2016 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: Ex-Post and Ex-Ante Load Impacts

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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 2016 (PY2016). 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 to 1) estimate the ex-post load impacts for PY2016, and 2) estimate ex-ante load impacts for the programs for years 2017 through 2027.

As part of these programs, DR aggregators contract with the IOUs and with non-residential 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.

Nominated customer service accounts in the DO versions of all of the programs exceeded those in the DA versions, and were higher for AMP than for CBP. Numbers of nominated customer service accounts[1] ranged from less than 30 service accounts for some CBP product types, to over 1,500 for AMP. The various programs and notice types were called from 7 to 98 times in 2016, 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, in cases of localized distribution events, or based upon CAISO awards.

AEG estimated hourly ex-post load impacts for each program, notice type, and event during 2016, using regression analysis of individual customer-level hourly load, weather, and event data. The estimated load impacts are reported here by IOU for each event associated with each program and product type (e.g., DA 1-4 hours and DO 2-6 hours). Load impacts for the average event day are also reported by industry type and CAISO local capacity area (LCA) where relevant. In addition, AEG estimated ex-post impacts associated with Technical Assistance and Technology Incentives (TA/TI) and AutoDR participants as compared with matched groups of similar non-enabled participants and reported the incremental impacts.

Estimated aggregate load impacts for the typical CBP DA event were [redacted] for PG&E, [redacted] for SCE, and 3.5 MW for SDG&E. Aggregate load impacts for CBP with DO notice were 9.2 MW for PG&E, [redacted] for SCE, and 4.8 MW for SDG&E. The typical AMP aggregate load impacts were generally larger, with PG&E's DO product averaging 64.9 MW and SCE's DO products averaging [redacted]. Overall, the results of the assessment of incremental savings due to AutoDR and TA/TI were inconclusive in PY2016. We saw a marked reduction in participation across the state vs. last year, and while some products did show incremental savings, others showed incremental increases, or insignificant results.

AEG developed ex-ante load impact forecasts by combining enrollment forecasts provided by the IOUs, 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 ex-ante load impacts presented in the report reflect several program changes expected to take place beginning in 2017.

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

Executive Summary

This report describes the load impact evaluation of aggregator DR programs offered by PG&E, SCE, and 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 types of price-responsive DR programs: Capacity Bidding Program (CBP), which is operated by all three IOUs, and PG&E's and SCE's Aggregator Managed Portfolio (AMP) programs. The AMP programs are utility-specific offerings 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 involved in the contracts between the aggregators and the participating customers.

The primary goals of the 2016 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU for PY2016.
- Estimate average monthly ex-ante load impacts for each product and IOU for years 2017 through 2027.

Program Descriptions

In the following subsections we present a description of each program and the total number of nominated accounts that responded to an average summer event for each program by IOU.

Capacity Bidding Program

CBP is a demand response program open to customers on a non-residential TOU rate. Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[2] Customers may sign up directly with the IOU as a self-aggregator or they can participate through a third party demand response aggregator.[3] CBP provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, the event duration, and the event notice option. The program has two notification options: day-ahead (DA) and day-of (DO). Additional energy payments ($/kWh) are made to some customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[4] 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).

The CBP aggregator's delivered monthly capacity incentive payment is adjusted based upon the aggregator's actual performance for the operating month. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50%, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[5] Aggregators pay incentives to the participating customers based on the agreement between the aggregator and the participating customer. Participating aggregators may adjust their CBP nominations each month, as well as their

[2] PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.
[3] The vast majority of the participants are third-party aggregators.
[4] PG&E and SDG&E's energy payments are made to bundled customers; SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.
[5] Customers participating directly receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. (Note that all of PG&E's CBP customers participate through aggregation.)

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 minimum-maximum event durations).

CBP events can be triggered under various conditions: 1) when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater for PG&E and SCE and 19,000 BTU/kWh for SDG&E;[6] 2) the utility receives a market award of dispatch instruction from the California Independent System Operator (CAISO); or 3) when the utility, in its sole opinion, forecasts that generation or electric resources may not be adequate.

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 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.

The IOUs anticipate several program changes to take place for CBP beginning in PY2017. The ex-ante analysis presented in this report addresses the changes that are expected to affect the enrollment and load impact forecasts for 2017-2027.

Aggregator Managed Portfolio

AMP is an aggregator-managed demand response program. Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[7] Under AMP, third-party demand response aggregators enter into bilateral contracts with PG&E and/or SCE, and may create their own aggregated DR program in which participating customers achieve load reductions. In addition to being responsible for designing their DR program, aggregators are also responsible for acquisition, marketing, sales, retention, support, and event notifications and tactics.

Each aggregator has a contractual curtailment level specified for each month. This curtailment comes from their portfolio of nominated customers. Capacity and energy payments vary with each aggregator.[8] The aggregators are penalized if they fail to deliver their committed load reductions. Aggregators determine compensation and/or penalties for their participating customers. The settlement baselines are based on the aggregate 10-in-10 method, with an optional day-of adjustment.

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, based upon a CAISO market award, and/or the utility, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system.

PG&E

PG&E's AMP program was open to customers on a non-residential TOU rate. In PY2016, PG&E had AMP contracts with two aggregators. Both offered DO contracts only. Each aggregator could call up to 76 hours of events each year between the hours of 11 a.m. and 7 p.m., including test events. PG&E had two types of products: DO Local, and DO system. The local product allowed program dispatch by Sub-Load Aggregation Points (Sub-LAPs), while the system product could only dispatch the service territory as a whole. Customers who participated in AMP with DO notice were also allowed to dually enroll in PG&E's Demand Bidding Program (DBP) or Peak Day Pricing (PDP).

PG&E's AMP program was discontinued at the end of PY2016.

SCE

SCE's AMP program is open to all customers. AMP aggregators have historically only enrolled non-residential customers. On December 22, 2014, the CPUC issued Resolution E-4695 approving two AMP contracts for SCE for 2015-2016. Both contracts are DO contracts. AMP aggregators have the ability to move between SCE's AMP and CBP programs, as long as they are also an authorized CBP

[6] In February 2016, SDG&E filed an Advice Letter to change its heat rate trigger from 15,000 to 19,000 BTU/kWh (AL 2858-E). It was approved by the Commission on June 24, 2016 and SDGE is now dispatching based on this new heat rate trigger.
[7] PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.
[8] PG&E's and SCE's AMP contracts only provide energy payments for Bundled-Service customers.

aggregator, but customers cannot be nominated for both programs for the same operating month. 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.

The CPUC issued Decision 16-06-029, which authorized SCE to continue its AMP program through PY2017.

Number of Accounts

In Table E-1, we present the total number of nominated accounts that responded for the average summer event day in 2016 by program, notice type, and utility.[9,10]

Table E-1 Summary of Nominated Accounts, Average Summer Event Day

		Nominated Accounts	
Program	**Utility**	**Day-Ahead**	**Day-Of**
CBP	PG&E	42	406
	SCE	28	243
	SDG&E	67	184
	Total	**137**	**833**
AMP	PG&E	-	1,236
	SCE	-	
	Total	**-**	

Evaluation Methods

AEG used customer-specific regression models as the primary evaluation method for both the ex-post and ex-ante load impact 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. 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.

[9]An average summer event day for each of PG&E and SDG&E's products is calculated as the average of all HE16 – HE19 system level events for the given product. For SCE's CBP DO program, the average summer event day is based on the average of all HE17 – HE19 events during June-September. For SCE's CBP DA program, the average summer event day is based on the average of all HE17 – HE19 events for the 1-4 Hour product during June-September, since the 2-6 Hour product only called events during non-summer months in 2016. For SCE's AMP DO program, the average summer event is calculated as a combination of a typical DO 1-5 Hour summer event and a typical DO 1-6 Hour summer event.

[10] 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. Therefore, the average number of accounts for an average day may be different than a simple average of total accounts across each event. In addition, the number of accounts for the combined products (e.g., CBP DO) may be different than the sum of the number of accounts for individual products (e.g., CBP DO 1-4 hour plus CBP DO 2-6 hour) because of the averaging method.

After developing a set of customer-specific regression models to estimate the ex-post impacts, AEG used the same models to predict the ex-ante impacts under the Utility and CAISO 1-in-2 and 1-in-10 weather scenarios.

AEG also estimated the incremental impacts associated with AutoDR and Technical Assistance and Technology Incentives (TA/TI) program participants as compared with non-enabled participants. The first step was to use a Euclidean Distance matching approach to select a group of CBP participants that were similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI. Then, AEG estimated the incremental impacts using a statistical difference-in-differences (DID) approach.

Results

2016 Events

Table E-2 shows the number of event days by notification type, program, and utility for the PY2016 evaluation period.[11]

Table E-2 Summary of PY2016 Event Days by Notice Type

		Nov 2015-Apr 2016 Number of Events by Notice Type		May-Oct 2016 Number of Events by Notice Type	
Program	**Utility**	**Day-Ahead**	**Day-Of**	**Day-Ahead**	**Day-Of**
CBP	PG&E	-	-	16	19
	SCE	7	46	50	52
	SDG&E	-	-	14	7
AMP	PG&E	-	-	-	14
	SCE	-	-	-	7

2016 Ex-Post Impacts

Table E-3 summarizes the 2016 ex-post load impacts and nominated capacity by notification type, program, and utility. The data presented are for the average summer event day.

Table E-3 Summary of PY2016 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

		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				22.6	9.2	12.0
	SCE						
	SDG&E	51.4	3.5	4.0	24.0	4.8	3.9
AMP	PG&E	-	-	-	52.5	64.9	76.3
	SCE	-	-	-			

Effects of Enabling Technology

Overall, the results of the assessment of incremental savings due to AutoDR and TA/TI were inconclusive in PY2016. We saw a marked reduction in participation across the state vs. last year, and while some products did show incremental savings, others showed incremental increases, or insignificant results.

[11] The PY2016 evaluation period is May 1 through Oct. 31, 2016 for PG&E and SDG&E, and is Nov. 1, 2015 – Oct. 31, 2016 for SCE.

Enrollment Forecast

Table E-4 summarizes the enrollment forecast by program, utility, notification type, and year, during the month of August.

- PG&E forecasts constant enrollment across the 2017-2027 horizon for the CBP products. PG&E forecasts no AMP accounts after 2016 due to program discontinuation.
- SDG&E's enrollment forecast for the CBP DA and DO products assumes the customer enrollment will increase by 3% per year starting in 2019 through 2022 due to the CBP program improvements proposed by SDG&E in the application for 2018-2022. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 7% per year starting in 2019 through 2022 due to growth in the Technical Incentives (TI) program. Therefore, total CBP DO enrollment for SDG&E is expected to increase by 10% per year (3% + 7%) starting in 2019 through 2022 due to program improvements and growth in TI. The enrollment forecasts for SDG&E's DA and DO products after 2022 and through 2027 show a flat trend at the 2022 values.
- SCE forecasts no AMP accounts after 2017 and an increase in service accounts for the CBP DO product beginning in 2018 due to the elimination of AMP.

Table E-4 2017-2027 Enrollment Forecast, During Month of August

			Number of Service Accounts					
Program	**Utility**	**Notice**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022-2027 (Each Year)**
CBP	PG&E	DA	50	50	50	50	50	50
		DO	611	611	611	611	611	611
	SCE	DA	30	90	90	90	90	90
		DO	814	1,250	1,250	1,250	1,250	1,250
	SDG&E	DA	70	70	72	74	76	78
		DO	199	199	219	241	265	292
AMP	SCE	DO		-	-	-	-	-

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.

Table E-5 Summary of Average Event-Hour Ex-Ante Impacts, August Peak Day, 2017

			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	6.9	6.9	6.9	6.8
		DO	13.6	13.8	13.7	13.7
	SCE	DA	1.6	1.6	1.6	1.6
		DO	29.3	29.3	29.3	29.3
	SDG&E	DA	0.8	0.9	0.9	0.9
		DO	5.1	5.0	5.0	5.0
AMP	SCE	DO				

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 forecasted numbers of nominated customer service accounts and aggregate load impacts reflect several anticipated program changes that were approved by the Commission on

June 9, 2016.[12] Specifically, PG&E's AMP program has been discontinued as of the end of PY2016 and therefore will not be a part of the ex-ante forecast. In addition, SCE plans to stop offering AMP after PY2017, so there will only be one year of ex-ante impacts for SCE's AMP program. For both utilities, some of the AMP accounts are expected to move to CBP as a result of AMP ending.

Another notable change reflected in the forecast is that the Commission has approved tariff changes for PG&E's CBP. The changes increase CBP incentive levels to bring them more in line with the current market. Our analysis shows that this change is expected to have only a minimal impact on per-customer ex-ante impacts for PG&E's CBP.

SCE is also making several changes to CBP, including but not limited to streamlining CBP offerings to two products, increasing capacity prices, and reducing the number of events. The SCE changes are expected to take effect Dec. 31, 2017 and are intended to improve and simplify bidding into the CAISO wholesale market, align prices with current value, decrease customer fatigue, and increase participation. As a result, the SCE changes are anticipated to increase CBP enrollment over time, beginning in 2018.

On August 1, 2016, all three IOUs filed Advice Letters proposing to add an energy price component to the current CBP heat rate trigger.[13] As of March 2017, the IOUs have not received the Commission's resolution on the proposed trigger changes.

Recommendations

For the PY2017 evaluation of CBP and AMP load impacts, AEG recommends investigating any AutoDR and TA/TI customers whose load impacts are far less than their load shed test results to determine the reasons for the discrepancy.

[12] Decision Adopting Bridge Funding for 2017 Demand Response Programs and Activities. Decision 16-06-029. June 9, 2016. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K467/163467479.PDF.

[13] SCE Advice Letter 3444-E; PG&E Advice Letter 4887-E; and SDG&E Advice Letter 2936-E.

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Introduction

This report documents the load impact evaluation of the aggregator-based DR programs operated by PG&E, SCE, and SDG&E for PY2016. The scope of the evaluation covers CBP and AMP. CBP is offered by all three IOUs and AMP is offered by PG&E and SCE.

Research Objectives

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

1. Ex-post impacts are calculated 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 and product. They are provided for the average customer and for all customers in aggregate. They are also presented separately for each industry group, each LCA, each size group, each aggregator, for AutoDR, for dually enrolled participants, and for the service territory as a whole.[14]
2. Ex-ante impacts are presented for each year over an 11-year time horizon, based on both 1-in-2 and 1-in-10 weather conditions. These results are presented separately for each program and notification type. The impacts are presented for all hours in which the program is available for: the average customer, all customers in aggregate, each LCA (as applicable), each size group (as applicable), and the service territory as a whole. In addition, results are provided for a typical event day and each monthly system peak day. 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.

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 2016 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.

[14] Some sub-categories of data are only available in the confidential versions of the Excel-based Protocol table generators that accompany the confidential report.

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

CBP is a demand response program open to customers on a non-residential TOU rate. Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[15] Customers may sign up directly with the IOU as a self-aggregator or they can participate through a third party demand response aggregator.[16] CBP provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, event duration, and the event notice option (DA or DO). Additional energy payments ($/kWh) are made to some customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[17] 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).

The CBP aggregator's delivered monthly capacity incentive payment is adjusted based upon the aggregator's actual performance for the operating month. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50%, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[18] Aggregators pay incentives to the participating customers based on the agreement between the aggregator and the participating customer. Participating aggregators may adjust their CBP 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 minimum-maximum event durations).

CBP events can be triggered under various conditions: 1) when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater for PG&E and SCE and 19,000 BTU/kWh for SDG&E;[19] 2) the utility receives a market award of dispatch instruction from the CAISO; or 3) when the utility, in its sole opinion, forecasts that generation or electric resources may not be adequate.

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.

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

[15] PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.
[16] The vast majority of the participants are third-party aggregators.
[17] PG&E and SDG&E's energy payments are made to bundled customers; SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.
[18] Customers participating directly receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. (Note that all of PG&E's CBP customers participate through aggregation.)
[19] In February 2016, SDG&E filed an Advice Letter to change its heat rate trigger from 15,000 to 19,000 BTU/kWh (AL 2858-E). It was approved by the Commission on June 24, 2016 and SDGE is now dispatching based on this new heat rate trigger.

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, Finance, Services	51-56, 62, 72
6. Schools	61
7. Institutional/Government	71, 81, 92
8. Other/Unknown	NA

Table 2-2 presents the number of nominated service accounts that responded during an average summer CBP event in 2016.

Table 2-2 CBP Nominated Service Accounts, by Utility and Industry Group, Average Summer Event Day (2016)

		Day-Ahead		Day-Of	
Utility	Industry Type	Accounts	Sum of Max Demand (kW)	Accounts	Sum of Max Demand (kW)
PG&E	1. Agriculture, Mining & Construction				
	2. Manufacturing				
	3. Wholesale, Transport, Other Utilities				
	4. Retail Stores	23	13,418	290	53,949
	5. Offices, Hotels, Finance, Services				
	6. Schools			-	-
	7. Institutional/Government				
	8. Other/Unknown				
	Total			406	111,701
SCE	1. Agriculture, Mining & Construction	-	-		
	2. Manufacturing	-	-		
	3. Wholesale, Transport, Other Utilities	-	-		
	4. Retail Stores			212	89,576
	5. Offices, Hotels, Finance, Services	-	-	24	13,908
	6. Schools	-	-		
	7. Institutional/Government	-	-		
	8. Other/Unknown	-	-	-	-
	Total				
SDG&E	1. Agriculture, Mining & Construction	-	-	-	-
	2. Manufacturing	2	14,802	1	1,920
	3. Wholesale, Transport, Other Utilities	-	-	-	-
	4. Retail Stores	5	3,231	194	52,759
	5. Offices, Hotels, Finance, Services	63	26,426	3	629
	6. Schools	-	-	-	-
	7. Institutional/Government	1	3,548	1	497
	8. Other/Unknown	-	-	-	-
	Total	69	48,006	200	55,804

Table 2-2 includes data for each utility, by notification type and industry group. The table also includes a sum of their maximum demand.[20] Since nominations vary by month, we use the number of nominated service accounts responding on an average summer event day to reflect the typical number of program participants.

Program Changes

The IOUs' CBP portfolios are in the process of integrating into the CAISO wholesale energy market. PY2016 and PY2017 are considered transition years, and each IOU has proposed some program changes to further enable integration of the CBP portfolios into the CAISO market. Several program changes proposed by the IOUs for CBP were approved by the Commission on June 9, 2016.[21] The IOUs anticipate that changes will begin taking place in PY2017. Therefore, the changes affect the ex-ante analysis.

Specifically, the Commission has approved tariff changes for PG&E's CBP. The changes increase CBP incentive levels to bring them more in line with the current market. The modifications will help integration into the CAISO market.

SCE completed the integration of 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. SCE is also making several changes to CBP, including but not limited to: streamlining CBP offerings to two products, increasing capacity prices, and reducing the number of events. SCE's changes are expected to take effect Dec. 31, 2017 and are intended to improve and simplify bidding into the CAISO wholesale market, align prices with current value, decrease customer fatigue, and increase participation.

SDG&E's CBP meets most of the CAISO market requirements, but has also proposed some changes to improve integration.

In addition, on August 1, 2016, all three IOUs filed Advice Letters proposing to include an energy price component to the current CBP heat rate trigger. As of March 2017, the IOUs have not received the Commission's resolution on the proposed trigger changes. In the meantime, PG&E and SCE are still dispatching CBP based upon a 15,000 BTU/kWh heat rate trigger and SDG&E is dispatching based upon a 19,000 BTU/kWh heat rate trigger.

Aggregator Managed Portfolio

AMP is an aggregator-managed demand response program. Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[22] Under AMP, third-party aggregators enter into bilateral contracts with PG&E and/or SCE, and may create their own aggregated DR program in which participating customers achieve load reductions. In addition to being responsible for designing their DR program, aggregators are also responsible for acquisition, marketing, sales, retention, support, and event notifications and tactics.

Each aggregator has a contractual curtailment level specified for each month. This curtailment comes from their portfolio of nominated customers. Capacity and energy payments vary with each aggregator.[23] The aggregators are penalized if they fail to deliver their committed load reductions. Aggregators determine compensation and/or penalties for their participating customers. The settlement baselines are based on the aggregate 10-in-10 method, with an optional day-of adjustment.

[20] For SCE and SDG&E, "Sum of Max Demand" is calculated as the sum over customers of their maximum demand, which is a metric provided by SDG&E and SCE. For PG&E, "Sum of Max Demand" is calculated as the sum over customers of their maximum reference load, regardless of the time of day those maximum loads occur. Customers' reference load on an event day is defined as their observed load, plus their estimated load impacts added back in.

[21] Decision Adopting Bridge Funding for 2017 Demand Response Programs and Activities. Decision 16-06-029. June 9, 2016. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K467/163467479.PDF.

[22] PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.

[23] PG&E's and SCE's AMP contracts only provide energy payments for Bundled-Service customers.

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, based upon a CAISO market award, and/or the utility, in its sole discretion, anticipates conditions or situations that may adversely impact the electric system.

