each customer, the model results are easily aggregated to represent impacts for each of the required subpopulations of participants for each of the three IOUs. This includes analysis of incremental impacts for TA&TI and Auto-DR participants, participants dually enrolled in other utility DR programs, and the distinction between DO and DA notifications.

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

In order to develop the uncertainty-adjusted load impacts associated with the average event hour (i.e., the bottom rows in the tables produced by the ex-post table generator), we estimated an additional regression model. In this model, we estimated the average event-hour load impact for each event-day, by using a single event window model (rather than the hour-specific models used in the primary model described above). The standard errors associated with impacts for the entire event window served as the basis for the average event-hour uncertainty-adjusted load impacts for each ex-post event day.

Calculating Impacts for an Average Event Day

For this analysis we defined an average event as the average of all system-level events with summer (May – October) event hours ending 16-19 and non-summer event hours ending 18-19.[16] While each event is system-wide, different service accounts can be nominated for each event; therefore, the average is necessarily made up of different groups of customers across different days. This can prove problematic when attempting to sum impacts and customer counts across the multiple combinations of subgroups presented as part of this analysis. As a result, we used an averaging approach that represents every customer that responded on any of the event days included in the average by creating the averages first at the lowest level of disaggregation, then summing them to the total. This approach results in different estimates of impacts and customer counts than one would obtain through a simple average at the total-program level; however, it also is able to better reflect all the customers that participated in the system-wide events.

Ex-Ante Impact Analysis

The main goal of the ex-ante analysis is to produce an annual ten-year forecast of the load impacts expected from the CBP and AMP programs.

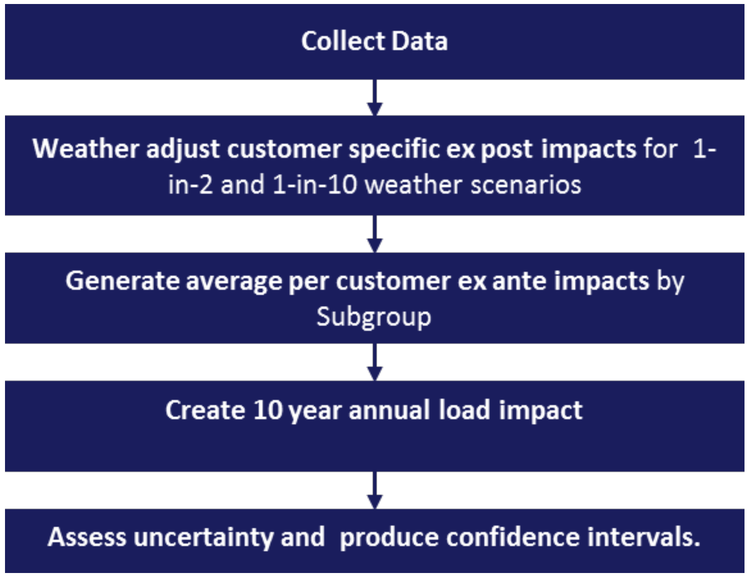
We developed the ex-ante forecasts using the following general steps:

1. AEG first provided the IOUs with the appropriate weather-adjusted, per-customer impacts for each subgroup.
2. The IOUs used the per-customer impacts, along with contractual MW agreements and adjustments based on historical load reduction performance and the latest development of the program, to determine the enrollment forecasts.
3. AEG then used the enrollment forecasts and the per-customer ex-ante impacts to develop the 10-year annual load impact forecasts for the participant populations and subgroups.

Figure 3-2 provides an overview of the ex-ante analysis approach which includes four basic steps after assembling the required data: 1) prediction of weather-adjusted impacts for each customer; 2) generation of per-customer average impacts by subgroup; 3) creation of annual load impact forecasts over the next 10 years; and 4) an assessment of uncertainty and the development of confidence intervals.

[16] For SCE's AMP DO product, we defined an average event as HE 14-18, an average summer event as HE 14-15, and an average non-summer event as HE 15-16.

Figure 3-2 Ex-Ante Analysis Approach



Weather-Adjusted Impacts for Each Customer

The first step in the ex-ante analysis is to use the customer-specific regression models to predict weather-adjusted per-customer average impacts for each IOU and for each of the appropriate subgroups (LCA, size, and industry segment). This produces a set of impacts under each of the different monthly weather conditions: 1-in-2 CAISO peak; 1-in-10 CAISO peak; 1-in-2 IOU peak; and 1-in-10 IOU peak. To do this, we completed the following steps:

- For each customer, we began with the coefficients estimated in the customer-specific regression models developed for the ex-post analysis.
- Then, we replaced the actual weather, from the program year, with the 1-in-2 and 1-in-10 weather data, based on the actual calendars for each year, to predict a customer's load for each of these scenarios on each day assuming no events are called. The result is a weather-adjusted reference load for each customer for each weather year.
- Next, we predicted the weather-adjusted event day load by again applying the coefficients from the ex-post models to both the 1-in-2 and 1-in-10 weather data; however this time we assumed that events were called on specific days by changing the event-indicator variables from zero to one. We also assumed that all events occurred during the Resource Adequacy window, which is between hour-ending 14 and hour-ending 18. As part of the ex-ante forecast development we assumed that the per-customer impacts would be the same under both 1-in-2 and 1-in-10 weather conditions and we applied the impacts predicted under July 1-in-2 weather conditions to each month so that the per-customer impacts would not vary by month in a given forecast year. The assumption is not unreasonable, as the load impacts should be a function of the monthly nomination, which is not weather-dependent within a given month. Aggregators target delivery at the nominated level, with little incentive to deliberately over-deliver the load reduction even under extreme weather.
- We then calculated the load impact for each of the participants by subtracting the weather-adjusted event-day load from the weather-adjusted reference load.

Generation of Per-Customer Average Impacts by Subgroup

Once weather-adjusted impacts have been predicted for each customer for each of the desired event day types, it becomes a relatively simple exercise to average the individual impacts and generate per-customer average impacts by subgroup. For example, the average impact for a particular LCA is the average of the impacts predicted for each customer in that LCA. At this stage, we also worked with the IOUs to determine the best way to account for dual participation between programs to ensure that they are not double-counted in the forecast. Since CBP and AMP are capacity-payment programs, the IOUs allocate the full load impacts from the dual participants of CBP/AMP and other energy-payment programs to CBP/AMP. Therefore, the CBP and AMP impacts for dual participants do not require adjustments.

Creation of 10-Year Annual Load Impact Forecasts

AEG provided the IOUs with the per-customer average ex-ante impacts by year and subgroup. The IOUs used the per-customer impacts—along with contractual MW adjusted by historical performance relative to the aggregator's MW nomination—to determine the enrollment forecasts. AEG used the enrollment forecasts and set of per-customer average ex-ante impacts to create the annual forecast of load impacts over the next 10 years.

Uncertainty Estimates and Confidence Intervals

Confidence intervals are provided for each hour as well as for an average event hour. Uncertainty in the ex-ante forecasts comes from modeling error, both from the customer-specific regressions, and from the weather adjustment to the 1-in-2 and 1-in-10 weather years. Though there is also error in the enrollment forecast, the confidence intervals do not include the enrollment forecast uncertainty.

Ex-Post Results

This section presents the ex-post impacts for each program and by segment for the 2015 DR Aggregator programs.

Capacity Bidding Program

All three IOUs offer CBP and each one offers three products, DA 1-4 hour, DO 1-4 hour, and DO 2-6 hour. SCE offers an additional product, DA 2-6 hour. In Table 4-1 below we present the average event day impacts by product and IOU, both at the per-customer level, and in aggregate.

For all three IOUs, the DO 1-4 hour product has the highest number of participants. For SCE it also has the highest per-customer impact, however for both PG&E and SDG&E the DO product has the lowest per-customer impact. In fact, PG&E's DA 1-4 hour product has the same aggregate impact as the DO 1-4 hour product (15.9 MW), even though it has less than half the number of participants. The per-customer impact for PG&E's DO 2-6 hour product falls in the middle of the three products, but the aggregate impacts are lowest due to fewer participants. For SDG&E, the DA 1-4 hour product has the highest aggregate impact (7.8 MW) and the highest per-customer impact (64.1 kW). SCE's DA 1-4 hour product has a per-customer impact of 18.2 kW and a total aggregate impact of 1.0 MW. The DA 2-6 hour product only has a single participant.

Table 4-1 Statewide CBP Impacts Summary

			Per Customer Impact (kW)		Aggregate Impact (MW)	
Utility	**Product**	**Accounts**	**Reference Load**	**Impact**	**Reference Load**	**Impact**
PG&E	DA 1-4 Hour	200	425.5	79.7	85.1	15.9
	DO 1-4 Hour	482	172.5	32.9	83.2	15.9
	DO 2-6 Hour	[redacted]				
SCE	DA 1-4 Hour	54	288.5	18.2	15.6	1.0
	DA 2-6 Hour	[redacted]				
	DO 1-4 Hour	563	148.2	23.6	83.4	13.3
	DO 2-6 Hour	[redacted]				
SDG&E	DA 1-4 Hour	122	148.0	64.1	18.1	7.8
	DO 1-4 Hour	160	182.8	21.9	29.2	3.5
	DO 2-6 Hour	63	273.3	34.8	17.2	2.2

PG&E

Events for PG&E CBP

Table 4-2 below presents a summary of the 2015 events for PG&E's CBP program by product. The DO participants experienced a total of 18 events over the course of the program year, while DA participants experienced only 16 events. Some of the events were localized, meaning that they were called for only some Sub-LAPs. Typical events were those called during hours-ending (HE) 16-19 and for all 15 Sub-LAPs.

Table 4-2 PG&E CBP Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts DO 1-4 Hour	# Accounts DO 2-6 Hour	# Accounts DA 1-4 Hour
Avg. Event	-	15	16-19	482	87	200
6/8/2015	Monday	15	16-19	439	69	-
6/9/2015	Tuesday	2	15-19[1]	56	7	-
6/12/2015	Friday	15	16-19	439	69	175
6/25/2015	Thursday	15	16-19	439	69	175
6/26/2015	Friday	15	16-19	439	69	175
6/30/2015	Tuesday	15	16-19	439	69	175
7/1/2015	Wednesday	15	16-19	528	105	181
7/16/2015	Thursday	8	17-19	369	81	126
7/28/2015	Tuesday	15	16-19	528	105	181
7/29/2015	Wednesday	15	16-19	528	105	181
7/30/2015	Thursday	15	16-19	528	105	181
8/17/2015	Monday	15	16-19	496	93	200
8/18/2015	Tuesday	15	16-19	496	93	200
8/26/2015	Wednesday	15,6[2]	16-19	496	93	96
8/27/2015	Thursday	15	16-19	496	93	200
9/9/2015	Wednesday	15	16-19	476	95	198
9/10/2015	Thursday	15	16-19	476	95	198
9/11/2015	Friday	15	16-19	476	95	198

[1]The 6/9/2015 event had four separate event windows: 51 DO 1-4 accounts were called from HE 16-19, 4 were called from HE 15-18, and 7 DO 2-6 accounts were called from HE 15-19.
[2]On the 8/26/2015 event, there were 15 Sub-LAPs called for DO and 6 for DA.

Summary Load Impacts

Table 4-3 to Table 4-4 show the average event-hour impacts for each event, and notification, both at the average per-customer level and in aggregate.

In Table 4-3 immediately below, we present the average event-hour impacts for the CBP DO 1-4 hour and the CBP DO 2-6 hour participants combined. The highest per-customer impacts, and overall aggregate impacts occurred during the events on July 28, 2015 and July 29, 2015. The maximum per-customer reductions were 44.8 kW and 43.4 kW respectively. The maximum aggregate impacts occurred on the same two days and were 28.3 MW and 27.5 MW, respectively. The impacts represent a 23% reduction over the reference load and a total of 633 nominated service accounts. The lowest impacts occurred on June 9, 2015, when only 63 service accounts were nominated.

Table 4-3 PG&E CBP Day-Of (1-4 Hour + 2-6 Hour): Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Temp (˚F)
Avg. Event	569	23.9	177.8	34.7	101.2	19.8	20%	90
6/8/2015	508	27.1	192.2	42.5	97.7	21.6	22%	94
6/9/2015	[redacted]							76
6/12/2015	[redacted]							88
6/25/2015	[redacted]							90
6/26/2015	[redacted]							87
6/30/2015	[redacted]							94
7/1/2015	633	31.7	175.8	39.4	111.3	24.9	22%	87
7/16/2015	450	15.3	157.0	17.3	70.6	7.8	11%	81
7/28/2015	[redacted]							93
7/29/2015	633	31.7	189.7	43.4	120.1	27.5	23%	91
7/30/2015	633	31.7	183.3	42.4	116.0	26.8	23%	87
8/17/2015	589	20.0	180.5	27.6	106.3	16.3	15%	91
8/18/2015	589	20.0	180.2	27.0	106.1	15.9	15%	84
8/26/2015	589	20.0	180.4	28.6	106.3	16.8	16%	88
8/27/2015	589	20.0	187.9	30.5	110.7	18.0	16%	91
9/9/2015	571	19.0	200.6	32.6	114.5	18.6	16%	95
9/10/2015	571	19.0	195.2	30.5	111.5	17.4	16%	93
9/11/2015	571	19.0	183.9	29.4	105.0	16.8	16%	90

Table 4-4, on the following page, shows the average event-hour impacts for the CBP DA 1-4 hour participants. The highest per-customer impact occurred on August 26, 2015 with a maximum per-customer impact of 168.7 kW representing 96 customer and a 27% reduction over the reference load. The largest aggregate impacts occurred on August 27, 2015 at 22.5 MW representing a total of 200 service accounts and a 21% reduction over the reference load. The lowest impacts occurred on July 16, 2015, when 126 service accounts provided only 8.8 MW of load reduction.

Table 4-4 PG&E CBP Day-Ahead 1-4 Hour: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Temp (˚F)
Avg. Event	200	23.7	425.5	79.7	85.1	15.9	19%	90
6/12/2015	175	21.4	405.4	67.0	71.0	11.7	17%	88
6/25/2015	175	21.4	411.8	63.2	72.1	11.1	15%	90
6/26/2015	175	21.4	393.2	68.0	68.8	11.9	17%	87
6/30/2015	175	21.4	407.4	75.8	71.3	13.3	19%	93
7/1/2015	181	20.7	417.0	67.0	75.5	12.1	16%	86
7/16/2015	126	14.3	391.2	69.5	49.3	8.8	18%	81
7/28/2015	181	20.7	416.0	62.6	75.3	11.3	15%	93
7/29/2015	181	20.7	419.3	66.3	75.9	12.0	16%	91
7/30/2015	181	20.7	440.1	65.1	79.7	11.8	15%	86
8/17/2015	200	29.9	531.3	110.2	106.3	22.0	21%	91
8/18/2015	200	29.9	522.3	107.5	104.5	21.5	21%	85
8/26/2015	96	20.7	627.9	168.7	60.3	16.2	27%	96
8/27/2015	200	29.9	533.8	112.5	106.8	22.5	21%	91
9/9/2015	198	27.6	544.2	102.8	107.8	20.4	19%	95
9/10/2015	198	27.6	515.6	104.8	102.1	20.8	20%	93
9/11/2015	198	27.6	501.8	103.7	99.4	20.5	21%	89

Table 4-5 and Table 4-6 present the impacts for an average event day by Industry and Local Capacity Area (LCA), respectively.[17] Manufacturing has the highest aggregate impacts for DA events and Retail Stores have the highest aggregate impacts for DO events. In terms of per-customer impacts, Manufacturing has the highest impacts for both DA and DO events. For DA events, Humboldt has the largest percentage of impacts with a [redacted] reduction over the reference load. For DO events, the "Other" LCA has the largest impacts at [redacted] (per-customer) and [redacted] (aggregate).

[17] The results in Table 4-5 and Table 4-6 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual industry segments (or LCAs). This is because different group of customers are called for each event, and in some cases, no customers in an industry segment (or LCA) may be called. So the average for that industry segment (or LCA) will reflect only those events where customers in that industry segment (or LCA) were called. But the total program is the average across all events, since some customers in the program were called for every event. Because the total program and the individual industry segments (or LCAs) are averaged across different events, the total program does not exactly match the sum of the individual industry segments (or LCAs).

Table 4-5 PG&E CBP Impacts by Industry and Notice

	Industry	# of Accts	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load	Aggregate Impact (MW) Impact	% Impact	Event Temp (˚F)
DA	Agriculture, Mining & Construction	[redacted]						96
	Manufacturing							93
	Wholesale, Transport, other Utilities							92
	Retail Stores	56	89.7	7.6	5.0	0.4	8%	87
	Offices, Hotels, Finance, Services	[redacted]						87
	Schools							88
	Institutional/Government							88
	Other or unknown							96
	Total DA	**200**	**425.5**	**79.7**	**85.1**	**15.9**	**19%**	**90**
DO	Agriculture, Mining & Construction	24	40.5	21.7	1.0	0.5	54%	100
	Manufacturing	[redacted]						90
	Wholesale, Transport, other Utilities							87
	Retail Stores	429	152.3	21.8	65.3	9.3	14%	90
	Offices, Hotels, Finance, Services	61	299.5	58.6	18.3	3.6	20%	86
	Schools	[redacted]						99
	Institutional/Government							99
	Other or unknown							87
	Total DO	**569**	**179.8**	**35.2**	**102.3**	**20.0**	**20%**	**90**
Total CBP		**769**	**243.7**	**46.7**	**187.4**	**35.9**	**19%**	**90**

Table 4-6 PG&E CBP Impacts by LCA and Notice

	LCA	# of Accts	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load	Aggregate Impact (MW) Impact	% Impact	Event Temp (˚F)
DA	Greater Bay Area	75	258.9	24.0	19.4	1.8	9%	83
	Greater Fresno	20	354.0	45.9	7.1	0.9	13%	103
	Humboldt	[redacted]						74
	Kern							101
	Northern Coast	16	235.2	34.9	3.8	0.6	15%	90
	Other	[redacted]						90
	Sierra							97
	Stockton							98
	Total DA	**200**	**425.5**	**79.7**	**85.1**	**15.9**	**19%**	**90**
DO	Greater Bay Area	260	183.9	20.1	47.8	5.2	11%	85
	Greater Fresno	53	166.6	51.0	8.8	2.7	31%	103
	Humboldt	[redacted]						72
	Kern	29	178.3	36.1	5.2	1.0	20%	101
	Northern Coast	39	187.7	17.9	7.3	0.7	10%	90
	Other	119	215.4	77.0	25.6	9.2	36%	90
	Sierra	29	152.2	17.3	4.4	0.5	11%	98
	Stockton	34	173.2	26.6	5.9	0.9	15%	99
	Total DO	**569**	**179.8**	**35.2**	**102.3**	**20.0**	**20%**	**90**
Total CBP		**769**	**243.7**	**46.7**	**187.4**	**35.9**	**19%**	**90**

Hourly Load Impacts

Figure 4-1 and Figure 4-2 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each of the PG&E CBP products on an average event day. The event window is hour-ending 16 to hour-ending 19 and is highlighted light grey in each figure. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-1 PG&E CBP Day-Of (1-4 Hour + 2-6 Hour): Average Hourly Per-Customer Impact, 2015

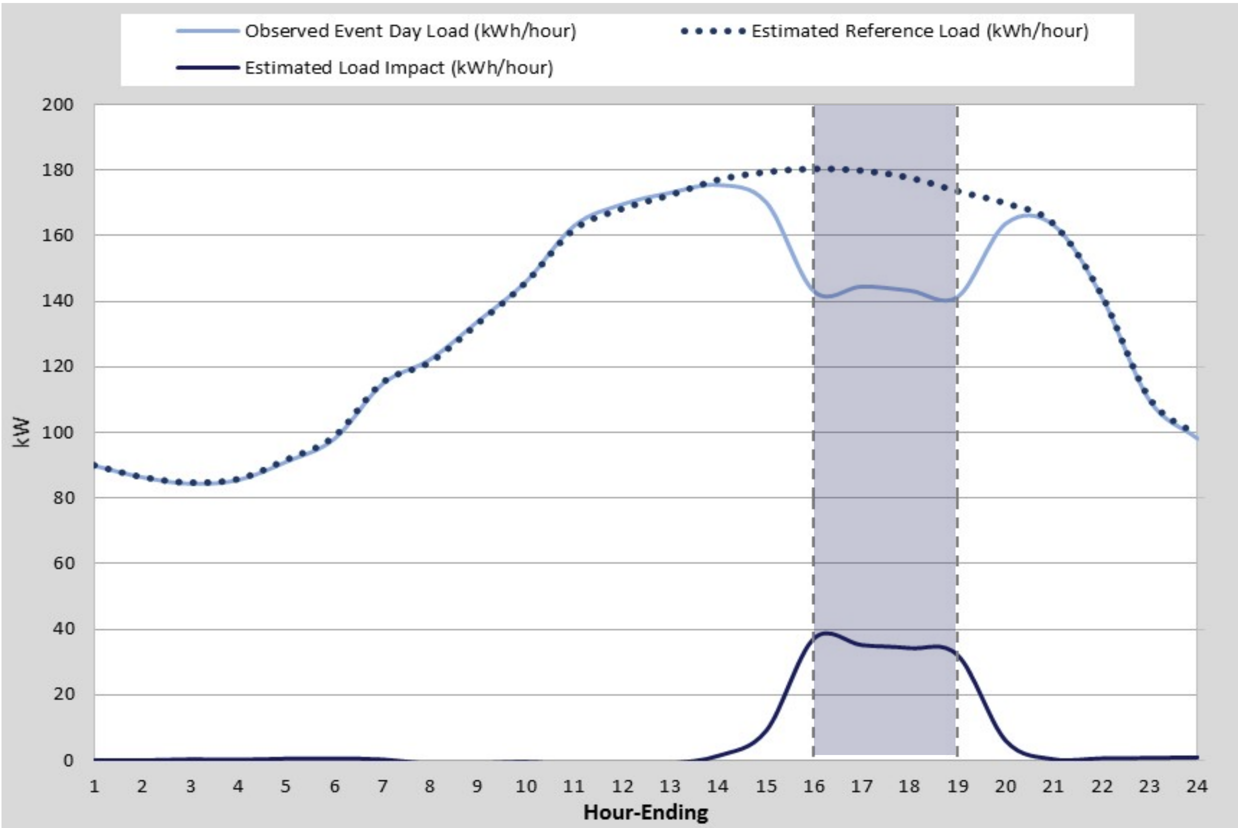
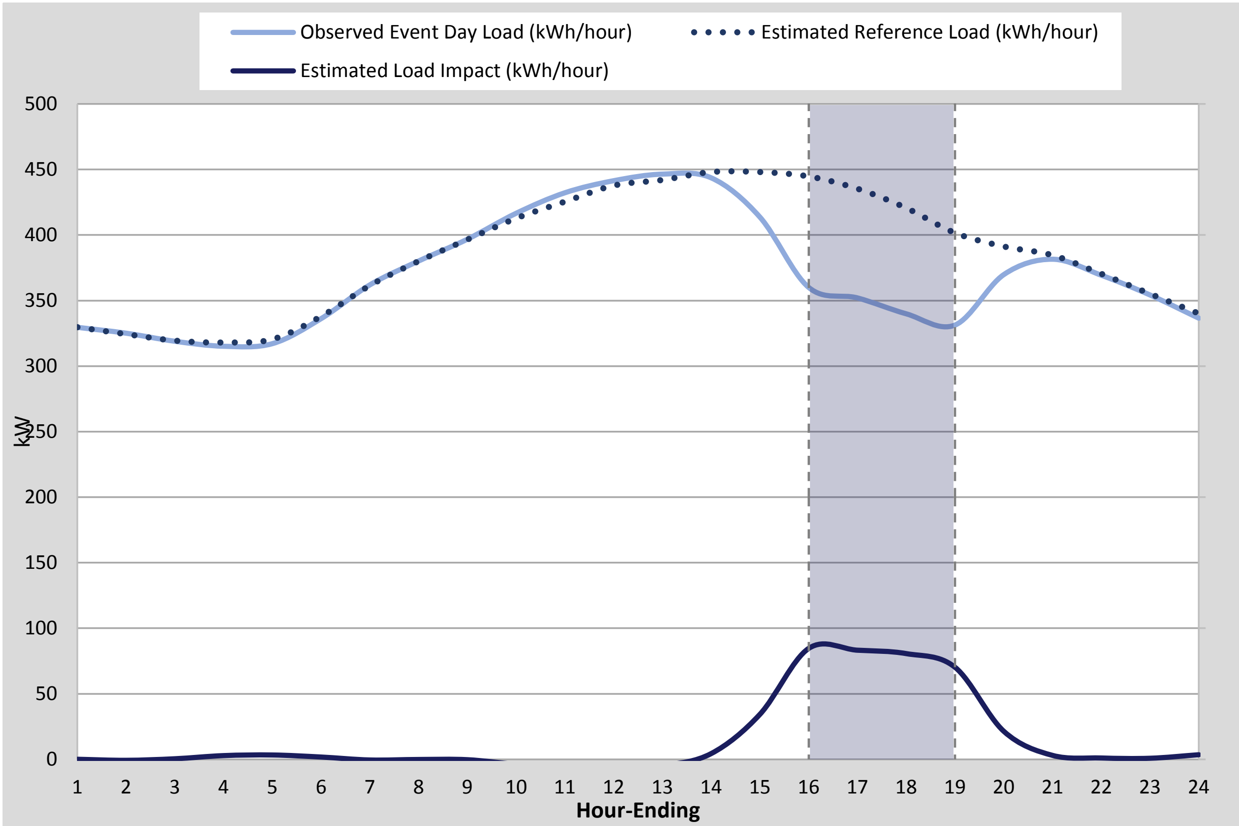


Figure 4-2 PG&E CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2015



Load Impacts of TA/TI and AutoDR Participants

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

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

The ex-post load impacts achieved by PG&E CBP customers that participated in TA/TI or AutoDR at some point in the current or previous years are presented below. It includes two sets of impacts: 1) the ex-post impacts for this subgroup, and 2) the incremental impacts achieved by the subgroup over similar program participants.

In Table 4-7 to Table 4-8 below we present the event day ex-post impacts and the aggregate load shed test results for the Auto-DR and TA/TI participants by notification. Table 4-7 shows the event day impacts for the two DO products combined, these customers achieved a maximum total aggregate impact of 4.9 MW on July 28, 2015, representing an 18% reduction over their reference load. On average, the aggregate ex-post impacts are lower than the aggregate load shed test results representing between 75% and 95% of the potential load shed depending on the event day in question.

Table 4-7 PG&E CBP Day-Of (1-4 Hour + 2-6 Hour): Auto-DR and TA/TI Participant Impacts by Event

		Per Customer Impact (kW)		Aggregate Impact (MW)				
Event	Number of Accounts	Reference Load	Impact	Reference Load	Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
6/8/2015	114	216.3	36.9	24.7	4.2	17%	4.9	96
6/9/2015	[redacted]							76
6/12/2015	114	215.9	38.5	24.6	4.4	18%	4.9	93
6/25/2015	114	217.3	36.3	24.8	4.1	17%	4.9	92
6/26/2015	114	224.7	37.0	25.6	4.2	16%	4.9	91
6/30/2015	114	236.6	39.7	27.0	4.5	17%	4.9	96
7/1/2015	121	223.6	38.5	27.1	4.7	17%	5.1	90
7/16/2015	75	233.2	35.2	17.5	2.6	15%	3.4	83
7/28/2015	121	226.4	40.2	27.4	4.9	18%	5.1	95
7/29/2015	121	214.2	37.6	25.9	4.6	18%	5.1	95
7/30/2015	121	217.5	37.0	26.3	4.5	17%	5.1	90
8/17/2015	114	234.4	36.6	26.7	4.2	16%	4.9	94
8/18/2015	114	223.5	34.9	25.5	4.0	16%	4.9	87
8/26/2015	114	220.7	38.0	25.2	4.3	17%	4.9	89
8/27/2015	114	236.6	41.1	27.0	4.7	17%	4.9	93
9/9/2015	114	245.2	42.0	27.9	4.8	17%	5.0	96
9/10/2015	114	235.7	37.7	26.9	4.3	16%	5.0	95
9/11/2015	114	219.8	37.0	25.1	4.2	17%	5.0	92

Table 4-8 PG&E CBP Day-Ahead 1-4 Hour: Auto-DR and TA/TI Participant Impacts by Event

		Per Customer Impact (kW)		Aggregate Impact (MW)				
Event	Number of Accounts	Reference Load	Impact	Reference Load	Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.								

In Table 4-8, we present the average event-hour impacts for the CBP DA 1-4 hour participants. This is by far the smallest group with only 4 Auto-DR or TA/TI participants. Their largest aggregate impact was [redacted] and a [redacted] reduction occurring on July 16, 2015.

Incremental Load Impacts of TA/TI and AutoDR Participants

In addition to presenting the ex-post impacts for the subgroup, we also estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with group of similar non-enabled participants. First, we selected a group of CBP participants that are similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID). We describe DID methodology first, and then describe the matching approach.

