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AEG
Applied Energy Group

2017 STATEWIDE LOAD IMPACT EVALUATION OF CALIFORNIA AGGREGATOR DEMAND RESPONSE PROGRAMS

Ex-Post and Ex-Ante Load Impacts

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Confidential information is redacted and denoted with black highlighting:

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PACIFIC GAS & ELECTRIC COMPANY
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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 2017 (PY2017). The scope of this evaluation covers the statewide Capacity Bidding Program (CBP), which is operated by all three IOUs, and the Aggregator Managed Portfolio (AMP) program, which was only offered by SCE during PY2017. The primary goals of this evaluation study are to 1) estimate the ex-post load impacts for PY2017, and 2) estimate ex-ante load impacts for the programs for years 2018 through 2028.

As part of these programs, DR aggregators contract with 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 contracts between the aggregator and the customer.

Nominated customer service accounts in the CBP DO products exceeded those in the CBP DA products for all three IOUs. For SCE, there were more nominated customer service accounts for AMP than for CBP. The number of nominated customer service accounts[1] ranged from less than 20 service accounts to over 800, depending on the product type. Some programs and notice types called events on as few as nine days in 2017, while others called events on up to 47 days, including several 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 2017, using regression analysis of individual customer-level hourly load, weather, and event data. The estimated load impacts are reported by IOU, for each event, associated with each program and product type (e.g., DA 1-4 hours and DO 1-4 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 Automated Demand Response (AutoDR) participants.[2]

Estimated aggregate load impacts for the typical CBP DA event were [redacted] MW for PG&E, [redacted] MW for SCE, and 0.7 MW for SDG&E. Aggregate load impacts for CBP with DO notice were 21.8 MW

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

[2] TA/TI and AutoDR participants are customers that have received technology incentives for the purchase and installation of load control equipment and technology that enables a customer's ability to automatically curtail its load during a DR event.

for PG&E, [redacted] MW for SCE, and 3.2 MW for SDG&E. The typical AMP aggregate load impacts were generally larger, with SCE's DO program averaging [redacted] MW.

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 2018.

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 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 covers two price-responsive DR programs: the Capacity Bidding Program (CBP) and the Aggregator Managed Portfolio (AMP) program. CBP is a statewide program available at the three IOUs, although the IOUs' programs differ slightly in program features and operation. AMP is a utility-specific program; in program year 2017, it was only offered by SCE. Under AMP, third-party aggregators enter into bilateral contracts with the IOU. The aggregators then enroll customers under the terms of their own contracts for the DR or load reduction capacity; the utilities are not involved in the contracts between the aggregators and the participating customers.

The primary goals of the 2017 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU for PY2017.
- Estimate average monthly ex-ante load impacts for each product and IOU for years 2018 through 2028.

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 that is primarily open to customers on a TOU rate.[3] In PY2017 and prior years, it was only open to non-residential customers.[4] Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[5] Customers may sign up directly with the IOU as a self-aggregator or they can participate through a third-party demand response aggregator.[6] 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

[3] There may be a few remaining customers that are not on a TOU rate.

[4] Starting in 2018, PG&E will allow residential customers to participate in CBP, but PG&E expects that material enrollment will start in 2019.

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

[6] The vast majority of the participants are third-party aggregators.

called.[7] 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 participant's monthly capacity incentive payment is adjusted based upon the actual aggregated delivered kilowatts (i.e., performance), relative to the aggregated baseline and nomination, for the operating month. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E, or less than 60% for PG&E, 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.[8] 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 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;[9,10] 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 in 2017 could be called on non-holiday weekdays in the months of May through October, between the hours of 11 AM and 7 PM, 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 in 2017 could be called on any non-holiday weekday year-round, between the hours of 11 AM and 7 PM, with a maximum of 30 event hours per month.

The IOUs anticipate several program changes to take place for CBP beginning in PY2018. The ex-ante analysis presented in this report addresses the changes that are expected to affect the enrollment and load impact forecasts for 2018-2028.

Aggregator Managed Portfolio

AMP is an aggregator demand response program. Customers that enroll with an aggregator must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service. Under AMP, third-party demand response aggregators enter into bilateral contracts with the utility for a specified capacity amount, and may create their own aggregated DR program in which participating customers achieve load reductions. In addition to being

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7 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.

8 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 and SCE's CBP customers participate through an aggregator.)

9 Each IOU also had a price trigger approved in 2017 per CPUC Resolution E-4819.

10 For SDG&E, the first condition is when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater and a price of $75/MWh for Day-Ahead or 15,000 BTU/kWh and a price of $140/MWh for Day-Of.

responsible for designing their DR program, aggregators are also responsible for acquisition, marketing, sales, retention, support, and event notifications and tactics.

Each DR aggregator has a contractual capacity level specified for each month. This capacity comes from the load curtailment of their portfolio of nominated customers. Capacity and energy payments vary with each aggregator.[11] The aggregators are penalized if they fail to deliver their committed capacity amounts. 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 a specified energy price, 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.