PG&E's AMP

PG&E's AMP program was open to customers on a non-residential TOU rate. In 2016, PG&E had AMP contracts with two aggregators. Both offered DO contracts only. Each aggregator could call up to 76 hours of events each year between the hours of 11 a.m. and 7 p.m., including test events. PG&E had two types of products: DO Local, and DO system. The local product allowed program dispatch by Sub-Load Aggregation Points (Sub-LAPs), while the system product could only dispatch the service territory as a whole. These events are described in Section 4. Customers who participated in AMP with DO notice were allowed to dually enroll in PG&E's Demand Bidding Program (DBP) or Peak Day Pricing (PDP).

Table 2-3 shows the number of customer service accounts nominated for the typical PG&E AMP DO event, by industry type, along with the sum of their maximum demand.[24] 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.

Table 2-3 PG&E AMP Nominated Accounts by Industry Group, Average Summer Event Day (2016)

Utility	Industry Type	DO Accounts	Sum of Max Demand (kW)
PG&E	1. Agriculture, Mining & Construction	526	130,196
	2. Manufacturing	64	85,921
	3. Wholesale, Transport, Other Utilities	136	100,915
	4. Retail Stores	389	97,134
	5. Offices, Hotels, Finance, Services	65	76,498
	6. Schools		
	7. Institutional/Government	38	10,013
	8. Other/Unknown	16	8,961
	Total	**1,236**	**519,393**

SCE's AMP

SCE's AMP program is open to all types of participating customers. AMP aggregators have historically only enrolled non-residential customers. On December 22, 2014, the CPUC issued Resolution E-4695 approving two AMP contracts for SCE for 2015-2016. Both contracts are DO contracts. AMP aggregators have the ability to move between SCE's AMP and CBP programs, as long as they are also an authorized CBP aggregator, but customers cannot be nominated for both programs for the same operating month. 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.

Table 2-4 shows the number of customer service accounts nominated for the typical SCE 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 typical summer event day here reflects the typical number of program participants.

[24] For PG&E, "Sum of Max Demand" is calculated as the sum over customers of their maximum reference load, regardless of the time of day those maximum loads occur. Customers' reference load on an event day is defined as their observed load, plus their estimated load impacts added back in.

Table 2-4 SCE AMP Nominated Accounts by Industry Group, Typical Summer Event Day (2016)

Utility	Industry Type	DO Accounts	Sum of Max Demand (kW)
SCE	1. Agriculture, Mining & Construction	[redacted]	
	2. Manufacturing		
	3. Wholesale, Transport, Other Utilities		
	4. Retail Stores		
	5. Offices, Hotels, Finance, Services		
	6. Schools		
	7. Institutional/Government		
	Total		

Program Changes

The IOU's AMP programs are undergoing changes related to better integration of DR resources into the CAISO wholesale energy market. PG&E's AMP program has been discontinued as of the end of PY2016. Customers are being encouraged to enroll in CBP instead. SCE completed the integration its AMP portfolio into the CAISO market on July 23, 2015 and considers the AMP program to be effectively integrated into the market for the purposes of DR program dispatch. However, SCE plans to stop offering AMP after PY2017. Some of SCE's AMP accounts are expected to move to CBP in PY2018 as a result of AMP ending. These program changes affect the ex-ante analysis. PG&E's AMP program is not in the ex-ante forecast and there is only one year of ex-ante impacts for SCE's AMP program.

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.

Ex-Post Impact Analysis

The PY2016 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 2016 program year.
2. To provide these estimates by various segments: IOU, program, LCA, industry group, Automated Demand Response (AutoDR) and TA&TI participation, and notification type.
3. To estimate the distribution of load impacts by customer segment for the average event.

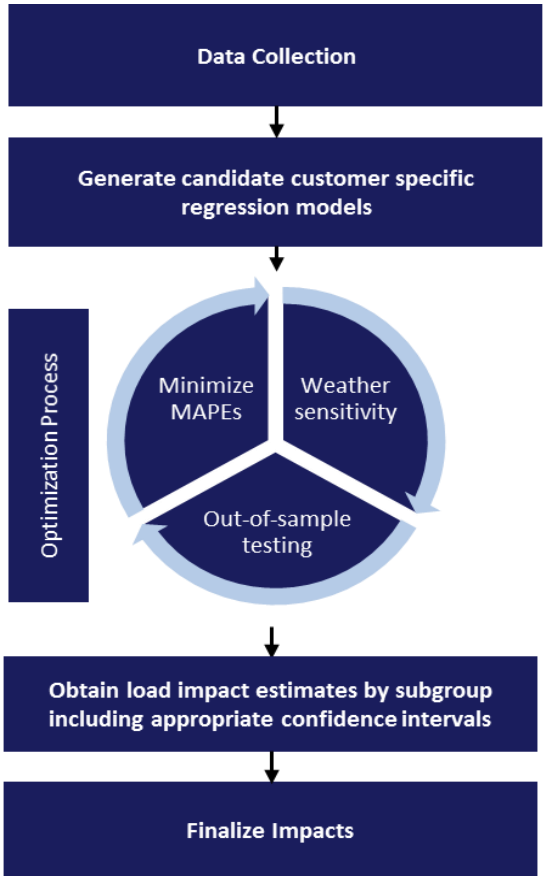
AEG used customer-specific regressions to estimate the load impact for each customer on each event day. Because AMP and CBP are implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling 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.[25]

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.

[25] Because of high event frequency for some of the programs, we used up to three years of data to ensure that enough similar non-event days were available for the estimation of the reference load.

Figure 3-1 Ex-Post Analysis Approach



Data Collection and Validation

AEG constructed a large database of different types of utility information including, but not limited to, interval data, billing data, weather data, DR event data, notification data, and settlement data. We then checked and validated all interval data using algorithms we have developed and enhanced over time. Our validation process included carefully checking the interval data for zero intervals, missing intervals, peaks, valleys, and erroneous intervals. Where possible, we edited the data. When it was not possible to edit the data, we omitted those intervals from the analysis. In cases where we needed to omit data for a customer on one or more event day, we use the average per-customer impact as a proxy for the "actual" impact realized by the customer for the given event day(s).

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.[26]

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.

[26] Any unexplained variation will end up in the error term.

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 2016[27]
$OtherEvt_{i,d}$	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
$P_{i,d}$	An indicator variable for aggregator program event days
$P * Month_{i,d}$	An indicator variable for aggregator program event days interacted with the month
$P * Year_{i,d}$	An indicator variable for aggregator program event days interacted with the year 2016
$P*NonTypEvent_{i,d}$	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 since much of the day-to-day variation in load is 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.[28]

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:

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

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.

[27] Because a large number of events were called in 2016, which was also a relatively mild year, we included data from 2014 and 2015 to ensure that we would have enough event-like days. Therefore, we also included a "year" indictor variable in the models.

[28] For more information on the model out-of-sample tests and MAPE results see Section 6, Model Validity.

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

Simple non-weather sensitive example:

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

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.

After the "best" model was selected for each customer, we 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 actual observed load (and avoid confusion associated with the predicted load) 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

Aggregation of Impacts

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. As mentioned previously, in some cases we needed to apply average per-customer impacts as a proxy for the "actual" impacts realized by one or more customers on a given event day because part of their data was invalid and, therefore, omitted during the data validation process. In these cases, we determined the aggregate impact for a particular grouping based on the per-customer average of the customers with valid data in the grouping and the total nominated accounts associated with that grouping for the given event.

It is important to note that the per-customer average may be different depending on the group or subgroup because of the different types and sizes of customers in the grouping. Therefore, during events where average per-customer data was used as a proxy for one or more customers, the sum of the individual subgroup totals for the event may not exactly add up to the total for the larger groupings or populations of customers. Consider the following hypothetical example:

- Subgroup #1 in Product A:
  - 24 nominated customers
  - 23 with sufficient valid data to estimate impacts
  - Aggregate impact for 23 customers = 2,300 kW
  - Average per-customer impact for the subgroup would be calculated with the aggregated data for the 23 customers: 2,300 kW / 23 customers = 100 kW per customer
  - Aggregate impact for all 24 nominated customers: 100 kW/customer x 24 customers = 2,400 kW

- Subgroup #2 in Product A:
  - 76 nominated customers, all with sufficient valid data to estimate impacts
  - Aggregate impact for 76 customers: 6,460 kW
  - Average per-customer impact: 6,460 kW / 76 customers = 85 kW per customer
- Total for Product A:
  - 100 nominated customers
  - 99 with sufficient valid data to estimate impacts
  - Aggregate impact for 99 customers = 2,300 kW + 6,460 kW = 8,760 kW
  - Average per-customer impact for the subgroup would be calculated with the aggregated data for the 99 customers: 8,760 kW / 99 customers = 88.48 kW per customer
  - Aggregate for all 100 nominated customers: 88.48 kW/customer x 100 customers = 8,848 kW
- Sum of Subgroup #1 plus Subgroup #2 = 2,400 kW + 6,460 kW= 8,860 kW, which does not equal the Total for Product A of 8,848 kW

Uncertainty

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 Excel-based Protocol 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 PG&E and SDG&E, we defined an average event as the average of all system-level events with event hours ending 16-19. For SCE's CBP, we defined an average summer event as the average of all events during June-September with event hours ending 17-19, and an average non-summer event as the average of all events during non-summer months with event hours ending 18-19. For SCE's AMP program, we used typical event days to represent the average event day for each AMP product.

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 average impacts and customer counts across the multiple combinations of subgroups presented as part of this analysis. The approach we used to determine the averages for each subgroup, and for combinations of groups, involved dividing the aggregate impact for the grouping by the total customer count for the grouping. Another way to do it would be to create the averages first at the lowest level of disaggregation, and then sum them to the total level of aggregation desired. Though both approaches are equally valid, they often result in slightly different values. Therefore, when viewing the *average* event day impact results in Chapter 4, one may notice that the sum of the subgroup level impacts do not always equal the program level impacts.

Estimating Incremental Impacts for Technology-Enabled Participants

We estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with a group of similar non-enabled participants for each program. First, we selected a group of program 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 and Y is the treatment group, as shown below in Equation 3.3.

$$Incremental\ Savings = (X_{PredActual} - Y_{PredActual}) - \left(X_{reference} - Y_{reference}\right) \quad (3.3)$$

Using algebra, this can be rewritten as the difference in impacts, show below in Equation 3.4.

$$Incremental\ Savings = \left(Y_{Refrence} - Y_{PredActual}\right) - \left(X_{reference} - X_{PredActual}\right) \quad (3.4)$$

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 3.5 below.

$$ED = \sqrt{(Off\_1 - Off\_1_C)^2 + (EOff\_2_T - EOff\_2_C)^2 + (kWh16_T - kWh16_C + \ldots + kWh19_T - kWh19_C)^2} \quad (3.5)$$

Ex-Ante Impact Analysis

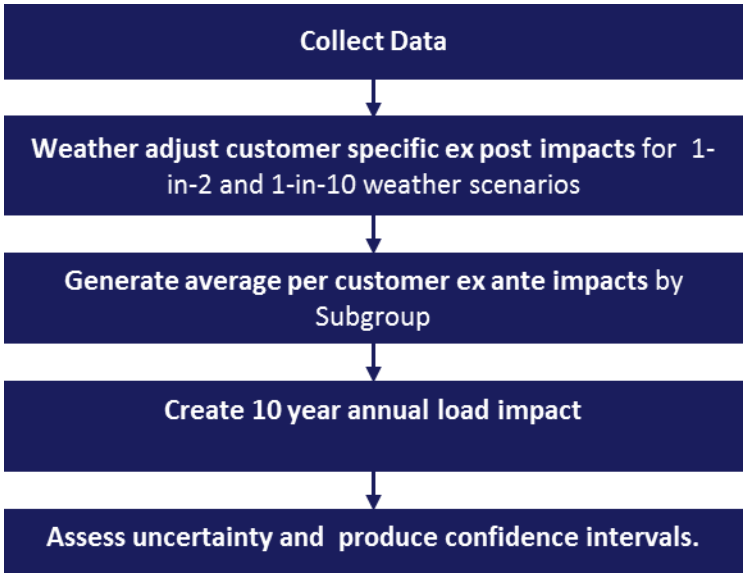
The main goal of the ex-ante analysis is to produce an annual 11-year forecast of the load impacts expected from the CBP and AMP programs.

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/or 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 11-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 11 years; and 4) an assessment of uncertainty and the development of confidence intervals.

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 peak day 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 monthly peak day 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 each monthly peak day 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.[29] As part of the ex-ante forecast development for PG&E and SDG&E,[30] we applied the impacts predicted under July (for PG&E) and August (for SDG&E) 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.

[29] For SCE with a year-round forecast, the Resource Adequacy window is between hour-ending 17 and hour-ending 21 for months November through March.
[30] For SCE, we varied the ex-ante impacts by month within the forecast year to capture differences between summer and non-summer events.

- 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 11-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 and/or anticipated program changes—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 11 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.

Elasticity Analysis

As part of the 2016 DR Aggregator evaluation, AEG developed a model to estimate the elasticity associated with the CBP incentives for PG&E. The goal of the model development was to estimate the price responsiveness of a CBP participant, and potentially adjust ex-ante estimates to reflect an increase in impacts, resulting from increased CBP incentives.

Model Development and Results

As with any model, the input data and its development is very important. In this case, we based the data development on our knowledge of the program, and some assumptions regarding how aggregators participate in the program.[31]

- The dependent variable. We defined the dependent variable as aggregate, aggregator level impacts in kW, on each event day for which all nominated customers were called. We included events from 2013 through 2016. This resulted in a total of 370 aggregator events over the four years. In the model, the aggregate kW impacts are expressed in natural logs.
- Independent variables.
  - Price is obviously the most important explanatory variable in an elasticity model. We included price as the monthly price per kW paid for the day-ahead program, or day-of program as appropriate. Price was also expressed in logs.
  - We also included weather to control for any weather-related variations in impacts that are unrelated to price. Weather was expressed as CDD days with a base of 65.

[31] One side note on monthly indicators in the model: It is not advisable to include both monthly indicators and price since price varies by month and each month across time historically has had the same price (e.g., price in May 2015 = price in May 2016). Including both variables results in a multicollinearity issue that biases the results. It also results in insignificant estimates across both months and price.

- Indicator variables.
  - Year indicators were used to control for differences between years.
  - A day-ahead indicator was used to control for differences in notification type.
  - Aggregator specific indicators were used to control for differences between aggregators.

Many different model specifications were tested including: aggregated models, individual aggregator level models, monthly observation models, and notification level models. Overall, the model with the most reasonable results estimates the incentive elasticity for CBP participants to be 0.19, meaning that if the incentive for CBP is increased by 1%, then the resulting increase in impacts is approximately 0.20%. Traditional elasticity literature estimates the price elasticity of demand for electricity to be about -0.20, therefore our results are in line with existing research showing a relatively inelastic response to price.

Implications

PG&E's approved CBP incentives for 2017 represent only about a 2-3% increase over previous incentives, and the resulting increase in impacts would likely be very small, on the order of 0.4% to 0.6%. AEG and PG&E determined that such a small increase in impacts would have an immaterial effect on the ex-ante forecast and elected not to adjust the ex-ante forecast to account for increased CBP incentives at this time.

Ex-Post Results

This section presents the ex-post impacts for each program, and by segment, for the 2016 DR Aggregator programs.

Capacity Bidding Program

All three IOUs offer CBP. In PY2016, each IOU had participants in three products, DA 1-4 hour, DO 1-4 hour, and DO 2-6 hour. For PY2016, SCE had participants in an additional product, DA 2-6 hour. Table 4-1 presents the PY2016 average event day impacts by product and IOU, both at the per-customer level, and in aggregate. The table also includes the impacts for PG&E and SDG&E's DO 1-4 hour and 2-6 hour products combined.[32]

Table 4-1 Statewide CBP Impacts Summary, Average Summer Event Day PY2016

Utility	Product	Accounts	Per Customer Impact (kW)		Aggregate Impact (MW)	
			Reference Load	Impact	Reference Load	Impact
PG&E	DA 1-4 Hour					
	DO 1-4 Hour					
	DO 2-6 Hour					
	DO 1-4 Hour and 2-6 Hour Products Combined	406	156.0	22.6	63.3	9.2
SCE	DA 1-4 Hour					
	DA 2-6 Hour					
	DO 1-4 Hour					
	DO 2-6 Hour					
SDG&E	DA 1-4 Hour	69	276.3	51.4	19.1	3.5
	DO 1-4 Hour	139	166.8	22.9	23.2	3.2
	DO 2-6 Hour	60	248.3	27.2	14.9	1.6
	DO 1-4 Hour and 2-6 Hour Products Combined	200	189.9	24.0	38.0	4.8

[32] Note that for the average event day, the number of accounts and aggregate impacts for the combined CBP DO offering do not equal the sum of the number of accounts and aggregate impacts for the DO 1-4 hour and DO 2-6 hour products due to the averaging approach described in Chapter 3.

PG&E

Events for PG&E CBP

Table 4-2 presents a summary of the 2016 events for PG&E's CBP program by product. The DO participants experienced a total of 19 event days[33] over the course of the program year, while DA participants experienced 16 event days. 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	349	96	42
6/2/2016	Thursday	15	19-19	352	-	-
6/3/2016	Friday	15	16-19	352	98	-
6/20/2016	Monday	15	16-19	352	98	42
6/21/2016	Tuesday	15	18-19	352	98	42
6/22/2016	Wednesday	15	18-19	352	98	42
6/27/2016	Monday	15	15-19, 16-19	352	98	42
6/28/2016	Tuesday	15	14-19, 16-19	352	98	42
6/30/2016	Thursday	15	17-19	155	32	42
7/13/2016	Wednesday	15	17-19	362	95	-
7/14/2016	Thursday	15	17-19, 18-19	362	95	45
7/25/2016	Monday	13	16-19	-	-	45
7/26/2016	Tuesday	15	16-19	362	95	-
7/27/2016	Wednesday	15	16-19	362	95	45
7/28/2016	Thursday	15	14-19, 16-19	362	95	45
7/29/2016	Friday	13	16-19	-	-	45
8/15/2016	Monday	15	15-19, 16-19	332	95	40
8/16/2016	Tuesday	15	16-19	332	95	40
8/17/2016	Wednesday	15	16-19	332	95	40
9/19/2016	Monday	14	17-19	331	95	-
9/26/2016	Monday	14	17-19	331	95	29
9/27/2016	Tuesday	14	17-19	331	95	29

Summary Load Impacts

Table 4-3 presents the average event-hour impacts for the CBP DO 1-4 hour and the CBP DO 2-6 hour participants combined, both at the average per-customer level and in aggregate. The aggregate reference load and impact values in this table represent the sum of average event-hour values for each product. The per-customer reference load and impact values are averaged across all customers participating in the combined DO program on the given event day.

[33] There were 19 event days for the CBP DO 1-4 hour product; the CBP DO 2-6 hour product had events on 18 of those days.

Table 4-3 PG&E CBP Day-Of Product (1-4 Hour and 2-6 Hour Products Combined): 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	406	12.0	156.0	22.6	63.3	9.2	14%	88
6/2/2016								
6/3/2016	450	15.5	179.9	24.9	81.0	11.2	14%	93
6/20/2016	450	15.5	166.6	24.4	75.0	11.0	15%	85
6/21/2016	450	15.5	166.9	22.7	75.1	10.2	14%	87
6/22/2016	450	15.5	155.3	22.4	69.9	10.1	14%	79
6/27/2016[1]								
6/28/2016[1]	450	15.5	160.2	24.5	72.1	11.0	15%	87
6/30/2016	187	4.1	126.9	27.1	23.7	5.1	21%	97
7/13/2016	457	11.9	155.2	22.9	70.9	10.5	15%	88
7/14/2016	457	11.9	157.0	22.9	71.7	10.5	15%	87
7/26/2016	457	11.9	167.4	25.4	76.5	11.6	15%	93
7/27/2016	457	11.9	161.6	24.8	73.9	11.4	15%	90
7/28/2016[1]	457	11.9	161.3	23.9	73.7	10.9	15%	88
8/15/2016[1]	427	10.1	134.9	22.3	57.6	9.5	17%	82
8/16/2016	427	10.1	134.5	22.7	57.4	9.7	17%	84
8/17/2016	427	10.1	136.8	22.9	58.4	9.8	17%	85
9/19/2016	426	9.2	141.6	26.6	60.3	11.3	19%	90
9/26/2016	426	9.2	140.1	26.6	59.7	11.3	19%	93
9/27/2016	426	9.2	132.3	26.5	56.4	11.3	20%	87

[1]The 1-4 hour and 2-6 hour DO products had different event windows on these dates.

Table 4-4 shows the average event-hour impacts for the CBP DA 1-4 hour participants at the per-customer level and in aggregate.

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)
Redacted to protect customer or aggregator confidentiality.								

Table 4-5 presents the impacts for an average event day by Industry.[34]

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]						
DA	Manufacturing	[redacted]						
DA	Wholesale, Transport, other Utilities	[redacted]						
DA	Retail Stores	23	374.8	57.0	8.6	1.3	15%	90
DA	Offices, Hotels, Finance, Services	[redacted]						
DA	Schools	[redacted]						
DA	Institutional/Government	[redacted]						
DA	Other/Unknown	[redacted]						
	Total DA	[redacted]						
DO	Agriculture, Mining & Construction	[redacted]						
DO	Manufacturing	[redacted]						
DO	Wholesale, Transport, other Utilities	[redacted]						
DO	Retail Stores	290	113.0	18.6	32.8	5.4	16%	88
DO	Offices, Hotels, Finance, Services	[redacted]						
DO	Schools	-	-	-	-	-	-	-
DO	Institutional/Government	[redacted]						
DO	Other/Unknown	[redacted]						
	Total DO	**406**	**156.0**	**22.6**	**63.3**	**9.2**	**14%**	**88**
Total CBP		[redacted]						

[34] 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 may not exactly match the sum of the individual industry segments (or LCAs).