The DID method involves taking the difference between the control group and treatment group energy use during both the treatment period and the non-treatment period, and then subtracting the pre-treatment difference from the treatment period difference. In this case we wanted to estimate the incremental impact associated with the treatment group. Therefore, we defined the non-treatment period as the average reference load on event days and the treatment period as the average predicted load on event days. The differences are done at the group level, based on the average across all customers in each group. Where X is the control group, Y is the treatment group, as shown below in equation 4.1

$$Incremental\ Savings = (X_{PredActual} - Y_{PredActual}) - (X_{reference} - Y_{reference}) \quad (4.1)$$

Using algebra, this can be rewritten as the difference in impacts, show below in equation 4.2.

$$Incremental\ Savings = (Y_{Refrence} - Y_{PredActual}) - (X_{reference} - X_{PredActual}) \quad (4.2)$$

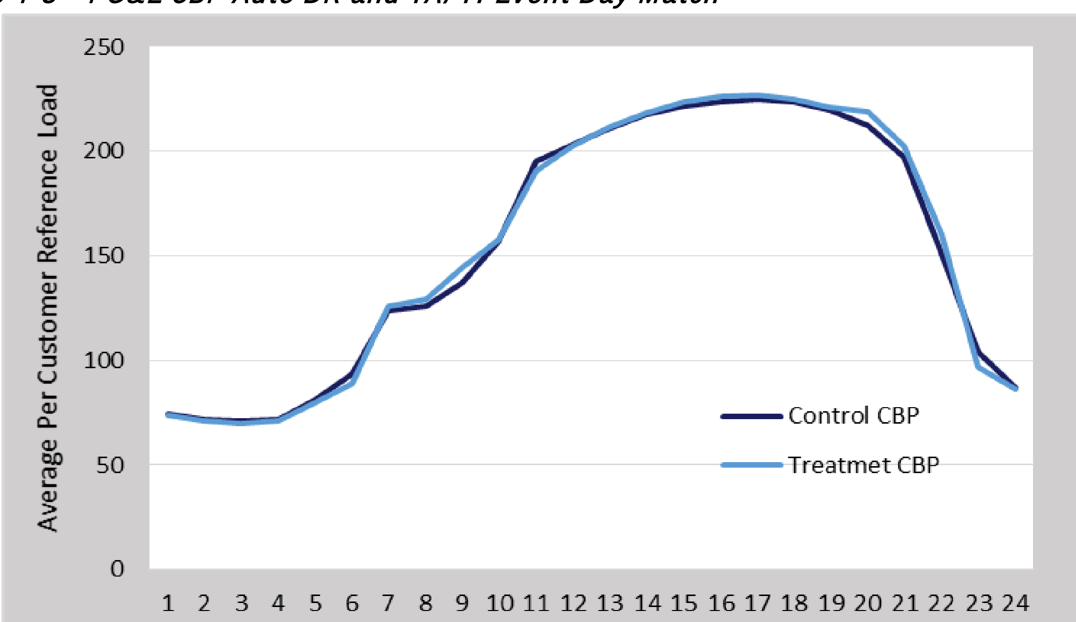
We then calculated the standard errors of the incremental savings and used them to establish a confidence interval at the 95% level.

When it is not practical to use a randomized control trial (RCT), as in this case, a matched control group can be created. Our goal was to select control customers that are as similar as possible to each treatment customer during the non-treatment period (which in our case is the average event day reference load), based on known observable characteristics. We used a stratified Euclidean distance to choose the best match within the control group pool for each participant. First we assigned each participant and potential control to a bucket based on their industry type, and product. Then we minimized the Euclidean distance (the square root of the sum of squared deviations) between the participant and control customers across as many characteristics from the non-treatment period as possible. Any number of relevant variables could be included in the Euclidean distance; in this case we used average hourly on-peak values, and both morning and evening off-peak averages. The Euclidean distance for this set of variables can be calculated by Equation 4.3 below.

$$ED = \sqrt{(Off\_1 - Off\_1_C)^2 + (EOff\_2_T - EOff\_2_C)^2 + (kWh16_T - kWh16_C + \ldots + kWh19_T - kWh19_C)^2} \quad (4.3)$$

In Figure 4-3 below we show the treatment and control group match on an average event day. The graph shows the reference load profile of each group for the overall CBP program. There are a total of 125 Auto-DR participants, and a total of 125 control group matches. While we did look at the results at the product level, and each participant is matched to a control customer within their product, the impacts were not significant across all products. Therefore we only show the statistically significant findings for the overall CBP program level.

Figure 4-3 PG&E CBP Auto DR and TA/TI Event Day Match



In Figure 4-4 and accompanying Table 4-9 we present the incremental impacts at the program level. In the figure, we show the average per-customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. As we would expect, the incremental impacts are very small, and often insignificant during non-event hours. However, during the HE16 to HE19 event window, we do see significant incremental impacts of approximately 11 kW per enabled customer.

As seen in Table 4-9, on an average event day, participants saved an additional 11.5 kW on average or 1.4 MW in aggregate over similar non-enabled customers.

Figure 4-4 PG&E CBP Auto DR and TA/TI Event Day Match

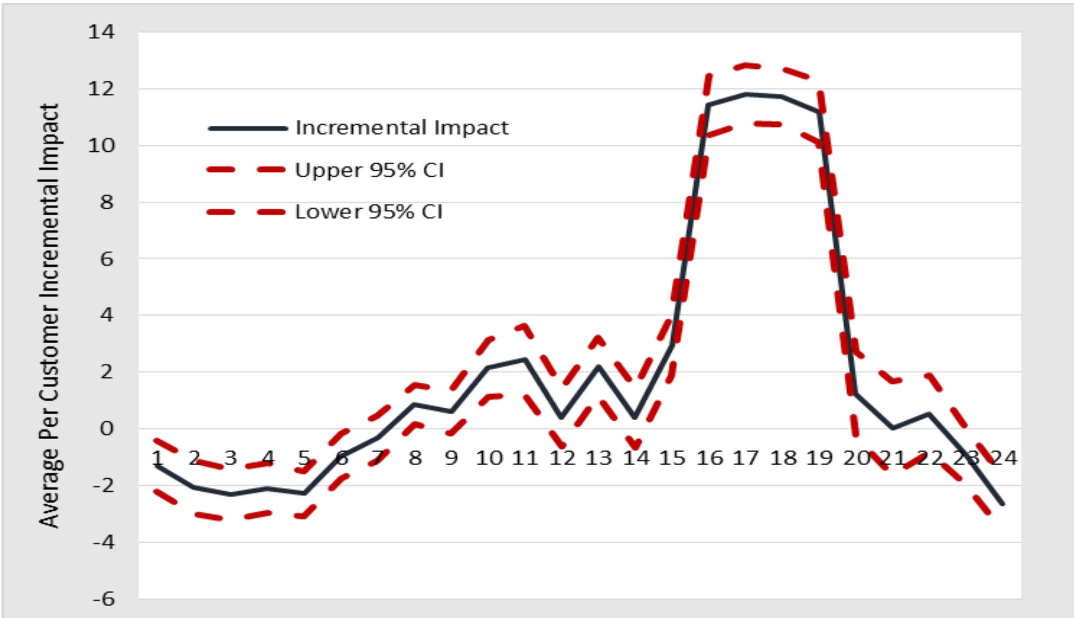


Table 4-9 PG&E CBP Program Level Incremental Auto-DR and TA/TI Impacts

Program	Number of Customers	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate(MW)	Significant
CBP	125	11.5	1.4	Yes

SCE

Events for SCE CBP

Table 4-10 below presents a summary of the PY2015 events for SCE's CBP program by product.[18] The table includes definitions of average summer and non-summer event days. The DO participants experienced a total of 42 events over the course of the program year, while DA participants experienced 61 events. Events were called with a wide variety of event hours.

Table 4-10 SCE CBP Event Summary

Date	Day of Week	Event Hours (HE)[1]	# Accts DO 1-4 Hour	# Accts DO 2-6 Hour	# Accts DA 1-4 Hour	# Accts DA 2-6 Hour
Avg. Summer	-	16-19	563	107	54	1
Avg. Non-Summer	-	18-19	479	-	201	2
11/4/2014	Tuesday	19-19	-	-	190	-
11/5/2014	Wednesday	18-19	-	-	190	1
11/6/2014	Thursday	18-19, 17-19	479	-	190	1
11/7/2014	Friday	18-19	-	-	190	1
11/10/2014	Monday	18-19	-	-	190	1
11/13/2014	Thursday	18-19	-	-	190	1
11/20/2014	Thursday	18-18	-	-	190	-
12/2/2014	Tuesday	18-18	-	-	160	-
12/3/2014	Wednesday	18-18	-	-	160	-
12/5/2014	Friday	18-18	-	-	160	-
12/8/2014	Monday	18-18	-	-	160	-
1/14/2015	Wednesday	18-18	-	-	167	-
1/29/2015	Thursday	18-18	-	-	167	-
1/30/2015	Friday	18-19	-	-	167	2
2/2/2015	Monday	18-19	-	-	168	2
2/3/2015	Tuesday	18-19	-	-	168	2
2/4/2015	Wednesday	19-19	-	-	168	-
2/5/2015	Thursday	19-19	-	-	168	-
2/9/2015	Monday	18-19	-	-	168	2
2/10/2015	Tuesday	19-19	-	-	168	-
2/11/2015	Wednesday	19-19	-	-	168	-
2/17/2015	Tuesday	19-19	-	-	168	-
2/18/2015	Wednesday	19-19	-	-	168	-
6/8/2015	Monday	15-18, 15-19	676	191	-	-
6/9/2015	Tuesday	15-18, 14-19	676	191	-	-
6/18/2015	Thursday	17-19	57	12	-	-
6/25/2015	Thursday	16-19, 15-19	676	191	-	-
6/26/2015	Friday	17-19	676	191	59	-
6/29/2015	Monday	19-19, 17-19, 19-19	676	191	59	-
6/30/2015	Tuesday	16-19	676	191	59	-

[18] SCE's PY2015 evaluation period is from Nov. 1, 2014 through Oct. 31, 2015.

Date	Day of Week	Event Hours (HE)[1]	# Accts DO 1-4 Hour	# Accts DO 2-6 Hour	# Accts DA 1-4 Hour	# Accts DA 2-6 Hour
7/1/2015	Wednesday	16-19, 14-19, 16-19	644	179	58	-
7/2/2015	Thursday	17-18	644	179	58	-
7/22/2015	Wednesday	16-16	57	-	4	-
7/28/2015	Tuesday	17/18-18/19, 17/18-19, 17/18-18/19	644	168	58	-
7/29/2015	Wednesday	17-19, 17-19, 16-19	644	179	58	-
7/30/2015	Thursday	17-18	644	179	58	-
7/31/2015	Friday	17-17	644	-	58	-
8/3/2015	Monday	17-17	-	-	56	-
8/6/2015	Thursday	17-17/18, 17-18, 17-17/18, 17-18	596	157	56	1
8/13/2015	Thursday	18-19	596	179	56	1
8/14/2015	Friday	17/18-17/18, 17-18, 17/18-18	306	69	34	-
8/17/2015	Monday	17-18, 17-18, 17-17/18, 17-18	596	179	56	1
8/26/2015	Wednesday	16/17-19, 16/17-19, 16/17-19, 17-19	596	179	56	1
8/27/2015	Thursday	18/19-19, 18-19, 18/19-19	596	80	56	-
8/28/2015	Friday	17/18-19, 17/18-19, 17/18-19, 17-19	581	172	56	1
9/8/2015	Tuesday	16-19, 15/16-19	590	170	-	-
9/9/2015	Wednesday	16-19, 15-19, 16-19, 15-19	590	170	47	1
9/10/2015	Thursday	16-19, 15-19, 16-19, 15-19	590	170	47	1
9/11/2015	Friday	15/16-18/19, 15-19, 15/16-18/19, 15-19	590	170	47	1
9/21/2015	Monday	16-19	-	-	47	1
9/24/2015	Thursday	19-19	590	-	47	-
9/25/2015	Friday	18-19	590	170	47	1
9/28/2015	Monday	19-19	545	-	-	-
9/29/2015	Tuesday	19-19, 18-18	259	-	30	-
10/8/2015	Thursday	19-19	607	-	48	-
10/9/2015	Friday	17/18-19, 17/18-19, 17/18-19, 18-19	607	92	48	1
10/12/2015	Monday	16/17-19, 16/17-19, 19-19	607	92	48	
10/13/2015	Tuesday	16/17-19, 16/17-19, 16/17-19, 17-19	607	92	48	1
10/14/2015	Wednesday	18-19	607	92	48	1
10/15/2015	Thursday	18/19-19, 18-19, 18/19-19, 18-19	607	80	48	1
10/16/2015	Friday	19-19	607	-	48	-
10/19/2015	Monday	19-19	-	-	48	-
10/26/2015	Monday	19-19	607	-	48	-
10/27/2015	Tuesday	19-19	607	-	48	-
10/28/2015	Wednesday	19-19	607	-	48	-
10/29/2015	Thursday	19-19	548	-	48	-
10/30/2015	Friday	19-19	607	-	48	-

[1]For events with multiple event windows, the hours are listed in the same order as the products in the columns. In some cases, more than one event window was called for a given product. For example, the designation of 18/19-19 signifies that some customers were called with a window of HE 18-19 and others with a window of HE19-19 for the given event and product.

Summary Load Impacts

Table 4-11 to Table 4-14 show the average event-hour impacts for each event, for each product, both at the average per-customer level and in aggregate. The tables include results for the average summer event and average non-summer event.

In Table 4-11 immediately below, we present the average event-hour impacts for the CBP DO 1-4 hour participants. Of the four products offered under SCE's CBP, the CBP DO 1-4 product has the most participants and largest aggregate load reduction. [redacted]. The maximum per-customer reduction (36 kW) was on August 14, 2015.

Table 4-11 SCE CBP Day-Of 1-4 Hour: Impacts by Event

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load.	Aggregate Impact (MW) Impact	% Impact	Temp (˚F)
Avg. Summer	16-19	563	19.0	148.2	23.6	83.4	13.3	16%	87
Avg. Non-Summer	18-19	479	27.6	111.0	18.5	53.2	8.9	17%	77
11/6/2014	18-19	[redacted]							77
6/8/2015	15-18	[redacted]							89
6/9/2015	15-18	676	21.3	174.6	31.3	118.0	21.2	18%	81
6/18/2015	17-19	57	21.3	158.4	31.7	9.0	1.8	20%	98
6/25/2015	16-19	676	21.3	184.5	31.3	124.7	21.2	17%	85
6/26/2015	17-19	676	21.3	178.5	30.0	120.6	20.3	17%	83
6/29/2015	19-19	676	21.3	180.4	26.9	122.0	18.2	15%	84
6/30/2015	16-19	[redacted]							83
7/1/2015	16-19	[redacted]							81
7/2/2015	17-18	[redacted]							84
7/22/2015	16-16	57	20.7	122.7	21.6	7.0	1.2	18%	76
7/28/2015	17-19 18-18 18-19	644	20.7	175.4	30.7	112.9	19.8	17%	86
7/29/2015	17-19	644	20.7	179.7	29.5	115.7	19.0	16%	84
7/30/2015	17-18	644	20.7	183.3	30.0	118.0	19.3	16%	86
7/31/2015	17-17	644	20.7	182.7	30.4	117.7	19.6	17%	87
8/6/2015	17-17 17-18	596	18.9	184.3	30.2	109.8	18.0	16%	88
8/13/2015	18-19	[redacted]							90
8/14/2015	17-17 17-18 18-18	306	18.9	193.3	36.0	59.1	11.0	19%	97
8/17/2015	17-18	596	18.9	204.5	31.4	121.9	18.7	15%	85
8/26/2015	16-19 17-19	596	18.9	196.0	30.3	116.8	18.1	15%	88
8/27/2015	18-19 19-19	596	18.9	197.1	28.2	117.5	16.8	14%	89
8/28/2015	17-19 18-19	581	18.9	206.8	30.8	120.2	17.9	15%	93
9/8/2015	16-19	[redacted]							93
9/9/2015	16-19	[redacted]							89

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
9/10/2015	16-19	590	17.2	207.1	33.1	122.2	19.6	16%	91
9/11/2015	15-18 16-19	590	17.2	205.7	32.6	121.3	19.2	16%	91
9/24/2015	19-19	590	17.2	195.8	28.3	115.5	16.7	14%	84
9/25/2015	18-19	[redacted]							87
9/28/2015	19-19	[redacted]							79
9/29/2015	19-19	259	17.2	176.4	19.3	45.7	5.0	11%	77
10/8/2015	19-19	[redacted]							83
10/9/2015	17-19 18-19	607	16.9	201.3	32.0	122.2	19.4	16%	94
10/12/2015	16-19 17-19	607	16.9	197.8	30.6	120.1	18.6	15%	89
10/13/2015	16-19 17-19	607	16.9	196.5	30.7	119.3	18.6	16%	84
10/14/2015	18-19	607	16.9	201.8	31.6	122.5	19.2	16%	81
10/15/2015	18-19 19-19	607	16.9	187.8	29.7	114.0	18.0	16%	75
10/16/2015	19-19	607	16.9	187.7	27.5	113.9	16.7	15%	73
10/26/2015	19-19	[redacted]							76
10/27/2015	19-19	[redacted]							74
10/28/2015	19-19	[redacted]							72
10/29/2015	19-19	[redacted]							74
10/30/2015	19-19	[redacted]							75

In Table 4-12 we present the average event-hour impacts for the CBP DO 2-6 hour participants. In this case, the largest aggregate impacts occurred on June 9, 2015 representing a total of 191 service accounts and a [redacted] reduction over the reference load. The highest per-customer impact occurred on October 9, 2015, with a maximum per-customer impact of [redacted].

Table 4-12 SCE CBP Day-Of 2-6 Hour: Impacts by Event

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.									

In Table 4-13 we present the average event-hour impacts for the CBP DA 1-4 hour participants. The highest per-customer impact occurred on January 29, 2015 with a maximum per-customer impact of 28.3 kW representing 167 service accounts and a 10% reduction over the reference load. The largest aggregate impact occurred on November 6, 2014 at [redacted].

Table 4-13 SCE CBP Day-Ahead 1-4 Hour: Impacts by Event

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)			Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact	% Impact	
Avg. Summer	16-19	54	2.1	288.5	18.2	15.6	1.0	6%	85
Avg. Non-Summer	18-19	201	6.7	278.6	21.1	56.0	4.2	8%	68
11/4/2014	19-19	[redacted]							68
11/5/2014	18-19	[redacted]							78
11/6/2014	17-19	[redacted]							80
11/7/2014	18-19	190	7.1	325.8	21.6	61.9	4.1	7%	76
11/10/2014	18-19	190	7.1	325.4	21.6	61.8	4.1	7%	65
11/13/2014	18-19	[redacted]							63
11/20/2014	18-18	[redacted]							62
12/2/2014	18-18	160	7.0	299.0	25.6	47.8	4.1	9%	51
12/3/2014	18-18	160	7.0	310.4	26.8	49.7	4.3	9%	58
12/5/2014	18-18	160	7.0	301.6	27.6	48.3	4.4	9%	63
12/8/2014	18-18	160	7.0	312.8	26.6	50.0	4.3	9%	68
1/14/2015	18-18	167	6.8	284.8	26.6	47.6	4.4	9%	65
1/29/2015	18-18	167	6.8	293.7	28.3	49.1	4.7	10%	67
1/30/2015	18-19	167	6.8	283.0	25.8	47.3	4.3	9%	61
2/2/2015	18-19	168	6.0	295.4	26.7	49.6	4.5	9%	68
2/3/2015	18-19	168	6.0	296.3	26.4	49.8	4.4	9%	67
2/4/2015	19-19	168	6.0	283.3	23.3	47.6	3.9	8%	66
2/5/2015	19-19	168	6.0	292.9	23.8	49.2	4.0	8%	67
2/9/2015	18-19	168	6.0	300.3	25.9	50.4	4.4	9%	68
2/10/2015	19-19	168	6.0	300.8	24.4	50.5	4.1	8%	69
2/11/2015	19-19	168	6.0	307.2	24.5	51.6	4.1	8%	75
2/17/2015	19-19	168	6.0	295.8	24.3	49.7	4.1	8%	65
2/18/2015	19-19	168	6.0	301.6	24.5	50.7	4.1	8%	65
6/26/2015	17-19	[redacted]							82
6/29/2015	19-19	[redacted]							82
6/30/2015	16-19	[redacted]							83
7/1/2015	16-19	[redacted]							81
7/2/2015	17-18	58	2.2	349.9	15.9	20.3	0.9	5%	83
7/22/2015	16-16	[redacted]							78
7/28/2015	17-19 18-18 18-19	[redacted]							86
7/29/2015	16-19	[redacted]							85
7/30/2015	17-18	[redacted]							85
7/31/2015	17-17	[redacted]							87
8/3/2015	17-17	[redacted]							84
8/6/2015	17-17 17-18	[redacted]							85
8/13/2015	18-19	[redacted]							88

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
8/14/2015	17-18 18-18	34	2.1	312.7	19.0	10.6	0.6	6%	89
8/17/2015	17-17 17-18	56	2.1	345.7	15.3	19.4	0.9	4%	84
8/26/2015	16-19 17-19	56	2.1	327.0	15.0	18.3	0.8	5%	89
8/27/2015	18-19 19-19	[redacted]							89
8/28/2015	17-19 18-19	[redacted]							89
9/9/2015	16-19	[redacted]							88
9/10/2015	16-19	[redacted]							90
9/11/2015	15-18 16-19	[redacted]							90
9/21/2015	16-19	[redacted]							78
9/24/2015	19-19	[redacted]							81
9/25/2015	18-19	[redacted]							85
9/29/2015	18-18	[redacted]							79
10/8/2015	19-19	[redacted]							82
10/9/2015	17-19 18-19	[redacted]							94
10/12/2015	19-19	[redacted]							88
10/13/2015	16-19 17-19	48	2.0	406.5	21.6	19.5	1.0	5%	83
10/14/2015	18-19	[redacted]							80
10/15/2015	18-19 19-19	[redacted]							73
10/16/2015	19-19	[redacted]							72
10/19/2015	19-19	[redacted]							68
10/26/2015	19-19	[redacted]							75
10/27/2015	19-19	[redacted]							73
10/28/2015	19-19	[redacted]							72
10/29/2015	19-19	[redacted]							74
10/30/2015	19-19	[redacted]							75

In Table 4-14 we present the average event-hour impacts for the CBP DA 2-6 hour participants. The largest aggregate impact ([redacted]) occurred on several events in January and February, representing 2 service accounts.

Table 4-14 SCE CBP Day-Ahead 2-6 Hour: Impacts by Event

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (kW)	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (kW) Ref. Load.	Impact	% Impact	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.									

Table 4-15 and Table 4-16 present the impacts for an average summer event day by Industry and LCA, respectively.[19]

- Manufacturing has the highest aggregate impacts for DA events and Retail Stores have the highest aggregate impacts for DO events. In terms of per-customer impacts, Wholesale, Transport, and Other Utilities have the highest impacts for DA events and Manufacturing has the highest impact for DO events.
- For both DA and DO events, LA Basin has the largest aggregate impacts. The highest per-customer impacts are associated with the Outside LA Basin LCA for both DO and DA events.

Table 4-15 SCE CBP Impacts by Industry and Notice

			Per Customer Impact (kW)		Aggregate Impact (MW)			
	Industry	**# of Accts**	**Ref. Load**	**Impact**	**Ref. Load**	**Impact**	**% Impact**	**Event Temp (˚F)**
DA	Agriculture, Mining & Construction	[redacted]						101
DA	Manufacturing	14	578.1	28.8	8.1	0.4	5%	80
DA	Wholesale, Transport, other Utilities	[redacted]						88
DA	Retail Stores	22	186.4	9.1	4.1	0.2	5%	83
DA	Offices, Hotels, Finance, Services	[redacted]						83
DA	Schools	[redacted]						77
DA	Institutional/Government	[redacted]						82
DA	**Total DA**	**55**	**284.5**	**18.6**	**15.6**	**1.0**	**7%**	**81**
DO	Agriculture, Mining & Construction	[redacted]						93
DO	Manufacturing	[redacted]						92
DO	Wholesale, Transport, other Utilities	43	127.2	95.8	5.5	4.1	75%	92
DO	Retail Stores	526	132.2	19.3	69.5	10.2	15%	86
DO	Offices, Hotels, Finance, Services	78	210.7	19.5	16.4	1.5	9%	81
DO	Schools	[redacted]						93
DO	Institutional/Government	[redacted]						77
DO	**Total DO**	**670**	**151.8**	**24.5**	**101.7**	**16.4**	**16%**	**87**
Total CBP		**725**	**161.9**	**24.0**	**117.4**	**17.4**	**15%**	**86**

[19] The results in Table 4-15 and Table 4-16 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual industry segments (or LCAs). This is because different group of customers are called for each event, and in some cases, no customers in an industry segment (or LCA) may be called. So the average for that industry segment (or LCA) will reflect only those events where customers in that industry segment (or LCA) were called. But the total program is the average across all events, since some customers in the program were called for every event. Because the total program and the individual industry segments (or LCAs) are averaged across different events, the total program does not exactly match the sum of the individual industry segments (or LCAs).

Table 4-16 SCE CBP Impacts by LCA and Notice

	LCA	# of Accts	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load	Aggregate Impact (MW) Impact	% Impact	Event Temp (˚F)
DA	LA Basin	37	357.4	17.2	13.2	0.6	5%	79
DA	Outside LA Basin	[redacted]						89
DA	Ventura / Big Creek							91
DA	**Total DA**	**55**	**284.5**	**18.6**	**15.6**	**1.0**	**7%**	**81**
DO	LA Basin	509	196.9	30.4	100.2	15.5	15%	85
DO	Outside LA Basin	43	213.0	43.0	9.2	1.8	20%	91
DO	Ventura / Big Creek	118	166.2	30.5	19.6	3.6	18%	88
DO	**Total DO**	**670**	**151.8**	**24.5**	**101.7**	**16.4**	**16%**	**87**
Total CBP		**725**	**161.9**	**24.0**	**117.4**	**17.4**	**15%**	**86**

Table 4-17 to Table 4-22 show the average event day impacts for two additional geographical areas in SCE's service territory: South of Lugo and Southern Orange County. Please note that there were no participants in the CBP DA 2-6 product in either area. The CBP DO 1-4 hour product participants in the South of Lugo area achieved a maximum load impact of 5.1 MW on June 8, 2015. The CBP DO 1-4 Hour product participants in South Orange County achieve a maximum load impact of 2.3 MW on October 9 and 13, 2015.

Table 4-17 South of Lugo Event Day Impacts: CBP DO 1-4 Hour

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load.	Aggregate Impact (MW) Impact	% Impact	Temp (˚F)
11/6/2014	[redacted]						86
6/8/2015	185	200.7	27.7	37.1	5.1	14%	89
6/9/2015	185	203.2	26.2	37.6	4.8	13%	88
6/25/2015	185	202.4	26.1	37.4	4.8	13%	86
6/26/2015	185	204.7	24.3	37.9	4.5	12%	85
6/29/2015	185	204.7	22.1	37.9	4.1	11%	84
6/30/2015	185	200.5	25.1	37.1	4.6	13%	87
7/1/2015	168	137.9	22.2	23.2	3.7	16%	83
7/2/2015	168	146.3	26.3	24.6	4.4	18%	87
7/28/2015	168	146.3	25.3	24.6	4.2	17%	89
7/29/2015	168	148.3	24.9	24.9	4.2	17%	90
7/30/2015	168	151.7	25.4	25.5	4.3	17%	86
7/31/2015	168	150.5	27.1	25.3	4.6	18%	94
8/6/2015	148	151.1	25.4	22.4	3.8	17%	91
8/13/2015	148	162.2	24.3	24.0	3.6	15%	88
8/14/2015	40	145.5	22.9	5.8	0.9	16%	91
8/17/2015	148	165.0	27.4	24.4	4.1	17%	90
8/26/2015	148	175.8	26.8	26.0	4.0	15%	96
8/27/2015	148	175.3	24.8	25.9	3.7	14%	98
8/28/2015	148	174.3	26.0	25.8	3.9	15%	90
9/8/2015	147	175.6	26.6	25.8	3.9	15%	94

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
9/9/2015	147	174.9	26.3	25.7	3.9	15%	94
9/10/2015	147	177.2	26.6	26.0	3.9	15%	86
9/11/2015	147	174.4	28.0	25.6	4.1	16%	91
9/24/2015	147	168.4	24.0	24.8	3.5	14%	83
9/25/2015	147	168.4	25.1	24.8	3.7	15%	77
9/28/2015	147	164.7	23.5	24.2	3.5	14%	87
9/29/2015	40	145.4	19.2	5.8	0.8	13%	97
10/8/2015	149	169.7	24.6	25.3	3.7	15%	91
10/9/2015	149	180.2	25.6	26.9	3.8	14%	84
10/12/2015	149	169.2	25.4	25.2	3.8	15%	83
10/13/2015	149	168.8	25.3	25.2	3.8	15%	77
10/14/2015	149	168.7	24.8	25.1	3.7	15%	74
10/15/2015	149	157.5	25.3	23.5	3.8	16%	79
10/16/2015	149	163.7	24.4	24.4	3.6	15%	77
10/26/2015	149	156.9	24.2	23.4	3.6	15%	73
10/27/2015	149	156.0	24.8	23.2	3.7	16%	76
10/28/2015	149	154.3	24.8	23.0	3.7	16%	77
10/29/2015	149	156.4	24.8	23.3	3.7	16%	74
10/30/2015	149	162.2	24.9	24.2	3.7	15%	75

Table 4-18 South of Lugo Event Day Impacts: CBP DO 2-6 Hour

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.							