In past years, both PG&E and SCE offered AMP. However, PG&E's AMP program was discontinued at the end of PY2016. Therefore, in PY2017, AMP was only offered by SCE.

SCE

CPUC Decision 16-06-029 authorized SCE to continue its AMP program through PY2017. SCE's AMP program is open to all customers, but AMP aggregators have historically only enrolled non-residential customers. 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. As in past years, the event notification type was DO for PY2017. SCE's AMP program was discontinued at the end of 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 2017 by program, notice type, and utility.[12,13]

[11] SCE's AMP contracts only provide energy payments for Bundled-Service customers.

[12] 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 1-4 hour product, the average summer event day is based on the average of all HE16 – HE19 events during June-September. For SCE's CBP DA program, the average summer event day is based on the average of all HE19 – HE19 events for the 1-4 Hour product and all HE16 – HE19 events for the 4-8 hour product. [redacted]

[13] 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.

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

Program	Utility	Nominated Accounts	
		Day-Ahead	Day-Of
CBP	PG&E	19	811
	SCE	48	348
	SDG&E	68	174
AMP	SCE	-	[redacted]

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.

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.

For SDG&E's CBP products, 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

2017 Events

Table E-2 shows the number of event days by notification type, program, and utility for the PY2017 evaluation period.[14]

Table E-2 Summary of PY2017 Event Days by Notice Type

Program	Utility	Nov 2016-Apr 2017 Number of Events by Notice Type		May-Oct 2017 Number of Events by Notice Type	
		Day-Ahead	Day-Of	Day-Ahead	Day-Of
CBP	PG&E	-	-	22	25
	SCE	-	19	47[15]	46
	SDG&E	-	-	20[16]	9
AMP	SCE	-	[redacted]	-	[redacted]

2017 Ex-Post Impacts

Table E-3 summarizes the 2017 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 PY2017 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

Program	Utility	Day-Ahead			Day-Of		
		Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
CBP	PG&E	[redacted]	[redacted]	[redacted]	26.8	21.8	19.5
	SCE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SDG&E	9.9	0.7	0.3	18.4	3.2	4.8
AMP	SCE	-	-	-	[redacted]	[redacted]	[redacted]

Enrollment Forecast

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

- Beginning in 2018, PG&E will only offer the CBP DA product, and forecasts constant non-residential enrollment across the 2018-2028 horizon. Residential CBP is expected to have material enrollment starting 2019 and remaining constant through the forecast horizon.

[14] The PY2017 evaluation period is May 1 through Oct. 31, 2017 for PG&E and SDG&E, and is Nov. 1, 2016 – Oct. 31, 2017 for SCE.

[15] SCE had 47 DA 1-4 hour event days, with DA 4-8 hour events on 6 of those same event days.

[16] SDG&E had 20 DA 1-4 hour event days, with DA 2-6 hour events on 12 of those same event days.

- 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 2028 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. SCE expects an influx of residential accounts to CBP DA in 2023 following full opening of the program to residential customers. However, residential CBP enrollment may occur earlier than 2023, pending the 2020 mid-cycle filing required in D.17-12-003.

Table E-4 2018-2028 Enrollment Forecast, During Month of August

			Number of Service Accounts					
Program	**Utility**	**Notice**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023-2028 (Each Year)**
CBP	PG&E (Non-residential)	DA	700	700	700	700	700	700
	SCE	DA	90	90	90	90	90	3,321[17]
		DO	1,250	1,250	1,250	1,250	1,250	1,250
	SDG&E	DA	69	71	73	75	78	78
		DO[18]	171	183	196	209	224	224

Ex-Ante Impacts

Table E-5 summarizes the aggregate load impact forecasts for an August peak day in 2018 by program and utility for each weather scenario.

[17] SCE's CBP DA enrollment forecast expects an influx of residential accounts in 2023 following full opening of program to residential customers. If CPUC abandons initiative to require the program to be open to residential customers, the enrollments should be 90, as for 2018-22.

[18] SDG&E has two CBP DO forecasts. The forecast listed here includes new enrollments in the Technical Incentives (TI) program.

Table E-5 Summary of Average Event-Hour Ex-Ante Impacts, August Peak Day, 2018

Program	Utility	Notice	Aggregate Impact (MW)			
			Utility Peak		CAISO Peak	
			1-in-2	1-in-10	1-in-2	1-in-10
CBP	PG&E (Non-residential)	DA	21.0	21.5	20.1	22.0
	SCE	DA	6.2	6.2	6.2	6.2
		DO	23.1	23.1	23.1	23.1
	SDG&E	DA	0.7	0.7	0.7	0.7
		DO	3.2	3.2	3.1	3.2

Ex-ante load impact forecasts are developed by combining enrollment forecasts provided by the utilities, and per-customer load impacts generated from analysis of current and prior ex-post load impact estimates. The 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 (Decision 16-06-029) and December 14, 2017 (Decision 17-12-003):[19,20]