Table 4-6 present the impacts for an average event day by Local Capacity Area (LCA).

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							
	Greater Fresno							
	Humboldt							
	Kern							
	Northern Coast							
	Other							
	Sierra							
	Stockton							
	Total DA							
DO	Greater Bay Area							
	Greater Fresno	32	126.6	23.6	4.1	0.8	19%	104
	Humboldt							
	Kern	29	101.7	19.7	2.9	0.6	19%	103
	Northern Coast	21	148.5	25.9	3.1	0.5	17%	86
	Other	89	127.5	29.8	11.4	2.7	23%	90
	Sierra							
	Stockton							
	Total DO	**406**	**156.0**	**22.6**	**63.3**	**9.2**	**14%**	**88**
Total CBP								

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 PG&E's CBP DO and DA products, respectively, 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): Avg. Hourly Per-Customer Impact, 2016

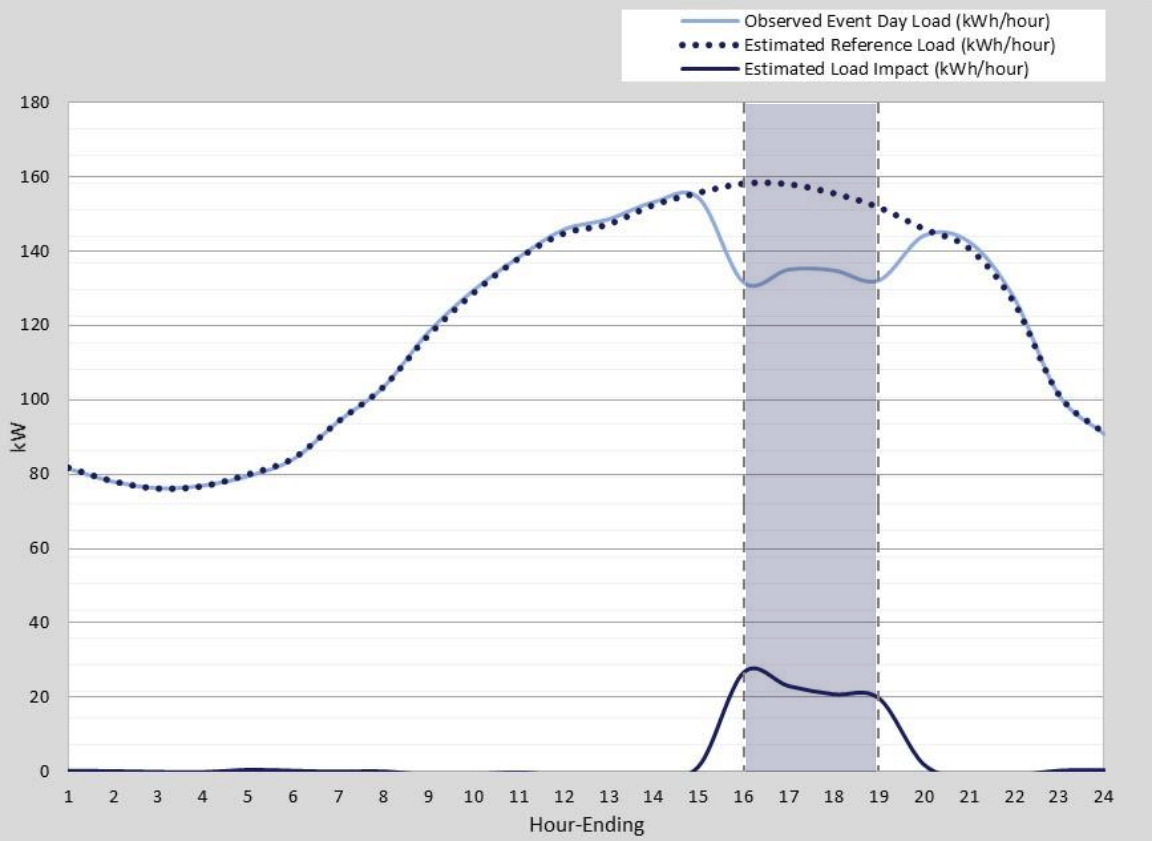


Figure 4-2 PG&E CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2016

Figure redacted to protect customer or aggregator confidentiality.

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. The results include 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 4-7 shows the event day ex-post impacts and the aggregate load shed test results for the AutoDR and TA/TI participants for the two CBP DO products combined. There were no AutoDR or TA/TI participants for the CBP DA product in PY2016.

Table 4-7 PG&E CBP Day-Of Product (1-4 Hour and 2-6 Hour Products Combined): AutoDR 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								

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 a 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) approach. We describe both the Euclidean Distance and DID methodology in Section 3: Study Methods.

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 for the CBP DO product. There were [redacted] control group matches for the incremental analysis ([redacted] for the DO 1-4 hour product and [redacted] for DO 2-6 hour product), and there were [redacted] participating accounts for CBP DO as a whole on the average event day.[35]

Figure 4-3 PG&E CBP DO AutoDR and TA/TI Event Day Match, kW

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-4 shows the incremental impacts for the CBP DO products. 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, the CBP DO 1-4 hour product shows statistically significant *negative* incremental impacts during the HE16 to HE19 event window, which is unexpected. Given that the sample size is only [redacted] customers spanning various industry types (manufacturing, agriculture, retail, and office), the negative impacts are more likely to be an artifact of customer variation, than a reflection of decreased impacts directly resulting from the enabling technology. On the other hand, we do see significant positive incremental impacts of approximately [redacted] per enabled customer for the CBP DO 2-6 hour product during the HE16 to HE19 event window.

Figure 4-4 PG&E CBP DO AutoDR and TA/TI Average Event Day Incremental Impacts, kW

Figure redacted to protect customer or aggregator confidentiality.

In Table 4-8, we present the incremental impacts for the two CBP DO products and for CBP as a whole (there were no CBP DA AutoDR or TA/TI participants).

Table 4-8 PG&E CBP Incremental AutoDR and TA/TI Impacts

Product	Number of Accounts	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate (kW)	Significant
Redacted to protect customer or aggregator confidentiality				

[35] The number of participants matched does not necessarily equal the number of participants on an average event day. In some cases the number matched is higher because we tried to match the maximum number of participating customers.

SCE

Events for SCE CBP

Table 4-9 and Table 4-10 present summaries of the PY2016 events for SCE's CBP program by product for DO and DA, respectively.[36] The table includes definitions of average summer and non-summer event days. The DO participants experienced a total of 98 events over the course of the program year, while DA participants experienced 57 events. Events were called with a wide variety of event hours.

Table 4-9 SCE CBP Day-Of Event Summary

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour	Event Hours (HE) DO 2-6 Hour	# Accts DO 2-6 Hour
Avg. Summer	-	17-19	139	17-19	
Avg. Non-Summer	-	18-19	129	-	-
11/2/2015	Monday	18-19	318	-	-
11/3/2015	Tuesday	18-19	318	-	-
11/4/2015	Wednesday	18-19	318	-	-
11/6/2015	Friday	18-19	318	-	-
11/9/2015	Monday	18-18 18-19	113 205	-	-
11/10/2015	Tuesday	18-19	318	-	-
11/12/2015	Thursday	18-19	318	-	-
11/13/2015	Friday	18-18	318	-	-
11/16/2015	Monday	18-18	205	-	-
11/17/2015	Tuesday	18-18	318	-	-
11/18/2015	Wednesday	18-18	274	-	-
11/19/2015	Thursday	18-18	318	-	-
11/20/2015	Friday	18-18	318	-	-
11/30/2015	Monday	18-18 18-19	123 195	-	-
12/1/2015	Tuesday	18-18	23	-	-
12/16/2015	Wednesday	18-19	23	-	-
12/17/2015	Thursday	18-19	23	-	-
12/29/2015	Tuesday	18-19	23	-	-
12/30/2015	Wednesday	18-19	23	-	-
1/6/2016	Wednesday	18-19	34	-	-
1/7/2016	Thursday	18-19	34	-	-
1/8/2016	Friday	18-19	34	-	-
1/11/2016	Monday	18-19	34	-	-
1/12/2016	Tuesday	18-19	34	-	-
1/13/2016	Wednesday	18-18	34	-	-
1/14/2016	Thursday	18-19	34	-	-
1/15/2016	Friday	18-18	34	-	-
1/20/2016	Wednesday	18-18	34	-	-
1/22/2016	Friday	18-18	34	-	-

[36] SCE's PY2016 evaluation period is from Nov. 1, 2015 through Oct. 31, 2016.

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour	Event Hours (HE) DO 2-6 Hour	# Accts DO 2-6 Hour
1/25/2016	Monday	18-18	34	-	-
2/2/2016	Tuesday	19-19	43	-	-
2/3/2016	Wednesday	18-19 19-19	17 26	-	-
2/4/2016	Thursday	19-19	17	-	-
2/8/2016	Monday	19-19	17	-	-
2/9/2016	Tuesday	19-19	17	-	-
2/10/2016	Wednesday	19-19	43	-	-
2/11/2016	Thursday	19-19	41	-	-
2/16/2016	Tuesday	19-19	17	-	-
2/22/2016	Monday	19-19	38	-	-
2/23/2016	Tuesday	19-19	43	-	-
2/24/2016	Wednesday	19-19	43	-	-
2/25/2016	Thursday	19-19	43	-	-
2/26/2016	Friday	19-19	17	-	-
2/29/2016	Monday	18-19 19-19	2 41	-	-
4/1/2016	Friday	19-19	46	-	-
4/6/2016	Wednesday	19-19	35	-	-
5/12/2016	Thursday	19-19	387	-	-
6/2/2016	Thursday	19-19	83	-	-
6/3/2016	Friday	16-19 17-19 18-19 19-19	83 136 18 11	16-19 17-19 18-19	[redacted]
6/6/2016	Monday	19-19	213	-	-
6/8/2016	Wednesday	19-19	202	-	-
6/20/2016	Monday	16-19	248	14-19	[redacted]
6/21/2016	Tuesday	16-19 17-19	220 28	16-19 17-19	[redacted]
6/22/2016	Wednesday	16-16 16-17	25 195	16-17	[redacted]
6/27/2016	Monday	16-19 17-19	140 108	16-19 17-19	[redacted]
6/28/2016	Tuesday	18-18	165	-	-
6/30/2016	Thursday	18-18	213	-	-
7/11/2016	Monday	15-18	102	14-18	[redacted]
7/12/2016	Tuesday	15-15	102	-	-
7/13/2016	Wednesday	14-15 15-15	102 84	14-15	[redacted]
7/14/2016	Thursday	17-19 19-19	102 137	17-19	[redacted]
7/20/2016	Wednesday	17-19	239	17-19	[redacted]
7/21/2016	Thursday	16-19	239	16-19	[redacted]

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour	Event Hours (HE) DO 2-6 Hour	# Accts DO 2-6 Hour
7/22/2016	Friday	16-19 17-19	195 44	15-19 16-19 17-19	
7/25/2016	Monday	16-19 17-19	80 159	16-19 17-19	
7/26/2016	Tuesday	17-19 19-19	137 102	17-19	
7/27/2016	Wednesday	16-19	239	15-19 16-19	
7/28/2016	Thursday	16-19 19-19	137 102	15-19 18-19	
7/29/2016	Friday	16-19 17-18 17-19	44 84 9	16-19 17-18	
8/1/2016	Monday	19-19	224	-	-
8/2/2016	Tuesday	19-19	198	-	-
8/4/2016	Thursday	19-19	77	-	-
8/12/2016	Friday	19-19	201	-	-
8/15/2016	Monday	15-18 16-19 17-19	23 77 124	14-19 16-19 17-19	
8/16/2016	Tuesday	17-19	224	17-19	
8/17/2016	Wednesday	18-19 19-19	23 201	18-19	
8/18/2016	Thursday	17-19 18-19	201 23	17-19 18-19	
8/19/2016	Friday	19-19	224	-	-
8/29/2016	Monday	19-19	224	-	-
8/30/2016	Tuesday	19-19	224	-	-
8/31/2016	Wednesday	17-19	224	17-19	
9/7/2016	Wednesday	19-19	220	-	-
9/26/2016	Monday	17-19	220	17-19	
9/27/2016	Tuesday	18-19	220	18-19	
9/28/2016	Wednesday	19-19	220	-	-
10/6/2016	Thursday	19-19	217	-	-
10/7/2016	Friday	18-19 19-19	75 142	-	-
10/10/2016	Monday	19-19	217	-	-
10/17/2016	Monday	19-19	217	-	-
10/18/2016	Tuesday	19-19	217	-	-
10/19/2016	Wednesday	18-19 19-19	214 3	-	-
10/20/2016	Thursday	18-19	217	-	-
10/21/2016	Friday	18-19 19-19	110 107	-	-
10/24/2016	Monday	19-19	195	-	-
10/25/2016	Tuesday	19-19	217	-	-

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour	Event Hours (HE) DO 2-6 Hour	# Accts DO 2-6 Hour
10/26/2016	Wednesday	19-19	217	-	-
10/27/2016	Thursday	18-19 19-19	3 214	-	-
10/28/2016	Friday	19-19	217	-	-

Table 4-10 SCE CBP Day-Ahead Event Summary

Date	Day of Week	Event Hours (HE) DA 1-4 Hour	# Accts DA 1-4 Hour	Event Hours (HE) DA 2-6 Hour	# Accts DA 2-6 Hour
Avg. Summer	-	17-19		-	-
Avg. Non-Summer	-	-	-	18-19	
11/3/2015	Tuesday	-	-	18-19	
11/4/2015	Wednesday	-	-	18-19	
11/6/2015	Friday	-	-	18-19	
11/9/2015	Monday	-	-	18-19	
11/10/2015	Tuesday	-	-	18-19	
11/12/2015	Thursday	-	-	18-19	
11/16/2015	Monday	-	-	18-19	
5/2/2016	Monday	19-19		-	-
5/12/2016	Thursday	19-19		-	-
6/3/2016	Friday	16-19 17-19 18-19 19-19		-	-
6/8/2016	Wednesday	19-19		-	-
6/20/2016	Monday	16-19		-	-
6/21/2016	Tuesday	16-19 17-19		-	-
6/22/2016	Wednesday	16-16 16-17		-	-
6/27/2016	Monday	16-19		-	-
6/28/2016	Tuesday	16-19 17-19		-	-
6/30/2016	Thursday	18-18		-	-
7/12/2016	Tuesday	15-15		-	-
7/13/2016	Wednesday	14-15 15-15		-	-
7/14/2016	Thursday	17-19 19-19		-	-
7/20/2016	Wednesday	17-19		-	-
7/21/2016	Thursday	16-19		-	-
7/22/2016	Friday	16-19 17-19		-	-
7/25/2016	Monday	16-19 17-19		-	-
7/26/2016	Tuesday	17-19 19-19		-	-
7/27/2016	Wednesday	16-19		-	-

Date	Day of Week	Event Hours (HE) DA 1-4 Hour	# Accts DA 1-4 Hour	Event Hours (HE) DA 2-6 Hour	# Accts DA 2-6 Hour
7/28/2016	Thursday	16-19 19-19	[redacted]	-	-
7/29/2016	Friday	16-19 17-18 17-19	[redacted]	-	-
8/1/2016	Monday	16-19	[redacted]	-	-
8/2/2016	Tuesday	19-19	[redacted]	-	-
8/4/2016	Thursday	19-19	[redacted]	-	-
8/12/2016	Friday	19-19	[redacted]	-	-
8/15/2016	Monday	17-19	[redacted]	-	-
8/16/2016	Tuesday	17-19	[redacted]	-	-
8/17/2016	Wednesday	18-19 19-19	[redacted]	-	-
8/18/2016	Thursday	17-19 18-19	[redacted]	-	-
8/19/2016	Friday	19-19	[redacted]	-	-
8/30/2016	Tuesday	19-19	[redacted]	-	-
8/31/2016	Wednesday	17-19	[redacted]	-	-
9/7/2016	Wednesday	19-19	[redacted]	-	-
9/26/2016	Monday	19-19	[redacted]	-	-
9/27/2016	Tuesday	18-19	[redacted]	-	-
9/28/2016	Wednesday	19-19	[redacted]	-	-
10/6/2016	Thursday	19-19	[redacted]	-	-
10/7/2016	Friday	18-19 19-19	[redacted]	-	-
10/10/2016	Monday	19-19	[redacted]	-	-
10/17/2016	Monday	19-19	[redacted]	-	-
10/18/2016	Tuesday	19-19	[redacted]	-	-
10/19/2016	Wednesday	18-19 19-19	[redacted]	-	-
10/20/2016	Thursday	18-19	[redacted]	-	-
10/21/2016	Friday	18-19 19-19	[redacted]	-	-
10/24/2016	Monday	19-19	[redacted]	-	-
10/25/2016	Tuesday	19-19	[redacted]	-	-
10/26/2016	Wednesday	19-19	[redacted]	-	-
10/27/2016	Thursday	18-19 19-19	[redacted]	-	-
10/28/2016	Friday	19-19	[redacted]	-	-
10/31/2016	Monday	19-19	[redacted]	-	-

Summary Load Impacts

Table 4-11 to Table 4-14 below show the average event-hour impacts for the four CBP products, respectively: DO 1-4 hour, DO 2-6 hour, DA 1-4 hour, and DA 2-6 hour. Impacts are included for

each event, both at the average per-customer level, and in aggregate. The tables include results for the average summer event and average non-summer event.

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)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
Avg. Summer	17-19								
Avg. Non-Summer	18-19								
11/2/2015	18-19								
11/3/2015	18-19								
11/4/2015	18-19								
11/6/2015	18-19								
11/9/2015[1]	18-18 18-19	318	8.03 6.39	136.7	31.0	43.5	9.9	23%	60
11/10/2015	18-19								
11/12/2015	18-19								
11/13/2015	18-18								
11/16/2015	18-18	205	6.39	78.6	15.9	16.1	3.3	20%	55
11/17/2015	18-18								
11/18/2015	18-18								
11/19/2015	18-18								
11/20/2015	18-18								
11/30/2015[1]	18-18 18-19	318	8.53 5.89	132.8	32.3	42.2	10.3	24%	58
12/1/2015	18-18								
12/16/2015	18-19	23	1.78	83.5	45.8	1.9	1.1	55%	47
12/17/2015	18-19								
12/29/2015	18-19	23	1.78	65.0	25.9	1.5	0.6	40%	46
12/30/2015	18-19								
1/6/2016	18-19								
1/7/2016	18-19	34	1.68	68.2	32.6	2.3	1.1	48%	49
1/8/2016	18-19	34	1.68	68.4	32.0	2.3	1.1	47%	49
1/11/2016	18-19								
1/12/2016	18-19	34	1.68	65.6	30.0	2.2	1.0	46%	56
1/13/2016	18-18	34	1.68	73.9	38.7	2.5	1.3	52%	57
1/14/2016	18-19								
1/15/2016	18-18								
1/20/2016	18-18	34	1.68	73.4	38.7	2.5	1.3	53%	59
1/22/2016	18-18	34	1.68	73.0	38.7	2.5	1.3	53%	62
1/25/2016	18-18								
2/2/2016	19-19	43	1.71	67.4	29.0	2.9	1.2	43%	54
2/3/2016[1]	18-19 19-19	43	0.43 1.28	81.2	27.3	3.5	1.2	34%	57
2/4/2016	19-19	17	0.43	49.1	22.6	0.8	0.4	46%	66
2/8/2016	19-19	17	0.43	50.4	22.6	0.9	0.4	45%	82

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
2/9/2016	19-19	17	0.43	63.8	22.6	1.1	0.4	35%	79
2/10/2016	19-19	43	1.71	74.1	28.5	3.2	1.2	38%	74
2/11/2016	19-19								
2/16/2016	19-19								
2/22/2016	19-19								
2/23/2016	19-19								
2/24/2016	19-19	43	1.71	67.6	27.4	2.9	1.2	41%	73
2/25/2016	19-19								
2/26/2016	19-19								
2/29/2016[1]	18-19 19-19	43	0.07 1.64	56.4	16.8	2.4	0.7	30%	72
4/1/2016	19-19	46	1.12	70.9	19.4	3.3	0.9	27%	68
4/6/2016	19-19	35	0.87	57.8	21.9	2.0	0.8	38%	67
5/12/2016	19-19								
6/2/2016	19-19	83	2.00	171.7	26.5	14.3	2.2	15%	70
6/3/2016[1]	16-19 17-19 18-19 19-19	248	2.00 3.69 0.25 0.32	209.5	22.7	51.9	5.6	11%	86
6/6/2016	19-19								
6/8/2016	19-19								
6/20/2016	16-19								
6/21/2016[1]	16-19 17-19	248	5.62 0.63	216.4	24.8	53.7	6.2	11%	90
6/22/2016[1]	16-16 16-17	220	0.47 5.15	228.1	27.6	50.2	6.1	12%	82
6/27/2016[1]	16-19 17-19								
6/28/2016	18-18								
6/30/2016	18-18								
7/11/2016	15-18								
7/12/2016	15-15								
7/13/2016[1]	14-15 15-15								
7/14/2016[1]	17-19 19-19								
7/20/2016	17-19								
7/21/2016	16-19								
7/22/2016[1]	16-19 17-19	239	5.06 0.72	234.1	24.9	55.9	6.0	11%	93
7/25/2016[1]	16-19 17-19								
7/26/2016[1]	17-19 19-19	239	2.66 3.11	219.3	22.2	52.4	5.3	10%	88
7/27/2016	16-19								

Event	Event Hrs (HE)	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
7/28/2016[1]	16-19 19-19								
7/29/2016[1]	16-19 17-18 17-19	137	0.72 1.75 0.19	200.6	25.3	27.5	3.5	13%	91
8/1/2016	19-19								
8/2/2016	19-19								
8/4/2016	19-19								
8/12/2016	19-19								
8/15/2016[1]	15-18 16-19 17-19	224	0.43 1.85 2.46	211.5	23.6	47.4	5.3	11%	92
8/16/2016	17-19								
8/17/2016[1]	18-19 19-19	224	0.43 4.30	187.3	23.2	42.0	5.2	12%	90
8/18/2016[1]	17-19 18-19	224	4.30 0.43	196.9	23.3	44.1	5.2	12%	89
8/19/2016	19-19								
8/29/2016	19-19								
8/30/2016	19-19								
8/31/2016	17-19								
9/7/2016	19-19								
9/26/2016	17-19								
9/27/2016	18-19								
9/28/2016	19-19								
10/6/2016	19-19								
10/7/2016[1]	18-19 19-19								
10/10/2016	19-19								
10/17/2016	19-19								
10/18/2016	19-19								
10/19/2016[1]	18-19 19-19								
10/20/2016	18-19								
10/21/2016[1]	18-19 19-19	217	2.21 2.16	183.3	21.5	39.8	4.7	12%	80
10/24/2016	19-19								
10/25/2016	19-19								
10/26/2016	19-19								
10/27/2016[1]	18-19 19-19								
10/28/2016	19-19								

[1]For event days with multiple event windows, the aggregate reference load and impact values in this table represent the sum of average event hour values for each window. The per-customer reference load and impact values are averaged across all customers participating on the given event day.