Table 4-19 South of Lugo Event Day Impacts: CBP DA 1-4 Hour

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
11/7/2014	50	321.2	22.6	16.1	1.1	7%	80
11/13/2014	50	312.1	22.6	15.6	1.1	7%	64
Remaining events redacted to protect customer or aggregator confidentiality.							

Table 4-20 South Orange County Event Day Impacts: CBP DO 1-4 Hour

		Per Customer Impact (kW)		Aggregate Impact (MW)			Temp
Event	# of Accts	Ref. Load	Impact	Ref. Load.	Impact	% Impact	(˚F)
11/6/2014	55	118.2	19.4	6.5	1.1	16%	80
6/8/2015	77	151.5	21.7	11.7	1.7	14%	79
6/9/2015	77	165.3	22.2	12.7	1.7	13%	82
6/25/2015	77	153.2	22.6	11.8	1.7	15%	74
6/26/2015	77	154.0	20.9	11.9	1.6	14%	75
6/29/2015	77	134.0	15.8	10.3	1.2	12%	74
6/30/2015	77	157.7	21.8	12.1	1.7	14%	78
7/1/2015	75	160.3	20.4	12.0	1.5	13%	74
7/2/2015	75	165.0	21.8	12.4	1.6	13%	75
7/28/2015	75	160.6	20.2	12.0	1.5	13%	76
7/29/2015	75	164.7	20.8	12.3	1.6	13%	76
7/30/2015	75	162.2	20.9	12.2	1.6	13%	77
7/31/2015	75	165.6	21.6	12.4	1.6	13%	79
8/6/2015	68	173.1	21.4	11.8	1.5	12%	75
8/13/2015	68	169.8	17.2	11.5	1.2	10%	85
8/14/2015	67	199.9	22.1	13.4	1.5	11%	89
8/17/2015	68	185.8	21.7	12.6	1.5	12%	77
8/26/2015	68	179.2	19.6	12.2	1.3	11%	85
8/27/2015	68	190.5	20.4	13.0	1.4	11%	84
8/28/2015	68	196.6	21.6	13.4	1.5	11%	87
9/8/2015	67	187.6	20.9	12.6	1.4	11%	92
9/9/2015	67	202.8	21.9	13.6	1.5	11%	88
9/10/2015	67	204.1	21.8	13.7	1.5	11%	88
9/11/2015	67	205.3	22.0	13.8	1.5	11%	86
9/24/2015	67	177.8	15.0	11.9	1.0	8%	80
9/25/2015	67	184.9	19.4	12.4	1.3	10%	82
9/28/2015	67	175.8	14.6	11.8	1.0	8%	77
9/29/2015	66	174.0	15.1	11.5	1.0	9%	76
10/8/2015	78	169.2	23.5	13.2	1.8	14%	78
10/9/2015	78	191.2	30.1	14.9	2.3	16%	97
10/12/2015	78	170.2	27.6	13.3	2.2	16%	90
10/13/2015	78	184.1	29.1	14.4	2.3	16%	81
10/14/2015	78	185.1	27.7	14.4	2.2	15%	80
10/15/2015	78	175.1	27.4	13.7	2.1	16%	74
10/16/2015	78	172.0	23.5	13.4	1.8	14%	73
10/26/2015	78	154.2	23.0	12.0	1.8	15%	76
10/27/2015	78	149.5	23.2	11.7	1.8	16%	72
10/28/2015	78	162.6	23.5	12.7	1.8	14%	72

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
10/29/2015	78	159.8	24.1	12.5	1.9	15%	76
10/30/2015	78	160.6	24.1	12.5	1.9	15%	73

Table 4-21 South Orange County Event Day Impacts: CBP DO 2-6 Hour

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.							

Table 4-22 South Orange County Event Day Impacts: CBP DA 1-4 Hour

Event	# of Accts	Per Customer Impact (kW) Ref. Load	Impact	Aggregate Impact (MW) Ref. Load.	Impact	% Impact	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.							

Hourly Load Impacts

Figure 4-5 through Figure 4-8 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each of the SCE CBP products on an average summer event day. The event window is hour-ending 16 to hour-ending 19 and is highlighted light grey in each Figure. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-5 SCE CBP Day-Of 1-4 Hour: Average Hourly Per-Customer Impact, 2015

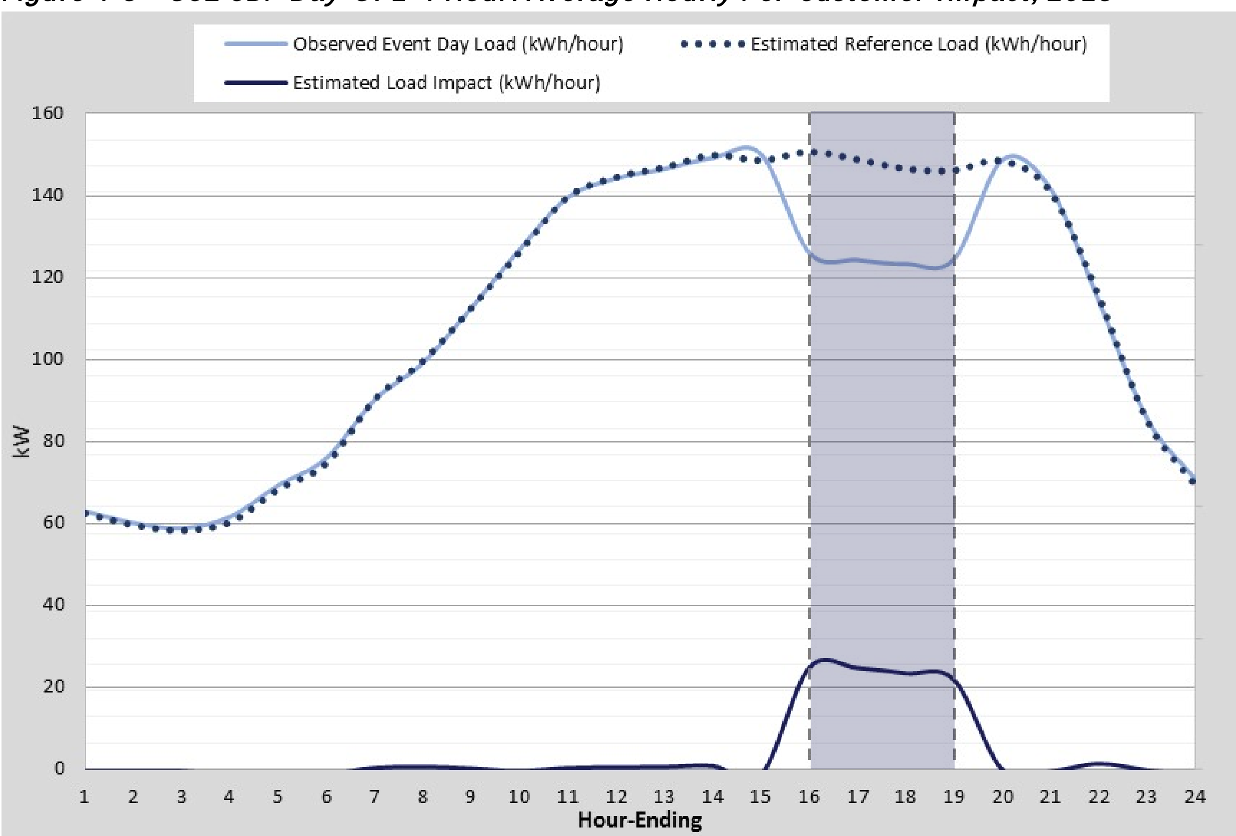


Figure 4-6 SCE CBP Day-Of 2-6 Hour: Average Hourly Per-Customer Impact, 2015

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-7 SCE CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2015

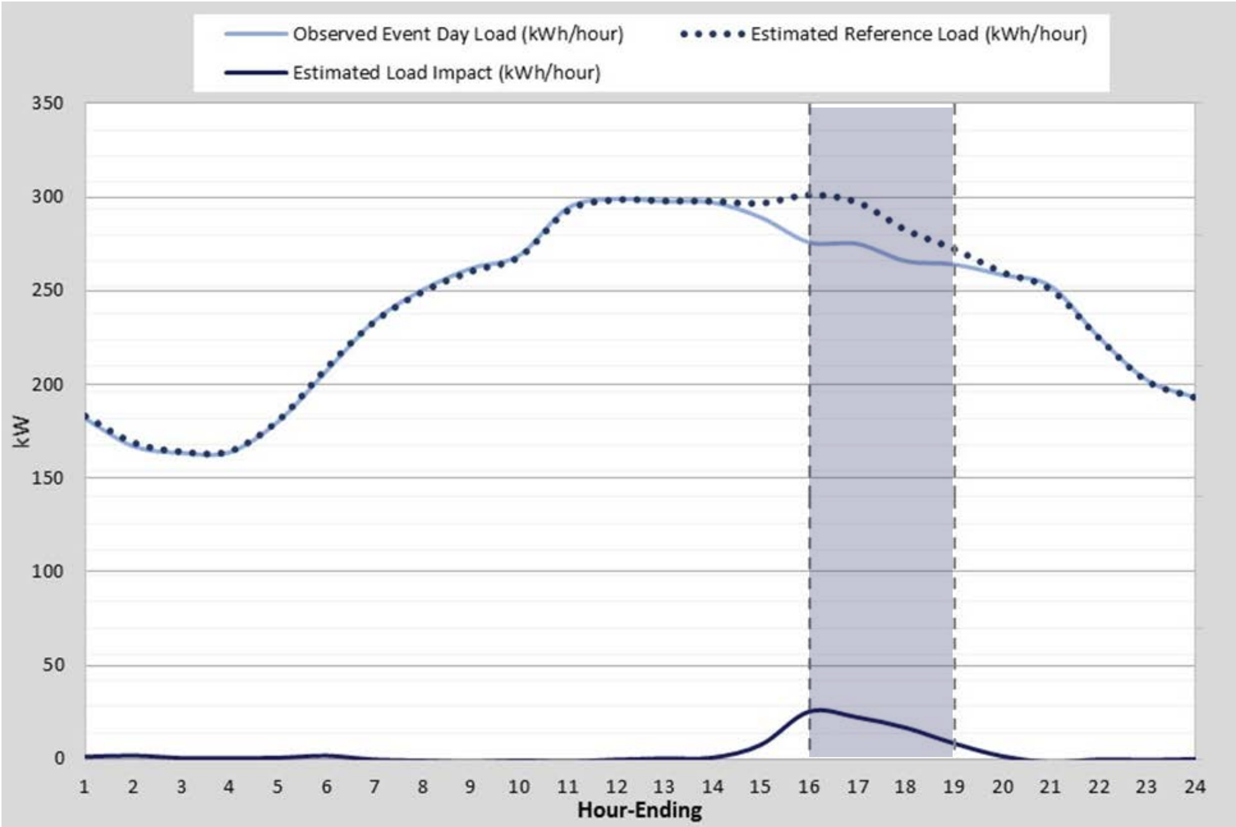


Figure 4-8 SCE CBP Day-Ahead 2-6 Hour: Average Hourly Per-Customer Impact, 2015

Figure redacted to protect customer or aggregator confidentiality.

Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved by SCE CBP customers that participated in TA/TI or AutoDR at some point in the current or previous years. In this section, as in the previous section, we present two sets of impacts: 1) the ex-post impacts for this subgroup, and 2) the incremental impacts achieved by the subgroup over similar program participants. Only DO 1-4 hour and DA 1-4 hour products had TA/TI or AutoDR participants in 2015.

In Table 4-23 to Table 4-24 below we present the event day ex-post impacts and aggregate load shed test results for the AutoDR and TA/TI participants by product. The participants in the Day of product with 1-4 hour notification had a maximum load reduction of 2.1 MW in aggregate, which represented a 25% reduction over their reference load. On average, the aggregate ex-post impacts are lower than the aggregate load shed test results representing between 31% and 85% of the potential load shed depending on the event day in question.

Table 4-23 SCE CBP Day-Of 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Event Hrs (HE)	Number of Accts	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
11/6/2014	18-19	[redacted]							74
6/8/2015	15-18	74	110.8	27.5	8.2	2.0	25%	2.5	87
6/9/2015	15-18	74	103.8	27.4	7.7	2.0	26%	2.5	81
6/18/2015	17-19	[redacted]							94
6/25/2015	16-19	74	113.6	28.2	8.4	2.1	25%	2.5	84
6/26/2015	17-19	74	116.2	25.8	8.6	1.9	22%	2.5	83
6/29/2015	19-19	74	110.4	21.6	8.2	1.6	20%	2.5	82
6/30/2015	16-19	74	112.1	25.9	8.3	1.9	23%	2.5	81
7/1/2015	16-19	81	103.2	18.2	7.2	1.3	18%	2.4	79
7/2/2015	17-18	74	113.0	27.6	7.9	1.9	24%	2.4	83
7/22/2015	16-16	[redacted]							77
7/28/2015	17-19 18-18 18-19	12	122.5	26.8	8.9	2.0	22%	2.5	84
7/29/2015	17-19	74	120.0	25.7	8.8	1.9	21%	2.5	82
7/30/2015	17-18	74	118.8	24.3	8.7	1.8	20%	2.5	85
7/31/2015	17-17	74	127.4	29.3	9.3	2.1	23%	2.5	86
8/6/2015	17-17 17-18	[redacted]							86
8/13/2015	18-19	70	103.3	24.1	7.4	1.7	23%	2.5	88
8/14/2015	17-17 17-18 18-18	70	143.1	25.6	5.7	1.0	18%	1.4	97
8/17/2015	17-18	7	127.3	27.2	9.2	2.0	21%	2.5	83
8/26/2015	16-19 17-19	[redacted]							88
8/27/2015	18-19 19-19	[redacted]							88
8/28/2015	17-19 18-19	73	129.4	26.9	9.3	1.9	21%	2.5	89
9/8/2015	16-19	73	127.2	28.5	9.2	2.0	22%	2.5	91
9/9/2015	16-19	72	133.8	28.7	9.6	2.1	21%	2.5	87
9/10/2015	16-19	72	134.5	28.4	9.7	2.0	21%	2.5	90
9/11/2015	15-18 16-19	40	134.9	29.1	9.7	2.1	22%	2.5	90
9/24/2015	19-19	72	113.6	21.9	8.2	1.6	19%	2.5	83
9/25/2015	18-19	72	122.9	26.8	8.8	1.9	22%	2.5	86
9/28/2015	19-19	72	109.1	20.5	7.7	1.5	19%	2.4	79
9/29/2015	19-19	72	124.0	18.7	4.8	0.7	15%	1.4	77
10/8/2015	19-19	72	112.0	22.1	8.1	1.6	20%	2.5	83
10/9/2015	17-19 18-19	[redacted]							92
10/12/2015	16-19 17-19	[redacted]							87

Event	Event Hrs (HE)	Number of Accts	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
10/13/2015	16-19 17-19	72	109.2	24.9	7.9	1.8	23%	2.5	83
10/14/2015	18-19	72	106.3	27.3	7.7	2.0	26%	2.5	80
10/15/2015	18-19 19-19	[redacted]							73
10/16/2015	19-19	71	108.9	21.8	7.8	1.6	20%	2.5	72
10/26/2015	19-19	39	108.6	22.3	8.4	1.7	21%	2.7	76
10/27/2015	19-19	72	109.8	22.6	8.5	1.7	21%	2.7	74
10/28/2015	19-19	72	108.0	22.6	8.3	1.7	21%	2.7	71
10/29/2015	19-19	72	103.9	22.2	7.6	1.6	21%	2.5	73
10/30/2015	19-19	72	107.4	22.7	8.3	1.7	21%	2.7	74

Table 4-24 SCE CBP Day-Ahead 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Event Hrs (HE)	Number of Accounts	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.									

Incremental Load Impacts of TA/TI and AutoDR Participants

In addition to presenting the ex-post impacts for the subgroup, we also estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with group of similar non-enabled participants. First, we selected a group of CBP participants that are similar to the AutoDR and TA/TI participants, but did not participate in Auto-DR or TATI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID). We describe both the Euclidean Distance and DID methodology in the PG&E CBP Section: Incremental Load Impacts of TA/TI and AutoDR Participants.

In Figure 4-9 below we show the treatment and control-group match on an average event day. The graph shows the reference load profile of each group for the overall CBP program. There are a total of 72 Auto-DR participants, and a total of 72 control group matches. Unfortunately we were unable to create a matched control group for the CBP DA 1-4 hour product because there were not enough potential matches for each participant within their industry and product. Therefore, we only show the statistically significant findings for the CBP DO 1-4 hour Product.

Figure 4-9 SCE CBP DO 1-4 Hour AutoDR and TA/TI Event Day Match

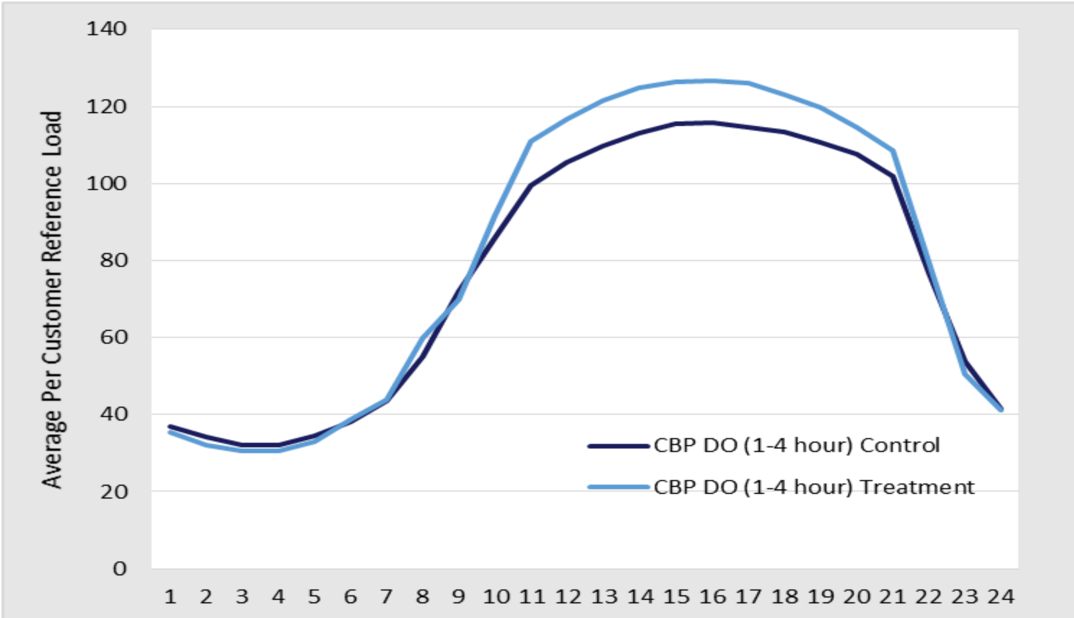


Figure 4-10 and accompanying Table 4-25 present the incremental impacts at the program level. The figure shows the average per-customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. As we would expect, the incremental impacts are very small, and often insignificant during non-event hours. However, during the HE16 to HE19 event window, we do see significant incremental impacts of approximately 10 kW per enabled customer.

Figure 4-10 presents the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants. On an average event day, each participant saved an additional 9.76 kW over a similar non-enabled customer, and in aggregate they saved an additional 0.70 MW over similar non-enabled customers.

Figure 4-10 SCE CBP AutoDR and TA/TI Average Event Day Incremental Impacts

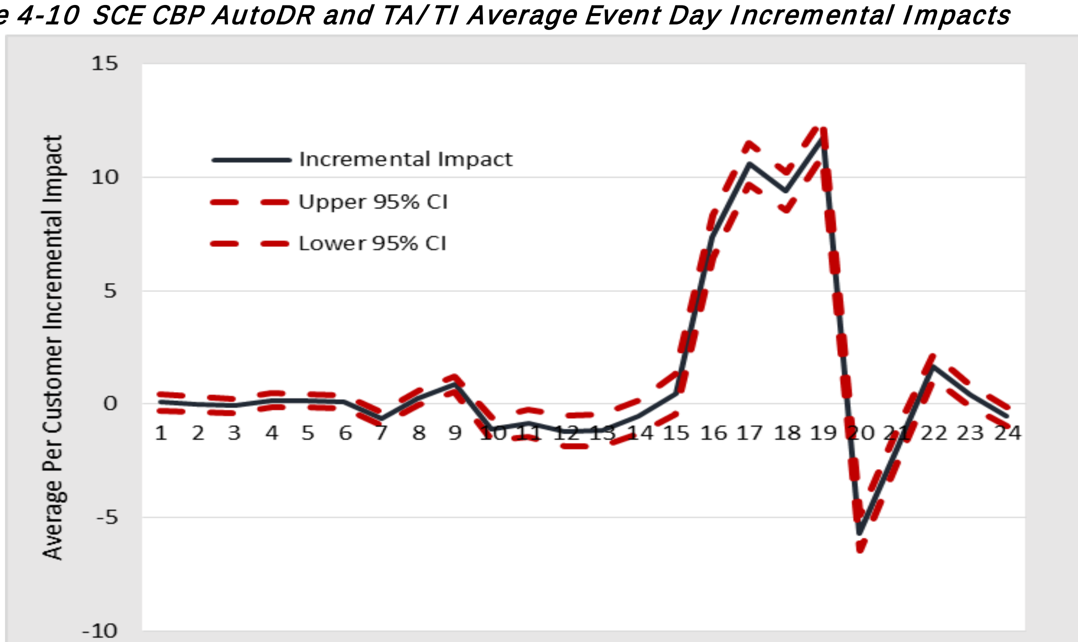


Table 4-25 SCE CBP Program Level Incremental AutoDR and TA/TI Impacts

Program	Number of Customers	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate(MW)	Significant
CBP DO 1-4 Hour	72	9.76	0.70	Yes

SDG&E

Events for SDG&E CBP

Table 4-26 below presents a summary of the 2015 events for SDG&E's CBP program by product. The table includes the definition of an average event day. The DO participants experienced a total of 24 events over the course of the program year, while DA participants experienced 42 events. Typical events were those called during hours-ending 16-19. For the DA product, approximately 70 accounts under a single aggregator were removed from the total number of accounts beginning in August of 2015 due to the fact that they changed their nomination to 0 MW for the remainder of the year.

Table 4-26 SDG&E CBP Event Summary

Date	Day of Week	Event Hours (HE)	# Accounts DO 1-4 Hour	# Accounts DO 2-6 Hour	# Accounts DA 1-4 Hour
Avg. Event	-	16-19	160	63	122
5/1/2015	Friday	16-19	173	70	123
6/9/2015	Tuesday	16-19	194	70	131
6/16/2015	Tuesday	16-19	-	-	131
6/17/2015	Wednesday	16-19	-	-	131
6/22/2015	Monday	16-19	-	-	131
6/24/2015	Wednesday	16-19	194	70	131
6/25/2015	Thursday	16-19	194	70	131
6/26/2015	Friday	16-19	194	70	131
6/29/2015	Monday	16-19	194	70	-
6/30/2015	Tuesday	16-19	194	70	131
7/1/2015	Wednesday	16-19	168	70	130
7/16/2015	Thursday	16-19	-	-	130
7/28/2015	Tuesday	16-19	-	-	130
7/29/2015	Wednesday	16-19	168	70	-
7/30/2015	Thursday	16-19	-	-	130
7/31/2015	Friday	16-19	-	-	130
8/5/2015	Wednesday	16-19	156	60	-
8/6/2015	Thursday	16-19	-	-	61
8/11/2015	Tuesday	16-19	-	-	61
8/12/2015	Wednesday	15-18	-	-	61
8/13/2015	Thursday	16-19	156	60	61
8/21/2015	Friday	15-18	-	-	61
8/25/2015	Tuesday	16-19	156	60	61
8/26/2015	Wednesday	16-19	156	60	61
8/27/2015	Thursday	16-19	156	60	61
8/28/2015	Friday	16-19	156	60	61
9/8/2015	Tuesday	16-19	155	60	-
9/9/2015	Wednesday	16-19	155	60	59
9/10/2015	Thursday	16-19	155	60	59
9/11/2015	Friday	16-19	155	60	59
9/21/2015	Monday	16-19	155	60	-
9/23/2015	Wednesday	16-19	-	-	59
9/24/2015	Thursday	16-19	-	-	59
9/25/2015	Friday	16-19	-	-	59
9/29/2015	Tuesday	16-19	-	-	59
9/30/2015	Wednesday	16-19	-	-	59
10/8/2015	Thursday	16-19	-	-	58
10/9/2015	Friday	16-19	158	60	58
10/12/2015	Monday	16-19	158	60	58
10/13/2015	Tuesday	16-19	158	60	58
10/14/2015	Wednesday	16-19	158	60	58
10/21/2015	Wednesday	16-19	-	-	58
10/22/2015	Thursday	16-19	-	-	58
10/23/2015	Friday	16-19	-	-	58
10/27/2015	Tuesday	16-19	-	-	58
10/28/2015	Wednesday	16-19	-	-	58
10/30/2015	Friday	16-19	-	-	58

Summary Load Impacts

Table 4-27 to Table 4-29 show the average event-hour impacts for each event, for each product, both at the average per-customer level and in aggregate. The tables include results for the average event day.

In Table 4-27 immediately below, we present the average event-hour impacts for the CBP DO 1-4 hour participants. Of the three products offered under SDG&E's CBP, the DO 1-4 has the most participants. The highest per-customer impacts (31.6 kW) and highest overall aggregate impacts (4.9 MW) occurred during the event on September 10, 2015. The impacts represent a 15% reduction over the reference load and a total of 155 nominated service accounts. The lowest impacts occurred during the first event which was on May 1, 2015 when impacts of only 11.3 kW (per-customer) and 2 MW (aggregate) were achieved.

Table 4-27 SDG&E CBP Day-Of 1-4 Hour: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	160	4.4	182.8	21.9	29.2	3.5	12%	81
5/1/2015	173	2.9	110.6	11.3	19.1	2.0	10%	76
6/9/2015	193	4.7	144.8	16.0	27.9	3.1	11%	70
6/24/2015	193	4.7	151.6	14.5	29.3	2.8	10%	76
6/25/2015	193	4.7	147.2	15.1	28.4	2.9	10%	74
6/26/2015	193	4.7	144.5	15.4	27.9	3.0	11%	74
6/29/2015	193	4.7	154.0	16.1	29.7	3.1	10%	74
6/30/2015	193	4.7	159.2	15.8	30.7	3.1	10%	81
7/1/2015	168	4.4	167.8	18.3	28.2	3.1	11%	76
7/29/2015	168	4.4	158.1	17.4	26.6	2.9	11%	76
8/5/2015	156	4.4	189.1	19.9	29.5	3.1	11%	80
8/13/2015	156	4.4	198.2	21.2	30.9	3.3	11%	82
8/25/2015	156	4.4	174.1	17.2	27.2	2.7	10%	78
8/26/2015	156	4.4	190.2	22.1	29.7	3.4	12%	84
8/27/2015	156	4.4	197.4	23.2	30.8	3.6	12%	87
8/28/2015	156	4.4	202.7	26.5	31.6	4.1	13%	90
9/8/2015	155	3.6	192.5	27.4	29.8	4.2	14%	88
9/9/2015	155	3.6	204.8	30.7	31.8	4.8	15%	94
9/10/2015	155	3.6	218.0	31.6	33.8	4.9	15%	90
9/11/2015	155	3.6	194.0	23.8	30.1	3.7	12%	84
9/21/2015	155	3.6	176.1	24.1	27.3	3.7	14%	78
10/9/2015	158	2.8	195.1	27.6	30.8	4.4	14%	95
10/12/2015	158	2.8	194.1	28.5	30.7	4.5	15%	88
10/13/2015	158	2.8	193.3	26.6	30.5	4.2	14%	82
10/14/2015	158	2.8	188.0	23.2	29.7	3.7	12%	80

In Table 4-28 we present the average event-hour impacts for the CBP DO 2-6 hour participants. In this case, the highest per-customer impacts occurred during August, with a maximum per-customer impact of 40.5 kW on August 5, 2015 representing 60 service accounts and an average 14% reduction over the reference load. The largest aggregate impacts occurred on June 26, 2015 at 2.7 MW representing a total of 70 service accounts and a 15% reduction over the reference load. The lowest impacts occurred on May 1, 2015. On that day 70 service accounts provided a total of 1.1 MW of load reduction.