- PG&E's AMP program was discontinued at the end of PY2016, and SCE's AMP program was discontinued at the end of PY2017; therefore, AMP is not a part of the ex-ante forecast for either utility.
- PG&E proposed changing its operating hours from 11 AM - 7 PM to 1 PM - 9 PM to improve grid support and cost-effectiveness. The Commission directed them to offer the new operation hours on an optional basis. Beginning in 2018, PG&E will only offer the CBP DA product. The Commission has also approved PG&E's proposal to open CBP to residential customers with multiple participation options. Due to regulatory delay, PG&E expects no material MW from residential CBP in 2018, but makes a constant 4 MW forecast through the forecast horizon starting 2019.
- SCE proposed several changes to CBP that were adopted by the Commission. The changes are anticipated to increase CBP enrollment over time, beginning in 2018. The changes include streamlining CBP offerings from six products to two products, changing the event window from 11 AM – 7 PM to 1 PM – 7PM, and establishing a monthly five event maximum. The changes are intended to improve and simplify bidding into the CAISO wholesale market, align prices with current value, decrease customer fatigue, and increase participation.
- The Commission approved several CBP changes requested by SDG&E. As a result, SDG&E is reducing its number of CBP products from nine to four beginning in 2018. There will be two DA 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1

[19] 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.

[20] Decision Adopting Demand Response Activities and Budgets for 2018 through 2022. Decision 17-12-003. December 14, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF.

PM - 9 PM. Similarly, there will be two DO 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1 PM - 9 PM. SDG&E has also proposed simplifying the trigger by basing it on price only, instead of on price and heat rate. The Commission will adopt final price triggers in a future decision, pending a proposal from SDG&E to describe methods of determining the price triggers.

- Decision 17-12-003 requires SCE and SDG&E to pilot a residential aggregator option in their CBP programs and authorizes a budget to administer the pilot and award incentives. SCE's CBP DA enrollment forecast accounts for residential participation beginning in 2023. SCE assumes a constant aggregate residential CBP forecast of 3 MW throughout the forecast horizon starting in 2023 due to the expected influx of residential customers. SDG&E's enrollment forecast does not include residential customers.

Recommendations

- In the next evaluation cycle, conduct analysis to estimate the ex-ante impacts for residential CBP customers for all IOUs.
- Further investigate the performance of AutoDR customers to determine the reasons for underperformance relative to load shed test results.

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1

INTRODUCTION

This report documents the load impact evaluation of the aggregator-based DR programs operated by PG&E, SCE, and SDG&E for PY2017. The scope of the evaluation covers CBP and AMP. During PY2017, CBP was offered by all three IOUs and AMP was offered by 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,

- 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.[21]
- 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 2017 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.

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

- Section 7 presents key findings and recommendations.

2

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 that is primarily open to customers on a TOU rate.[22] In PY2017 and prior years, it was only open to non-residential customers.[23] Customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[24] Customers may sign up directly with the IOU as a self-aggregator or they can participate through a third-party demand response aggregator.[25] 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.[26] 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 participant's monthly capacity incentive payment is adjusted based upon the actual aggregated delivered kilowatts (i.e., performance), relative to the aggregated baseline and nomination, for the operating month. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, 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.[27] 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 option (e.g., DA or DO event notice, and 1-to-4, 2-to-6, or 4-to-8 hour minimum-maximum event durations).

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[22] There may be a few remaining customers that are not on a TOU rate.

[23] Starting in 2018, PG&E will allow residential customers to participate in CBP, but PG&E expects that material enrollment will start in 2019.

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

[25] The vast majority of the participants are third-party aggregators.

[26] 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.

[27] 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 and SCE's CBP customers participate through an aggregator.)

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;[28,29] 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 in 2017 could be called on non-holiday weekdays in the months of May through October, between the hours of 11 AM and 7 PM, 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 in 2017 could be called on any non-holiday weekday year-round, between the hours of 11 AM and 7 PM, 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.

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 2017.

[28] Each IOU also had a price trigger approved in 2017 per CPUC Resolution E-4819.

[29] For SDG&E, the first condition is when the utility expects the dispatch of electric supply resource with implied heat rates of 15,000 BTU/kWh or greater and a price of $75/MWh for Day-Ahead or 15,000 BTU/kWh and a price of $140/MWh for Day-Of.

Table 2-2 CBP Nominated Service Accounts, by Utility and Industry Group, Average Summer Event Day (2017)