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

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

Table 4-14 SCE CBP Day-Ahead 2-6 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)
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, for the CBP DO 1-4 hour product.[37] Tables for the other three products (DO 2-6 hour, DA 1-4 hour, and DA 2-6 hour) have been excluded to protect customer or aggregator confidentiality.

Table 4-15 SCE CBP DO 1-4 Hour 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)
DO 1-4 Hr.	Agriculture, Mining & Construction	[redacted]						
	Manufacturing							
	Wholesale, Transport, other Utilities							
	Retail Stores	108	128	18	13.8	1.9	14%	91
	Offices, Hotels, Finance, Services	24	226	33	5.4	0.8	15%	93
	Schools	[redacted]						
	Institutional/Government							
	Total DO 1-4 Hr.							

[37] 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 may not exactly match the sum of the individual industry segments (or LCAs).

Table 4-16 SCE CBP DO 1-4 Hour 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)
DO 1-4 Hr.	LA Basin							
	Outside LA Basin							
	Ventura / Big Creek	29	120.0	19.4	3.5	0.6	16%	87
	Total DO 1-4 Hr.							

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 hour product in either area.

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)
11/2/2015	50	88.5	14.8	4.4	0.7	17%	63
11/3/2015	50	83.6	19.6	4.2	1.0	23%	55
11/4/2015	50	88.8	20.4	4.4	1.0	23%	59
11/6/2015	50	90.6	19.6	4.5	1.0	22%	65
11/9/2015	50	84.2	15.0	4.2	0.8	18%	60
11/10/2015	50	86.4	19.6	4.3	1.0	23%	58
11/12/2015	50	87.6	18.4	4.4	0.9	21%	66
11/13/2015	50	87.6	17.4	4.4	0.9	20%	70
11/16/2015							
11/17/2015	50	87.5	17.6	4.4	0.9	20%	64
11/18/2015	50	85.9	14.5	4.3	0.7	17%	70
11/19/2015	50	85.7	14.7	4.3	0.7	17%	75
11/20/2015	50	96.1	19.1	4.8	1.0	20%	75
11/30/2015							
12/1/2015							
12/16/2015							
12/17/2015							
12/29/2015							
12/30/2015							
1/6/2016	19	53.6	26.1	1.0	0.5	49%	45
1/7/2016	19	55.2	27.4	1.0	0.5	50%	46
1/8/2016	19	52.7	26.1	1.0	0.5	50%	46
1/11/2016	19	52.8	26.4	1.0	0.5	50%	50
1/12/2016	19	51.2	26.1	1.0	0.5	51%	54
1/13/2016	19	52.5	26.6	1.0	0.5	51%	55
1/14/2016	19	53.1	26.1	1.0	0.5	49%	54
1/15/2016	19	53.6	26.6	1.0	0.5	50%	53

		Per Customer Impact (kW)		Aggregate Impact (MW)			
Event	# of Accts	Ref. Load	Impact	Ref. Load.	Impact	% Impact	Temp (˚F)
1/20/2016	19	50.5	26.6	1.0	0.5	53%	58
1/22/2016	19	49.0	26.6	0.9	0.5	54%	60
1/25/2016	19	51.6	27.4	1.0	0.5	53%	56
2/2/2016							
2/3/2016							
2/4/2016							
2/8/2016							
2/9/2016							
2/10/2016	16	65.0	23.7	1.0	0.4	36%	77
2/11/2016	16	65.0	23.7	1.0	0.4	36%	77
2/16/2016							
2/22/2016	16	64.6	23.7	1.0	0.4	37%	72
2/23/2016	16	64.4	23.7	1.0	0.4	37%	75
2/24/2016	16	50.3	23.7	0.8	0.4	47%	75
2/25/2016							
2/26/2016							
2/29/2016	16	26.8	0.0	0.4	0.0	0%	71
4/1/2016							
4/6/2016							
5/12/2016	137	134.9	13.5	18.5	1.8	10%	78
6/2/2016							
6/3/2016	70	161.4	18.1	11.3	1.3	11%	87
6/6/2016	70	139.1	17.9	9.7	1.3	13%	78
6/8/2016	70	145.4	17.9	10.2	1.3	12%	80
6/20/2016	70	177.6	18.7	12.4	1.3	11%	104
6/21/2016	70	163.4	18.2	11.4	1.3	11%	87
6/22/2016	70	162.2	19.4	11.4	1.4	12%	89
6/27/2016	70	161.0	18.4	11.3	1.3	11%	86
6/28/2016	53	162.8	20.6	8.6	1.1	13%	94
6/30/2016	70	159.3	18.5	11.2	1.3	12%	86
7/11/2016	48	165.8	23.1	8.0	1.1	14%	90
7/12/2016	48	162.6	27.0	7.8	1.3	17%	89
7/13/2016	65	171.1	25.4	11.1	1.6	15%	86
7/14/2016	65	167.6	20.4	10.9	1.3	12%	84
7/20/2016	65	181.6	19.7	11.8	1.3	11%	96
7/21/2016	65	188.0	20.3	12.2	1.3	11%	98
7/22/2016	65	195.9	20.2	12.7	1.3	10%	101
7/25/2016	65	185.2	20.1	12.0	1.3	11%	88

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)
7/26/2016	65	175.4	19.9	11.4	1.3	11%	88
7/27/2016	65	184.7	20.3	12.0	1.3	11%	93
7/28/2016	65	176.0	20.6	11.4	1.3	12%	87
7/29/2016	17	193.5	15.6	3.3	0.3	8%	79
8/1/2016	67	153.7	24.3	10.3	1.6	16%	84
8/2/2016	67	152.6	24.1	10.2	1.6	16%	86
8/4/2016	16	143.4	20.9	2.3	0.3	15%	76
8/12/2016	67	147.9	23.6	9.9	1.6	16%	85
8/15/2016	67	170.0	21.9	11.4	1.5	13%	93
8/16/2016	67	159.3	22.1	10.7	1.5	14%	95
8/17/2016	67	152.4	23.6	10.2	1.6	15%	91
8/18/2016	67	154.1	22.3	10.3	1.5	14%	91
8/19/2016	67	148.3	23.6	9.9	1.6	16%	87
8/29/2016	67	152.7	24.0	10.2	1.6	16%	90
8/30/2016	67	151.0	23.6	10.1	1.6	16%	88
8/31/2016	67	156.5	22.1	10.5	1.5	14%	93
9/7/2016	67	133.4	22.2	8.9	1.5	17%	77
9/26/2016	67	157.0	22.0	10.5	1.5	14%	94
9/27/2016	67	153.9	21.4	10.3	1.4	14%	87
9/28/2016	67	139.9	22.7	9.4	1.5	16%	85
10/6/2016	67	136.3	21.4	9.1	1.4	16%	80
10/7/2016	67	144.3	21.2	9.7	1.4	15%	84
10/10/2016	67	136.6	21.2	9.2	1.4	16%	78
10/17/2016	67	125.3	21.2	8.4	1.4	17%	67
10/18/2016	67	125.4	20.8	8.4	1.4	17%	72
10/19/2016	67	135.0	21.0	9.0	1.4	16%	85
10/20/2016	67	140.3	21.2	9.4	1.4	15%	87
10/21/2016	67	130.2	20.5	8.7	1.4	16%	82
10/24/2016	67	120.7	21.3	8.1	1.4	18%	64
10/25/2016	67	125.1	21.4	8.4	1.4	17%	70
10/26/2016	67	126.6	20.6	8.5	1.4	16%	73
10/27/2016	67	128.8	20.9	8.6	1.4	16%	77
10/28/2016	67	123.4	20.9	8.3	1.4	17%	74

Table 4-18 South of Lugo Event Day Impacts: CBP DO 2-6 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)
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)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
Redacted to protect customer or aggregator confidentiality.							

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
11/2/2015	31	151.3	21.5	4.7	0.7	14%	66
11/3/2015	31	145.9	21.6	4.5	0.7	15%	64
11/4/2015	31	146.0	21.6	4.5	0.7	15%	64
11/6/2015	31	147.9	21.6	4.6	0.7	15%	69
11/9/2015	31	143.1	21.6	4.4	0.7	15%	63
11/10/2015	31	142.3	21.6	4.4	0.7	15%	63
11/12/2015	31	142.7	21.6	4.4	0.7	15%	69
11/13/2015	31	147.3	20.0	4.6	0.6	14%	69
11/16/2015	30	141.6	20.6	4.2	0.6	15%	62
11/17/2015	31	142.0	20.0	4.4	0.6	14%	64
11/18/2015	31	146.5	20.0	4.5	0.6	14%	67
11/19/2015	31	145.0	20.0	4.5	0.6	14%	75
11/20/2015	31	156.0	20.5	4.8	0.6	13%	72
11/30/2015	31	134.3	21.6	4.2	0.7	16%	62
1/6/2016	[redacted]						
1/7/2016	[redacted]						
1/8/2016	[redacted]						
1/11/2016	[redacted]						
1/12/2016	[redacted]						
1/13/2016	[redacted]						
1/14/2016	[redacted]						
1/15/2016	[redacted]						
1/20/2016	[redacted]						
1/22/2016	[redacted]						
1/25/2016	[redacted]						
2/2/2016	[redacted]						
2/3/2016	[redacted]						
2/4/2016	[redacted]						
2/8/2016	[redacted]						
2/9/2016	[redacted]						
2/10/2016	[redacted]						

		Per Customer Impact (kW)		Aggregate Impact (MW)			
Event	# of Accts	Ref. Load	Impact	Ref. Load.	Impact	% Impact	Temp (˚F)
2/11/2016							
2/16/2016							
2/22/2016							
2/23/2016							
2/24/2016							
2/25/2016							
2/26/2016							
2/29/2016							
4/1/2016							
4/6/2016							
5/12/2016	56	110.1	9.2	6.2	0.5	8%	65
6/2/2016	26	135.7	11.5	3.5	0.3	8%	73
6/3/2016	27	159.5	20.7	4.3	0.6	13%	74
6/6/2016							
6/8/2016	27	123.8	11.8	3.3	0.3	10%	68
6/20/2016	27	177.8	19.8	4.8	0.5	11%	94
6/21/2016	27	166.6	20.1	4.5	0.5	12%	78
6/22/2016	27	175.8	23.8	4.7	0.6	14%	76
6/27/2016	27	164.2	19.7	4.4	0.5	12%	76
6/28/2016							
6/30/2016	27	159.8	19.8	4.3	0.5	12%	73
7/11/2016							
7/12/2016							
7/13/2016	26	188.4	33.0	4.9	0.9	18%	78
7/14/2016	26	141.5	15.1	3.7	0.4	11%	75
7/20/2016	26	176.4	21.4	4.6	0.6	12%	87
7/21/2016	26	181.7	23.9	4.7	0.6	13%	86
7/22/2016	26	183.1	23.9	4.8	0.6	13%	89
7/25/2016	26	176.2	23.2	4.6	0.6	13%	80
7/26/2016	26	176.9	21.6	4.6	0.6	12%	81
7/27/2016	26	181.5	23.9	4.7	0.6	13%	82
7/28/2016	26	179.6	23.9	4.7	0.6	13%	78
7/29/2016	25	188.5	25.4	4.7	0.6	13%	79
8/1/2016	26	121.5	16.8	3.2	0.4	14%	76
8/2/2016	26	118.8	16.8	3.1	0.4	14%	76
8/4/2016	25	120.6	17.1	3.0	0.4	14%	75
8/12/2016	26	115.8	16.8	3.0	0.4	15%	75
8/15/2016	26	154.8	23.2	4.0	0.6	15%	86

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)
8/16/2016	26	146.6	21.6	3.8	0.6	15%	80
8/17/2016	26	119.7	16.8	3.1	0.4	14%	78
8/18/2016	26	134.7	22.5	3.5	0.6	17%	76
8/19/2016	26	114.8	16.8	3.0	0.4	15%	74
8/29/2016	26	119.0	16.8	3.1	0.4	14%	78
8/30/2016	26	118.0	16.8	3.1	0.4	14%	76
8/31/2016	26	145.3	21.6	3.8	0.6	15%	79
9/7/2016	26	115.2	19.0	3.0	0.5	16%	69
9/26/2016	26	158.5	28.2	4.1	0.7	18%	91
9/27/2016	26	146.3	25.2	3.8	0.7	17%	83
9/28/2016	26	129.4	20.4	3.4	0.5	16%	82
10/6/2016	26	112.3	17.1	2.9	0.4	15%	76
10/7/2016	26	122.3	21.2	3.2	0.6	17%	82
10/10/2016	26	116.5	17.5	3.0	0.5	15%	72
10/17/2016	26	108.6	17.1	2.8	0.4	16%	66
10/18/2016	26	109.9	17.1	2.9	0.4	16%	67
10/19/2016	26	130.8	22.1	3.4	0.6	17%	88
10/20/2016	26	132.8	22.9	3.5	0.6	17%	85
10/21/2016	26	121.8	21.2	3.2	0.6	17%	78
10/24/2016	26	110.4	18.0	2.9	0.5	16%	66
10/25/2016	26	107.5	16.9	2.8	0.4	16%	66
10/26/2016	26	106.8	16.8	2.8	0.4	16%	69
10/27/2016	26	111.9	17.2	2.9	0.4	15%	72
10/28/2016	26	112.5	16.9	2.9	0.4	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	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load.	Aggregate Impact (MW) 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	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load.	Aggregate Impact (MW) 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 (for DO 1-4 hour, DO 2-6 hour, and DA 1-4 hour) or an average non-summer event day (for DA 2-6 hour). The event window 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, 2016

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-6 SCE CBP Day-Of 2-6 Hour: Average Hourly Per-Customer Impact, 2016

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-7 SCE CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2016

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-8 SCE CBP Day-Ahead 2-6 Hour: Average Hourly Per-Customer Impact, 2016

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 DO 2-6 hour products had TA/TI or AutoDR participants in 2016.

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.

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)
Avg. Summer	17-19	[redacted]							
Avg. Non-Summer	18-19	[redacted]							
11/2/2015	18-19	[redacted]							
11/3/2015	18-19	[redacted]							
11/4/2015	18-19	[redacted]							
11/6/2015	18-19	[redacted]							
11/9/2015	18-18 18-19	[redacted]							
11/10/2015	18-19	[redacted]							
11/12/2015	18-19	[redacted]							
11/13/2015	18-18	[redacted]							
11/16/2015	18-18	[redacted]							
11/17/2015	18-18	[redacted]							
11/18/2015	18-18	[redacted]							
11/19/2015	18-18	[redacted]							
11/20/2015	18-18	[redacted]							
11/30/2015	18-18 18-19	[redacted]							
12/1/2015	18-18	16	73.9	23.3	1.2	0.4	31%	1.2	53

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)
12/16/2015	18-19	16	74.9	24.1	1.2	0.4	32%	1.2	45
12/17/2015	18-19	16	74.5	24.1	1.2	0.4	32%	1.2	51
12/29/2015	18-19								
12/30/2015	18-19								
1/6/2016	18-19								
1/7/2016	18-19								
1/8/2016	18-19								
1/11/2016	18-19								
1/12/2016	18-19								
1/13/2016	18-18								
1/14/2016	18-19								
1/15/2016	18-18								
1/20/2016	18-18								
1/22/2016	18-18								
1/25/2016	18-18								
2/2/2016	19-19								
2/3/2016	18-19 19-19								
2/10/2016	19-19								
2/11/2016	19-19								
2/23/2016	19-19								
2/24/2016	19-19								
2/25/2016	19-19								
2/29/2016	18-19 19-19								
4/1/2016	19-19								
5/12/2016	19-19								
6/2/2016	19-19	18	224.1	14.0	4.0	0.3	6%	1.0	72
6/3/2016	16-19 17-19 18-19 19-19	35	585.9	24.3	20.5	0.8	4%	2.6	85
6/6/2016	19-19								
6/8/2016	19-19								
6/20/2016	16-19								
6/21/2016	16-19 17-19								
6/22/2016	16-16 16-17								
6/27/2016	16-19 17-19	35	632.3	24.4	22.1	0.9	4%	2.6	85
6/28/2016	18-18								
6/30/2016	18-18								
7/11/2016	15-18								

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)
7/12/2016	15-15								
7/13/2016	14-15 15-15	25	828.6	27.5	20.7	0.7	3%	2.1	82
7/14/2016	17-19 19-19	34	583.1	13.5	19.8	0.5	2%	2.5	81
7/20/2016	17-19								
7/21/2016	16-19								
7/22/2016	16-19 17-19								
7/25/2016	16-19 17-19	34	635.7	20.1	21.6	0.7	3%	2.5	86
7/26/2016	17-19 19-19	34	577.8	18.8	19.6	0.6	3%	2.5	85
7/27/2016	16-19								
7/28/2016	16-19 19-19	34	605.8	19.9	20.6	0.7	3%	2.5	85
7/29/2016	16-19 17-18 17-19	27	258.9	26.1	7.0	0.7	10%	1.4	93
8/1/2016	19-19								
8/2/2016	19-19								
8/4/2016	19-19	18	246.1	21.1	4.4	0.4	9%	1.0	75
8/12/2016	19-19								
8/15/2016	15-18 16-19 17-19	31	640.6	23.7	19.9	0.7	4%	2.3	91
8/16/2016	17-19								
8/17/2016	18-19 19-19								
8/18/2016	17-19 18-19								
8/19/2016	19-19								
8/29/2016	19-19								
8/30/2016	19-19								
8/31/2016	17-19								
9/7/2016	19-19								
9/26/2016	17-19								
9/27/2016	18-19								
9/28/2016	19-19								
10/6/2016	19-19								
10/7/2016	18-19 19-19								
10/10/2016	19-19								
10/17/2016	19-19								
10/18/2016	19-19								

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)
10/19/2016	18-19 19-19	[redacted]							
10/20/2016	18-19	[redacted]							
10/21/2016	18-19 19-19	27	651.3	33.8	17.6	0.9	5%	1.7	79
10/24/2016	19-19	[redacted]							
10/25/2016	19-19	[redacted]							
10/26/2016	19-19	[redacted]							
10/27/2016	18-19 19-19	[redacted]							
10/28/2016	19-19	[redacted]							

Table 4-24 SCE CBP Day-Of 2-6 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)
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 a 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) approach.

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 in the CBP DO program. There were 67 control group matches for the incremental analysis, and there were 31 participating accounts for an average summer event.[38] Unfortunately, the match for the CBP DO 1-4 product was not very successful due to a lack of appropriately sized customers within each industry group. Therefore, the overall CBP match is quite off in magnitude, although similar in shape.

[38] The number of participants matched does not necessarily equal the number of participants on an average event day. In some cases, the number matched is higher because we tried to match the maximum number of participating customers.