Table 4-28 SDG&E CBP Day-Of 2-6 Hour: Impacts by Event

			Per Customer Impact (kW)		Aggregate Impact (MW)			
Event	# of Accts	Nominated Capacity (MW)	Reference Load	Impact	Reference Load	Impact	% Impact	Temp (˚F)
Avg. Event	63	1.7	273.3	34.8	17.2	2.2	13%	82
5/1/2015	70	2.2	188.5	15.9	13.2	1.1	8%	76
6/9/2015	70	2.0	236.6	33.6	16.6	2.3	14%	71
6/24/2015	70	2.0	249.9	37.7	17.5	2.6	15%	76
6/25/2015	70	2.0	247.9	37.8	17.4	2.6	15%	74
6/26/2015	70	2.0	252.7	38.1	17.7	2.7	15%	74
6/29/2015	70	2.0	249.4	37.0	17.5	2.6	15%	74
6/30/2015	70	2.0	260.3	35.3	18.2	2.5	14%	81
7/1/2015	70	2.0	240.6	25.9	16.8	1.8	11%	76
7/29/2015	70	2.0	246.4	35.1	17.2	2.5	14%	76
8/5/2015	60	1.7	297.9	40.5	17.9	2.4	14%	80
8/13/2015	60	1.7	278.1	38.2	16.7	2.3	14%	82
8/25/2015	60	1.7	276.0	40.3	16.6	2.4	15%	78
8/26/2015	60	1.7	276.7	36.1	16.6	2.2	13%	84
8/27/2015	60	1.7	274.9	34.7	16.5	2.1	13%	88
8/28/2015	60	1.7	281.7	33.7	16.9	2.0	12%	90
9/8/2015	60	1.7	283.5	33.0	17.0	2.0	12%	88
9/9/2015	60	1.7	279.8	31.3	16.8	1.9	11%	94
9/10/2015	60	1.7	296.9	31.8	17.8	1.9	11%	90
9/11/2015	60	1.7	289.2	32.9	17.4	2.0	11%	84
9/21/2015	60	1.7	288.9	39.6	17.3	2.4	14%	78
10/9/2015	60	1.7	306.8	33.6	18.4	2.0	11%	95
10/12/2015	60	1.7	302.8	34.9	18.2	2.1	12%	88
10/13/2015	60	1.7	311.9	36.0	18.7	2.2	12%	82
10/14/2015	60	1.7	308.1	35.2	18.5	2.1	11%	80

Table 4-29 presents the average event-hour impacts for the CBP DA 1-4 hour participants.[20] The highest per-customer impacts and aggregate impacts occurred in August, with a maximum per-customer impact of 148.7 kW and 9.1 MW on August 12, 2015 representing 61 service accounts and an average 55% reduction over the reference load. The lowest impacts occurred on October 30, 2015. On that day 58 service accounts provided a total of [redacted] of load reduction.

[20] It is important to note that approximately 70 accounts under a single aggregator were removed from the analysis beginning in August of 2015 due to the fact that they changed their nomination to 0 MW for the remainder of the year.

Table 4-29 SDG&E CBP Day-Ahead 1-4 Hour: Impacts by Event

			Per Customer Impact (kW)		Aggregate Impact (MW)			
Event	# of Accts	Nominated Capacity (MW)	Reference Load	Impact	Reference Load	Impact	% Impact	Temp (˚F)
Avg. Event	122	7.3	148.0	64.1	18.1	7.8	43%	80
5/1/2015	[redacted]							76
6/9/2015	[redacted]							70
6/16/2015	[redacted]							70
6/17/2015	[redacted]							73
6/22/2015	[redacted]							76
6/24/2015	[redacted]							75
6/25/2015	[redacted]							74
6/26/2015	[redacted]							73
6/30/2015	[redacted]							81
7/1/2015	[redacted]							75
7/16/2015	[redacted]							74
7/28/2015	[redacted]							75
7/30/2015	[redacted]							76
7/31/2015	[redacted]							76
8/6/2015	61	7.3	249.0	130.6	15.2	8.0	52%	77
8/11/2015	61	7.3	242.9	137.0	14.8	8.4	56%	74
8/12/2015	61	7.3	270.1	148.7	16.5	9.1	55%	81
8/13/2015	61	7.3	242.8	129.1	14.8	7.9	53%	83
8/21/2015	61	7.3	263.1	137.2	16.0	8.4	52%	77
8/25/2015	61	7.3	247.4	130.8	15.1	8.0	53%	79
8/26/2015	[redacted]							85
8/27/2015	61	7.3	244.7	125.3	14.9	7.6	51%	89
8/28/2015	61	7.3	260.8	123.1	15.9	7.5	47%	91
9/9/2015	59	7.3	245.1	124.2	14.5	7.3	51%	95
9/10/2015	59	7.3	231.9	118.4	13.7	7.0	51%	91
9/11/2015	59	7.3	230.9	121.1	13.6	7.1	52%	86
9/23/2015	59	7.3	236.1	132.1	13.9	7.8	56%	79
9/24/2015	59	7.3	245.6	131.5	14.5	7.8	54%	83
9/25/2015	[redacted]							84
9/29/2015	59	7.3	231.9	132.1	13.7	7.8	57%	79
9/30/2015	59	7.3	242.1	134.1	14.3	7.9	55%	81
10/8/2015	[redacted]							81
10/9/2015	[redacted]							96
10/12/2015	58	7.1	253.9	123.7	14.7	7.2	49%	89
10/13/2015	58	7.1	248.3	125.8	14.4	7.3	51%	83
10/14/2015	58	7.1	298.3	129.7	17.3	7.5	43%	81
10/21/2015	58	7.1	239.9	139.3	13.9	8.1	58%	74
10/22/2015	58	7.1	234.8	139.0	13.6	8.1	59%	74
10/23/2015	58	7.1	230.6	140.5	13.4	8.2	61%	75
10/27/2015	[redacted]							78
10/28/2015	58	7.1	229.6	141.4	13.3	8.2	62%	76
10/30/2015	[redacted]							78

Table 4-30 presents the impacts for an average event day by industry group.[21] Manufacturing has the highest aggregate impacts for DA events while Retail Stores have the highest aggregate impacts for the DO events. For DA events, Manufacturing has an average per-customer impact of [redacted] and a total aggregate load reduction of [redacted] with only 5 accounts called. In addition, the percent impact is [redacted] for Manufacturing during DA events. For DO events, Manufacturing also has the largest per customer impacts at [redacted] representing only 2 account called and a [redacted] reduction over the reference load. Agriculture, Mining & Construction has the most dramatic percent load impact, with [redacted] of the reference load reduced during DO events.

Table 4-30 SDG&E CBP Impacts by Industry and Notice

			Per Customer Impact (kW)		Aggregate Impact (MW)			Event
	Industry	# of Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (˚F)
DA	Manufacturing	[redacted]						
DA	Wholesale, Transport, other Utilities	[redacted]						
DA	Retail Stores	[redacted]						
DA	Offices, Hotels, Finance, Services	69	67.4	1.3	4.7	0.1	2%	78
DA	Schools	27	42.8	0.8	1.2	0.0	2%	81
DA	Institutional/Government	[redacted]						
DA	**Total DA**	**122**	**148.0**	**64.1**	**18.1**	**7.8**	**43%**	**80**
DO	Agriculture, Mining & Construction	[redacted]						
DO	Manufacturing	[redacted]						
DO	Retail Stores	201	194.1	20.9	39.0	4.2	11%	82
DO	Offices, Hotels, Finance, Services	[redacted]						
DO	Institutional/Government	[redacted]						
DO	Other or unknown	[redacted]						
DO	**Total DO**	**223**	**208.4**	**25.6**	**46.5**	**5.7**	**12%**	**82**
Total CBP		**345**	**187.0**	**39.2**	**64.5**	**13.5**	**21%**	**81**

Hourly Load Impacts

Figure 4-11 through Figure 4-13 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each of the SDG&E CBP products on an average event day. The event window is hour-ending 16 to hour-ending 19 and is highlighted light grey in each figure. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

[21] SDG&E's service territory is classified as a single LCA so we have only included a subgroup comparison by industry type.

Figure 4-11 SDG&E CBP Day-Of 1-4 Hour: Average Hourly Per-Customer Impact, 2015

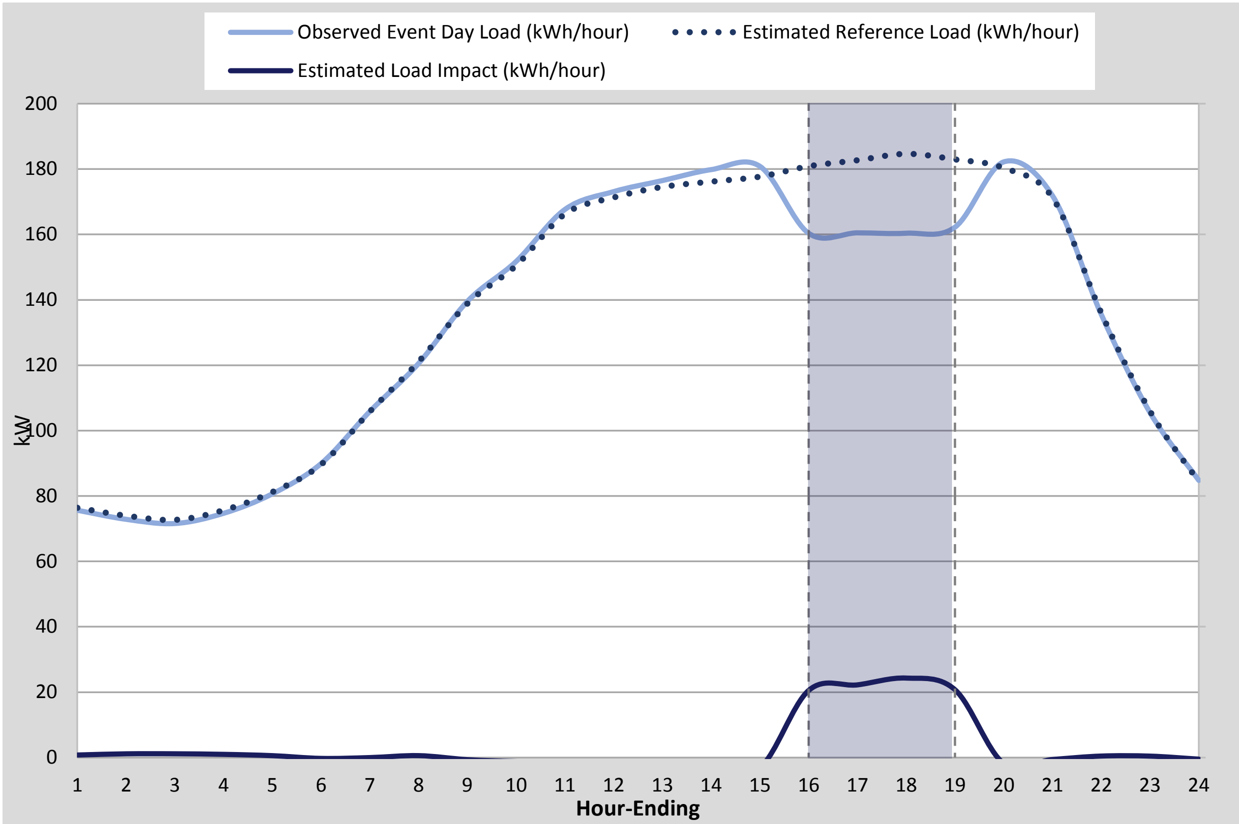


Figure 4-12 SDG&E CBP Day-Of 2-6 Hour: Average Hourly Per-Customer Impact, 2015

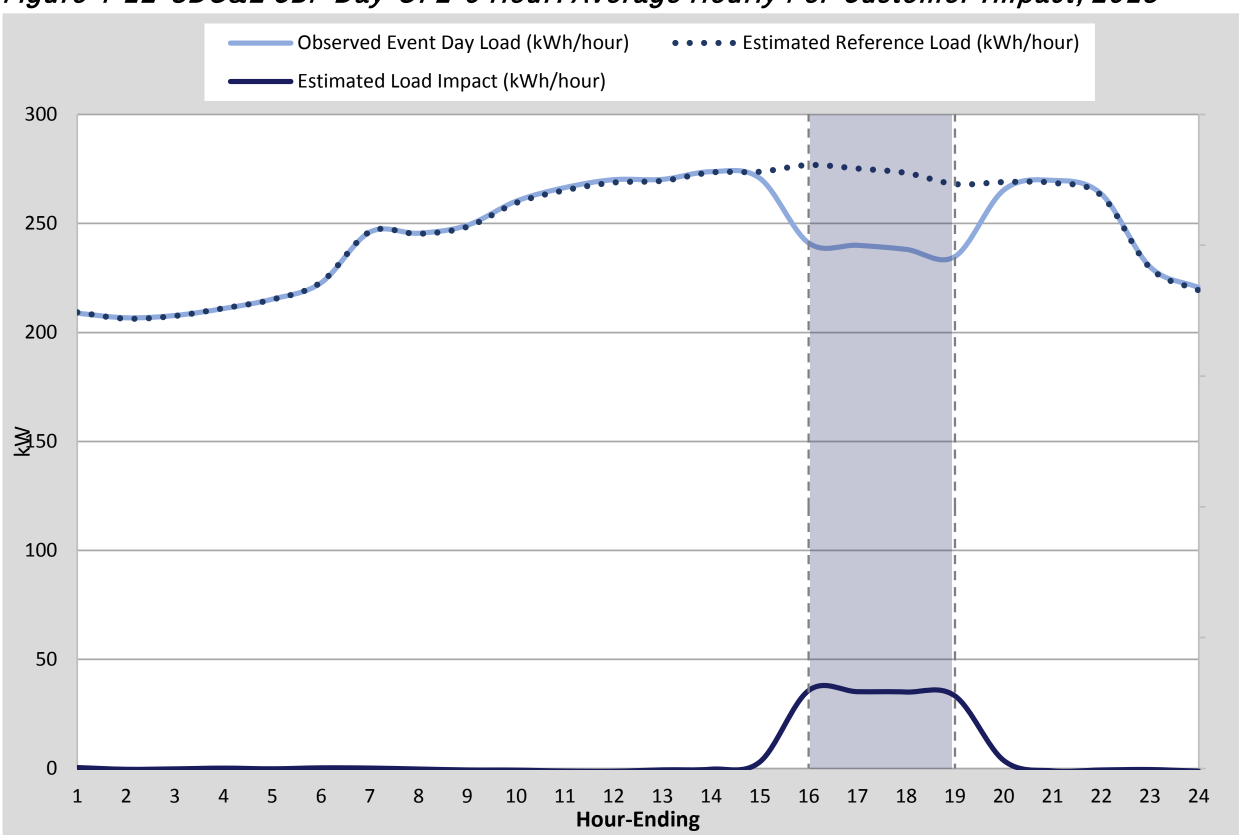
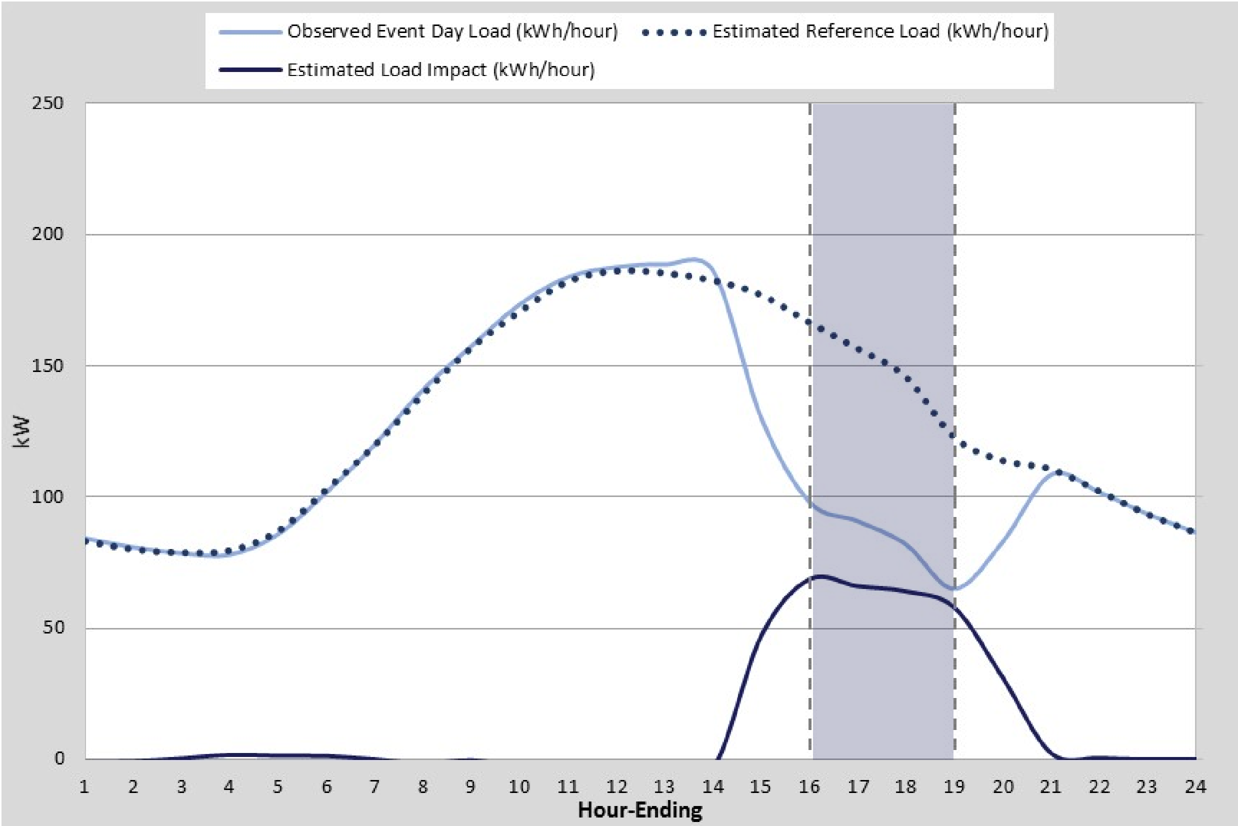


Figure 4-13 SDG&E CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2015



Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved by SDG&E CBP customers that participated in TA/TI or AutoDR at some point in the current or previous years. In this section, as in the previous section, we present two sets of impacts: 1) the ex-post impacts for this subgroup, and 2) the incremental impacts achieved by the subgroup over similar program participants.

Table 4-31 presents the average event-hour impacts and aggregate load shed test results for the CBP DO 1-4 hour participants. The largest percent impact (13%) occurred on October 9, 2015. On average, the aggregate ex-post impacts are slightly higher than the aggregate load shed test results representing between 81% and 147% of the potential load shed depending on the event day in question.

Table 4-31 SDG&E CBP Day-Of 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Number of Accts	Per Customer Impact (kW) Reference Load	Impact	Aggregate Impact (MW) Reference Load	Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
5/1/2015	74	116.3	14.0	8.6	1.0	12%	1.2	76
6/9/2015	76	158.5	17.9	12.0	1.4	11%	1.2	70
6/24/2015	85	162.4	14.9	13.8	1.3	9%	1.2	76
6/25/2015	85	152.7	15.9	13.0	1.3	10%	1.2	74
6/26/2015	85	158.4	16.4	13.5	1.4	10%	1.2	74
6/29/2015	85	157.4	16.8	13.4	1.4	11%	1.2	74
6/30/2015	85	160.0	16.8	13.6	1.4	11%	1.2	81
7/1/2015	72	172.9	19.0	12.4	1.4	11%	1.0	76
7/29/2015	72	178.1	17.9	12.8	1.3	10%	1.0	76
8/5/2015	61	217.0	19.8	13.2	1.2	9%	1.2	80
8/13/2015	61	221.5	21.4	13.5	1.3	10%	1.2	82
8/25/2015	61	195.1	18.0	11.9	1.1	9%	1.2	78
8/26/2015	61	217.6	21.5	13.3	1.3	10%	1.2	84
8/27/2015	61	229.0	25.2	14.0	1.5	11%	1.2	87
8/28/2015	61	227.0	26.0	13.8	1.6	11%	1.2	90
9/8/2015	62	206.9	23.4	12.8	1.4	11%	1.2	88
9/9/2015	62	212.6	26.2	13.2	1.6	12%	1.2	94
9/10/2015	62	241.2	29.1	15.0	1.8	12%	1.2	90
9/11/2015	62	217.2	26.5	13.5	1.6	12%	1.2	84
9/21/2015	62	192.8	22.2	12.0	1.4	11%	1.2	78
10/9/2015	69	205.7	26.6	14.2	1.8	13%	1.7	95
10/12/2015	69	210.4	25.7	14.5	1.8	12%	1.7	88
10/13/2015	81	181.7	22.6	14.7	1.8	12%	1.8	82
10/14/2015	81	167.1	18.2	13.5	1.5	11%	1.8	80

Table 4-32 presents the average event-hour impacts for the CBP DO 2-6 hour participants who also participated in AutoDR or TA/TI. The largest aggregate impacts occurred on August 21, 2015 when the seven participants achieved a total of [redacted], which represents a [redacted] reduction over the reference load.

Table 4-32 SDG&E CBP Day-Of 2-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Number of Accts	Per Customer Impact (kW) Reference Load	Impact	Aggregate Impact (MW) Reference Load	Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.								

Table 4-33 presents the average event-hour impacts for the CBP DA 1-4 hour participants. This is the smallest group with only six Auto-DR or TA/TI participants. Their largest aggregate impact was [redacted] reduction, occurring on June 30, 2015.

Table 4-33 SDG&E CBP Day-Ahead 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

		Per Customer Impact (kW)		Aggregate Impact (MW)				
Event	Number of Accts	Reference Load	Impact	Reference Load	Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
Redacted to protect customer or aggregator confidentiality.								

Incremental Load Impacts of TA/TI and AutoDR Participants

In addition to presenting the ex-post impacts for the subgroup, we also estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with group of similar non-enabled participants. First, we selected a group of CBP participants that are similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID). We describe both the Euclidean Distance and DID methodology in the PG&E CBP Section: Incremental Load Impacts of TA/TI and AutoDR Participants.

Figure 4-14 shows the treatment and control-group match on an average event day. The graph shows the reference load profile of each group for the overall CBP program. There are a total of 97 Auto-DR participants, and a total of 97 control-group matches. While we did look at the results at the product level, and each participant is matched to a control customer within their product, the impacts were not significant across all products. Therefore we only show the statistically significant findings for the overall CBP program level.

Figure 4-14 SDG&E CBP AutoDR and TA/TI Event Day Match

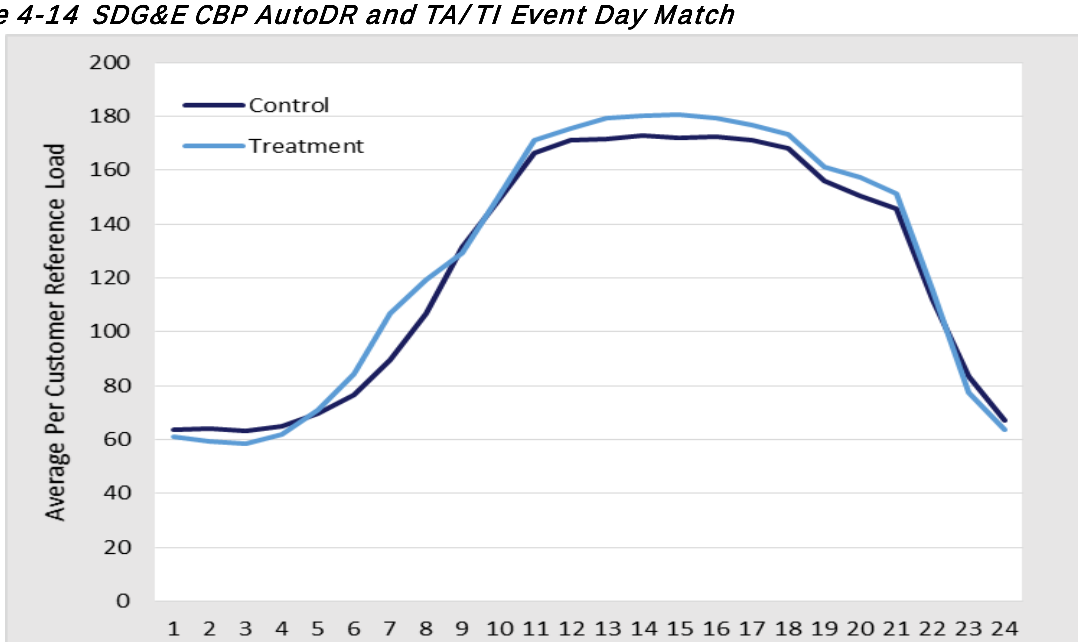


Figure 4-15 and accompanying Table 4-34 present the incremental impacts at the program level. The figure shows the average per-customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. As we would expect, the incremental impacts are very small, and often insignificant during non-event hours. However, during the HE16 to HE19 event window, we do see significant incremental impacts of approximately 6-8 kW per enabled customer.

Table 4-34 presents the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants. On an average event day, each participant saved an additional 6.20 kW over a similar non-enabled customer, and in aggregate they saved an additional 0.60 MW over similar non-enabled customers.

Figure 4-15 SDG&E CBP AutoDR and TA/TI Average Event Day Incremental Impacts

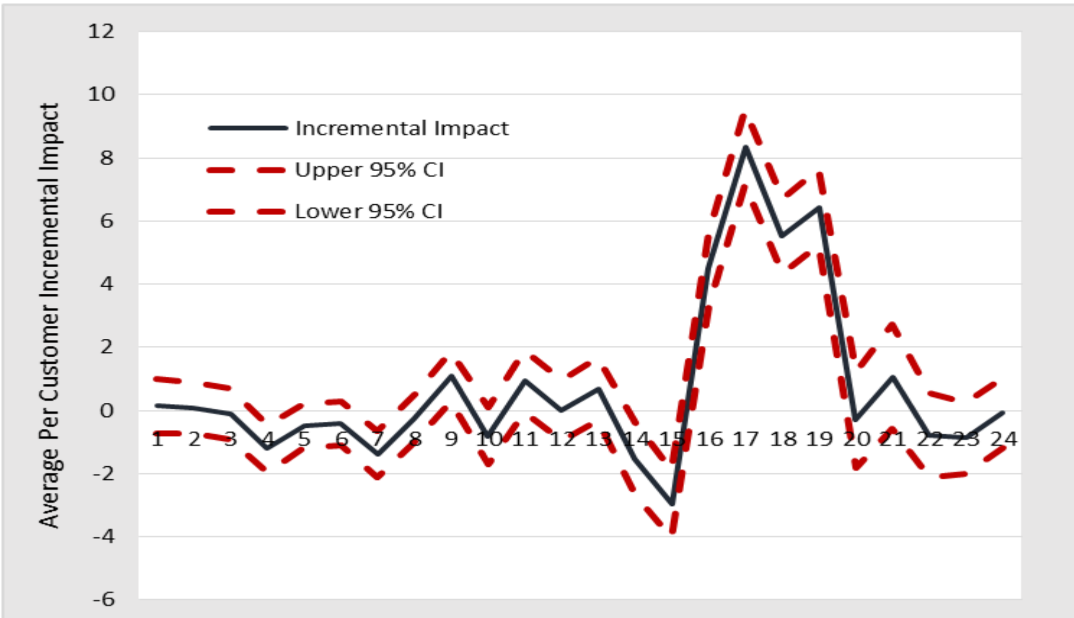


Table 4-34 SDG&E CBP Program Level Incremental AutoDR and TA/TI Impacts

Program	Number of Customers	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate(MW)	Significant
CBP	97	6.20	0.60	Yes

Aggregator Managed Portfolio

PG&E and SCE both offer AMP. PG&E had two types of products: DO Local, and DO system. The local product allows program dispatch by Sub-LAP, while the system product can only dispatch the service territory as a whole. In June and July 2015, SCE bid its AMP resources into the CAISO wholesale energy market. Based upon the market awards, SCE's AMP program can be dispatched locally (e.g. a specific Sub-LAP) or system-wide. In Table 4-35 below we present the average event day impacts by product and IOU, both at the per-customer level, and in aggregate.

PG&E's DO Local option is larger with nearly 1,000 participants on an average event day. This group also has larger per-customer and aggregate impacts at 74.3 kW and 73.3 MW, respectively. SCE's DO programs offer either 1-5 Hour or 1-6 Hour options. The 1-6 Hour option is the larger of the two programs with a [redacted] per customer impact and a [redacted] aggregate impacts.