Utility	Industry Type	Day-Ahead		Day-Of	
		Accounts	Sum of Max Demand (kW)	Accounts	Sum of Max Demand (kW)
PG&E	1. Agriculture, Mining & Construction	2	[redacted]	172	21.4
	2. Manufacturing	7	[redacted]	6	[redacted]
	3. Wholesale, Transport, Other Utilities	-	-	5	[redacted]
	4. Retail Stores	4	[redacted]	539	126.4
	5. Offices, Hotels, Finance, Services	3	[redacted]	100	58.5
	6. Schools	1	[redacted]	-	-
	7. Institutional/Government	1	[redacted]	3	[redacted]
	8. Other/Unknown	-	-	-	-
	Total	**19**	[redacted]	**811**	**217.0**
SCE	1. Agriculture, Mining & Construction	-	-	-	-
	2. Manufacturing	1	[redacted]	1	[redacted]
	3. Wholesale, Transport, Other Utilities	36	[redacted]	2	[redacted]
	4. Retail Stores	24	[redacted]	315	55.5
	5. Offices, Hotels, Finance, Services	-	-	21	[redacted]
	6. Schools	-	-	5	[redacted]
	7. Institutional/Government	-	-	3	[redacted]
	8. Other/Unknown	-	-	-	-
	Total	**48**	[redacted]	**348**	[redacted]
SDG&E	1. Agriculture, Mining & Construction	-	-	4	0.5
	2. Manufacturing	-	-	1	2.0
	3. Wholesale, Transport, Other Utilities	-	-	-	-
	4. Retail Stores	3	1.6	151	28.4
	5. Offices, Hotels, Finance, Services	63	20.2	17	3.5
	6. Schools	-	-	-	-
	7. Institutional/Government	1	3.4	1	0.5
	8. Other/Unknown	-	-	-	-
	Total	**68**	**25.3**	**174**	**34.8**

Table 2-2 includes data for each utility, by notification type and industry group. The table also includes a sum of their maximum demand.[30] 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

Several program changes have been proposed by the IOUs and adopted by the Commission. Two key decisions are Decision 16-06-029 and Decision 17-12-003.[31,32] Some of the key changes are as follows:

- PG&E proposed changing its operating hours from 11 AM - 7 PM to 1 PM - 9 PM to improve grid support and cost-effectiveness. The Commission directed them to offer the new operation hours on an optional basis. Beginning in 2018, PG&E will only offer the CBP DA product. The Commission has also approved PG&E's proposal to open CBP to residential customers with multiple participation options. Given regulatory delay in tariff changes thus far, PG&E expects material residential load reduction starting 2019.
- SCE proposed several changes to CBP that were adopted by the Commission. The changes are anticipated to increase CBP enrollment over time, beginning in 2018. The changes include streamlining CBP offerings from six products to two products, changing the event window from 11 AM – 7 PM to 1 PM – 7PM, and establishing a monthly five event maximum. The changes are intended to improve and simplify bidding into the CAISO wholesale market, align prices with current value, decrease customer fatigue, and increase participation.
- The Commission approved several CBP changes requested by SDG&E. As a result, SDG&E is reducing its number of CBP products from nine to four beginning in 2018. There will be two DA 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1 PM - 9 PM. Similarly, there will be two DO 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1 PM - 9 PM. Table 2-3 and Table 2-4 compare the 2017 and 2018 CBP products for SDG&E. SDG&E has also proposed simplifying the trigger by basing it on price only, instead of on price and heat rate. The Commission will adopt final price triggers in a future decision, pending a proposal from SDG&E to describe methods of determining the price triggers.

[30] 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.

[31] 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.

[32] Decision Adopting Demand Response Activities and Budgets for 2018 through 2022. Decision 17-12-003. December 14, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF.

Table 2-3 2017 CBP Products for SDG&E

Product / Notification Time	Event Duration Limit	Hours	Triggers
Day-Ahead / by 3 PM day prior to event	1-4 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $75/MWh
Day-Ahead / by 3 PM day prior to event	2-6 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $75/MWh
Day-Ahead / by 3 PM day prior to event	4-8 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $75/MWh
Day-Of – 30 min.	1-4 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of – 30 min.	2-6 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of – 30 min.	4-8 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of / two hours prior to event	1-4 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of / two hours prior to event	2-6 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of / two hours prior to event	4-8 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh

Table 2-4 2018 CBP Products for SDG&E

Product / Notification Time	Event Duration Limit	Hours	Triggers ***NOTE: subject to change due to AL3157-E***
Day-Ahead 11 AM-7 PM	2-4 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $75/MWh
Day-Ahead 1 PM-9 PM	2-4 hours	1 PM – 9 PM	15,000 Btu/kWh heat rate AND $75/MWh
Day-Of 11 AM-7 PM	2-4 hours	11 AM – 7 PM	15,000 Btu/kWh heat rate AND $140/MWh
Day-Of 1 PM-9 PM	2-4 hours	1 PM – 9 PM	15,000 Btu/kWh heat rate AND $140/MWh

- Decision 17-12-003 requires SCE and SDG&E to pilot a residential aggregator option in their CBP programs and authorizes a budget to administer the pilot and award incentives. SCE's CBP DA enrollment forecast accounts for residential participation beginning in 2023; SDG&E's enrollment forecast does not.

Aggregator Managed Portfolio

AMP is an aggregator demand response program. Customers that enroll with an aggregator must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service. Under AMP, third-party demand response aggregators enter into bilateral contracts with the utility for a specified capacity amount, 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 DR aggregator has a contractual capacity level specified for each month. This capacity comes from the load curtailment of their portfolio of nominated customers. Capacity and energy payments vary with each aggregator.[33] The aggregators are penalized if they fail to deliver their committed capacity amounts. 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 a specified energy price, 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.

In past years, both PG&E and SCE offered AMP. However, PG&E's AMP program was discontinued at the end of PY2016. Therefore, in PY2017, AMP was only offered by SCE.