Figure 4-9 SCE CBP DO AutoDR and TA/TI Event Day Match, kW

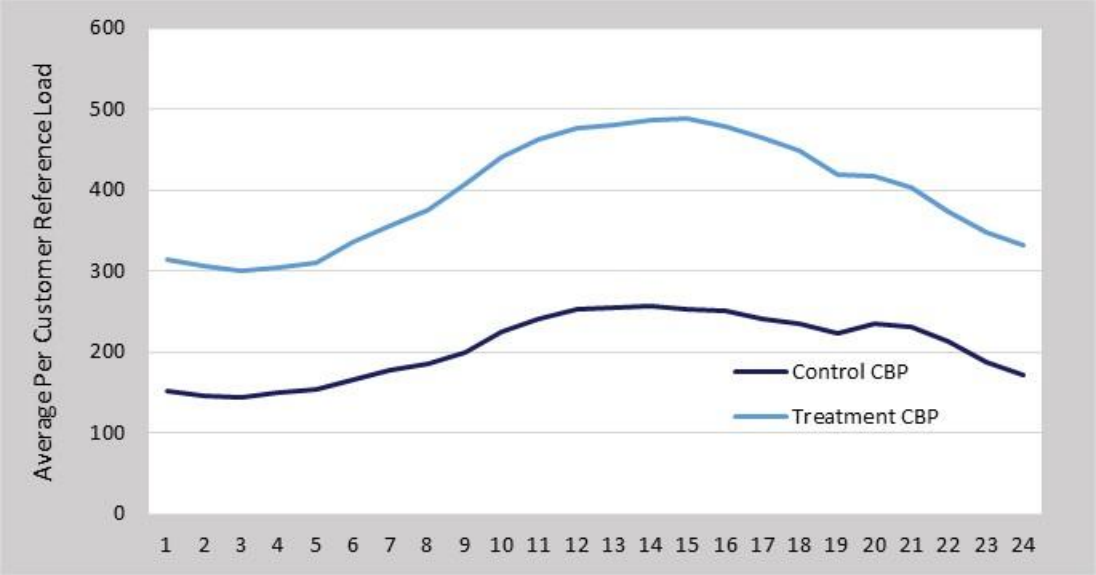


Figure 4-10 and accompanying Table 4-25 present the incremental impacts at the product level. The figure shows the average per-customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. As we would expect, the incremental 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 [redacted] per enabled customer in the DO 1-4 group, and [redacted] in the DO 2-6 group. [redacted].

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

Figure redacted to protect customer or aggregator confidentiality.

Table 4-25 presents the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants for both CBP DO products and for CBP as a whole (there were no AutoDR or TA/TI participants in CBP DA).

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

Product	Number of Accounts	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate (kW)	Significant
Redacted to protect customer or aggregator confidentiality.				

SDG&E

Events for SDG&E CBP

Table 4-26 below presents a summary of the 2016 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 7 event days over the course of the program year, while DA participants experienced 14 events. Typical events were those called during hours-ending 16-19.

Table 4-26 SDG&E CBP Event Summary

	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	139	60	69
6/20/2016	Monday	16-19	144	61	-
7/20/2016	Wednesday	16-19	137	60	68
7/21/2016	Thursday	16-19	137	60	68
7/22/2016	Friday	16-19	137	60	68
7/26/2016	Tuesday	16-19	-	-	68
7/27/2016	Wednesday	16-19	-	-	68
7/28/2016	Thursday	16-19	-	-	68
7/29/2016	Friday	16-19	-	-	68
8/15/2016	Monday	16-19	140	60	-
8/16/2016	Tuesday	16-19	-	-	72
8/17/2016	Wednesday	16-19	-	-	72
8/18/2016	Thursday	16-19	-	-	72
8/19/2016	Friday	16-19	-	-	72
9/26/2016	Monday	16-19	142	60	72
9/27/2016	Tuesday	16-19	142	60	72
10/20/2016	Thursday	16-19	-	-	71

Summary Load Impacts

Table 4-27 and Table 4-28 show the average event-hour impacts for the CBP DO product and the DA 1-4 hour product. Impacts are included for each event, both at the average per-customer level and in aggregate. The tables include results for the average event day.

Table 4-27 SDG&E CBP Day-Of Product (1-4 Hour and 2-6 Hour Products Combined): 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	200	3.9	189.9	24.0	38.0	4.8	13%	84
6/20/2016	205	3.6	198.9	19.9	40.8	4.1	10%	80
7/20/2016	197	3.6	176.2	17.7	34.7	3.5	10%	80
7/21/2016	197	3.6	180.0	17.8	35.5	3.5	10%	82
7/22/2016	197	3.6	189.3	18.1	37.3	3.6	10%	84
8/15/2016	200	4.5	198.6	22.2	39.7	4.4	11%	83
9/26/2016	202	4.3	198.9	37.2	40.2	7.5	19%	97
9/27/2016	202	4.3	189.6	35.7	38.3	7.2	19%	83

Table 4-28 SDG&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	69	4.0	276.3	51.4	19.1	3.5	19%	79
7/20/2016	68	0.5	207.6	4.0	14.1	0.3	2%	79
7/21/2016	68	0.5	221.3	12.3	15.1	0.8	6%	80
7/22/2016	68	0.5	216.0	12.9	14.7	0.9	6%	81
7/26/2016	68	0.5	217.7	12.2	14.8	0.8	6%	76
7/27/2016	68	0.5	214.7	12.1	14.6	0.8	6%	77
7/28/2016	68	0.5	212.0	12.0	14.4	0.8	6%	77
7/29/2016	68	0.5	198.8	4.0	13.5	0.3	2%	72
8/16/2016	72	7.8	309.2	93.9	22.3	6.8	30%	78
8/17/2016	72	7.8	369.2	45.7	26.6	3.3	12%	77
8/18/2016	72	7.8	303.5	94.1	21.9	6.8	31%	74
8/19/2016	72	7.8	288.4	94.3	20.8	6.8	33%	75
9/26/2016	72	7.8	377.1	130.7	27.1	9.4	35%	97
9/27/2016	72	7.8	356.5	124.6	25.7	9.0	35%	81
10/20/2016	71	5.7	331.5	58.4	23.5	4.1	18%	88

Table 4-29 presents the impacts for an average event day by industry group.[39, 40]

Table 4-29 SDG&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	Manufacturing	2	3,473.0	2,681.5	6.9	5.4	77%	81
DA	Retail Stores	5	480.2	68.1	2.4	0.3	14%	81
DA	Offices, Hotels, Finance, Services	63	205.6	6.9	13.0	0.4	3%	79
DA	Institutional/Government	1	2,682.6	320.3	2.7	0.3	12%	88
DA	**Total DA**	69	276.3	51.4	19.1	3.5	19%	79
DO	Manufacturing	1	1,406.4	226.4	1.4	0.2	16%	87
DO	Retail Stores	194	183.6	23.0	35.6	4.5	13%	84
DO	Offices, Hotels, Finance, Services	3	170.7	22.9	0.5	0.1	13%	85
DO	Institutional/Government	1	401.3	36.8	0.4	0.0	9%	82
DO	**Total DO**	200	189.9	24.0	38.0	4.8	13%	84
Total CBP		148	225.9	35.5	33.4	5.3	16%	80

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

[39] SDG&E's service territory is classified as a single LCA so we have only included a subgroup comparison by industry type.
[40] The results in Table 4-29 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. This is because different group of customers are called for each event, and in some cases, no customers in an industry segment may be called. So, the average for that industry segment will reflect only those events where customers in that industry segment 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 are averaged across different events, the total program may not exactly match the sum of the individual industry segments.

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 4-11 SDG&E CBP Day-Of 1-4 Hour: Average Hourly Per-Customer Impact, 2016

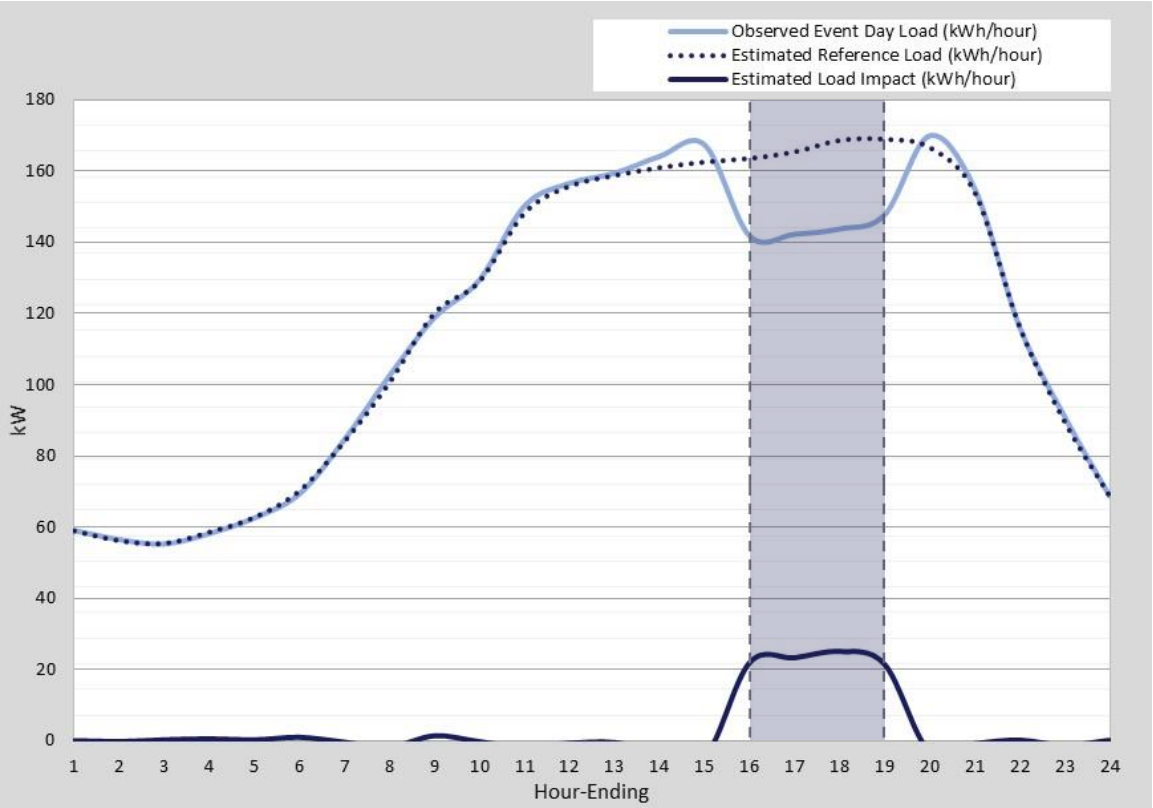


Figure 4-12 SDG&E CBP Day-Of 2-6 Hour: Average Hourly Per-Customer Impact, 2016

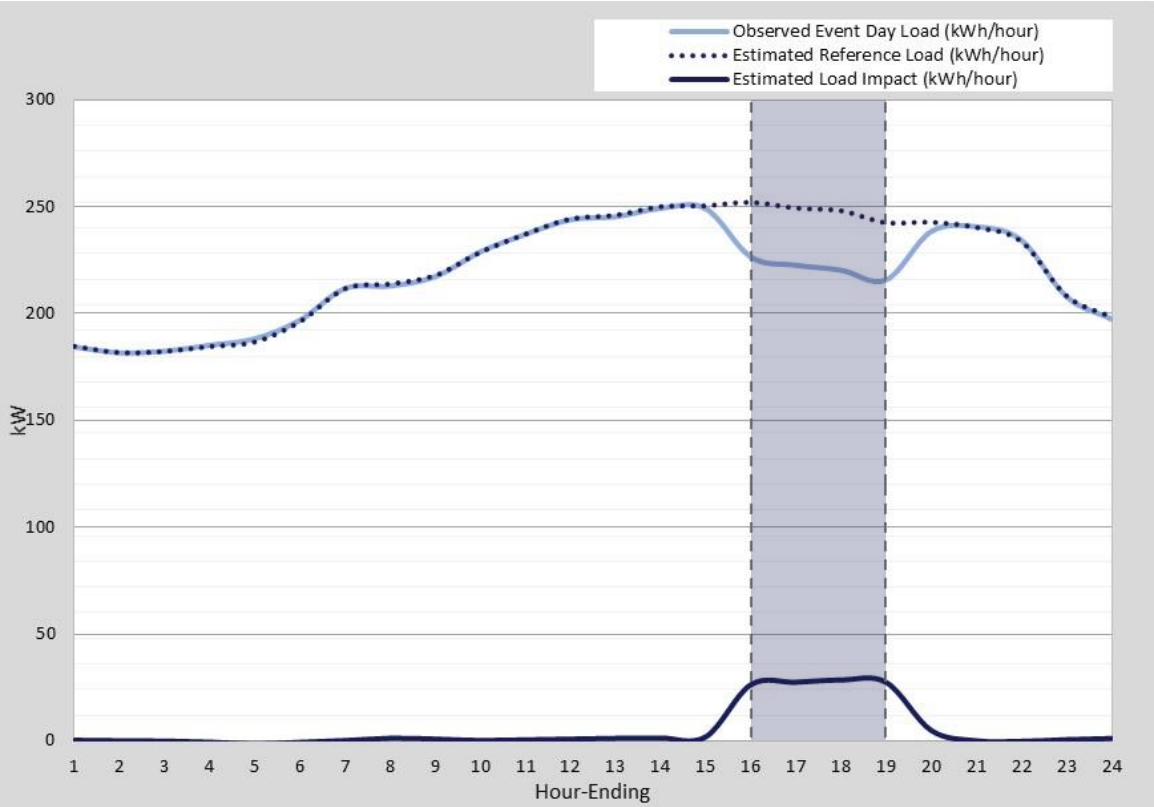
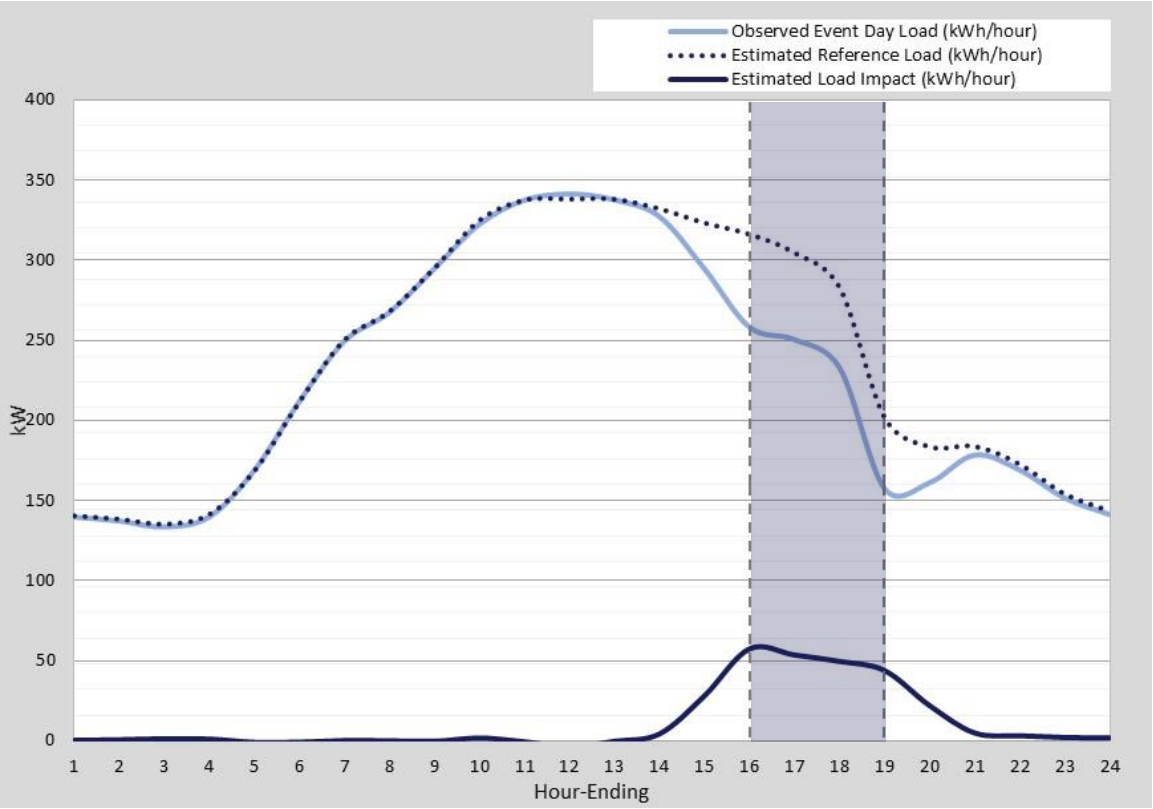


Figure 4-13 SDG&E CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2016



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 4-30 presents the average event-hour impacts and aggregate load shed test results for the CBP DO 1-4 hour and 2-6 hour products combined.

Table 4-30 SDG&E CBP Day-Of Product (1-4 Hour and 2-6 Hour Products Combined): 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)
Avg. Event	63	100.3	24.6	6.3	1.6	25%	5.0	84
6/20/2016	64	105.9	15.1	6.8	1.0	14%	5.0	80
7/20/2016	63	87.9	22.8	5.5	1.4	26%	5.0	80
7/21/2016	63	95.4	23.5	6.0	1.5	25%	5.0	82
7/22/2016	63	104.3	24.3	6.6	1.5	23%	5.0	84
8/15/2016	63	94.5	17.9	6.0	1.1	19%	5.0	83
9/26/2016	65	110.4	34.1	7.2	2.2	31%	4.9	97
9/27/2016	65	100.6	30.7	6.5	2.0	30%	4.9	83

Table 4-31 presents the average event-hour impacts for the CBP DA 1-4 hour participants.

Table 4-31 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)
Avg. Event	17	603.2	18.8	10.3	0.3	3%	2.3	79
7/20/2016	16	575.5	5.1	9.2	0.1	1%	2.3	79
7/21/2016	16	599.2	25.8	9.6	0.4	4%	2.3	80
7/22/2016	16	578.7	25.8	9.3	0.4	4%	2.3	81
7/26/2016	16	591.8	25.8	9.5	0.4	4%	2.3	76
7/27/2016	16	584.6	25.8	9.4	0.4	4%	2.3	77
7/28/2016	16	584.6	25.8	9.4	0.4	4%	2.3	77
7/29/2016	16	549.6	5.1	8.8	0.1	1%	2.3	72
8/16/2016	18	620.2	11.6	11.2	0.2	2%	2.3	78
8/17/2016	18	605.7	-8.6	10.9	-0.2	-1%	2.3	77
8/18/2016	18	584.0	11.8	10.5	0.2	2%	2.3	74
8/19/2016	18	539.2	11.8	9.7	0.2	2%	2.3	75
9/26/2016	18	684.6	34.7	12.3	0.6	5%	2.3	97
9/27/2016	18	621.0	38.1	11.2	0.7	6%	2.3	81
10/20/2016	18	566.5	25.1	10.2	0.5	4%	2.3	88

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 a 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) approach.

Figure 4-14 shows the treatment and control-group match on an average event day. The graph shows the load profile of each group for the overall CBP program. There were 83 control-group matches for the incremental analysis, and there were 80 participating accounts on the average event day.[41] While we did look at the results at the product level, and each participant is matched to a control customer within their product, we show only the program level match here.

[41] The number of participants matched does not necessarily equal the number of participants on an average event day. In some cases, the number matched is higher because we tried to match the maximum number of participating customers.

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

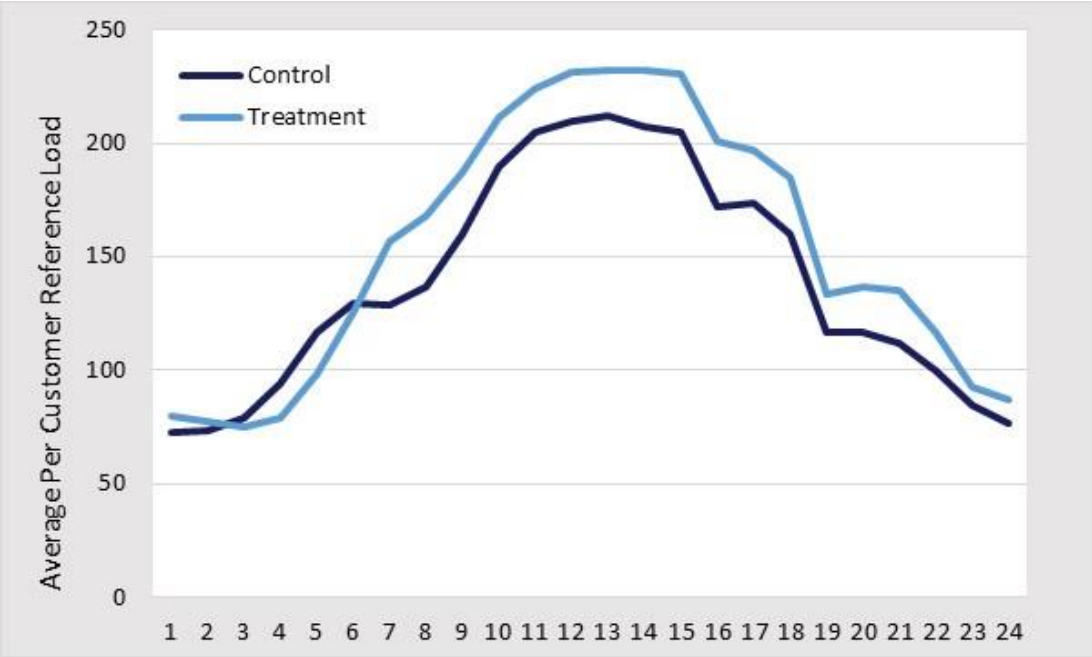


Figure 4-15 and accompanying Table 4-32 present the incremental impacts at the product level. The figure shows the average per-customer incremental impact for each hour of an average event day. We also present the upper and lower confidence intervals at the 95th percentile. For CBP DO, the incremental 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 16 kW per enabled customer. However, for CBP DA, there are some significant impacts across the entire day, and the on-peak impacts are negative, indicating an average incremental decrease in savings relative to similar non-enabled participants of 58.8 kW.