Table 4-35 Statewide AMP Impacts Summary

Utility	Product	Accounts	Per Customer Impact (kW)		Aggregate Impact (MW)	
			Reference Load	Impact	Reference Load	Impact
PG&E	DO Local	986	343.9	74.3	339.1	73.3
	DO System	[redacted]				
SCE	DO 1-5 Hour	[redacted]				
	DO 1-6 Hour					

PG&E

Events for PG&E AMP

Table 4-36 below presents a summary of the 2015 events for PG&E's AMP program. The DO local participants experienced a total of 18 events over the course of the program year, while DO system participants experienced only 16 events. The table shows the count of Sub-LAPs called during each event for the local product. Typical events were system wide events called during hours ending 16-19.

Table 4-36 PG&E AMP Event Summary

Date	Day of Week	Event Hours (HE)	# Accounts DO System	# of Sub-LAPs for Local	# Accounts DO Local	# Accounts Total AMP DO
Avg. Event	-	16-19	431	16	986	1,417
6/8/2015	Monday	16-19	447	16	1,010	1,457
6/9/2015	Tuesday	15-19, 14-18	-	2	213	213
6/12/2015	Friday	16-19	447	16	1,010	1,457
6/25/2015	Thursday	16-19	447	16	1,010	1,457
6/26/2015	Friday	16-19	447	16	1,010	1,457
6/30/2015	Tuesday	16-19	447	16	1,010	1,457
7/1/2015	Wednesday	16-19	428	16	1,019	1,447
7/16/2015	Thursday	16-19	-	6	687	687
7/28/2015	Tuesday	16-19	428	16	1,018	1,446
7/29/2015	Wednesday	16-19	428	16	1,018	1,446
7/30/2015	Thursday	16-19	428	16	1,018	1,446
8/17/2015	Monday	16-19	432	16	1,034	1,466
8/18/2015	Tuesday	16-19	432	16	1,034	1,466
8/26/2015	Wednesday	16-19	432	16	1,034	1,466
8/27/2015	Thursday	16-19	432	16	1,034	1,466
9/9/2015	Wednesday	15-19	415	16	1,019	1,434
9/10/2015	Thursday	15-19	415	16	1,019	1,434
9/11/2015	Friday	16-19	415	16	1,019	1,434

Summary Load Impacts

Table 4-37 shows the average event-hour impacts for each event, for the system and local products, combined, both at the average per-customer level and in aggregate. The highest per-customer impacts occurred on the August 11, 2015 event, with a maximum per-customer impact of 70.0 kW representing 1,434 service accounts and an average 23% reduction over the reference load. The largest aggregate impacts also occurred on August 11, 2015 with a reduction of 100.5 MW. The lowest aggregate impacts occurred on June 9, 2015. On that day [redacted] provided a total of [redacted] of load reduction.

Table 4-37 PG&E AMP Total Day-Of (System + Local): Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Temp (˚F)
Avg. Event	1,417	120.9	285.0	67.3	403.9	95.3	24%	92
6/8/2015	1,457	121.4	288.6	67.4	420.5	98.2	23%	96
6/9/2015	[redacted]							
6/12/2015	1,457	121.4	275.0	68.1	400.6	99.2	25%	89
6/25/2015	1,457	121.4	284.8	67.7	415.0	98.6	24%	93
6/26/2015	1,457	121.4	278.6	66.3	405.9	96.6	24%	90
6/30/2015	1,457	121.4	290.7	66.3	423.6	96.6	23%	96
7/1/2015	1,447	121.4	271.2	67.8	392.5	98.1	25%	89
7/16/2015	687	119.4	259.0	78.4	177.9	53.8	30%	92
7/28/2015	1,446	121.4	297.7	71.1	430.4	102.8	24%	94
7/29/2015	1,446	121.4	295.9	68.9	427.9	99.6	23%	94
7/30/2015	1,446	120.3	297.4	66.5	430.0	96.2	22%	89
8/17/2015	1,466	120.3	289.7	68.3	424.7	100.1	24%	95
8/18/2015	1,466	120.3	288.5	65.3	422.9	95.7	23%	89
8/26/2015	1,466	120.3	286.3	64.1	419.8	94.0	22%	91
8/27/2015	1,466	119.1	298.2	68.3	437.1	100.1	23%	93
9/9/2015	1,434	119.1	296.9	53.5	425.7	76.7	18%	96
9/10/2015	1,434	119.1	295.4	57.3	423.5	82.2	19%	95
9/11/2015	1,434	120.9	299.6	70.0	429.6	100.5	23%	92

Table 4-38 and Table 4-39 present the impacts for an average event day for two subgroups of interest: Industry and LCA.[22] Schools have the highest per-customer impacts, with an average per-customer impact of [redacted]. Agricultural, Mining, and Construction has the largest aggregate impact, with a total of 33.5 MW load reduction and 578 accounts called – by far the largest number of accounts.

[22] The results in Table 4-38 and Table 4-39 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual industry segments (or LCAs). This is because different group of customers are called for each event, and in some cases, no customers in an industry segment (or LCA) may be called. So the average for that industry segment (or LCA) will reflect only those events where customers in that industry segment (or LCA) were called. But the total program is the average across all events, since some customers in the program were called for every event. Because the total program and the individual industry segments (or LCAs) are averaged across different events, the total program does not exactly match the sum of the individual industry segments (or LCAs).

Table 4-38 PG&E AMP DO Impacts by Industry

		Per Customer Impact (kW)		Aggregate Impact (MW)			
Industry	**# of Accts**	**Ref. Load**	**Impact**	**Ref. Load**	**Impact**	**% Impact**	**Event Temp (˚F)**
Agriculture, Mining & Construction	578	107.4	57.9	62.1	33.5	54%	97
Manufacturing	112	935.1	149.6	104.7	16.8	16%	91
Wholesale, Transport, other Utilities	141	454.2	170.1	64.0	24.0	37%	95
Retail stores	328	175.4	17.1	57.5	5.6	10%	89
Offices, Hotels, Finance, Services	188	488.4	60.8	91.8	11.4	12%	84
Schools	[redacted]						
Institutional/Government	53	209.5	56.2	11.1	3.0	27%	85
Other or unknown	[redacted]						
Total DO	**1,417**	**288.3**	**68.4**	**408.5**	**96.9**	**24%**	**92**

Kern has the largest percentage of impacts with a 55% reduction over the reference load. The “Other” LCA has the largest aggregate impact (30.0 MW). Stockton as the largest per-customer impact (153.5 kW).

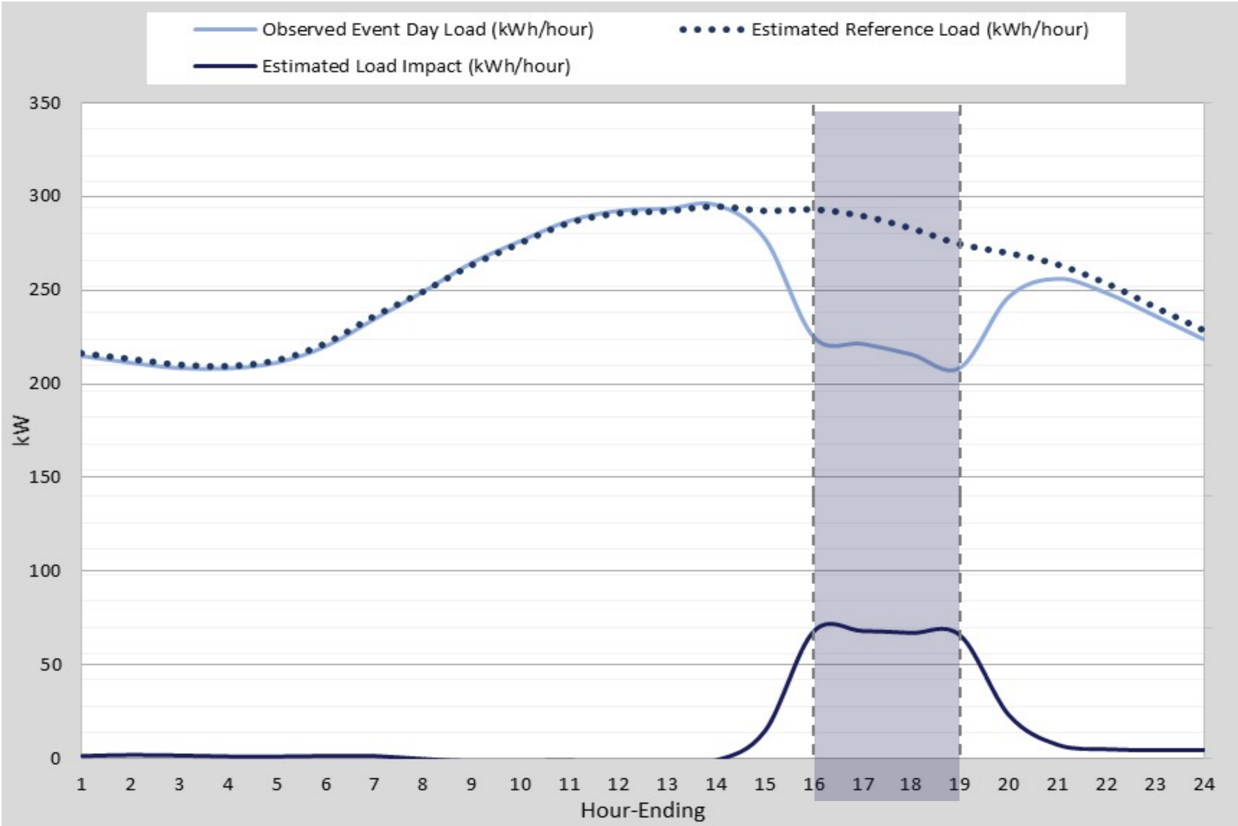
Table 4-39 PG&E AMP DO Impacts by LCA

		Per Customer Impact (kW)		Aggregate Impact (MW)			
LCA	**# of Accts**	**Reference Load**	**Impact**	**Reference Load**	**Impact**	**% Impact**	**Event Temp (˚F)**
Greater Bay Area	391	350.2	31.6	136.9	12.4	9%	84
Greater Fresno	237	170.1	82.5	40.3	19.5	48%	103
Humboldt	16	297.2	150.5	4.8	2.4	51%	80
Kern	285	115.9	64.0	33.0	18.2	55%	101
Northern Coast	79	304.9	52.2	24.1	4.1	17%	89
Other	314	432.3	95.4	135.8	30.0	22%	89
Sierra	44	235.5	67.2	10.4	3.0	29%	99
Stockton	51	513.7	153.5	26.2	7.8	30%	98
Total DO	**1,417**	**288.3**	**68.4**	**408.5**	**96.9**	**24%**	**92**

Hourly Load Impacts

Figure 4-16 illustrates the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for PG&E AMP DO on an average event day. The event window is hour-ending 16 to hour-ending 19 and is highlighted light grey in the figure. The data underlying the figure are available in the Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-16 PG&E AMP Day-Of: Average Hourly Per-Customer Impact, 2015



Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved by PG&E AMP customers that participated in TA/TI or AutoDR at some point in the current or previous years. In this section, as in the previous section, we present two sets of impacts: 1) the ex-post impacts for this subgroup, and 2) the incremental impacts achieved by the subgroup over similar program participants.

In Table 4-40 below we present the event day ex-post impacts and aggregate load shed test results for the AutoDR and TA/TI participants for AMP DO Local and System combined. On August 9, 2015 the participants achieved a maximum load reduction of 9.1 MW in aggregate, which represented a 15% reduction over their reference load. On average, the aggregate ex-post impacts are lower than the aggregate load shed test results representing between 57% and 99% of the potential load shed depending on the event day in question.

Table 4-40 PG&E AMP Day-Of (Local+ System): AutoDR and TA/TI Participant Impacts by Event

Event	Number of accounts	Per Customer Impact (kW) Reference Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Reference Load	Aggregate Impact (MW) Impact	% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
6/8/2015	64	368.4	78.9	23.6	5.0	21%	5.3	98
6/9/2015	[redacted]							87
6/12/2015	64	338.7	78.1	21.7	5.0	23%	5.3	90
6/25/2015	64	387.6	76.5	24.8	4.9	20%	5.3	95
6/26/2015	64	394.9	77.3	25.3	4.9	20%	5.3	92
6/30/2015	64	359.2	74.9	23.0	4.8	21%	5.3	97
7/1/2015	66	354.0	80.5	23.4	5.3	23%	5.4	91
7/16/2015	32	391.4	142.1	12.5	4.5	36%	4.5	92
7/28/2015	66	378.4	75.8	25.0	5.0	20%	5.4	95
7/29/2015	66	377.4	73.3	24.9	4.8	19%	5.4	96
7/30/2015	66	365.1	73.3	24.1	4.8	20%	5.4	90
8/17/2015	68	293.5	68.6	20.0	4.7	23%	5.4	97
8/18/2015	68	359.0	67.9	24.4	4.6	19%	5.4	92
8/26/2015	68	338.3	72.4	23.0	4.9	21%	5.4	93
8/27/2015	68	349.1	79.5	23.7	5.4	23%	5.4	95
9/9/2015	61	342.6	76.4	20.9	4.7	22%	5.3	97
9/10/2015	61	331.0	81.7	20.2	5.0	25%	5.3	97
9/11/2015	61	326.1	84.0	19.9	5.1	26%	5.3	94

Incremental Load Impacts of TA/TI and AutoDR Participants

In addition to presenting the ex-post impacts for the subgroup, we also estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with group of similar non-enabled participants. First, we selected a group of AMP participants that are similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID). We describe both the Euclidean Distance and DID methodology above in the PG&E CBP Section: Incremental Load Impacts of TA/TI and AutoDR Participants.

Figure 4-17 below shows the treatment and control group match on an average event day. The graph shows the reference load profile of each group for the overall AMP program. There are a total of 68 AutoDR participants, and a total of 68 control group matches. While we did look at the results at the product level, and each participant is matched to a control customer within their product, the impacts were not significant across all products. Therefore we only show the statistically significant findings for the overall AMP program level.

Figure 4-17 PG&E AMP AutoDR and TA/TI Event Day Match

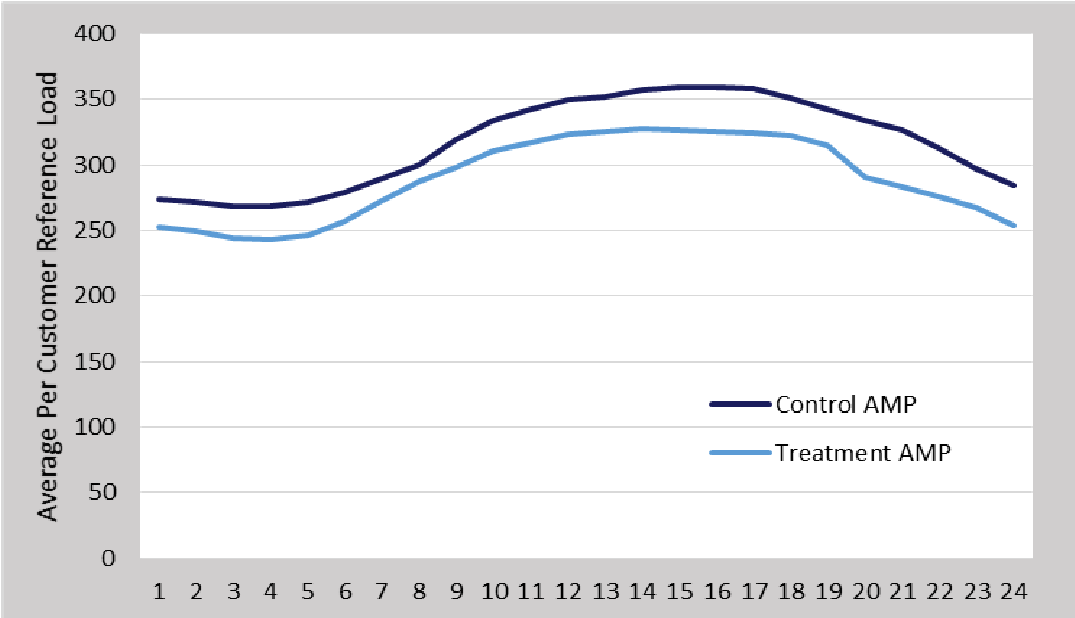


Figure 4-18 and accompanying Table 4-41 present the incremental impacts at the program level. The figure shows the average per customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. In this case, the incremental impacts across the day are nearly all positive and significant. We suspect this is a result of a less well-matched control group than we see in the CBP programs. However, we do also see significant incremental differences during the on-peak hours which are larger than those in the off-peak.

Table 4-41 presents the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants. On an average event day, each participant saved an additional 10.21 kW over a similar non-enabled customer, and in aggregate they saved an additional 0.66 MW over similar non-enabled customers.

Figure 4-18 PG&E AMP AutoDR and TA/TI Average Event Day Incremental Impacts

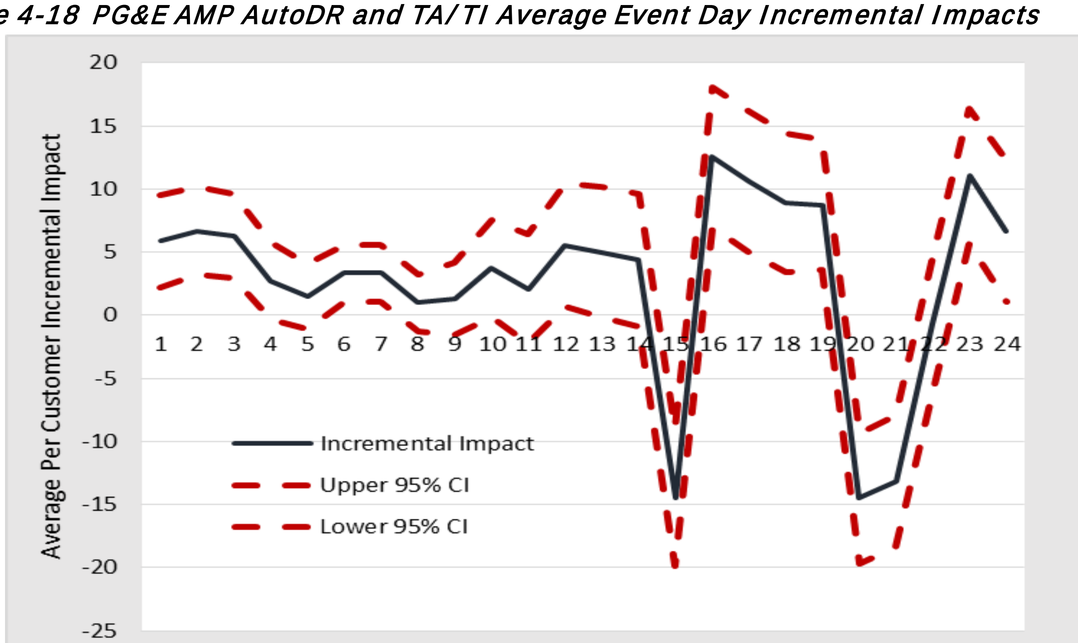


Table 4-41 PG&E AMP Program Level Incremental AutoDR and TA/TI Impacts

Program	Number of Customers	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate(MW)	Significant
AMP	68	10.21	0.66	Yes

SCE

The entire subsection has been redacted to protect customer or aggregator confidentiality.

Ex-Ante Results

This section presents the ex-ante results, which include the load impact forecasts for the 1-in-2 and 1-in-10 weather conditions for each utility and product. To make the relationship between ex-post and ex-ante estimates more easily understood and transparent, we discuss how the

1. Current ex-post results differ from last year's ex-post results,
2. Current ex-post results differ from last year's forecast,
3. Current ex-ante results differ from last year's forecast, and
4. Current ex-ante results differ from the current ex-post results.

Capacity Bidding Program

PG&E

Enrollment and Load Impact Summary

PG&E anticipates that CBP nominations will remain consistent with the PY2015 level throughout the forecast horizon (2016-2026), with an estimated 175 customers for the DA product and 609 customers for the DO product during May through October. These enrollment forecasts are higher than those for PY2014, which were estimated at 37 service accounts for DA and 530 for DO. In the current forecasts, most customers for the DA product are in the 200 kW or larger size range, while most customers for the DO product fall in the 20 to <200 kW size range. For both products, the Greater Bay Area LCA accounts for the highest number of services accounts forecasted across the LCAs.

The ex-ante impact results also forecast annual CBP load impacts for the DA and DO products which are consistent with the PY2015 impacts across the 2016-2026 horizon. In addition, the impacts are expected to remain constant across the months of May through October.

Table 5-1 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2016.[23] The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. The ex-ante impacts are assumed to be the same under both 1-in-2 and 1-in-10 weather conditions. The assumption is not unreasonable, as the load impacts should be a function of the monthly nomination, which is not weather-dependent within a given month.

The table shows that per-customer impacts for CBP DA are roughly 121 kW under the utility peak weather conditions and 120 kW under the CAISO peak conditions. For CBP DO, the per-customer impacts are about 28.1 kW and 27.6 kW for utility peak and CAISO peak weather, respectively. Aggregate impacts for the CBP DA product are roughly 21 MW under both weather conditions for DA and are about 17 MW under both weather conditions for DO.

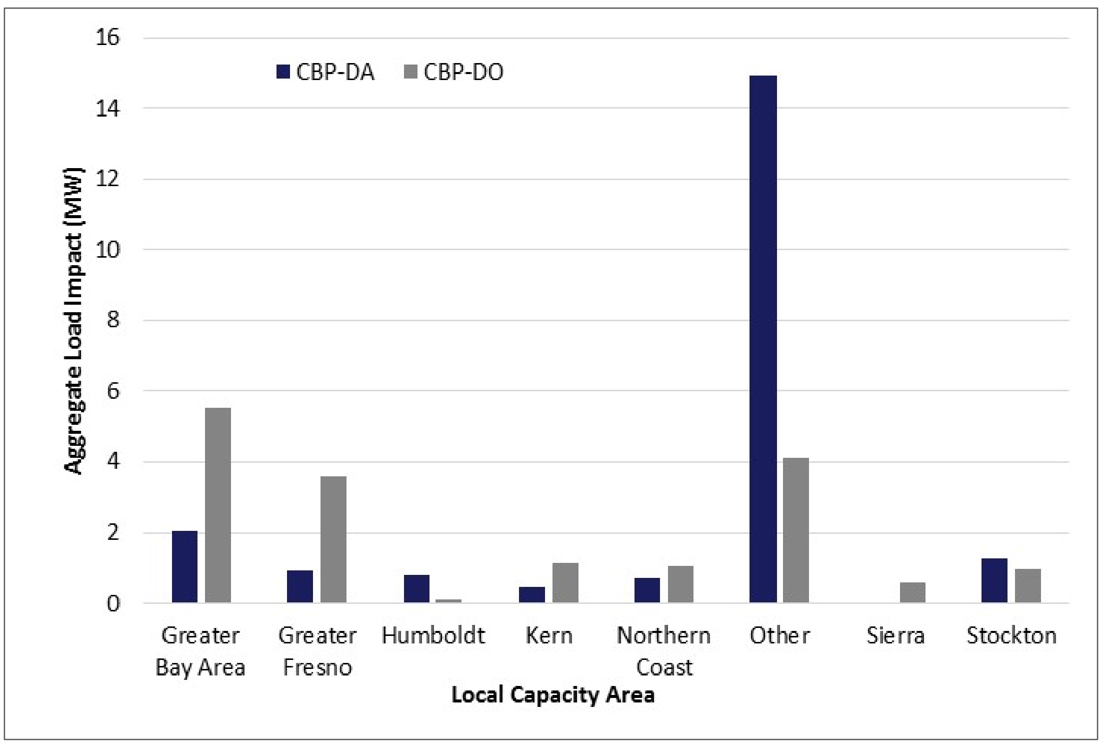
[23] Though labeled as an August peak day in 2016, the results in Table 5-1 would be identical for each month, May through October, and each year, 2016 through 2026, in the forecast.

Table 5-1 PG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2016

			Per Customer Impact (kW)				Aggregate Impact (MW)			
			Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
	Size	Accts	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
DA	< 20 kW	-	-	-	-	-	-	-	-	-
DA	20 to < 200 kW	57	9.54	9.54	9.60	9.60	0.54	0.54	0.55	0.55
DA	≥ 200 kW	118	174.75	174.75	173.03	173.03	20.62	20.62	20.42	20.42
DA	**Total DA**	**175**	**120.94**	**120.94**	**119.80**	**119.80**	**21.16**	**21.16**	**20.97**	**20.97**
DO	< 20 kW	10	1.58	1.58	0.56	0.56	0.02	0.02	0.01	0.01
DO	20 to < 200 kW	351	14.61	14.61	14.07	14.07	5.13	5.13	4.94	4.94
DO	≥ 200 kW	248	48.14	48.14	47.79	47.79	11.94	11.94	11.85	11.85
DO	**Total DO**	**609**	**28.05**	**28.05**	**27.58**	**27.58**	**17.09**	**17.09**	**16.80**	**16.80**

Figure 5-1 illustrates the average event-hour load impacts distributed by LCA for the two CBP products on an August peak day in 2016. The results shown are for 1-in-2 weather conditions for the utility peak. For the DA product, the largest share of impacts occurs in the “Other” LCA, followed by the Greater Bay Area LCA. For the DO product, the Greater Bay Area LCA has the largest share of impacts, followed by the “Other” LCA, and the Greater Fresno LCA. Shares of impacts represented by the other areas are noticeably lower across the two products. The DA forecast has zero impacts for the Sierra LCA.

Figure 5-1 PG&E CBP: Average Event-Hour Aggregate Load Impacts by LCA for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions



Hourly Reference Loads and Load Impacts

Figure 5-2 and Figure 5-3 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2016 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak. The load profiles are very similar in shape for the DA and DO products, but the magnitudes of the reference load and impacts are higher for the DO product.

Figure 5-2 PG&E CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions

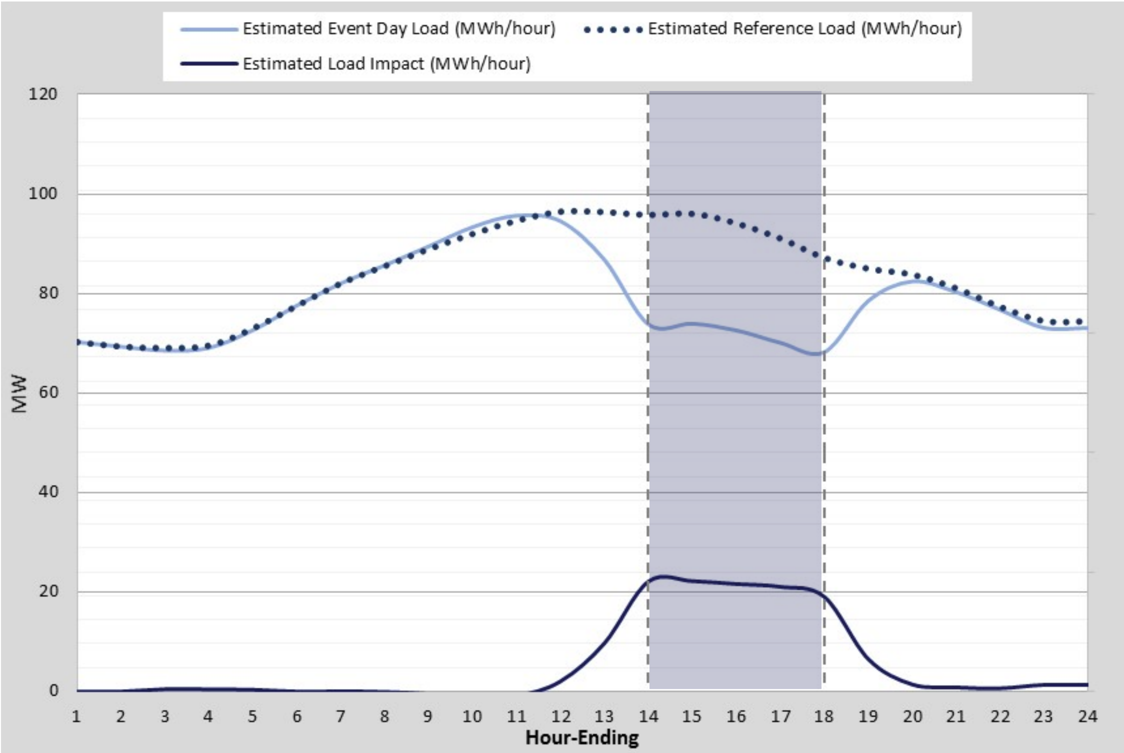
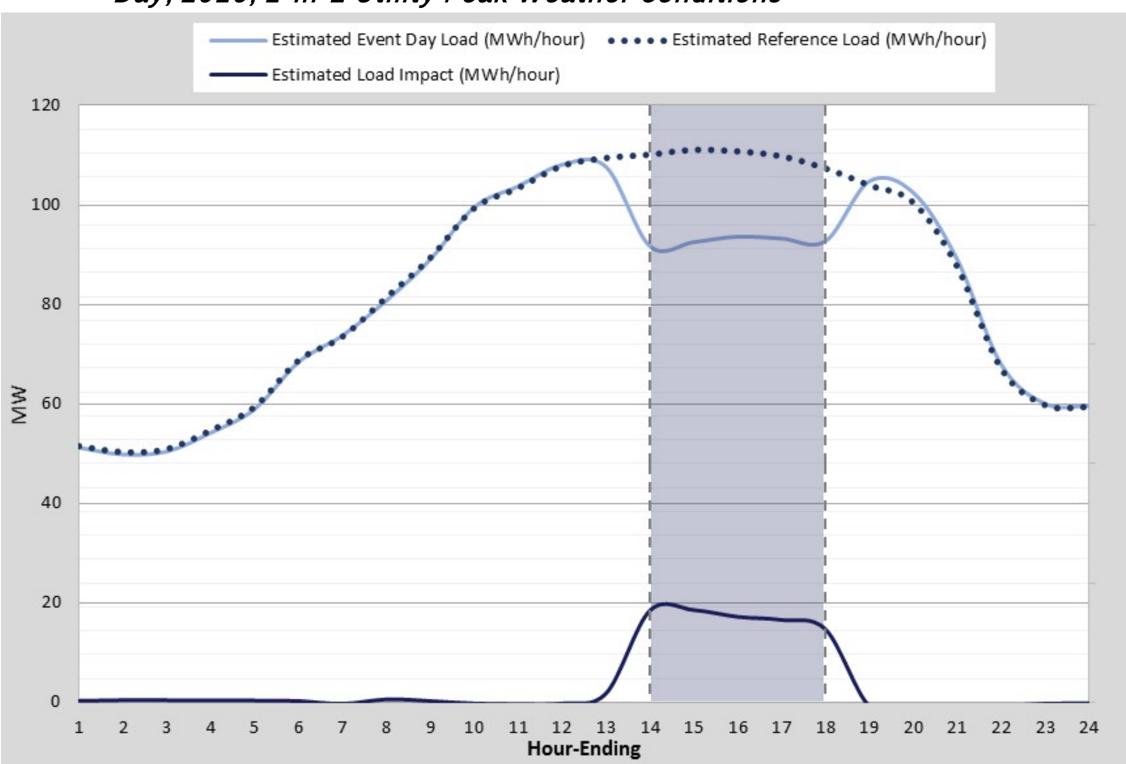


Figure 5-3 PG&E CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment and Load Impact Summary

SCE forecasts the CBP DA enrollment to stay constant at 30 customers throughout the forecast horizon (2016-2026). For the CBP DO product, SCE forecasts enrollment of 814 customers in 2016 and 2017 and then an increase to 1,264 customers after 2017.[24]

The ex-ante impact results also forecast constant annual load impacts across the 2016-2026 horizon for the DA product, and an increase in impacts for the DO product after 2017, commensurate with the enrollment trends. In addition, the impacts are expected to remain relatively constant during the months of May through October.