SCE

CPUC Decision 16-06-029 authorized SCE to continue its AMP program through PY2017. SCE's AMP program is open to all types of participating customers. AMP aggregators have historically only enrolled non-residential customers. 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. As in past years, the event notification type was DO for PY2017. SCE's AMP program was discontinued at the end of PY2017.

Table 2-5 shows the number of customer service accounts nominated for the average 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 average summer event day here reflects the typical number of program participants.

[33] SCE's AMP contracts only provide energy payments for Bundled-Service customers.

Table 2-5 SCE AMP Nominated Accounts by Industry Group, Average Summer Event Day (2017)

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

Program Changes

PG&E's AMP program was discontinued as of the end of PY2016. Customers have been enrolled in CBP instead. SCE AMP program was discontinued as of the end of 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. Because the AMP program will not be offered in 2018, it is not included in the ex-ante impact forecast.

3

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 PY2017 ex-post analysis was designed specifically to meet each of the following goals:

- To develop hourly and daily load impact estimates for each event in the 2017 program year.
- To provide these estimates by various segments: IOU, program, LCA, industry group, Automated Demand Response (AutoDR) and TA&TI participation, and notification type.
- To estimate the distribution of load impacts by customer segment for the average event.

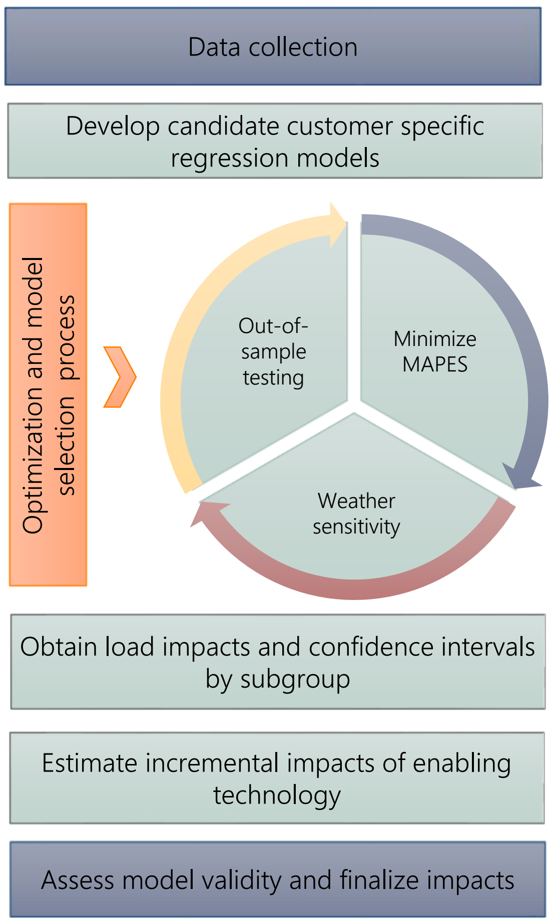
AEG used customer-specific regressions to estimate the load impact for each customer on each event day. Because AMP and CBP are implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling and analysis. However, the same basic methodology was employed across all three IOUs to balance consistency of results with modifications 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.[34]

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

Figure 3-1 Ex-Post Analysis Approach



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

[34] 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.

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.[35]

Table 3-1 presents the different explanatory variables used to create candidate models for the CBP and AMP participants.

[35] 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 2017[36]
$OtherEvt_{i,d}$	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 AM through 10 AM
	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 2017
$P * Weather_{i,d}$	An indicator variable for aggregator program event days interacted with weather
$P*NonTypEvent_{i,d}$	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:

- 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.[37]

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:

[36] We included data from previous years to ensure that we would have enough event-like days. Therefore, we also included a "year" indictor variable in the models.

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

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

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.

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:

- We obtained the actual and predicted load on each hour and day based on the best model specification for each customer.
- 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.
- 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.
- 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.

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

We calculated impacts for an average event day for each utility as follows:

- 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 DO 1-4 hour product, we defined an average summer event as the average of all events during June-September with event hours ending 16-19, 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 CBP DA, we defined an average event as the average of all events with event hours ending 19-19 for the DA 1-4 hour product and event hours ending 16-19 for the DA 4-8 hour product. [redacted]

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 does 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 SDG&E's CBP products. 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.

$$Incremental\ Savings = (X_{PredActual} - Y_{PredActual}) - (X_{reference} - Y_{reference}) \tag{3.3}$$

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

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

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.

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

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.

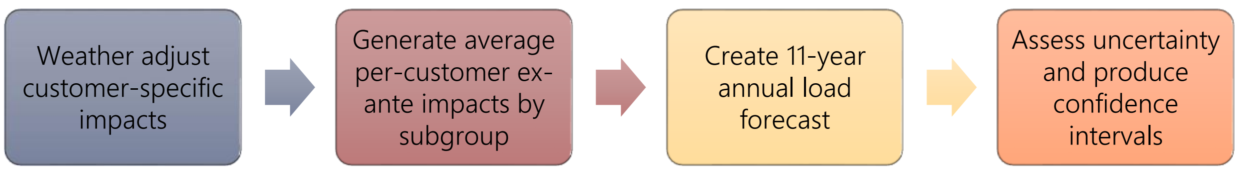
We developed the ex-ante forecasts using the following general steps:

- AEG first provided the IOUs with the appropriate weather-adjusted, per-customer impacts for each subgroup.