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

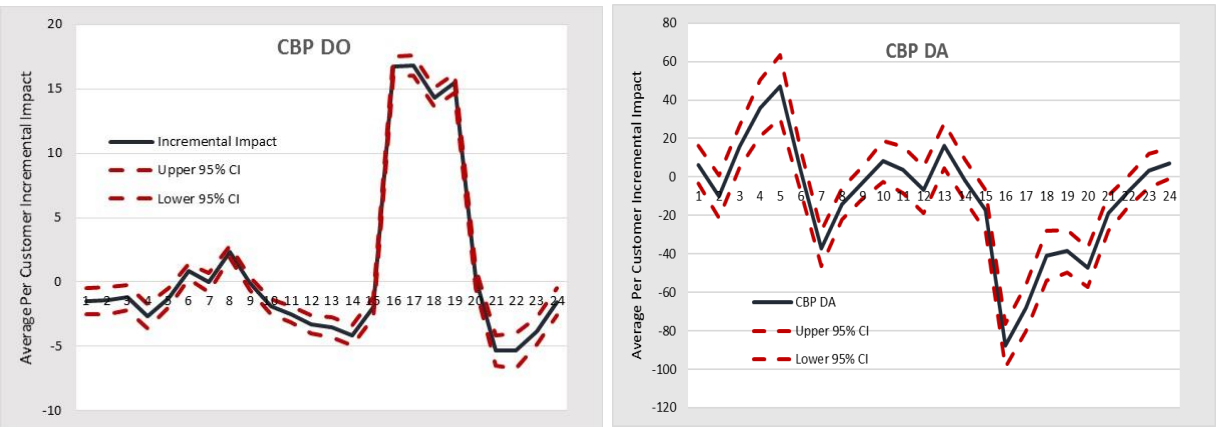


Table 4-32 presents the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants.

Table 4-32 SDG&E CBP Incremental AutoDR and TA/TI Impacts

Product	Number of Accounts	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate (kW)	Significant
CBP DO	63	15.84	998	Yes
CBP DA	17	-58.83	-1,000	Yes
CBP Total	**80**	**-3.02**	**-242**	**No**

Aggregator Managed Portfolio

PG&E and SCE both offered AMP in PY2016. 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. Beginning 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. Table 4-33 presents the average event day impacts by product and IOU, both at the per-customer level, and in aggregate.

Table 4-33 Statewide AMP Impacts Summary, Average Summer Event Day PY2016

			Per Customer Impact (kW)		Aggregate Impact (MW)	
Utility	Product	Accounts	Reference Load	Impact	Reference Load	Impact
PG&E	DO Local + System	1,236	223.6	52.5	276.3	64.9
SCE	DO 1-5 Hour					
	DO 1-6 Hour					

PG&E

Events for PG&E AMP

Table 4-34 presents a summary of the 2016 events for PG&E's AMP program. The DO local participants experienced a total of 14 event days over the course of the program year, while DO system participants experienced 13 event days. The table shows the count of Sub-LAPs called during each event for the local product. Typical events were called during hours ending 16-19.

Table 4-34 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	607	15	684	1,236
6/3/2016	Friday	16-19	618	16	717	1,335
6/20/2016	Monday	16-19	618	16	717	1,335
6/27/2016	Monday	16-19	618	16	717	1,335
6/28/2016	Tuesday	14-19	618	16	717	1,335
7/25/2016	Monday	16-19	611	16	743	1,354
7/27/2016	Wednesday	16-19	611	16	743	1,354
7/28/2016	Thursday	16-19	611	16	743	1,354
7/29/2016	Friday	16-19	611	16	743	1,354
8/15/2016	Monday	16-19	600	16	688	1,288
8/16/2016	Tuesday	15-19	600	16	688	1,288
8/17/2016	Wednesday	15-19	600	16	688	1,288
9/19/2016	Monday	16-19		2	307	307
9/26/2016	Monday	16-19	589	16	705	1,294
9/27/2016	Tuesday	16-19	589	16	705	1,294

Summary Load Impacts

Table 4-35 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.

Table 4-35 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	1,236	76.3	223.6	52.5	276.3	64.9	23%	94
6/3/2016	1,335	79.1	224.4	51.2	299.5	68.4	23%	96
6/20/2016	1,335	79.1	220.5	51.3	294.4	68.5	23%	90
6/27/2016	1,335	79.1	229.2	51.8	305.9	69.2	23%	95
6/28/2016	1,335	79.1	236.4	49.2	315.6	65.6	21%	93
7/25/2016	1,354	83.3	232.7	57.6	315.1	77.9	25%	93
7/27/2016	1,354	83.3	228.3	57.3	309.1	77.6	25%	97
7/28/2016	1,354	83.3	231.6	56.4	313.6	76.3	24%	95
7/29/2016	1,354	83.3	232.1	57.3	314.3	77.6	25%	96
8/15/2016	1,288	80.1	217.7	46.9	280.4	60.4	22%	90
8/16/2016	1,288	80.1	223.7	51.4	288.1	66.2	23%	90
8/17/2016	1,288	80.1	224.6	51.0	289.3	65.7	23%	91
9/19/2016								
9/26/2016	1,294	80.1	219.7	44.7	284.3	57.8	20%	95
9/27/2016	1,294	80.1	220.4	45.7	285.2	59.1	21%	92

Table 4-36 and Table 4-37 present the impacts for an average event day for two subgroups of interest: Industry and LCA.[42]

Table 4-36 PG&E AMP DO Impacts by Industry

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)
Agriculture, Mining & Construction	526	95.4	48.2	50.2	25.4	51%	101
Manufacturing	64	686.4	94.9	43.9	6.1	14%	90
Wholesale, Transport, other Utilities	136	375.3	140.9	51.0	19.2	38%	98
Retail stores	389	177.6	25.8	69.1	10.0	15%	89
Offices, Hotels, Finance, Services	65	699.9	45.9	45.5	3.0	7%	82
Schools							
Institutional/Government	38	153.5	13.5	5.8	0.5	9%	83
Other/Unknown	16	345.2	34.1	5.5	0.5	10%	92
Total DO	**1,236**	**223.6**	**52.5**	**276.3**	**64.9**	**23%**	**94**

[42] The results in Table 4-36 and Table 4-37 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 may not exactly match the sum of the individual industry segments (or LCAs).

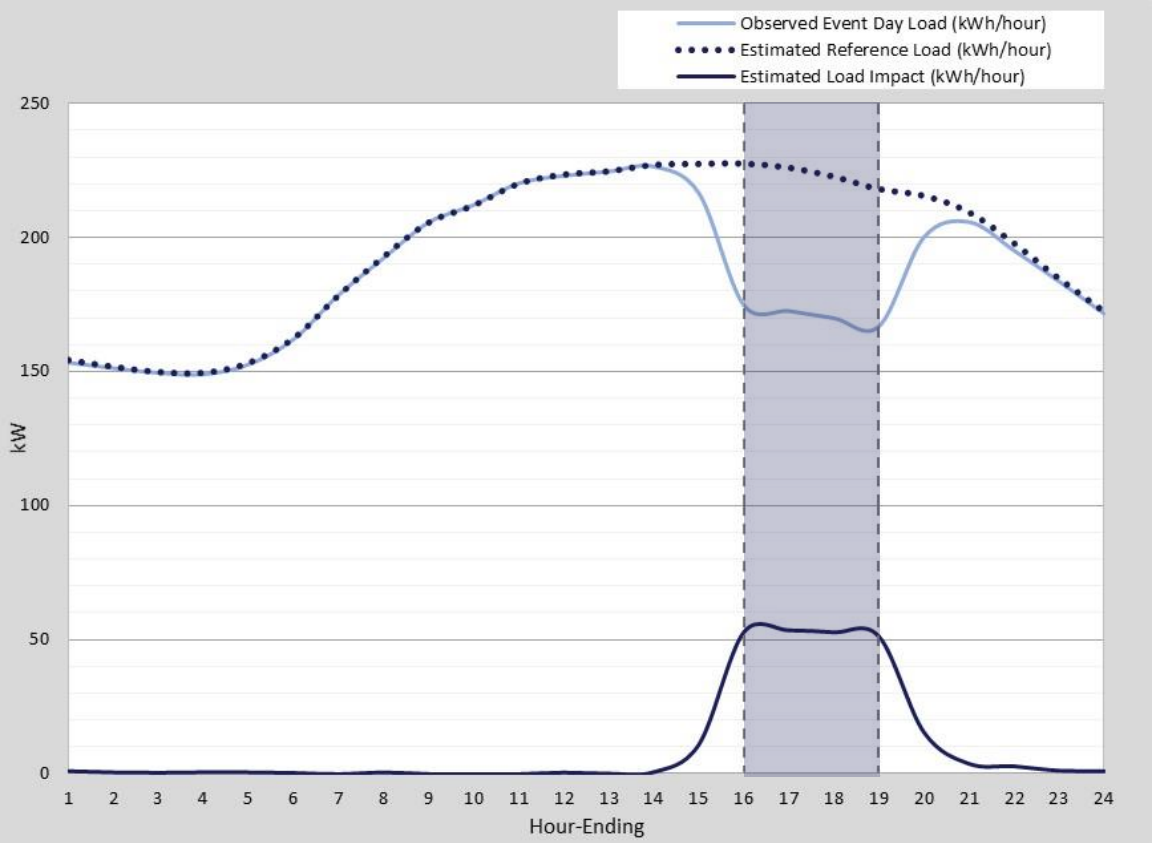
Table 4-37 PG&E AMP DO Impacts by LCA

LCA	# of Accts	Per Customer Impact (kW) Reference Load	Impact	Aggregate Impact (MW) Reference Load	Impact	% Impact	Event Temp (˚F)
Greater Bay Area	312	332.3	29.1	103.7	9.1	9%	83
Greater Fresno	289	118.3	49.7	34.2	14.4	42%	103
Humboldt							
Kern	306	98.8	60.3	30.2	18.5	61%	103
Northern Coast	63	227.2	34.7	14.3	2.2	15%	88
Other	215	352.6	76.8	75.8	16.5	22%	87
Sierra	35	234.3	42.2	8.2	1.5	18%	97
Stockton							
Total DO	**1,236**	**223.6**	**52.5**	**276.3**	**64.9**	**23%**	**94**

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, 2016



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 4-38 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.

Table 4-38 PG&E AMP Day-Of Product (Local and System Products Combined): AutoDR 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.								

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 a 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) approach.

Figure 4-17 below shows the treatment and control group match on an average event day. The graph shows the reference load profile for the AMP products. There were 44 control group matches for the incremental analysis, and there were 38 participating accounts on the average event day. Unfortunately, this year the incremental savings results were not significant at either the product or program level. In Figure 4-18 below, we show the average estimated per customer incremental impacts for the AMP participants. The average incremental savings estimate for AMP was [redacted] per participant.

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

Figure redacted to protect customer or aggregator confidentiality.

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

Figure redacted to protect customer or aggregator confidentiality.

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 estimates that CBP nominations will remain constant throughout the forecast horizon (2017-2027), with an estimated 50 customers for the DA product and 611 customers for the DO product.

The ex-ante impact results forecast annual CBP load impacts for the DA and DO products that are commensurate with the PY2016 per customer impacts and the 2017-2027 enrollment forecast. The impacts are estimated to remain constant across the months of May through October due to the inability to forecast the month-to-month variation.

Table 5-1 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2017.[43] 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.

[43] Though labeled as an August peak day in 2017, the results in Table 5-1 would be identical for each month, May through October, and each year, 2017 through 2027, in the forecast.

Table 5-1 PG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2017

			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	[redacted]								
	20 to < 200 kW	[redacted]								
	≥ 200 kW	45	148.9	148.9	148.9	148.9	6.67	6.67	6.67	6.67
	Total DA	**50**	**138.1**	**138.1**	**138.1**	**138.1**	**6.85**	**6.85**	**6.85**	**6.85**
DO	< 20 kW	[redacted]								
	20 to < 200 kW	405	12.7	13.0	12.7	12.7	5.15	5.25	5.15	5.15
	≥ 200 kW	197	42.8	43.2	43.2	43.2	8.41	8.50	8.50	8.50
	Total DO	**611**	**22.2**	**22.5**	**22.4**	**22.4**	**13.57**	**13.75**	**13.66**	**13.66**

Figure 5-1 illustrates the average event-hour load impacts distributed by LCA for the two CBP products on an August peak day in 2017. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 5-1 PG&E CBP: Average Event-Hour Aggregate Load Impacts by LCA for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions

Figure redacted to protect customer or aggregator confidentiality.

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 2017 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-2 PG&E CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions

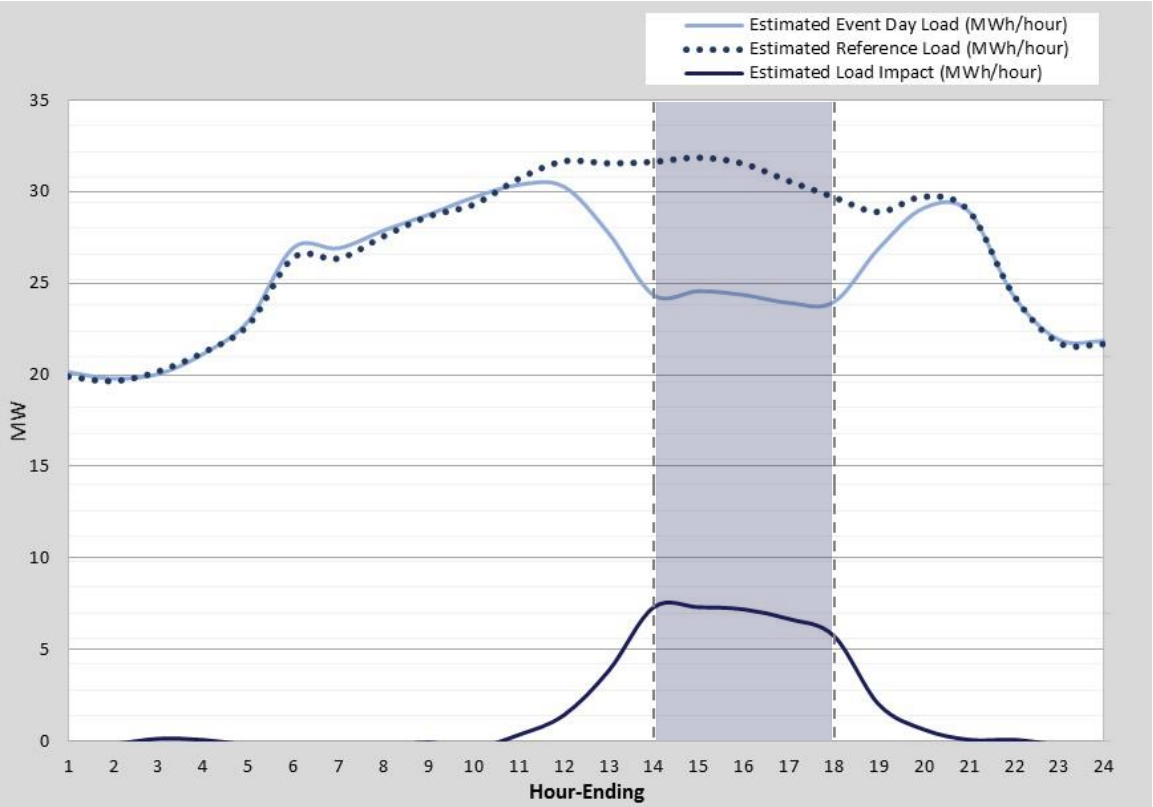
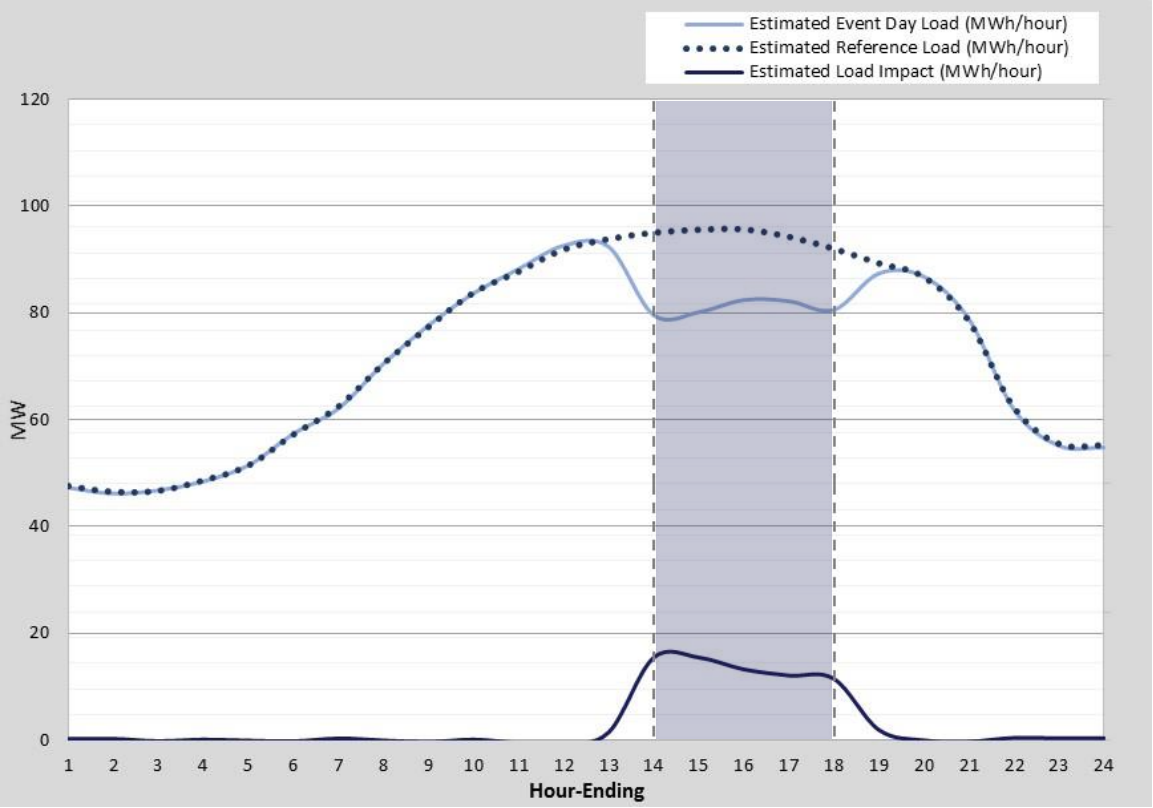


Figure 5-3 PG&E CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment and Load Impact Summary

SCE forecasts the CBP DA enrollment to be 30 customers in 2017 and then to stay constant at 90 customers throughout the remainder of the forecast horizon (2018-2027). For the CBP DO product, SCE forecasts the enrollment to be 814 customers in 2017 and then to stay constant at 1,250 customers throughout the remainder of the forecast horizon (2018-2027).

The ex-ante impact results forecast annual CBP load impacts for the DA and DO products that are commensurate with the PY2016 per customer impacts and the 2017-2027 enrollment forecast.

Table 5-2 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2017. 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.