Table 5-2 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2016.[25] The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. The ex-ante impacts are assumed to be the same under both 1-in-2 and 1-in-10 weather conditions. The assumption is not unreasonable, as the load impacts should be a function of the monthly nomination, which is not weather-dependent within a given month. The table shows that per-customer impacts for CBP DA are roughly 41 kW under both the utility peak and CAISO peak weather conditions. For CBP DO, the per-customer impacts are about 37 kW under both weather conditions. Aggregate impacts for the CBP DA product are roughly 1.2 MW under both weather conditions for DA and are about 30 MW under both weather conditions for DO.

Table 5-2 SCE CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2016

		Per Customer Impact (kW)				Aggregate Impact (MW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
Notice	Accts	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Total DA	30	41.34	41.34	41.34	41.34	1.24	1.24	1.24	1.24
Total DO	814	37.15	37.15	37.15	37.15	30.24	30.24	30.24	30.24

Hourly Reference Loads and Load Impacts

Figure 5-4 and Figure 5-5 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2016 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak. The figures illustrate the significantly larger impacts associated with the DO product.

[24] The fate of AMP contracts for 2018 and beyond is unknown. Therefore, SCE assumes Commission will not approve AMP contracts for 2018-2026. If there are no contracts for 2018-2026, then SCE anticipates some Aggregators will participate in other programs such as CBP and DR Auction Mechanism (DRAM). As a result, beginning in 2018, SCE estimates 450 additional accounts to participate in CBP DO as a result of elimination of AMP. This to remain constant through 2026 assuming DRAM will exist beyond 2017.

[25] Though labeled as an August peak day in 2016, the results in Table 5-2 would be identical for each month, May through October, and each year in the forecast for DA (2016-2026) and for 2016 and 2016 for DO.

Figure 5-4 SCE CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions

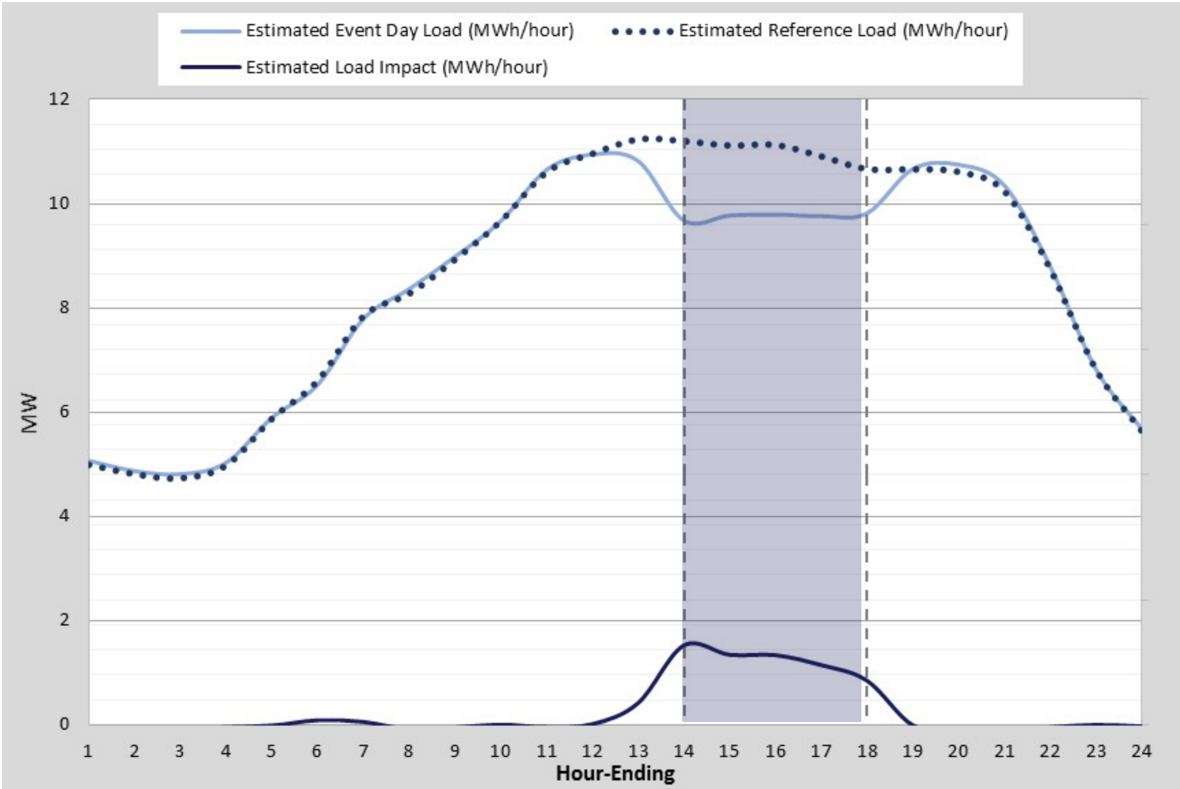
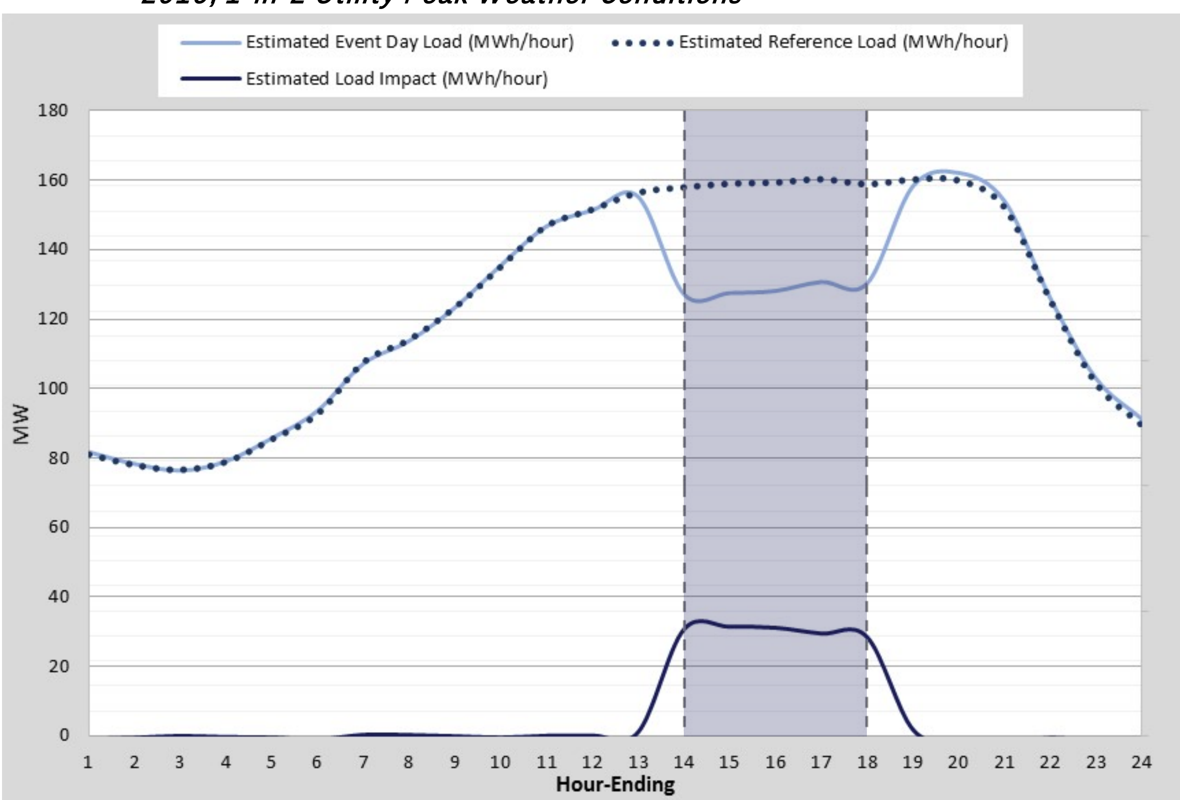


Figure 5-5 SCE CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions



SDG&E

Enrollment and Load Impact Summary

SDG&E forecasts the CBP nominations to stay constant across the 2016-2026 horizon, with an estimated 122 service accounts for the DA product, 160 for the DO 1-4 hour product, and 60 for the DO 2-6 hour product during May through October. These enrollment forecasts are lower than those estimated in PY2014, which were held constant at 159 service accounts for the DA product and increased from 239 to 284 for the DO 1-4 hour and 2-6 hour products combined.

The ex-ante impact results also forecast constant annual CBP load impacts across the 2016-2026 horizon for the DA and DO products. In addition, the impacts are expected to remain constant during the months of May through October.

Table 5-3 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2016.[26] The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. The ex-ante impacts are assumed to be the same under both 1-in-2 and 1-in-10 weather conditions. The assumption is not unreasonable, as the load impacts should be a function of the monthly nomination, which is not weather-dependent within a given month. The table shows that per-customer impacts for CBP DA are 62.87 kW under the utility peak weather conditions and 62.82 kW under the CAISO peak conditions. For CBP DO, the per-customer impacts are 20.69 kW and 20.66 kW for utility peak and CAISO peak weather, respectively. Aggregate impacts for the CBP DA product are 7.67 MW under utility peak weather and 7.66 MW under CAISO peak weather for DA, and are 4.55 MW under utility peak weather and 4.54 MW under CAISO peak weather for DO.

Table 5-3 SDG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2016

		Per Customer Impact (kW)				Aggregate Impact (MW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
Notice	Accts	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Total DA	**122**	**62.87**	**62.87**	**62.82**	**62.82**	**7.67**	**7.67**	**7.66**	**7.66**
DO, 1-4 Hour	160	14.60	14.60	14.23	14.23	2.34	2.34	2.28	2.28
DO, 2-6 Hour	60	36.95	36.95	37.79	37.79	2.22	2.22	2.27	2.27
Total DO	**220**	**20.69**	**20.69**	**20.66**	**20.66**	**4.55**	**4.55**	**4.54**	**4.54**

Hourly Reference Loads and Load Impacts

Figure 5-6 through Figure 5-8 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2016 for the DA, DO 1-4 hour, and DO 2-6 hour products, respectively. The results are for 1-in-2 weather conditions and the utility peak. The shapes are different between the DA and DO products. The DA reference load peaks in the late morning around HE 11, and then gradually declines during the rest of the day. The maximum load impact occurs between HE 14 and 15, but there are impacts as early as HE 13 and as late as HE 20. For the two DO products, the reference load peaks during the event window, and impacts have a smaller magnitude and represent a lower percentage of the reference load than for DA.

[26] Though labeled as an August peak day in 2016, the results in Table 5-3 would be identical for each month, May through October, and each year, 2016 through 2026, in the forecast.

Figure 5-6 SDG&E CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day in 1-in-2 Utility Peak Weather Conditions

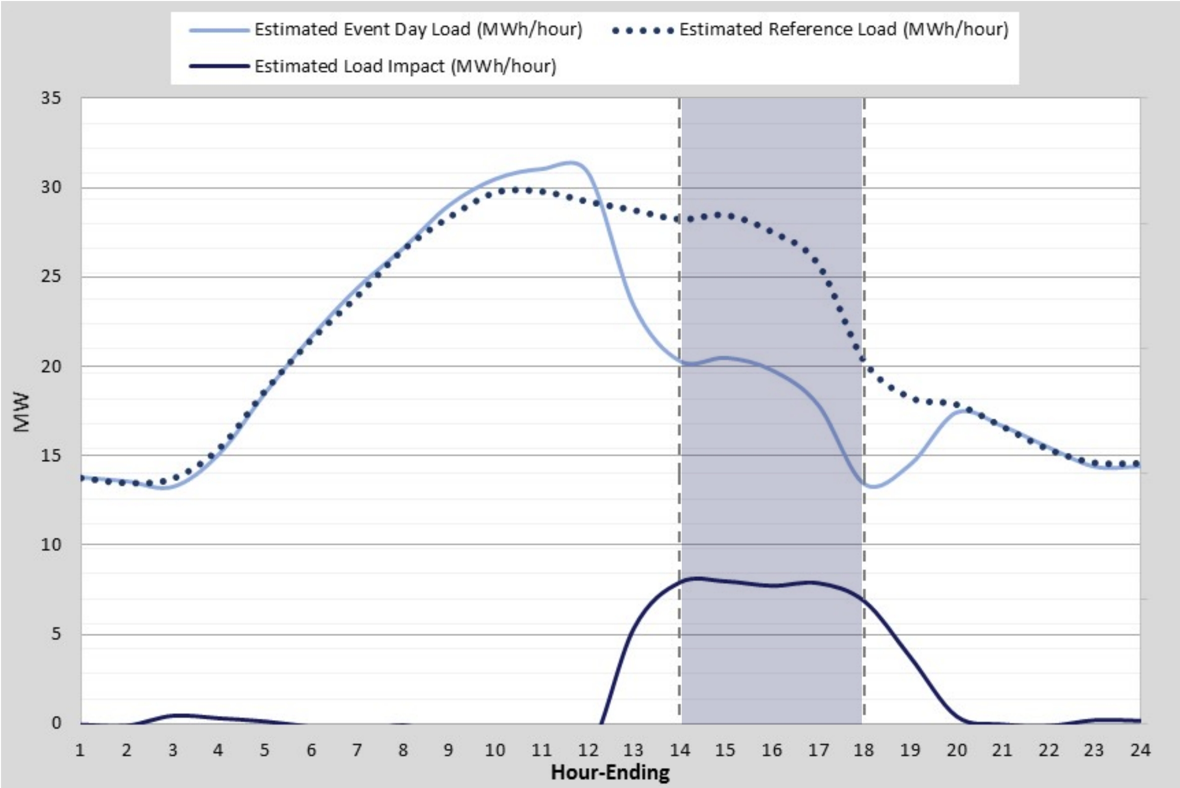


Figure 5-7 SDG&E CBP DO 1-4 Hour: Hourly Event-Day Aggregate Load Impacts for an August Peak Day in 1-in-2 Utility Peak Weather Conditions

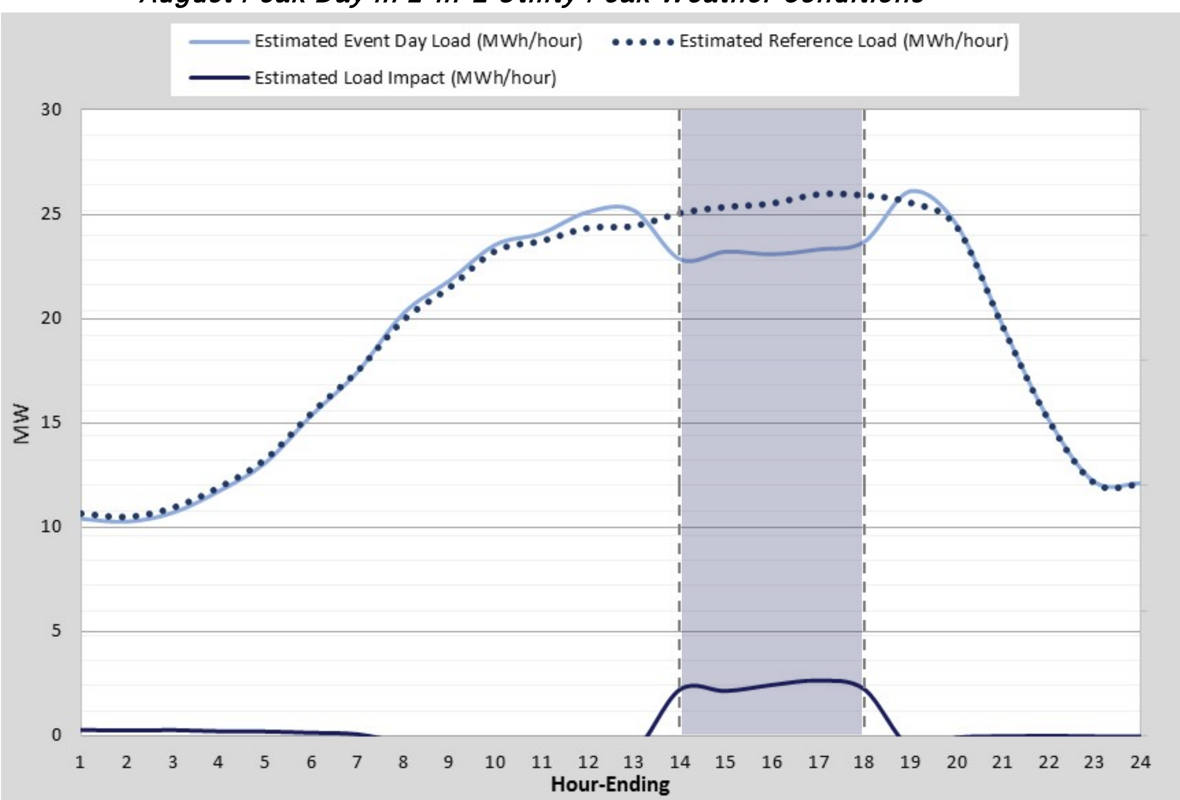
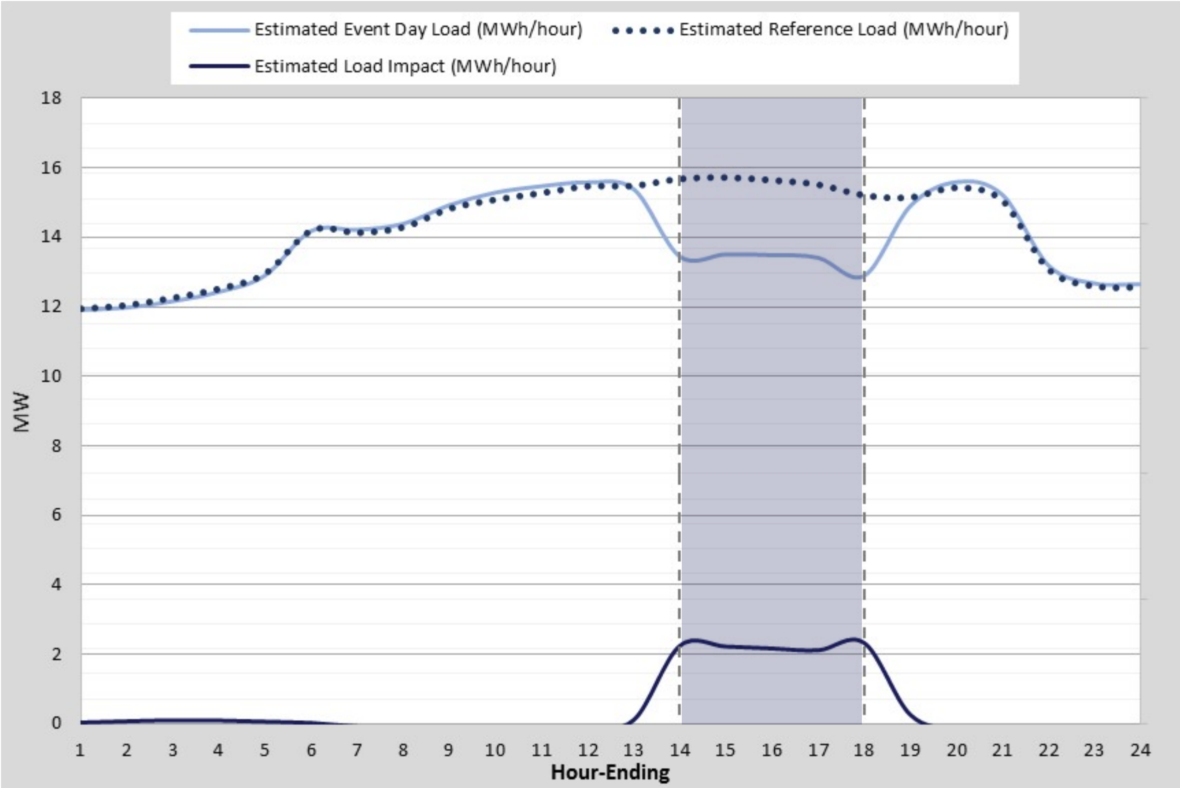


Figure 5-8 SDG&E CBP DO 2-6 Hour: Hourly Event-Day Aggregate Load Impacts for an August Peak Day in 1-in-2 Utility Peak Weather Conditions



Aggregator Managed Portfolio

PG&E

Enrollment and Load Impact Summary

As described in Section 3, PG&E's ex-ante load impact forecast for AMP DO came from the aggregators' 2016 load reduction nominations, adjusted based on each aggregator's actual performance relative to its contractual commitment over the previous three years. PG&E then determined the enrollment forecast by dividing the aggregate load reduction forecast by AEG's estimates of per-customer average ex-ante impacts.

While PG&E has proposed in its 2017 DR Transition Filing to close AMP after 2016, with a CPUC decision pending, the forecast simply assumes status quo. In particular, PG&E forecasts that AMP enrollment will stay relatively constant across the 2016-2026 horizon, with an estimated 1,459 service accounts for the DO product during May through October. About 46% of the accounts are estimated to be in the 20 to 200 kW size range, another 37% in the 200 kW plus range, and the balance in the less than 20 kW range.

Table 5-4 summarizes the average event-hour load impact forecasts for the AMP DO product on an August peak day in 2016.[27] The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. The ex-ante impacts are not forecast to change from 1-in-2 to 1-in-10 weather conditions, as the impact delivered depends on the MW nomination, which is not weather-dependent. In addition, there is little incentive for aggregators to deliberately over-deliver their nominated MW. The table shows that per-customer impacts for AMP DO are about 55 kW and 56 kW under the utility peak and CAISO peak weather conditions,

[27] Though labeled as an August peak day in 2016, the results in Table 5-4 would be identical for each month, May through October, and each year, 2016 through 2026, in the forecast.

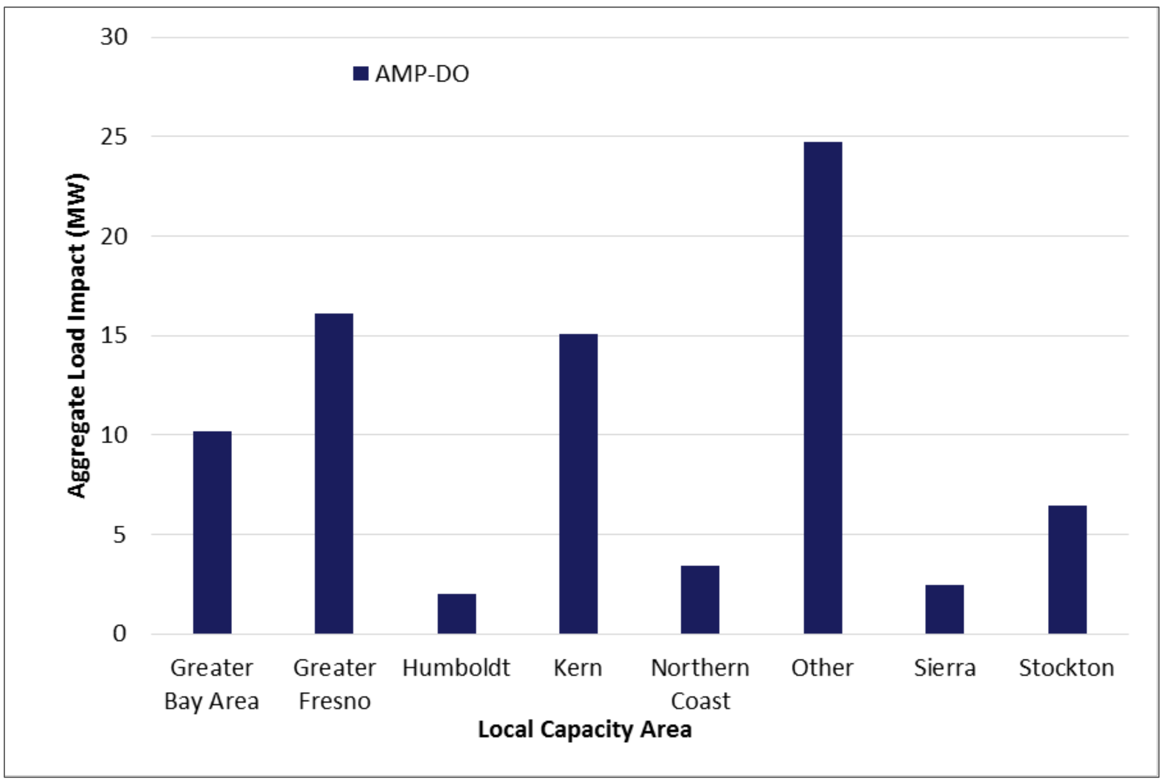
respectively. Aggregate impacts for the AMP DO product are roughly 80 MW and 81 MW under the utility peak and CAISO peak weather conditions, respectively.

Table 5-4 PG&E AMP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2016

			Per Customer Impact (kW)				Aggregate Impact (MW)			
			Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
	Size	Accts	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
DO	< 20 kW	233	0.41	0.41	0.38	0.38	0.10	0.10	0.09	0.09
DO	20 to < 200 kW	684	25.69	25.69	25.63	25.63	17.58	17.58	17.54	17.54
DO	≥ 200 kW	542	115.63	115.63	117.89	117.89	62.70	62.70	63.92	63.92
DO	**Total DO**	**1,459**	**55.07**	**55.07**	**55.88**	**55.88**	**80.38**	**80.38**	**81.55**	**81.55**

Figure 5-9 illustrates the average event-hour load impacts distributed by LCA for the AMP DO product on an August peak day in 2016. The results shown are for 1-in-2 weather conditions for the utility peak. The largest share of impacts occurs in the "Other" LCA, followed by the Greater Fresno, Kern, Greater Bay Area, and Stockton LCAs. Shares of impacts represented by the other three areas are relatively small in comparison.