- 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.
- 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.[38] As part of the ex-ante forecast development for PG&E and SDG&E,[39] we applied the impacts predicted under

[38] 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.

[39] For SCE, we varied the ex-ante impacts by month within the forecast year to capture differences between summer and non-summer events.

August weather conditions to each month so that the per-customer impacts would not vary by month in a given forecast year. The assumption is not unreasonable, as the load impacts should be a function of the monthly nomination, which is not weather-dependent within a given month. Aggregators target delivery at the nominated level, with little incentive to deliberately over-deliver the load reduction even under extreme weather.

- We then calculated the load impact for each of the participants by subtracting the weather-adjusted event-day load from the weather-adjusted reference load.

Generation of Per-Customer Average Impacts by Subgroup

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

Creation of 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.

4

EX-POST RESULTS

This section presents the ex-post impacts for each program, and by segment, for the 2017 DR Aggregator programs.

Capacity Bidding Program

All three IOUs offered CBP DO and DA products in PY2017. Table 4-1 presents the PY2017 average event day impacts by product and IOU, both at the per-customer level, and in aggregate.

Table 4-1 Statewide CBP Impacts Summary, Average Summer Event Day PY2017

Utility	Product	Accounts	Per Customer Impact (kW)		Aggregate Impact (MW)	
			Reference Load	Impact	Reference Load	Impact
PG&E	DA 1-4 Hour	19	[redacted]	[redacted]	[redacted]	[redacted]
	DO 1-4 Hour	811	138.1	26.8	112.0	21.8
SCE	DA 1-4 Hour	30	[redacted]	[redacted]	[redacted]	[redacted]
	DA 4-8 Hour	18	[redacted]	[redacted]	[redacted]	[redacted]
	DO 1-4 Hour	348	[redacted]	[redacted]	[redacted]	[redacted]
SDG&E	DA 1-4 Hour	41	268.0	11.5	11.0	0.5
	DA 2-6 Hour	62	203.6	7.6	12.6	0.5
	DO 1-4 Hour	170	147.2	18.5	25.0	3.1
	DO 2-6 Hour	4	20.3	13.4	0.1	0.1

PG&E

Events for PG&E CBP

Table 4-2 presents a summary of the 2017 events for PG&E's CBP program by product. The DO participants experienced a total of 25 event days over the course of the program year, while DA participants experienced 22 event days. Some of the events were localized, meaning that they were called for only some Sub-LAPs. An average event is defined as one called during hours-ending (HE) 16-19 for all 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 DA 1-4 Hour
Avg. Event	-	14	16-19	811	19
5/22/2017	Monday	14	16-19 18-19	875 -	- 12
5/23/2017	Tuesday	13	16-19	521	17
6/16/2017	Friday	3	16-19	167	-
6/19/2017	Monday	14	16-19	901	23
6/20/2017	Tuesday	14	16-19	901	23
6/22/2017	Thursday	14	16-19	901	23
6/23/2017	Friday	1	17-19	26	1
7/7/2017	Friday	14	17-19	908	17
7/27/2017	Thursday	14	19-19	908	17
7/31/2017	Monday	14	18-19 19-19	380 528	6 11
8/1/2017	Tuesday	14	16-19 17-19	911 -	- 20
8/2/2017	Wednesday	14	16-19	911	20
8/28/2017	Monday	14	16-19	911	20
8/29/2017	Tuesday	14	16-19	911	20
8/31/2017	Thursday	14	16-19	911	20
9/1/2017	Friday	14	16-19	912	20
9/5/2017	Tuesday	14	18-19 19-19	907 5	- -
9/11/2017	Monday	14	18-19	912	-
9/26/2017	Tuesday	14	17-19 19-19	5 907	- -
9/27/2017	Wednesday	14	19-19	912	20
9/28/2017	Thursday	9	19-19	-	20
10/6/2017	Friday	13	19-19	854	-
10/16/2017	Monday	12	18-19	804	-
10/17/2017	Tuesday	12	18-19	804	13
10/18/2017	Wednesday	12	19-19 18-19	804 -	- 13
10/23/2017	Monday	12	18-19	804	-
10/24/2017	Tuesday	6	17-19	-	13
10/25/2017	Wednesday	6	16-19	-	13
10/26/2017	Thursday	6	16-19	-	13

Summary Load Impacts

Table 4-3 presents the average event-hour impacts for the CBP DO 1-4 hour participants, both at the average per-customer level and in aggregate.