Table 5-2 SCE CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2017

		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	52.8	52.8	52.8	52.8	1.58	1.58	1.58	1.58
Total DO	814	36.1	36.1	36.1	36.1	29.35	29.35	29.35	29.35

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 2017 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-4 SCE CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions

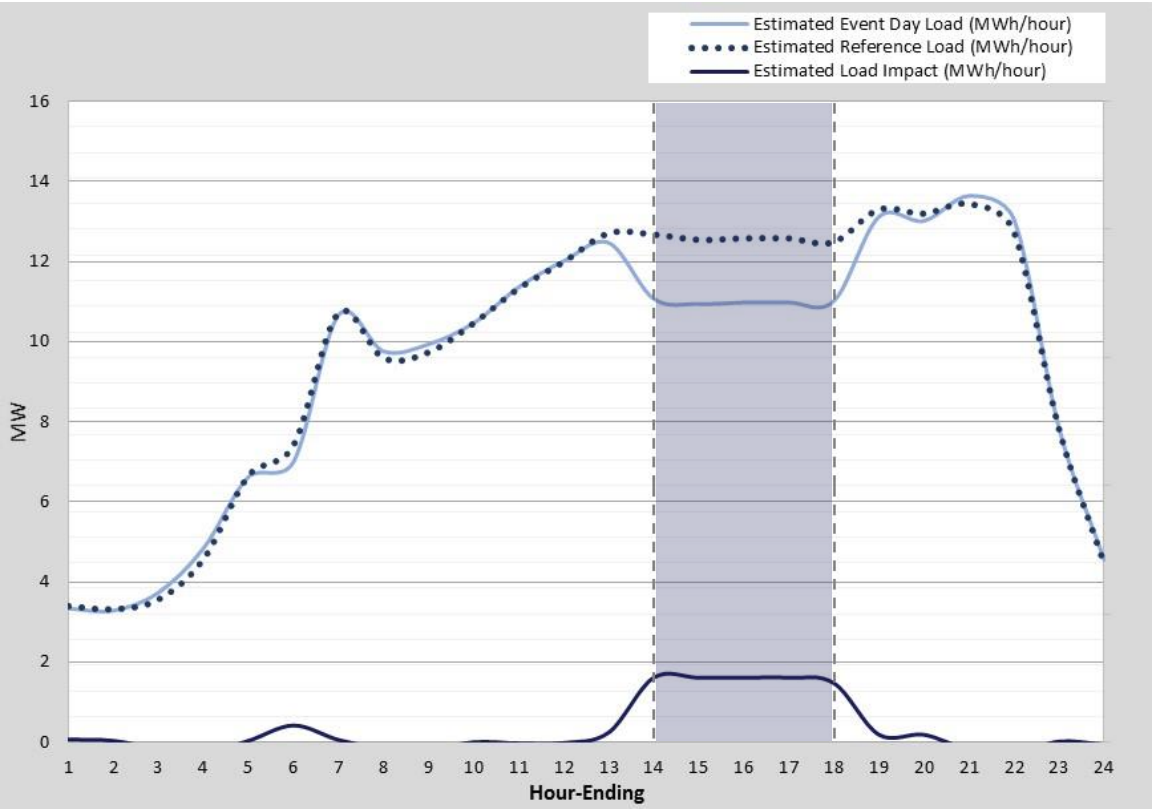
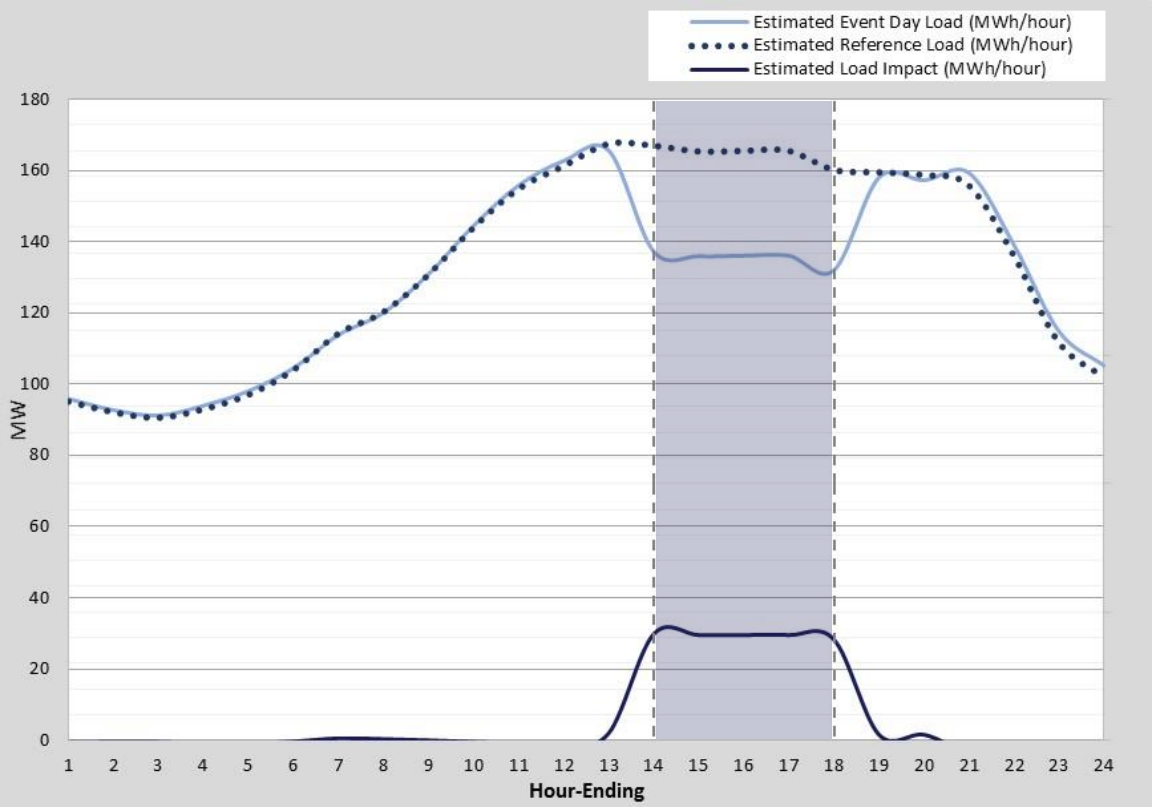


Figure 5-5 SCE CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions



SDG&E

Enrollment and Load Impact Summary

For the CBP DA and DO products, the enrollment forecast assumes the customer enrollment will increase by 3% per year starting in 2019 through 2022 due to the CBP program improvements proposed by SDG&E in the application for 2018-2022. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 7% per year starting in 2019 through 2022 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 10% per year (3% + 7%) starting in 2019 through 2022 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2022 and through 2027 show a flat trend at the 2022 values.

The ex-ante load impact forecast follows the 2017-2027 enrollment forecast trends 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 2017.[44] 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.

[44] Though labeled as an August peak day in 2017, the results in Table 5-3 would be identical for each month, May through October, in the 2017 forecast.

Table 5-3 SDG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2017

		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	70	12.1	12.7	12.6	12.9	0.85	0.89	0.88	0.90
Total DO	199	25.5	25.2	25.2	25.0	5.07	5.02	5.02	4.98

Hourly Reference Loads and Load Impacts

Figure 5-6 and Figure 5-7 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2017 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-6 SDG&E CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions

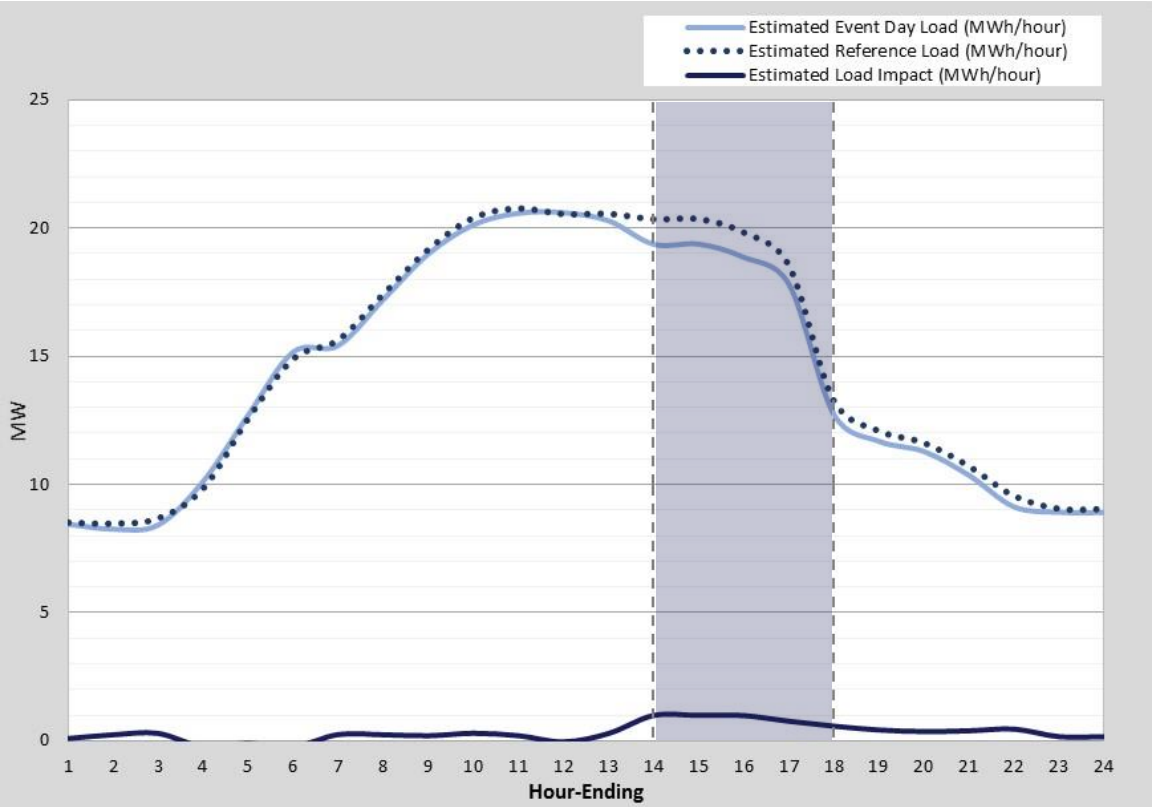
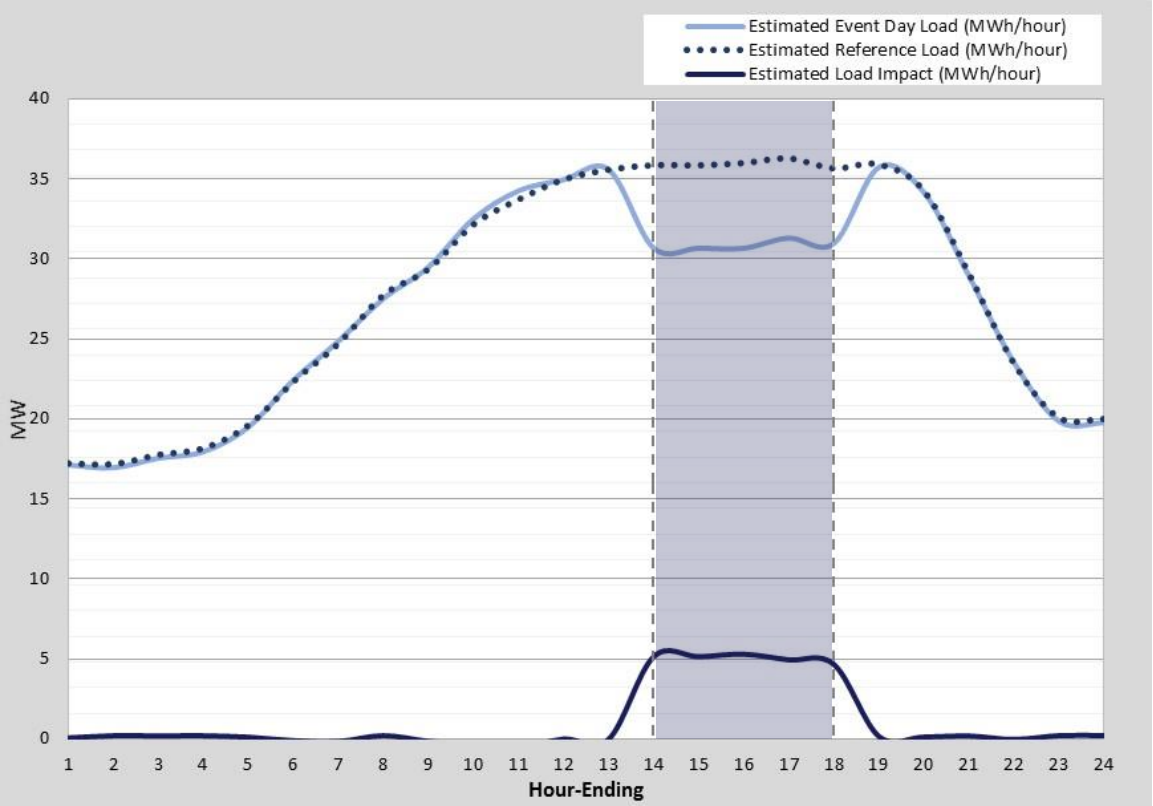


Figure 5-7 SDG&E CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2017, 1-in-2 Utility Peak Weather Conditions



Aggregator Managed Portfolio

PG&E

PG&E has discontinued AMP as of the end of PY2016. Therefore, there are no ex-ante impacts for 2017-2027.

SCE

SCE's AMP ex-ante impact data has been redacted to protect customer or aggregator confidentiality.

Comparisons of Ex-Post and Ex-Ante Results

PG&E

Previous and Current Ex-Post: CBP

Table 5-4 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past five 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 5-4 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	282.1	122.9	46.8	20.4	44%	95
	2013	25	604.8	188.0	15.1	4.7	31%	86
	2014	33	396.4	148.3	13.1	4.9	37%	89
	2015	200	425.5	79.7	85.1	15.9	19%	90
	2016							
DO	2012	370	272.0	62.8	100.6	23.3	23%	88
	2013	480	197.8	28.5	94.9	13.7	14%	90
	2014	542	153.3	19.5	83.2	10.6	13%	87
	2015	569	177.8	34.7	101.2	19.8	20%	90
	2016	406	156.0	22.6	63.3	9.2	14%	88

Previous and Current Ex-Post: AMP

Table 5-5 summarizes the AMP DO average event-hour ex-post load impact results for the past five years for an average event day. The aggregate ex-post impacts were lower in PY2016 than in the previous ex-post analysis primarily because one aggregator no longer participated in AMP.

Table 5-5 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	414.6	115.2	466.5	129.6	28%	89
	2013	1,344	374.6	115.5	503.4	155.2	31%	85
	2014	1,397	334.1	87.9	466.6	122.7	26%	89
	2015	1,417	285.0	67.3	403.9	95.3	24%	93
	2016	1,236	223.6	52.5	276.3	64.9	23%	94

Previous and Current Ex-Ante and Ex-Post: CBP

Table 5-6 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.[45] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.

[45] 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.

Table 5-6 PG&E CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

	Model	Year	Day	Accts	Per Customer (kW) Ref. Load	Per Customer (kW) Impact	Aggregate (MW) Ref. Load	Aggregate (MW) Impact	% Impact	Event Temp (˚F)
DA	Current	Ex-Post 2016	Aug 17	[redacted]						
		Ex-Ante 2017	Aug Peak	50	626.7	138.1	31.1	6.9	22%	92
	Previous	Ex-Post 2015	Aug 27	200	533.8	112.5	106.8	22.5	21%	91
		Ex-Ante 2016	Aug Peak	175	530.7	120.9	92.9	21.2	23%	90
		Ex-Ante 2017	Aug Peak	175	532.2	120.9	93.1	21.2	23%	90
DO	Current	Ex-Post 2016	Aug 17	427	136.8	22.9	58.4	9.8	17%	85
		Ex-Ante 2017	Aug Peak	611	154.7	22.2	94.5	13.6	14%	92
	Previous	Ex-Post 2015	Aug 26	589	180.4	28.6	106.3	16.8	16%	88
		Ex-Ante 2016	Aug Peak	609	180.4	28.1	109.9	17.1	16%	91
		Ex-Ante 2017	Aug Peak	609	180.5	28.1	109.9	17.1	16%	91

Table 5-6 shows the following trends for the CBP DA and DO products:

- **Current Ex-Post Compared with Previous Ex-Ante:** The aggregate ex-post impacts were lower in PY2016 than projected to be in the previous ex-ante forecast due primarily to lower than forecasted enrollment. Some of the AMP customers were expected to migrate to CBP in 2016, but it did not materialize as much as forecast.
- **Current Ex-Ante Compared with Previous Ex-Ante:** The current ex-ante analysis for DA projects lower impacts than did the previous ex-ante analysis due to lower-than-expected enrollment realized for PY2016. The current ex-ante analysis for the DO product assumes some modest growth in enrollment although it is still lower than the previous ex-ante analysis due to the lower-than-expected enrollment realized in PY2016.
- **Current Ex-Ante Compared with Current Ex-Post:** For DA, the current ex-ante estimates for PY2017 and the current ex-post estimates for PY2016 are [redacted]. For DO, the current ex-ante estimates for PY2017 show higher aggregate impacts than the current ex-post estimates for PY2016 due mainly to higher expected enrollment, resulting from some migration from AMP.

Previous and Current Ex-Ante and Ex-Post: AMP

Since PG&E's AMP has been discontinued as of the end of PY2016, there are no ex-ante impacts for the program.

SCE

Previous and Current Ex-Post: CBP

Table 5-7 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past five 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 5-7 SCE CBP: Previous and Current Ex-Post, Average Summer 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	[redacted]						
	2013	20	638.2	145.4	13.1	3.0	23%	85
	2014	231	430.5	41.5	99.4	9.6	10%	84
	2015	55	284.5	18.6	15.6	1.0	7%	81
	2016	[redacted]						
DO	2012	359	243.0	45.9	87.3	16.5	19%	90
	2013	420	214.1	43.9	89.8	18.4	21%	90
	2014	1,236	221.4	42.6	273.7	52.7	19%	88
	2015	670	151.8	24.5	101.7	16.4	16%	87
	2016	[redacted]						

Previous and Current Ex-Post: AMP

SCE's AMP ex-post impact data has been redacted to protect customer or aggregator confidentiality.

Previous and Current Ex-Ante and Ex-Post: CBP

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. The ex-ante impacts in the table reflect the utility peak 1-in-2 weather scenario on an August system peak day. The ex-post impacts reflect the average summer event day results.[46]

Table 5-8 SCE CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

	Model	Year	Day	Accts	Per Customer (kW) Ref. Load	Per Customer (kW) Impact	Aggregate (MW) Ref. Load	Aggregate (MW) Impact	% Impact	Event Temp (˚F)
DA	Current	Ex-Post 2016	Summer	[redacted]						
		Ex-Ante 2017	Aug Peak	30	419.2	52.8	12.6	1.6	13%	94
	Previous	Ex-Post 2015	Summer	55	284.5	18.6	15.6	1.0	7%	81
		Ex-Ante 2016	Aug Peak	30	366.8	41.3	11.0	1.2	11%	92
		Ex-Ante 2017	Aug Peak	30	366.8	41.3	11.0	1.2	11%	92
DO	Current	Ex-Post 2016	Summer	[redacted]						
		Ex-Ante 2017	Aug Peak	814	202.4	36.1	164.8	29.3	18%	92
	Previous	Ex-Post 2015	Summer	670	151.8	24.5	101.7	16.4	16%	87
		Ex-Ante 2016	Aug Peak	814	195.4	37.2	159.0	30.2	19%	92
		Ex-Ante 2017	Aug Peak	814	195.4	37.2	159.0	30.2	19%	92

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

- **Current Ex-Post Compared with Previous Ex-Ante:** For DA, the current ex-post results show [redacted] aggregate impacts than the previous ex-ante projections for PY2016 due to [redacted] per customer impacts. For DO, the current ex-post results show [redacted] aggregate impacts than the previous ex-ante projections for PY2016 due mainly to [redacted] enrollment.
- **Current Ex-Ante Compared with Previous Ex-Ante:** The current ex-ante analysis for DA projects higher impacts than did the previous ex-ante analysis due to higher expected per

[46] For CBP DA, the 2016 ex-post average summer event day results are averaged across DA 1-4 Hour events with HE 17-19 during summer months. For CBP DO, the 2016 ex-post average summer event day results are averaged across the DO 1-4 Hour and DO 2-6 Hour products with HE 17-19 during summer months.

customer impacts in PY2017. The current PY2017 ex-ante estimates for DO are very close to previous ex-ante impacts for PY2017.

- **Current Ex-Ante Compared with Current Ex-Post:** For DA, the current ex-ante estimates for PY2017 and the current ex-post estimates for PY2016 [redacted]. For DO, the current ex-ante estimates for PY2017 show [redacted] aggregate impacts than the current ex-post estimates for PY2016 due mainly to [redacted] expected enrollment.

Previous and Current Ex-Ante and Ex-Post: AMP

SCE's AMP impact data has been redacted to protect customer or aggregator confidentiality.

SDG&E

Previous and Current Ex-Post: CBP

Table 5-9 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past five 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.

Table 5-9 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	320.3	81.6	25.0	6.4	25%	83
	2013	142	304.8	75.9	43.2	10.8	25%	88
	2014	163	247.0	60.6	40.4	9.9	25%	87
	2015	122	148.0	64.1	18.1	7.8	43%	80
	2016	69	276.3	51.4	19.1	3.5	19%	79
DO	2012	321	229.7	30.5	73.7	9.8	13%	86
	2013	260	234.5	40.2	61.1	10.5	17%	87
	2014	237	228.5	37.0	54.1	8.8	16%	87
	2015	223	208.4	25.6	46.4	5.7	12%	82
	2016	200	189.9	24.0	38.0	4.8	13%	84

Previous and Current Ex-Ante and Ex-Post: CBP

Table 5-10 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.[47] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.

[47] 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.