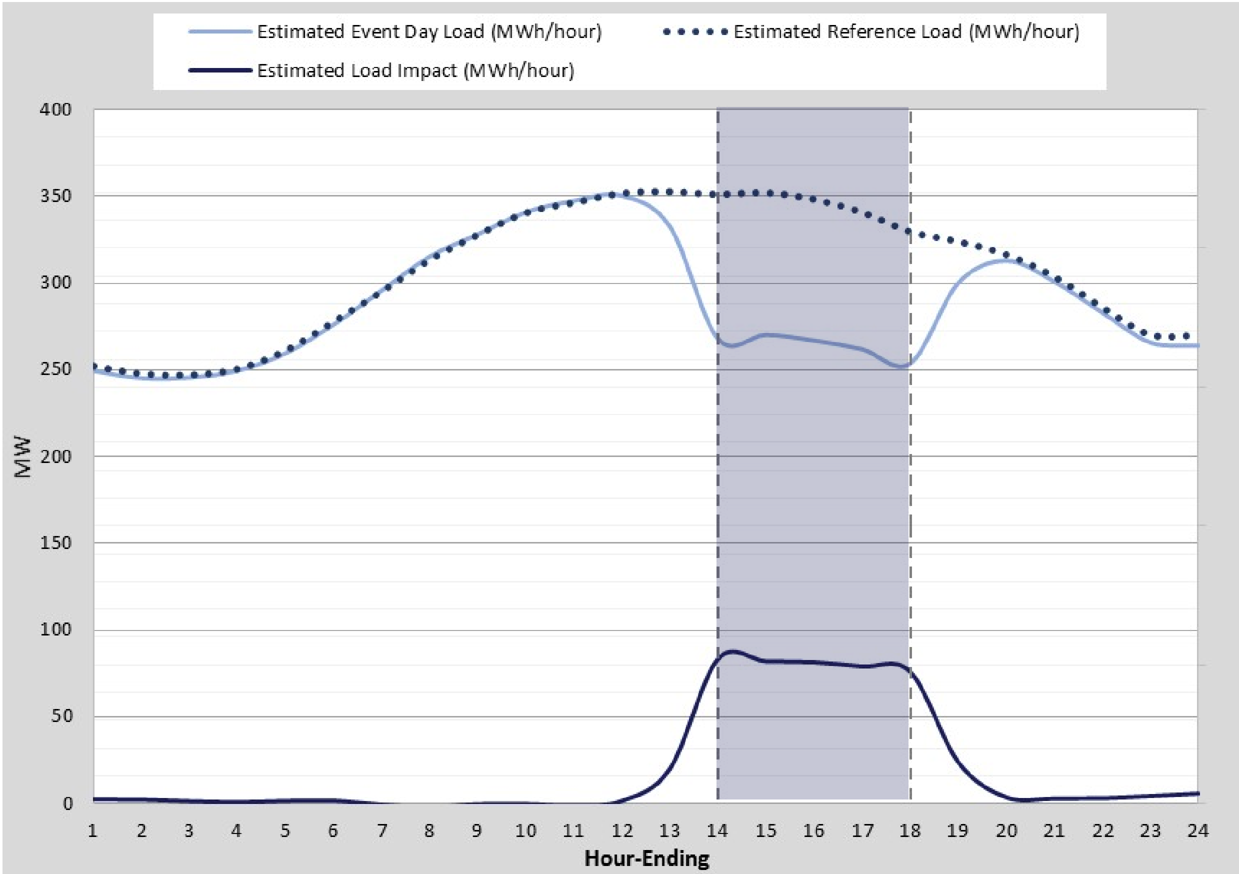
Figure 5-9 PG&E AMP: Average Event-Hour Aggregate Load Impacts by LCA for an August Peak Day, 2016, 1-in-2 Utility Peak Weather Conditions



Hourly Reference Loads and Load Impacts

Figure 5-10 compares the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2016 for the AMP DO product. The results are for 1-in-2 weather conditions and the utility peak. The graph shows how the load impacts are roughly one-quarter of the reference load during the event period.

Figure 5-10 PG&E AMP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day in 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment Forecasts, Reference Loads, and Load Impacts

SCE forecasts that AMP enrollment will be [redacted] customers in 2016 and 2017 and then will have zero enrollment after 2017.[28]

Table 5-5 summarizes the average event-hour load impact forecasts for the AMP DO product on an August peak day in 2016.[29] The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. The ex-ante impacts are not forecast to change from 1-in-2 to 1-in-10 weather conditions. The table shows that per-customer impacts for AMP DO are about 73 kW under both the utility peak and CAISO peak weather conditions. Aggregate impacts for the AMP DO product are roughly 94 MW under both weather conditions.

[28] The fate of AMP contracts for 2018 and beyond is unknown. Therefore, SCE assumes Commission will not approve AMP contracts for 2018-2026. If there are no contracts for 2018-2026, then SCE anticipates some Aggregators will participate in other programs such as CBP and DR Auction Mechanism (DRAM). As a result, beginning in 2018, SCE estimates 450 additional accounts to participate in CBP DO as a result of elimination of AMP. This to remain constant through 2026 assuming DRAM will exist beyond 2017.

[29] Though labeled as an August peak day in 2016, the results in Table 5-5 would be the same for each month, May through October, and for 2016 and 2017. The forecast assumes zero impacts for AMP after 2017.

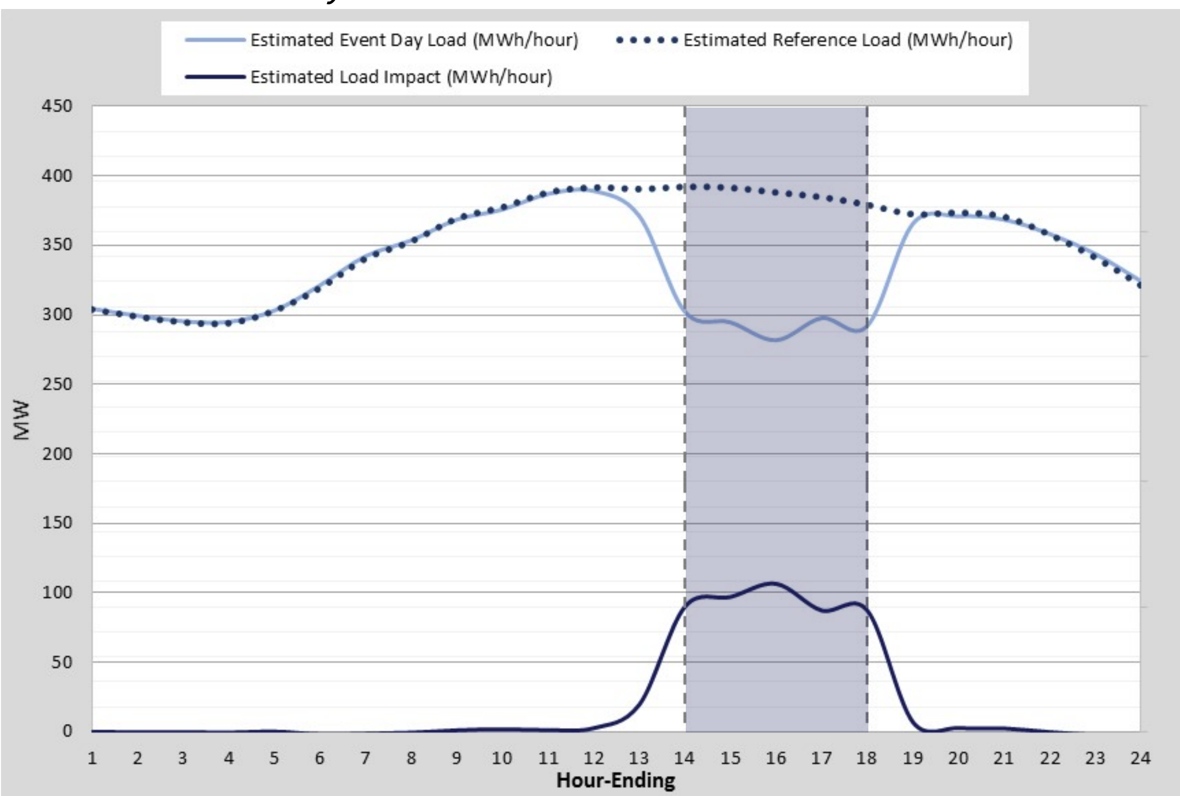
Table 5-5 SCE AMP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2016

		Per Customer Impact (kW)				Aggregate Impact (MW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
Notice	Accts	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Total DO	[redacted]	73.42	73.42	73.42	73.42	93.68	93.68	93.68	93.68

Hourly Reference Loads and Load Impacts

Figure 5-11 compares the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2016 for the AMP DO product. The results are for 1-in-2 weather conditions and the utility peak. The graph shows how the load impacts are near 100 MW during the event period.

Figure 5-11 SCE AMP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day in 1-in-2 Utility Peak Weather Conditions



Comparisons of Ex-Post and Ex-Ante Results

PG&E

Previous and Current Ex-Post

Table 5-6 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past four years on an average event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

Table 5-6 PG&E CBP: Previous and Current Ex-Post, Average Event Day

	Ex-Post Year	Accounts	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Impact	Event Temp (˚F)
DA	2012	166	282	123	46.8	20.4	44%	95
	2013	25	605	188	15.1	4.7	31%	86
	2014	33	396	148	13.1	4.9	37%	89
	2015	200	426	80	85.1	15.9	19%	90
DO	2012	370	272	63	100.6	23.3	23%	88
	2013	480	198	29	94.9	13.7	14%	90
	2014	542	153	20	83.2	10.6	13%	87
	2015	569	180	35	102.3	20.0	20%	90

After the AMP-DA aggregator left AMP, CBP-DA received more customers and higher nominated load reduction. For the CBP DA product, the number of accounts increased considerably from 33 in 2014 to 200 in 2015. The aggregate impacts had a corresponding increase, but the increase was suppressed somewhat due to lower per-customer impacts in 2015 compared to 2014. On a percent impact basis, 2015 realized only 19%, while the 2014 program yielded an average percent impact of 37%, which indicates that the customer mix has changed materially.

In 2015, CBP DO also benefitted from a higher enrollment. The number of accounts has increased during the past few years, from 370 in 2012 to 569 in 2015. The aggregate load impact nearly doubled from 2014 to 2015 due to a notable increase in per-customer load impacts. The percent impacts in 2015 were also higher in 2015 (20%) compared to 2014 (13%).

Table 5-7 summarizes the AMP DO average event-hour ex-post load impact results for the past four years for an average event day.

Table 5-7 PG&E AMP: Previous and Current Ex-Post, Average Event Day

	Ex-Post Year	Accounts	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Impact	Event Temp (˚F)
DO	2012	1,125	415	115	466.5	129.6	28%	89
	2013	1,344	375	116	503.4	155.2	31%	85
	2014	1,397	334	88	466.6	122.7	26%	89
	2015	1,417	288	68	408.5	96.9	24%	93

The enrollment of AMP DO stayed relatively constant from 2014 to 2015 at roughly 1,400. However, the per-customer and aggregate impacts decreased. Some aggregators performed better than others and the product type (i.e., system versus local) also made a difference. On a percent impact basis, 2015 realized 24%, while the 2014 program yielded an average percent impact of 26%.

Previous and Current Ex-Ante and Ex-Post

Table 5-8 compares the current year's analysis with the previous year's analysis of CBP ex-post and ex-ante average event-hour impacts. To make the comparison as consistent as possible, the ex-post and ex-ante results represent events on monthly system peak days in August, unless otherwise noted.[30] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.[31]

Table 5-8 PG&E CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day, 2016

					Per Customer (kW)		Aggregate (MW)			Event
Model		Year	Day	Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (˚F)
DA	Current	Ex-Post 2015	Aug 27	200	533.8	112.5	106.8	22.5	21.1%	91.4
DA	Current	Ex-Ante 2016	Aug Peak	175	530.7	120.9	92.9	21.2	22.8%	90.4
DA	Previous	Ex-Post 2014	Avg. Event[32]	33	396.4	148.3	13.1	4.9	37.0%	89.0
DA	Previous	Ex-Ante 2015/16	Aug Peak	37	444.0	147.4	16.4	5.5	33.0%	96.0
DO	Current	Ex-Post 2015	Aug 26	589	180.4	28.7	106.3	16.9	15.9%	87.8
DO	Current	Ex-Ante 2016	Aug Peak	609	180.4	28.1	109.9	17.1	15.5%	90.9
DO	Previous	Ex-Post 2014	Aug 1	502	165.6	23.7	83.2	11.9	14.3%	91.7
DO	Previous	Ex-Ante 2015/16	Aug Peak	530	162.0	18.8	85.9	9.9	11.5%	86.0

Table 5-8 shows the following trends for the CBP DA and DO products:

- **Current Ex-Post Compared with Previous Ex-Ante:** Because aggregators nominated more customers in 2015, especially for CBP DA, more load impacts were provided relative to the previous ex-ante estimates.
- **Current Ex-Ante Compared with Previous Ex-Ante:** Each of the two years' ex-ante estimates were informed by the performance of the prior ex-post results and PG&E assumed status quo going forward in the absence of better information. The increase in the ex-ante impacts results from more customers and load nominated in the 2015 season.
- **Current Ex-Ante Compared with Current Ex-Post:** PG&E assumed status quo based on the performance of the 2015 season. As such, the current ex-ante forecast is comparable with the ex-post impacts of 2015.

Table 5-9 compares the current year's analysis with the previous year's analysis of AMP ex-post and ex-ante average event-hour impacts. Again, to make the comparison as consistent as possible, the ex-post and ex-ante results represent events on monthly system peak days in August. In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario. System and local impacts are combined.

Table 5-9 PG&E AMP: Previous and Current Ex-Ante and Ex-Post, August Peak Day, 2016

					Per Customer (kW)		Aggregate (MW)			Event
Model		Year	Day	Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (˚F)
DO	Current	Ex-Post 2015	Aug 26	1,466	286.3	64.1	419.8	94.0	22.4%	91.7
DO	Current	Ex-Ante 2016	Aug Peak	1,459	236.5	55.1	344.4	80.4	23.3%	94.2
DO	Previous	Ex-Post 2014	Aug 1	1,403	338.7	88.8	475.2	124.6	26.2%	91.6

[30] Though the ex-ante impacts are labeled as an August peak day, the ex-ante results are identical for each monthly system peak day, May through October, because of the way the PG&E ex-ante impacts were modeled.
[31] The 1-in-2 and 1-in-10 ex-ante impacts are equal for the 1-in-2 and 1-in-10 weather conditions, because of the PG&E ex-ante modeling approach.
[32] The 2014 ex-post results for the CBP DA product were not available in the previous year's load impact tables, so we have used the average event day results as a proxy.

		Ex-Ante 2015/16	Aug Peak	1,511	253.3	84.9	382.7	102.0	33.5%	96.8

Table 5-9 shows the following trends for the AMP DO product:

- **Current Ex-Post Compared with Previous Ex-Ante:** The current ex-post analysis shows lower per-customer, aggregate, and percent impacts for 2015 than predicted in the previous forecast for a monthly system peak day.[33]
- **Current Ex-Ante Compared with Previous Ex-Ante:** Given the opportunity of DR Auction Mechanism (DRAM)—a DR pay-as-bid auction of monthly system Resource Adequacy where aggregators offer directly into the CAISO DA energy market, aggregators were allowed to lower their committed load reduction in AMP and some aggregators did take advantage of the provision. Also, due to the operational plans (e.g., MW nominations) of the aggregators in 2016, the current ex ante estimate is noticeably lower than the previous forecast.
- **Current Ex-Ante Compared with Current Ex-Post:** The difference between the two estimates can be explained by the aggregators' participation in the DR auction mechanism (DRAM) and their commitment level for 2016. Aggregators are allowed to lower their contractual load reduction as a result of their participation in DRAM.

[33] Note that the previous ex-ante impacts for 2015 were the same as for 2016 for the AMP DO product.

SCE

Previous and Current Ex-Post

Table 5-10 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past four years on an average summer event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

Table 5-10 SCE CBP: Previous and Current Ex-Post, Average Summer Event Day

			Per Customer (kW)		Aggregate (MW)			
	Ex-Post Year	Accounts	Reference Load	Load Impact	Reference Load	Load Impact	% Impact	Event Temp (˚F)
DA	2012	[redacted]						80
	2013	20	638	145	13.1	3.0	23%	85
	2014	231	431	42	99.4	9.6	10%	84
	2015	55	284	19	15.6	1.0	7%	81
DO	2012	359	243	46	87.3	16.5	19%	90
	2013	420	214	44	89.8	18.4	21%	90
	2014	1,236	221	43	273.7	52.7	19%	88
	2015	670	152	24	101.7	16.4	16%	87

For the CBP DA product, the number of accounts called on an average summer day decreased from 231 in 2014 to 55 in 2015. The aggregate impacts had a corresponding decrease that was also more pronounced due to a decrease in per-customer impacts. On a percent impact basis, 2015 realized 7%, while the 2014 program yielded an average percent impact of 10%.

CBP DO had about half the enrollment during the average 2015 summer event day than in 2014. The aggregate and per-customer load impacts also decreased. The percent impacts in 2015 were 16% in 2015 compared to 19% in 2014.

Table 5-11 summarizes the AMP DO average event-hour ex-post load impact results for the past four years for an average event day. The 2015 values are for the average event day DO 1-5 hour product combined with the average summer event day DO 1-6 hour product. The per-customer, aggregate, and percent load impact decreased between 2014 and 2015.

Table 5-11 SCE AMP: Previous and Current Ex-Post, Average Event Day

			Per Customer (kW)		Aggregate (MW)			
	Ex-Post Year	Accounts	Reference Load	Load Impact	Reference Load	Load Impact	% Impact	Event Temp (˚F)
DO	2012	1,648	334	97	550.6	160.1	29%	91
	2013	1,531	294	80	449.6	122.6	27%	85
	2014	920	331	98	304.5	90.3	30%	82
	2015	[redacted]	259	63	307.7	74.3	24%	87

Previous and Current Ex-Ante and Ex-Post

Table 5-12 compares the current year's analysis with the previous year's analysis of CBP ex-post and ex-ante average event-hour impacts. The ex-ante impacts in the table reflect the utility peak 1-in-2 weather scenario on an August system peak day in 2016.[34] Because of the wide variability in event windows, we were unable to find suitable August 2014 and August 2015 ex-post events for

[34] Though the ex-ante impacts are labeled as an August peak day, the ex-ante results are identical for each monthly system peak day, May through October, because of the way the SCE ex-ante impacts were modeled.

comparison. For ex-post 2014, we have used the average event day results as a proxy. For ex-post 2015, we have used the average summer event day results for comparison.

Table 5-12 SCE CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day, 2016

					Per Customer (kW)		Aggregate (MW)			Event
	Model	Year	Day	Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (˚F)
DA	Current	Ex-Post 2015	Summer	55	284.5	18.6	15.6	1.0	6.5%	80.6
		Ex-Ante 2016	Aug Peak	30	366.8	41.3	11.0	1.2	11.3%	92.4
	Previous	Ex-Post 2014	Avg. Event	231	430.5	41.5	99.4	9.6	10.0%	84.0
		Ex-Ante 2015/16	Aug Peak	129	508.5	42.6	65.6	5.5	8.4%	86.8
DO	Current	Ex-Post 2015	Summer	670	151.8	24.5	101.7	16.4	16.1%	86.6
		Ex-Ante 2016	Aug Peak	814	195.4	37.2	159.0	30.2	19.0%	92.4
	Previous	Ex-Post 2014	Avg. Event	1,236	221.4	42.6	273.7	52.7	19.0%	88.0
		Ex-Ante 2015/16	Aug Peak	1,162	212.6	42.0	247.0	48.8	19.8%	93.2

Table 5-12 shows the following trends for the CBP DA and DO products:

- **Current Ex-Post Compared with Previous Ex-Ante:** For both the DA and DO product, the current ex-post analysis shows significantly lower per-customer and aggregate impacts for 2015 than predicted in the previous forecast for a monthly system peak day.[35] The percent impacts are also a bit smaller for 2015 ex-post results, but are more in line with the previous ex-ante estimates.
- **Current Ex-Ante Compared with Previous Ex-Ante:** For the DA product, the current ex-ante analysis predicts a comparable per-customer impact, a lower aggregate impact, and a higher percent impact for a monthly system peak day in 2016 than did the previous ex-ante analysis for 2016. For the DO product, the current ex-ante analysis predicts comparable per-customer and percent impacts, but lower aggregate impacts than did the previous ex-ante analysis for a monthly system peak day in 2016. The differences are primarily due to different ex-ante enrollment estimates.
- **Current Ex-Ante Compared with Current Ex-Post:** For the DA product, the current analysis predicts comparable aggregate impacts, but an increase in per-customer and percent impacts between 2015 (ex-post) and 2016 (ex-ante) for a monthly system peak day. For the DO product, the current analysis predicts an increase in per-customer, aggregate, and percent impacts between 2015 (ex-post) and 2016 (ex-ante) for a monthly system peak day.

Table 5-13 compares the current year's analysis with the previous year's analysis of AMP ex-post and ex-ante average event-hour impacts. The ex-ante impacts in the table reflect the utility peak 1-in-2 weather scenario on an August system peak day in 2016. Because of the wide variability in event windows, we were unable to find suitable August 2014 and August 2015 ex-post events for comparison. For ex-post 2014 and 2015, we have used the average event day results as a proxy.

Table 5-13 SCE AMP: Previous and Current Ex-Ante and Ex-Post, August Peak Day, 2016

					Per Customer (kW)		Aggregate (MW)			Event
	Model	Year	Day	Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (˚F)
DO	Current	Ex-Post 2015	Avg. Event	[redacted]						86.7
		Ex-Ante 2016	Aug Peak							93.8
	Previous	Ex-Post 2014	Avg. Event	920	331.0	98.2	304.5	90.3	30.0%	82.0
		Ex-Ante 2015/16	Aug Peak	1,057	306.0	88.5	323.4	93.5	28.9%	93.0

[35] Note that the previous ex-ante impacts for 2015 were the same as for 2016 for both the CBP DA and CBP DO products.

Table 5-13 shows the following trends for the AMP DO product:

- **Current Ex-Post Compared with Previous Ex-Ante:** The current ex-post analysis for an average event day [redacted] combined with an average summer event day [redacted] shows lower per-customer, aggregate, and percent impacts for 2015 than predicted in the previous forecast for a monthly system peak day.[36] The discrepancies could be due in part to the assumptions used in determining an average ex-post 2015 event day.
- **Current Ex-Ante Compared with Previous Ex-Ante:** The current ex-ante analysis predicts very similar aggregate impacts (~94 MW), but a little smaller per-customer and percent impacts for a monthly system peak day in 2016 than did the previous ex-ante analysis for 2016.
- **Current Ex-Ante Compared with Current Ex-Post:** The current analysis predicts a moderate increase in per-customer and aggregate impacts and comparable percent impacts between 2015 and 2016.

SDG&E

Previous and Current Ex-Post

Table 5-14 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past four years for an average event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

For the CBP DA product, the number of accounts decreased from 163 in 2014 to 122 in 2015. The aggregate impacts were also smaller in 2015 (7.8 MW) than in 2014 (9.9 MW). However, on a percent impact basis, 2015 realized 43%, while the 2014 program yielded 25%, which can be explained by the significant decrease in reference load between 2014 and 2015.

For the CBP DO product, the number of accounts decreased from 237 to 223 between 2014 and 2015. The aggregate load impact also decreased, falling from 8.8 MW in 2014 to 5.7 MW in 2015. The percent impacts in 2015 were 12% in 2015 compared to 16% in 2014.

Table 5-14 SDG&E CBP: Previous and Current Ex-Post, Average Event Day

			Per Customer (kW)		Aggregate (MW)			
	Ex-Post Year	Accounts	Reference Load	Load Impact	Reference Load	Load Impact	% Impact	Event Temp (˚F)
DA	2012	78	320	82	25.0	6.4	25%	83
	2013	142	305	76	43.2	10.8	25%	88
	2014	163	247	61	40.4	9.9	25%	87
	2015	122	148	64	18.1	7.8	43%	80
DO	2012	321	230	31	73.7	9.8	13%	86
	2013	260	235	40	61.1	10.5	17%	87
	2014	237	229	37	54.1	8.8	16%	87
	2015	223	208	26	46.4	5.7	12%	81.5

Previous and Current Ex-Ante and Ex-Post

Table 5-15 compares the current year's analysis with the previous year's analysis of CBP ex-post and ex-ante average event-hour impacts. To make the comparison as consistent as possible, the ex-post

[36] Note that the previous ex-ante impacts for 2015 were the same as for 2016 for the AMP DO product.

and ex-ante results represent events on monthly system peak days in August, unless otherwise noted.[37] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.[38]

Table 5-15 SDG&E CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day, 2016

					Per Customer (kW)		Aggregate (MW)			Event
	Model	Year	Day	Accts	Ref. Load	Impact	Ref. Load	Impact	% Impact	Temp (°F)
DA	Current	Ex-Post 2015	Jun 30[39]	131	205.7	65.1	27.0	8.5	31.6%	80.5
DA	Current	Ex-Ante 2016	Aug Peak	122	213.5	62.9	26.0	7.7	29.5%	81.0
DA	Previous	Ex-Post 2014	Aug 1	161	251.4	63.4	40.5	10.2	25.2%	80.8
DA	Previous	Ex-Ante 2015/16	Aug Peak	159	269.4	74.8	42.8	11.9	27.8%	81.0
DO	Current	Ex-Post 2015	Aug 26	216	214.2	25.9	46.3	5.6	12.1%	83.7
DO	Current	Ex-Ante 2016	Aug Peak	220	187.0	20.7	41.2	4.6	11.1%	81.3
DO	Previous	Ex-Post 2014	Avg. Event[40]	237	228.5	37.0	54.1	8.8	16.0%	87.0
DO	Previous	Ex-Ante 2015/16	Aug Peak	284	216.8	36.6	61.5	10.4	16.9%	81.5

Table 5-15 shows the following trends for the CBP DA and DO products:

- **Current Ex-Post Compared with Previous Ex-Ante:** For the DA product, the current ex-post analysis shows a smaller number of accounts, lower per-customer and aggregate impacts, but a higher percent impact for 2015 than predicted in the previous forecast for a monthly system peak day.[41] An explanation for the higher percent impact is the lower reference load in 2015 than predicted for 2016. For the DO product, the current ex-post analysis shows a smaller number of accounts, lower per-customer and aggregate impacts, and a lower percent impact for 2015 than predicted in the previous forecast for a monthly system peak day.
- **Current Ex-Ante Compared with Previous Ex-Ante:** For the DA product, the current ex-ante analysis predicts a smaller number of accounts, lower per-customer and aggregate impacts, but a slightly higher percent impact for a monthly system peak day in 2016 than did the previous ex-ante analysis for 2016. For the DO product, the current ex-ante analysis predicts a smaller number of accounts, lower per-customer and aggregate impacts, and a lower percent impact than did the previous ex-ante analysis for a monthly system peak day in 2016.
- **Current Ex-Ante Compared with Current Ex-Post:** For the DA product, the current analysis predicts that the number of accounts and impacts will be roughly equivalent (albeit slightly smaller) for a 2016 monthly system peak event (ex-ante) compared with the 2015 event (ex-post) with greatest enrollment and highest temperatures (which was June 30). For the DO product, the current analysis predicts enrollment and impacts will be fairly comparable between 2015 (ex-post) and 2016 (ex-ante) for a monthly system peak day, with impacts a little smaller in 2016.

[37] Though the ex-ante impacts are labeled as an August peak day, the ex-ante results are identical for each monthly system peak day, May through October, because of the way the SDG&E ex-ante impacts were modeled.
[38] The 1-in-2 and 1-in-10 ex-ante impacts are equal for the 1-in-2 and 1-in-10 weather conditions, because of the SDG&E ex-ante modeling approach.
[39] For the CBP DA product, approximately 70 accounts under a single aggregator were removed from the ex-post analysis beginning in August of 2015 due to the fact that they changed their nomination to 0 MW. Therefore, we have used the hottest event day (June 30) prior to the removal of these accounts to have a more direct comparison with the ex-ante enrollment and weather forecast.
[40] The 2014 ex-post results for the CBP DO product were not available in the previous year's load impact tables, so we have used the average event day results as a proxy.
[41] Note that the previous ex-ante impacts for 2015 were the same as for 2016 for both the CBP DA and CBP DO products.

Model Validity

As we mention in Section 3, Study Methods, we selected and validated the customer-specific regression models during our optimization process. The customer-specific models are designed to be able to:

1. Accurately predict the actual participant load on event days, and
2. Accurately predict the reference load, or what customers would have used on event days, in absence of an event.

In order to meet these two specific goals, our optimization process included an analysis of both the in-sample and out-of-sample MAPE and the MPE for each of the candidate regression models for each customer. We used the out-of-sample tests to show how well each of the candidate models could predict a customer's load on non-event days that were as similar as possible to actual event days; this test gave us an estimate of how well each model could predict the reference load. We used the in-sample tests to show how well each model performed on the actual event days; therefore, it helped us understand how well the model was able to match the actual load. Our optimization procedure had several steps, which are described below:

- First, we identified the out-of-sample event-like days as several days that are similar to event days, but were not event days, based on temperature, month, and day of the week. In some cases because of the frequency of events, event-like days were selected from 2014.
- After identifying the event-like days, those days were removed from the analysis dataset and the candidate models were fit to the remaining data.
- Next, the results of the candidate models were used to predict the usage on the out-of-sample days. Then we assessed the error and bias in the reference load by calculating the MAPE and MPE between the actual usage and the predicted usage on the out-of-sample days.
- Finally, we compared the actual and predicted loads on the event days from 2015. We also calculated the MAPE and MPE on these days to assess the error and bias in the actual predicted load.