Table 4-3 PG&E CBP Day-Of 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	811	19.5	138.1	26.8	112.0	21.8	19%	91
05/22/17	875	20.3	113.6	24.6	99.4	21.5	22%	86
05/23/17	521	12.5	126.9	22.9	66.1	11.9	18%	74
06/16/17	167	4.0	130.7	25.6	21.8	4.3	20%	89
06/19/17	901	21.1	146.0	27.7	131.5	25.0	19%	93
06/20/17	901	21.1	141.1	26.9	127.2	24.3	19%	91
06/22/17	901	21.1	144.4	27.7	130.1	25.0	19%	93
06/23/17	26	1.4	196.3	76.7	5.1	2.0	39%	95
07/07/17	908	21.0	135.5	26.7	123.0	24.2	20%	94
07/27/17	908	21.0	133.2	22.8	120.9	20.7	17%	88
07/31/17	908	21.0	129.7	24.0	117.7	21.7	18%	86
08/01/17	911	19.4	133.2	27.5	121.4	25.0	21%	91
08/02/17	911	19.4	140.4	26.6	127.9	24.2	19%	93
08/28/17	911	19.4	142.1	27.9	129.4	25.4	20%	93
08/29/17	911	19.4	128.6	25.9	117.1	23.6	20%	88
08/31/17	911	19.4	137.7	26.6	125.4	24.2	19%	95
09/01/17	912	20.1	158.4	29.1	144.5	26.5	18%	103
09/05/17	912	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
09/11/17	912	20.1	142.0	27.3	129.5	24.9	19%	86
09/26/17	912	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
09/27/17	912	20.1	131.8	22.1	120.2	20.1	17%	84
10/06/17	854	19.0	119.8	22.6	102.3	19.3	19%	78
10/16/17	804	18.0	119.1	24.5	95.8	19.7	21%	78
10/17/17	804	18.0	114.0	23.9	91.7	19.2	21%	74
10/18/17	804	18.0	107.1	19.3	86.1	15.5	18%	66
10/23/17	804	18.0	122.0	24.3	98.1	19.5	20%	80

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)		Aggregate Impact (MW)		% Impact	Temp (˚F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
05/22/17	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
05/23/17	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
06/19/17	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
06/20/17	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
06/22/17	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
06/23/17	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
07/07/17	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
07/27/17	17	2.0	912.0	239.7	15.5	4.1	26%	91
07/31/17	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
08/01/17	20	2.1	1,039.0	230.3	20.8	4.6	22%	92
08/02/17	20	2.1	1,140.9	262.0	22.8	5.2	23%	93
08/28/17	20	2.1	1,472.8	253.8	29.5	5.1	17%	95
08/29/17	20	2.1	1,399.2	273.0	28.0	5.5	20%	89
08/31/17	20	2.1	1,361.6	293.9	27.2	5.9	22%	97
09/01/17	20	3.9	1,671.7	255.7	33.4	5.1	15%	104
09/27/17	20	3.9	1,451.0	183.3	29.0	3.7	13%	86
09/28/17	20	3.9	1,459.1	188.0	29.2	3.8	13%	82
10/17/17	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
10/18/17	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
10/24/17	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
10/25/17	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/26/17	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84

Table 4-5 presents the impacts for an average event day by Industry.[40]

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	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
DA	Manufacturing	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
DA	Retail Stores	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
DA	Offices, Hotels, Finance, Services	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
DA	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
DA	Institutional/Government	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
DA	**Total DA**	**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**91**
DO	Agriculture, Mining & Construction	172	25.1	12.2	4.3	2.1	48%	103
DO	Manufacturing	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
DO	Wholesale, Transport, other Utilities	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	106
DO	Retail Stores	539	137.0	29.1	73.8	15.7	21%	89
DO	Offices, Hotels, Finance, Services	100	294.7	28.3	29.5	2.8	10%	85
DO	Institutional/Government	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101
DO	**Total DO**	**811**	**138.1**	**26.8**	**112.0**	**21.8**	**19%**	**91**
Total CBP		**830**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**91**

[40] 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)		Aggregate Impact (MW)		% Impact	Event Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact		
DA	Greater Bay Area	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
DA	Greater Fresno	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101
DA	Kern	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	105
DA	Northern Coast	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
DA	Other	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
DA	Stockton	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100
DA	**Total DA**	**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**91**
DO	Greater Bay Area	371	174.3	24.6	64.7	9.1	14%	83
DO	Greater Fresno	222	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	106
DO	Humboldt	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
DO	Kern	37	136.2	33.0	5.0	1.2	24%	104
DO	Northern Coast	57	145.8	24.4	8.3	1.4	17%	89
DO	Other	108	100.2	32.2	10.8	3.5	32%	95
DO	Sierra	46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100
DO	Stockton	26	198.9	76.4	5.2	2.0	38%	101
DO	**Total DO**	**811**	**138.1**	**26.8**	**112.0**	**21.8**	**19%**	**91**
Total CBP		**830**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**91**

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: Average Hourly Per-Customer Impact, 2017