Table 5-10 SDG&E CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

	Model	Year	Day	Accts	Per Customer (kW) Ref. Load	Per Customer (kW) Impact	Aggregate (MW) Ref. Load	Aggregate (MW) Impact	% Impact	Event Temp (˚F)
DA	Current	Ex-Post 2016	Aug 16	72	309.2	93.9	22.3	6.8	30%	78
		Ex-Ante 2017	Aug Peak	70	264.2	12.1	18.5	0.8	5%	83
	Previous	Ex-Post 2015	Jun 30	131	205.7	65.1	27.0	8.5	32%	81
		Ex-Ante 2016	Aug Peak	122	213.5	62.9	26.0	7.7	30%	81
		Ex-Ante 2017	Aug Peak	122	213.5	62.9	26.0	7.7	30%	81
DO	Current	Ex-Post 2016	Aug 15	200	198.6	22.2	39.7	4.4	11%	83
		Ex-Ante 2017	Aug Peak	199	180.6	25.5	35.9	5.1	14%	85
	Previous	Ex-Post 2015	Aug 26	216	214.2	25.9	46.3	5.6	12%	84
		Ex-Ante 2016	Aug Peak	220	187.0	20.7	41.2	4.6	11%	81
		Ex-Ante 2017	Aug Peak	220	187.0	20.7	41.2	4.6	11%	81

Table 5-10 shows the following trends for the CBP DA and DO products:

- **Current Ex-Post Compared with Previous Ex-Ante:** For DA, the current ex-post results show lower aggregate impacts than the previous ex-ante projections for PY2016 due to lower enrollment. For DO, the current ex-post results show comparable aggregate impacts to the previous ex-ante projections for PY2016.
- **Current Ex-Ante Compared with Previous Ex-Ante:** The current ex-ante analysis for DA projects lower impacts in PY2017 than did the previous ex-ante analysis due to lower expected per customer impacts and lower enrollment. The current PY2017 ex-ante estimates for DO are similar to previous ex-ante impacts for PY2017, but slightly higher.
- **Current Ex-Ante Compared with Current Ex-Post:** For DA, the current ex-ante estimates for PY2017 show lower aggregate impacts than the current ex-post estimates for PY2016 due to lower expected per customer impacts. For DO, the current ex-ante estimates for PY2017 show fairly comparable aggregate impacts to the current ex-post estimates for PY2016, although the ex-ante impacts are projected to be slightly larger.

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 and 2015.
- 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 2016. We also calculated the MAPE and MPE on these days to assess the error and bias in the 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 program year, we used three different Euclidean distance metrics to select similar non-event days: (1) daily maximum temperature; (2) average daily and daily maximum temperatures; (3) average daily temperature. The Euclidean distance metrics used can be calculated by Equations 6.1 through 6.3 below.

$$ED_1 = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2} \tag{6.1}$$

$$ED_2 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2 + (MaxTemp_{event} - MaxTemp_{non-event})^2} \tag{6.2}$$

$$ED_3 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2} \quad (6.3)$$

Because both PG&E and SCE had several different event windows, we decided to put the focus on the entire day instead of the typical event window HE16-HE19. We also selected more similar non-event days for this program year analysis to accommodate both the non-event day pool and the available customer data. For example, a newer customer without available 2014 usage data will be at a disadvantage if we have more 2014 similar non-event days.

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 daily temperature by product for each day.

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

Dates	CBP DA	CBP DO	AMP DO
5/13/2014	74	75	76
7/2/2014	72	70	77
7/8/2014	75	73	79
7/15/2014	76	74	80
7/24/2014	75	75	78
8/8/2014	74	72	78
8/11/2014	73	72	77
8/27/2014	74	73	77
8/28/2014	74	73	77
9/3/2014	71	71	75
9/10/2014	72	72	75
9/11/2014	75	74	78
10/8/2014	70	71	73
6/17/2015	72	71	77
6/29/2015	74	73	78
7/15/2015	73	72	76
7/17/2015	75	74	79
7/20/2015	79	79	81
7/27/2015	75	75	78
7/31/2015	75	74	81
8/19/2015	72	72	77
9/8/2015	78	79	80
9/21/2015	78	79	82
9/24/2015	74	75	77
9/25/2015	74	74	78
10/12/2015	72	73	75
10/13/2015	75	76	78
5/18/2016	74	73	76
5/31/2016	75	74	78
6/23/2016	72	71	76
6/29/2016	74	70	79
7/1/2016	75	72	79
8/2/2016	73	72	78
8/3/2016	74	72	78
8/12/2016	74	72	77
8/18/2016	75	73	79
9/7/2016	75	75	77

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

Summer Dates	CBP DA	CBP DO	AMP DO	Non Summer Dates	CBP DA	CBP DO	AMP DO
5/16/2014	81	79	80	1/2/2014	61	59	58
5/28/2014	70	70	70	1/7/2014	57	56	55
5/30/2014	71	71	72	1/8/2014	54	53	53
7/8/2014	78	76	78	1/14/2014	64	65	64
7/9/2014	77	75	77	1/15/2014	67	68	66
7/24/2014	80	80	81	2/7/2014	53	53	53
7/28/2014	78	78	79	2/13/2014	65	63	63
8/7/2014	70	71	72	2/14/2014	65	63	64
8/15/2014	76	76	77	2/20/2014	62	61	60
8/18/2014	76	76	77	2/24/2014	59	59	59
9/2/2014	74	74	75	3/10/2014	66	65	64
9/3/2014	73	73	74	3/14/2014	60	60	60
9/22/2014	71	72	72	4/4/2014	56	55	55
9/23/2014	73	73	74	4/14/2014	66	65	66
10/1/2014	70	70	70	4/24/2014	64	64	64
10/2/2014	77	77	76	12/12/2014	47	48	47
10/16/2014	66	66	66	12/15/2014	53	53	52
10/28/2014	66	65	65	12/17/2014	49	50	49
5/6/2015	61	60	60	12/18/2014	53	53	52
5/7/2015	58	57	57	12/26/2014	50	50	49
5/8/2015	54	55	54	12/30/2014	46	47	47
7/17/2015	74	75	76	1/2/2015	46	45	45
8/4/2015	78	78	78	2/24/2015	56	56	55
8/5/2015	79	79	79	3/3/2015	53	53	53
8/10/2015	71	72	72	3/12/2015	70	69	68
8/18/2015	76	76	78	3/18/2015	65	64	64
8/24/2015	77	78	79	3/26/2015	74	73	72
9/30/2015	76	76	76	4/6/2015	58	57	57
10/23/2015	69	69	68	4/9/2015	61	60	60
5/10/2016	64	64	64	4/27/2015	69	70	69
6/29/2016	81	79	80	4/29/2015	75	74	75
8/3/2016	78	76	78	11/5/2015	57	57	56
8/24/2016	77	75	76	11/23/2015	64	63	62
9/13/2016	65	65	64	12/8/2015	65	63	62
9/22/2016	68	68	68	12/14/2015	50	49	48
9/29/2016	78	78	78	12/18/2015	55	53	52
				12/25/2015	50	49	47
				12/31/2015	50	49	48
				1/4/2016	56	56	55
				2/18/2016	57	58	58
				3/1/2016	63	63	64
				3/18/2016	63	63	64
				4/5/2016	69	68	69
				4/11/2016	63	62	62

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

Dates	CBP DA	CBP DO
6/30/2015	73	74
7/1/2015	73	74
7/21/2015	73	74
7/22/2015	75	75
7/23/2015	74	75
7/29/2015	72	73
8/3/2015	72	73
8/4/2015	74	75
8/13/2015	76	77
8/14/2015	77	79
8/19/2015	73	73
8/21/2015	73	73
8/25/2015	74	75
8/27/2015	79	81
9/8/2015	81	83
9/9/2015	85	87
9/10/2015	84	86
9/11/2015	81	83
9/22/2015	76	76
9/25/2015	77	78
10/2/2015	74	73
10/8/2015	74	75
10/12/2015	82	82
8/1/2016	73	73
8/3/2016	72	72
8/29/2016	72	72
8/30/2016	71	72
10/7/2016	73	73
10/21/2016	75	76
10/28/2016	71	72

Optimization Process and Results

Next, we estimated the MAPE and MPE, for the entire day, for each customer, and for each candidate model, both for the in-sample period and for the out-of-sample period. Again, because of the several different event windows, we decided to forego the on-peak window HE16-HE19 and give more weight to the entire day. 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 6.4 below:

$$\boldsymbol{metric_{ic}} = (0.5 * DailyEvntMAPE) + (0.5 * DailyEvntlikeMAPE) \tag{6.4}$$

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.[48,49] Across all three IOUs, programs, and products, all MAPE and MPE estimates are below 12%; 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%, with the exception of SCE's CBP-DO. 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.

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

			Out-of-Sample		In-Sample	
Utility	Program	Notice	MAPE	MPE	MAPE	MPE
PG&E	CBP	DA	0.8%	-0.5%	0.7%	-0.2%
		DO	3.5%	-3.0%	3.0%	-1.9%
	AMP	DO	11.3%	-9.6%	9.3%	-4.9%
SCE	CBP	DA	0.1%	-0.0%	0.1%	-0.0%
		DO	11.0%	-9.1%	7.2%	-4.2%
	AMP	DO	9.1%	-7.2%	6.1%	-3.9%
SDG&E	CBP	DA	3.5%	-3.1%	2.0%	-1.6%
		DO	0.4%	-0.3%	0.2%	-0.1%

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.

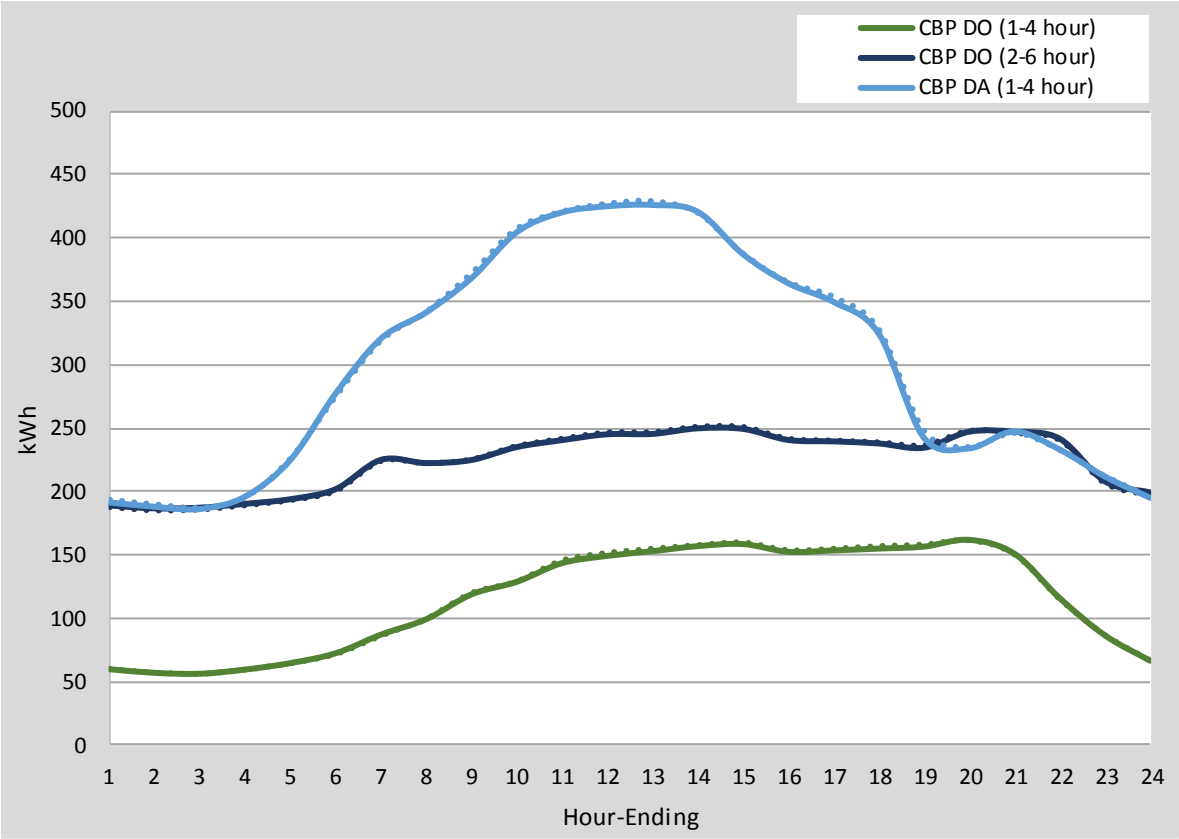
Figure 6-3 SCE Actual and Predicted Loads on Winter Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

[48] 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.

[49] 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.

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

Below we present some additional key findings for each IOU.

PG&E

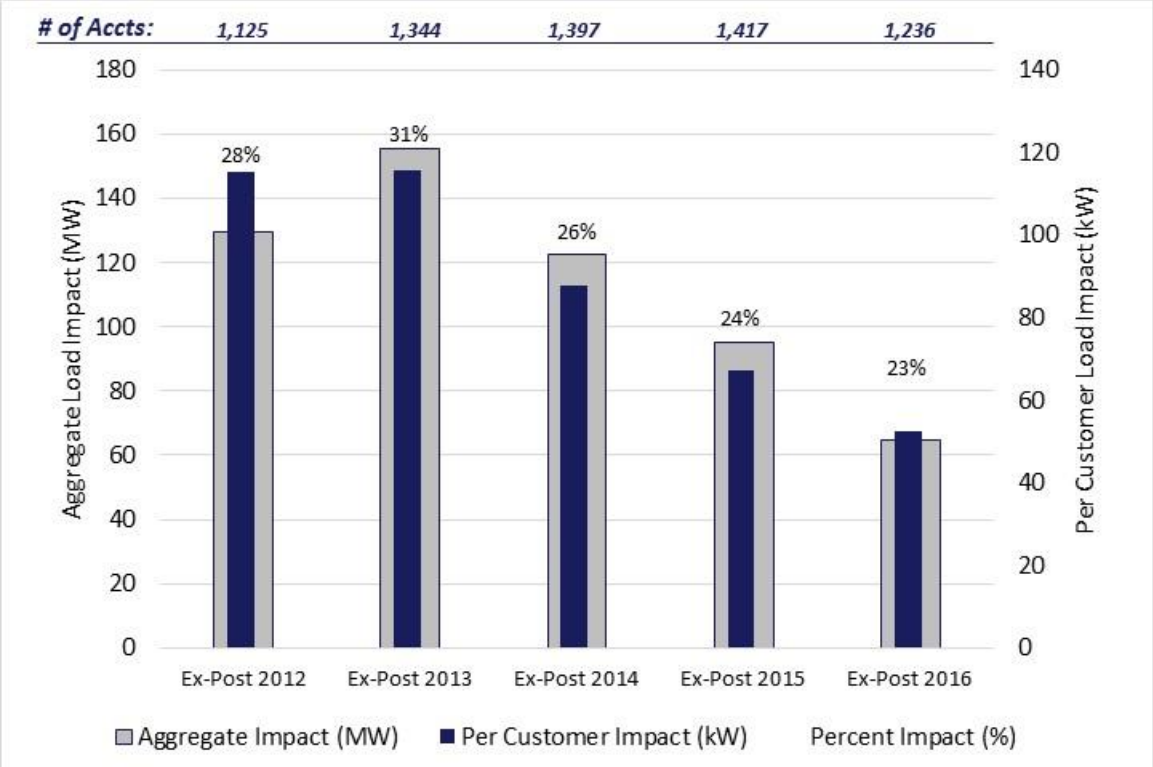
Figure 7-1 and Figure 7-2 summarize the average event-hour load impacts for PG&E's CBP and AMP offerings, respectively. The figures include the average event day ex-post impacts for 2012 through 2016 for CBP and AMP and the August peak ex-ante impacts projected for 2017 for CBP under the utility 1-in-2 weather condition. 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 have [redacted] since 2015.
- CBP DA percent impacts are [redacted].
- CBP DO percent impacts declined in 2016.
- CBP DO [redacted] DA in aggregate impacts, [redacted] in per customer impacts.
- AMP DO impacts have been on the decline.
- AMP DO has consistently outperformed CBP DO in aggregate and per customer impacts.
- AMP is no longer offered as of the end of 2016.

Figure 7-1 PG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2017

Figure redacted to protect customer or aggregator confidentiality.

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 2016 and the August peak ex-ante impacts projected for 2017 under the utility 1-in-2 weather condition. 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 aggregate and per customer impacts were [redacted] in 2016 than 2015, [redacted] nominations.
- CBP DO aggregate impacts were [redacted] in 2016 than in 2015, [redacted] in 2017.
- CBP DO [redacted] DA in aggregate impacts.
- AMP DO aggregate impacts were [redacted] in 2016 than in 2015.
- AMP DO has [redacted] CBP DO and DA in aggregate and per customer impacts.
- AMP will no longer be offered as of the end of 2017.

Figure 7-3 SCE CBP: Comparison of Average Event-Hour Load Impacts, 2012-2017

Figure redacted to protect customer or aggregator confidentiality.

Figure 7-4 SCE AMP: Comparison of Average Event-Hour Load Impacts, 2012-2017

Figure redacted to protect customer or aggregator confidentiality.

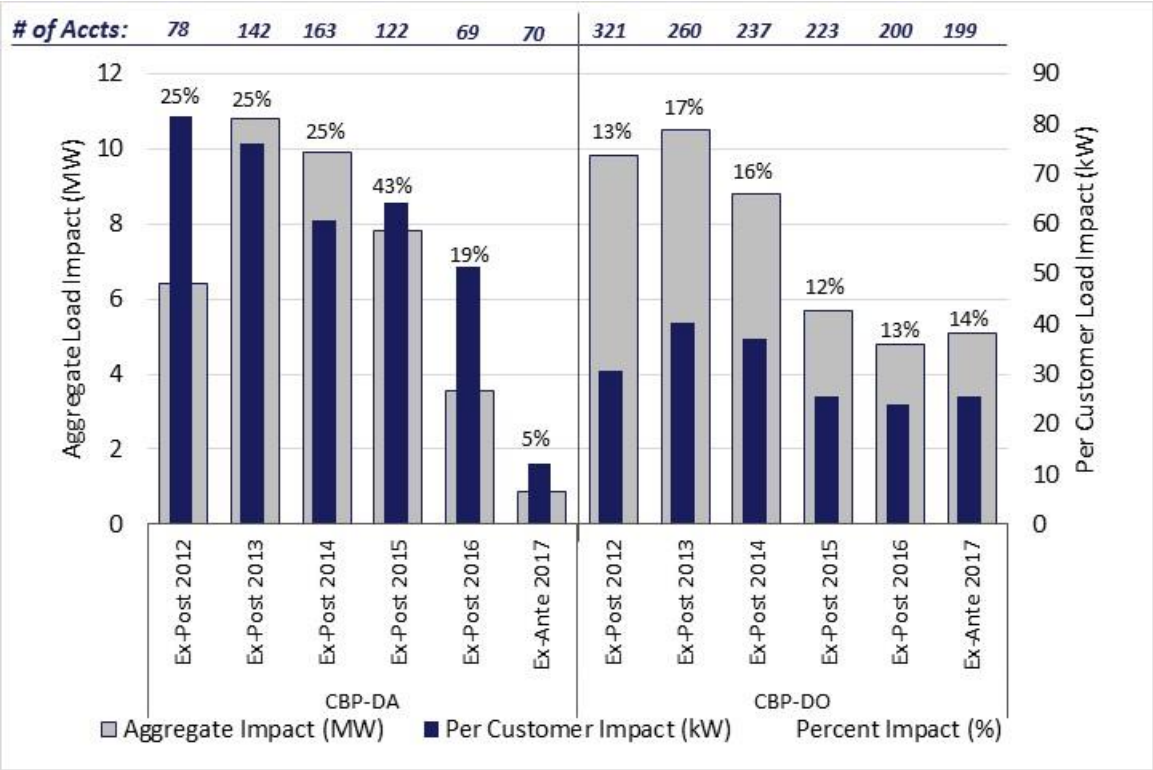
SDG&E

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 2016 and the August peak ex-ante

impacts projected for 2017 under the utility 1-in-2 weather condition. 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 aggregate impacts fell in 2016 due to lower enrollment. SDG&E attributes the reduction in number of DA accounts and load impacts to how many times SDG&E called the program in 2015. In 2015, SDG&E called the program 42 times (versus 14 times in 2014), which caused supplier fatigue and reluctance to participate in 2016. SDG&E modifications to the 2016 CBP heat rate trigger from 15,000 to 19,000 BTU/kWh resulted in calling the DA product only 14 times in 2016.
- CBP DO impacts in 2016 and projected for 2017 are comparable to 2015 impacts, albeit slightly lower.
- CBP DO is expected to outperform DA in per-customer and aggregate impacts in 2017. This is due in part to a projected decrease in per-customer impacts for the DA product.

Figure 7-5 SDG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2017



Effects of Enabling Technology

This evaluation was unable to estimate the statewide incremental impacts of AutoDR and TA/TI enablement during PY2016. Table 7-1 shows the incremental per customer impacts and aggregate impacts for each program for an average summer event. Within individual products there were some statistically significant savings, both positive and negative; however, given the small number of AutoDR and TA/TI participants, and the largely insignificant results at the program level, we conclude that there were no statistically significant statewide savings from AutoDR and TA/TI participants during PY2016.

Table 7-1 Statewide Incremental Impacts Associated with AutoDR: Average Summer Event

Program	Number of Accounts	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate (kW)	Total Aggregate Impact (kW)	Significant
PG&E CBP					
PG&E AMP					
SCE CBP					
SCE AMP					
SDG&E CBP	80	-3.02	-242	1,873	No
Statewide	**259**	**-0.75**	**-194**	**15,088**	**No**

Recommendations

For the PY2017 evaluation of CBP and AMP load impacts, AEG recommends investigating any AutoDR and TA/TI customers whose load impacts are far less than their load shed test results to determine the reasons for the discrepancy.

Load Impact Tables

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