The final step of the process was to select the candidate model with the minimum weighted MAPE and MPE for each individual customer. This model then became the final model specification. We describe the steps in more detail in the subsections that follow.

Selecting Event-Like Days

In order to select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. To determine how close event day temperature is to a potential event-like day, we calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance; in this case we used average on-peak and average daily temperatures. The Euclidean distance for this set of variables can be calculated by Equation 6.1 below.

$$ED = \sqrt{(OnPeakTemp_{event} - OnPeakTemp_{non-event})^2 + (DailyTemp_{event} - DailyTemp_{non-event})^2} \quad (6.1)$$

In Table 6-1 to Table 6-3 below we show the event-like days that we selected for each utility along with the average on-peak temperature by product for each day.

Table 6-1 PG&E Event-Like Days and Average On-Peak Temperatures (°F) by Product

Dates	CBP DA	CBP DO	AMP DO
6/10/2014	81	81	86
7/24/2014	88	88	89
7/30/2014	86	87	89
7/31/2014	87	87	92
9/10/2014	86	87	89
9/12/2014	87	88	90
9/17/2014	82	82	87
6/18/2015	81	80	86
7/13/2015	81	80	84
7/20/2015	86	87	88
7/31/2015	82	81	88
8/7/2015	81	80	84
8/28/2015	91	90	94
9/8/2015	94	95	95
9/21/2015	92	92	94
9/24/2015	89	89	90
10/12/2015	87	87	88
10/13/2015	88	88	89

Table 6-2 SCE Event-Like Days and Average On-Peak Temperatures (°F) by Product

Summer Dates	CBP DA	CBP DO	AMP DO	Non Summer Dates	CBP DA	CBP DO	AMP DO
5/1/2014	88	88	88	1/13/2014	73	71	68
5/7/2014	64	65	66	1/16/2014	79	77	75
5/16/2014	87	88	90	1/22/2014	68	67	67
5/19/2014	70	71	72	1/31/2014	60	58	57
6/3/2014	78	81	83	2/18/2014	62	64	64
6/12/2014	73	77	80	2/19/2014	63	65	65
7/1/2014	78	83	87	2/24/2014	67	69	70
7/8/2014	82	86	90	3/6/2014	67	68	68
7/24/2014	88	91	93	3/21/2014	65	66	67
7/28/2014	83	86	88	4/7/2014	81	81	82
7/29/2014	83	86	89	4/9/2014	77	81	83
8/18/2014	81	84	87	4/16/2014	69	71	74
10/2/2014	91	89	89	1/7/2015	72	71	70
10/21/2014	73	73	73	2/6/2015	69	70	71
5/12/2015	68	69	70	3/5/2015	72	72	71
5/14/2015	55	56	55	3/12/2015	82	80	80
5/18/2015	66	67	67	3/24/2015	73	71	70
5/22/2015	63	63	63	4/6/2015	62	62	63
6/10/2015	74	75	77	4/10/2015	67	69	70
6/24/2015	82	84	88				
7/10/2015	74	75	77				
7/20/2015	83	83	85				
7/24/2015	83	85	87				
8/4/2015	84	86	87				
9/14/2015	78	78	78				
9/16/2015	75	75	75				
9/17/2015	78	78	79				
9/22/2015	79	80	82				

Table 6-3 SDG&E Event-Like Days and Average On-Peak Temperatures (°F) by Product

Dates	CBP DA	CBP DO
5/2/2014	84	84
5/13/2014	90	90
6/3/2014	73	73
7/3/2014	75	75
7/7/2014	76	76
7/9/2014	74	74
7/24/2014	81	81
7/25/2014	76	75
7/29/2014	80	80
8/13/2014	74	74
8/15/2014	79	79
9/8/2014	84	83
10/7/2014	79	79
10/24/2014	79	79
6/19/2015	77	76
6/23/2015	78	78
7/23/2015	77	77
8/7/2015	73	73

Optimization Process and Results

Next we estimated the MAPE and MPE, for the entire day, and for the on-peak period, for each customer, and for each candidate model, both for the in-sample period and for the out-of-sample period. This resulted in thousands of in-sample and out-of-sample tests. Recall that the goal of the tests is to find the best model for each customer in terms of its ability to predict the reference load, and its ability to predict the actual load. Therefore, we collapsed the tests into a single metric, which could be calculated for each customer and each candidate model.

The metric is defined in Equation 6.2 below:

$$\boldsymbol{metric_{ic}} = 0.7\{\,(0.5 * DailyEvntMAPE) + (0.5 * DailyEvntlikeMAPE)\} + 0.3\{\,(0.5 * OnpkEvntMAPE) + (0.5 * OnpkEvntlikeMAPE) \qquad (6.2)$$

Once we computed a single metric for each customer and candidate model combination, we then selected the best model for each customer by choosing the model specification with the smallest overall metric. The results of the optimization process are shown in the following tables and figures.

In Table 6-4 below we present the weighted average MAPE and MPE for the final set of per customer models for each utility, by product.[42] [43] Across all three IOUs, programs, and products, all MAPE and MPE estimates are below 11%; in addition, they tend to be lower for the CBP programs across the board, with all MPE and MAPE values being less than 7.0%. All of the MPE values are negative, indicating that the models tend to under predict the load rather than over predict, however the MPE values are still relatively small indicating a relatively low level of bias.

[42] We present a weighted average where the weights are based on each customer's contribution to the total load impact. This weighted MAPE is more comparable, but likely still higher than, the MAPE that might come from an aggregate regression.
[43] We also excluded any very extreme cases since individual customer MAPES can be misleading, especially for customers with very large impacts, but very low actual event day loads, e.g. agricultural customers that drop load to near zero can have very large impacts and any deviation from a very small number can yield an extreme error. No more than 2% of the population was excluded in any given group.

Table 6-4 Weighted Average MAPE and MPE by Utility and Product

Utility	Program	Notice	Out-of-Sample MAPE	Out-of-Sample MPE	In-Sample MAPE	In-Sample MPE
PG&E	CBP	DA	0.6%	-0.4%	1.7%	-1.5%
		DO	0.6%	-0.5%	0.6%	-0.3%
	AMP	DO	8.9%	-7.2%	9.4%	-5.0%
SCE	CBP	DA	0.9%	-0.7%	0.6%	-0.3%
		DO	6.1%	-5.0%	6.7%	-2.0%
	AMP	DO	8.9%	-7.5%	10.6%	-4.3%
SDG&E	CBP	DA	1.4%	-0.9%	3.3%	-2.0%
		DO	0.6%	-0.4%	2.8%	-1.6%

In Figure 6-1 to Figure 6-4 below we present the average event-like day predicted and actual loads from the out-of-sample tests, by product and utility. In each case the predicted load is very close to the actual load. This tells us that on average, the customer-specific regression models do a very good job estimating what customer loads would be like on event-like days, and therefore are able to produce very accurate reference loads.

Figure 6-1 PG&E Actual and Predicted Loads on Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

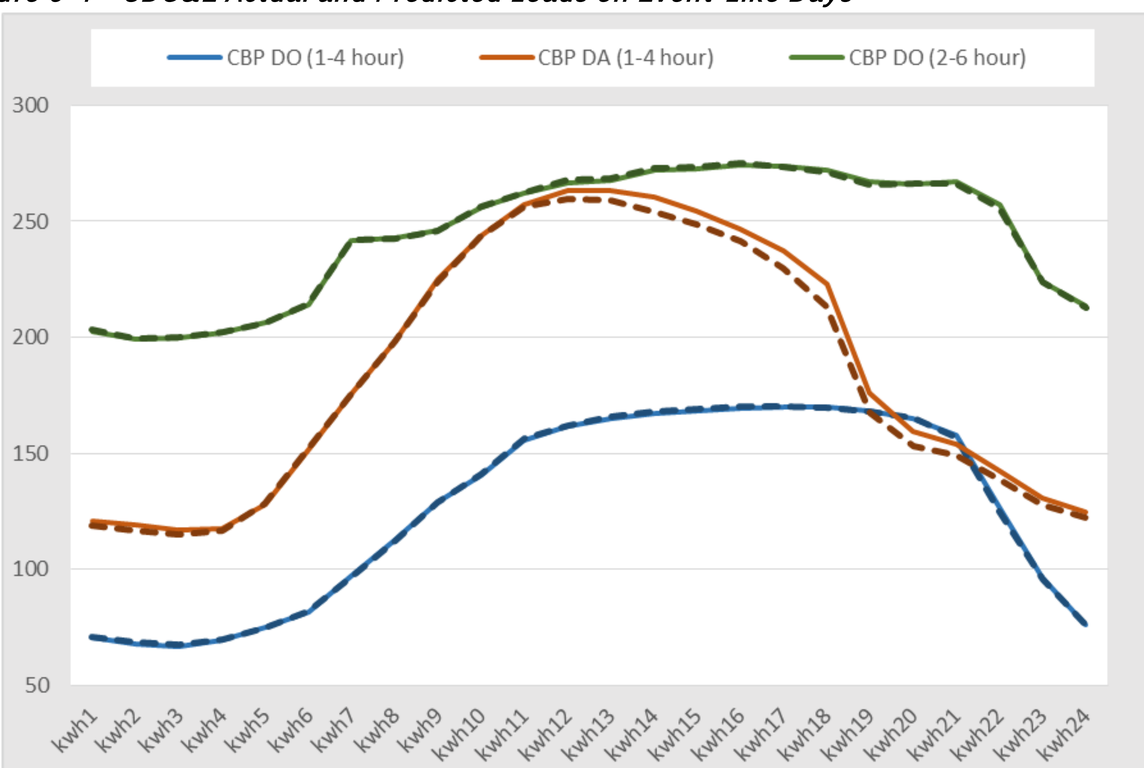
Figure 6-2 SCE Actual and Predicted Loads on Summer Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

Figure 6-3 SCE Actual and Predicted Loads on Winter Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

Figure 6-4 SDG&E Actual and Predicted Loads on Event-Like Days



Additional Checks

Visual inspection can be a simple but highly effective tool. During the inspection, we looked for specific aspects of the subgroup level predicted and reference load shapes to tell us how well the models performed. For example,

- We checked to make sure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate that there is a problem with the reference load either over or under estimating usage in absence of the event.
- We closely examined the reference load for odd increases or decreases in load that could indicate an effect that is not properly being captured in the models. If we found such an increase or decrease, we investigated the cause and attempted to control for the effect in the models.
- We also looked for bias both visually and mathematically. Bias is the consistent over or under prediction of the actual load. We may see bias that is temperature-related, under-predicting on hot days, and over-predicting on cool days. We have also seen bias that is time-based, over-predicting in the beginning of the year, and under-predicting at the end of the year. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

Key Findings and Recommendations

Key Findings

This evaluation was able to estimate the incremental impacts of AutoDR participants using a matched control group with statistical DID. Table 7-1 shows the incremental per customer impacts and aggregate impacts for each product with a statistically significant estimate.[44] Statewide AutoDR participants achieved impacts that are approximately 9 kW higher, on average, than their non-enabled counterparts. In addition, the enabling technology accounts for an incremental reduction of approximately 3.4 MW. Given that, in total, the AutoDR participants provided approximately 13.6 MW, we can conclude that the AutoDR technology allowed for an incremental additional impact of approximately 25%.

Table 7-1 Statewide Incremental Impacts Associated with AutoDR

Program	Number of Customers	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate(MW)	Total Aggregate Impact (MW)	Significant
PG&E AMP	68	10.2	0.7	5.0	Yes
PG&E CBP	125	11.5	1.4	4.3	Yes
SDG&E CBP	97	6.2	0.6	2.2	Yes
SCE CBP	72	9.76	0.7	2.1	Yes
Statewide	**362**	**9.28**	**3.4**	**13.6**	

Below we present some additional key findings for each IOU.

PG&E

Figure 7-1 and Figure 7-2 summarize the average event-hour load impacts for PG&E's CBP and AMP offerings, respectively. The figures include the average event day ex-post impacts for 2012 through 2015 and the August peak ex-ante impacts projected for 2016 under the utility 1-in-2 weather condition.[45] The gray bars are aggregate impacts (left y-axis) and the dark blue bars are per-customer impacts (right y-axis). The figures also include values for the average event-hour percent load impact relative to the reference load above the bars (%) and the number of accounts along the top of each figure. The figures illustrate several key findings:

- **CBP DA and DO Aggregate Impacts are on the Rise:** The aggregate impacts dropped between 2012 and 2014 for both DA and DO. However, the aggregate impacts increased in 2015 and are expected to increase even more for DA in 2016. For the DA product, this trend is due predominantly to a much greater number of nominated accounts in 2015 and 2016 than in 2013 and 2014. For DO, the upward trend is due to a gradual increase in the number of nominated accounts coupled with an increase in per-customer impacts relative to 2014.
- **CBP DA Percent Impacts are Lower than in Past Years:** The percent impacts realized for an average event day in 2015 (19%) and projected for a monthly system peak day in 2016 (23%) are less than those for the 2012-2014 average event days (range of 31-44%).

[44] For SCE's AMP participants, there were enough non-enabled customers to select a control group, however, there were simply not enough events with similar windows called to estimate statistically significant impacts for either of the AMP products.
[45] The ex-ante impacts for PG&E's 1-in-2 and 1-in-10 weather conditions are the same.

- **CBP DO Percent Impacts Increased in 2015:** The lowest percent impacts for DO were in 2014 (14%). They rose considerably in 2015 (20%) for an average event day and are projected to decrease to 16% for a monthly system peak day in 2016.
- **CBP DO Outperforms DA in Aggregate Impacts, but Underperforms in Per-Customer Impacts:** In 2012 through 2015, the DO product has had higher aggregate impacts. Much of this is due to more nominated accounts for DO than for DA. In contrast, the per-customer impacts have been substantially lower for DO than DA. In 2016, DA's aggregate impacts are expected to be higher than DO's.
- **AMP DO Impacts are on the Decline:** Since 2013, aggregate and per-customer impacts for AMP have declined. The impacts are expected to continue to decline in 2016. Since the number of nominated accounts has increased slowly since 2012, the driving factor for the decline is a decrease in per-customer load impacts.
- **AMP DO Outperforms CBP in Aggregate Impacts; Comparable to CBP DA in Per Customer Impacts:** With aggregate impacts near 100 MW in 2015, AMP DO greatly exceeds 2015 impacts for CBP DA (16 MW) and CBP DO (20 MW). AMP's per-customer impacts (68 kW) are relatively close to that of CBP DA (80 kW).

Figure 7-1 PG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2016

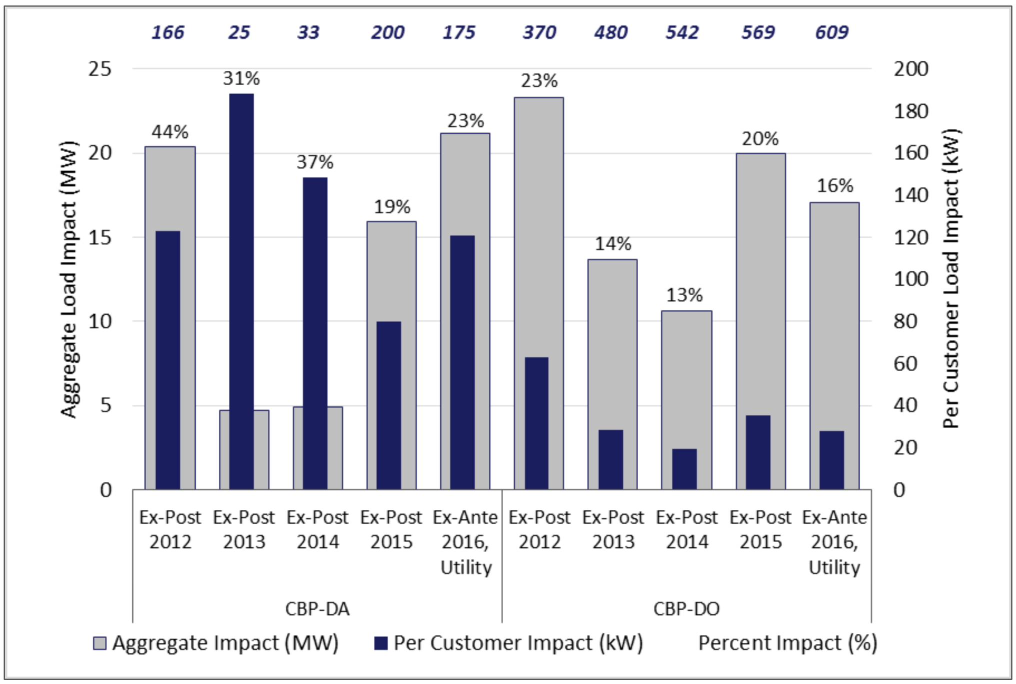
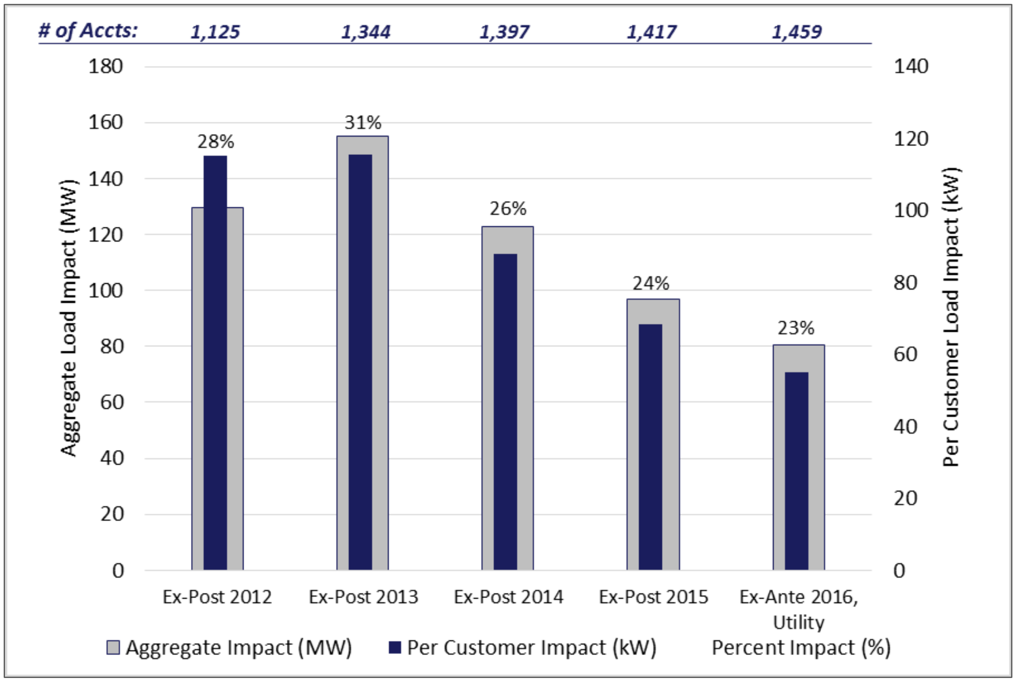


Figure 7-2 PG&E AMP: Comparison of Average Event-Hour Load Impacts, 2012-2016



SCE

Figure 7-3 and Figure 7-4 on the following page summarize the average event-hour load impacts for SCE's CBP and AMP offerings, respectively. The figures include the average event day ex-post impacts for 2012 through 2015 and the August peak ex-ante impacts projected for 2016 under the utility 1-in-2 weather condition.[46] The gray bars are aggregate impacts (left y-axis) and the dark blue bars are per-customer impacts (right y-axis). The figures also include values for the average event-hour percent load impact relative to the reference load above the bars (%) and the number of accounts along the top of each figure. Because the figures compare ex-ante results under full enrollment and peak weather conditions, the ex-ante impacts are generally overstated relative to the ex-post impacts, which represent results for an average event day that would on average have lower participation and less extreme weather. Nevertheless, the figures illustrate several key findings:

- **CBP DA and DO Aggregate Impacts are Lower than in 2014:** The aggregate impacts dropped between 2014 and 2015 for both DA and DO due to lower enrollment and lower per-customer impacts. However, the per-customer, aggregate, and percent impacts are expected to increase for both products in 2016.
- **CBP DO Outperforms DA in Aggregate Impacts:** In 2012 through 2015, the DO product has had higher aggregate impacts. This is primarily due to a much greater number of nominated accounts for DO than for DA. In 2016, DO's aggregate impacts are again expected to be higher than DA's, but DO's per-customer impacts are expected to be slightly lower.
- **AMP DO Impacts Dipped in 2015:** AMP aggregate impacts dipped in 2015 but are expected to increase in 2016. After 2017, the fate of AMP contracts is unknown. Percent impacts have been relatively stable for the program since 2012.
- **AMP DO Outperforms CBP:** AMP DO has consistently had greater aggregate, per-customer, and percent impacts than either of the two CBP products since 2012.

[46] The ex-ante impacts for PG&E's 1-in-2 and 1-in-10 weather conditions are the same.

Figure 7-3 SCE CBP: Comparison of Average Event-Hour Load Impacts, 2012-2016

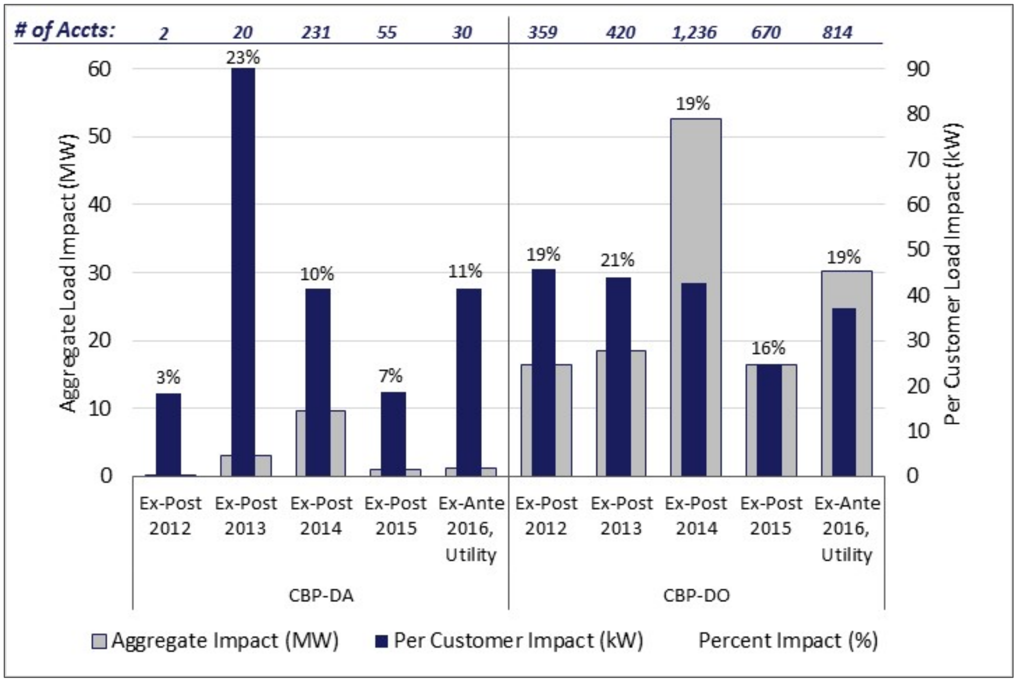


Figure 7-4 SCE AMP: Comparison of Average Event-Hour Load Impacts, 2012-2016

Figure redacted to protect customer or aggregator confidentiality.

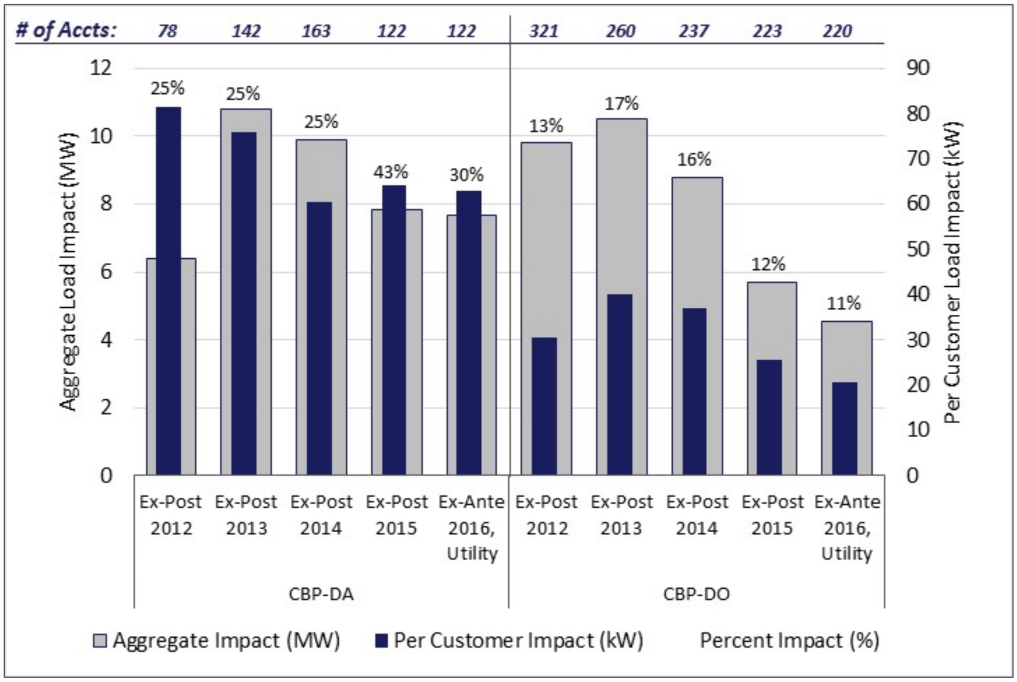
SDG&E

Figure 7-5 summarizes the average event-hour load impacts for SDG&E's CBP offerings. The figure includes the average event day ex-post impacts for 2012 through 2015 and the August peak ex-ante impacts projected for 2016 under the utility 1-in-2 weather condition.[47] The gray bars are aggregate impacts (left y-axis) and the dark blue bars are per-customer impacts (right y-axis). The figures also include values for the average event-hour percent load impact relative to the reference load above the bars (%) and the number of accounts along the top of each figure. Because the figures compare ex-ante results under full enrollment and peak weather conditions with ex-post results for an average event day that may on average have lower participation and less extreme weather, caution should be exercised in making direct comparisons between the ex-post and ex-ante impacts. The figures illustrate several key findings:

- **CBP DA and DO Aggregate Impacts Peaked in 2013:** The aggregate impacts for the average event day dropped between 2013 and 2015 for both DA and DO. They are predicted to stay about the same for DA in 2016 and decrease a bit more for DO on a monthly system peak day.
- **CBP DA Percent Impacts are Higher than in Past Years:** The percent impacts realized for the average event day in 2015 (43%) and projected for a monthly system peak day in 2016 (30%) are greater than those for 2012-2014 (25%).
- **CBP DO Percent Impacts are Decreasing:** The highest percent impacts for DO were in 2013 (17%) for the average event day. They decreased in 2015 (12%) and are projected to decrease again slightly for a monthly system peak day in 2016 (11%).
- **CBP DA Currently Outperforms DO:** Since 2013, the DA product has had higher aggregate impacts than DO, and the forecast points to higher impacts again in 2016. Since there are fewer nominated accounts for DA, the higher impacts are due to substantially higher per-customer impacts for DA than DO.

[47] The ex-ante impacts for SDG&E's 1-in-2 and 1-in-10 weather conditions are the same.

Figure 7-5 SDG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2016



Recommendations

AEG's recommendations for the PY2016 CBP and AMP program operations and the evaluation of load impacts are as follows:

- **Continue to offer AutoDR Enablement:** This evaluation was able to show incrementally higher impacts for AutoDR enabled customers. Therefore AEG recommends that the IOUs continue to encourage participants to adopt automated response technology. However, the actual ex-post impacts achieved by AutoDR participants are generally lower than the total kW indicated by the load shed test results. This suggests that these customers have the potential to provide incrementally more impacts.

Rationale: The evaluation identified an incremental per customer impacts of 9 kW, on average, which is approximately a 25% increase over a similar non-enabled load impact.

- **Compare Reference Load and Estimated Observed Load:** AEG recommends using difference between the reference load and the estimated observed load in both the hourly load profiles and to estimate the impacts for the programs.

Rationale: The current approach, creating the estimated reference load by adding back the impacts, can have unintended impacts on the shape of the reference load in specific cases.

Load Impact Tables

PG&E CBP Ex-Post Load Impact Tables

SCE CBP Ex-Post Load Impact Tables

SDG&E CBP Ex-Post Load Impact Tables

PG&E AMP Ex-Post Load Impact Tables

SCE AMP Ex-Post Load Impact Tables

PG&E CBP Ex-Ante Load Impact Tables

SCE CBP Ex-Ante Load Impact Tables

SDG&E CBP Ex-Ante Load Impact Tables

PG&E AMP Ex-Ante Load Impact Tables

SCE AMP Ex-Ante Load Impact Tables

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