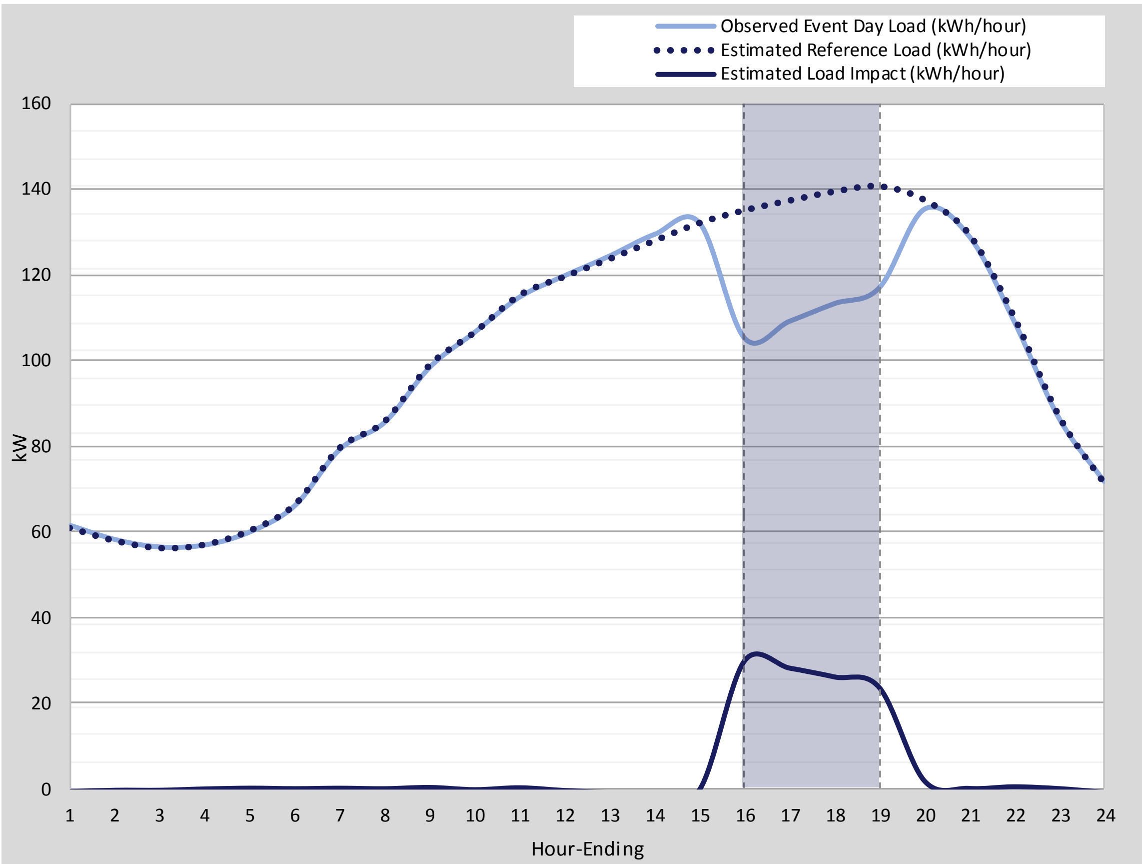


Figure 4-2 PG&E CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2017

Figure redacted to protect customer or aggregator confidentiality.

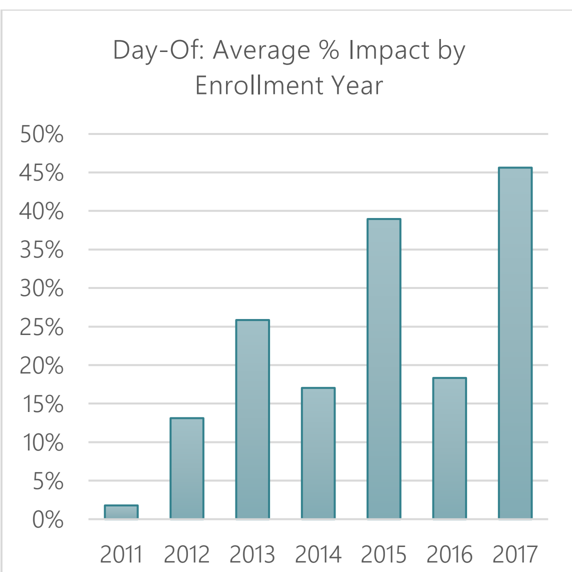
Load Impacts of TA/TI and AutoDR Participants

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 PY2017 PG&E CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years are presented below. Figure 4-3 shows the percentage impacts achieved by PY2017 AutoDR and TA/TI participants averaged across the customers and the 2017 events, as a function of AutoDR or TA/TI enrollment year for each product. The graph for CBP DA is redacted to protect customer or aggregator confidentiality. For DO, on average, there does not appear to be a strong trend showing deterioration of impacts for early enrollees relative to recent enrollees.[41] For DA, there are only two enrollment years associated with PY2017 participants, and the 2016 enrollees show positive impacts, on average, while the 2008 enrollees show negative impacts. However, it is important to note that the percentage impacts are also a function of the types of customers enrolled each year, so inherent differences in the customer make-up in each enrollment year may also play a role in the resulting impacts.

Figure 4-3 PG&E CBP: AutoDR and TA/TI Participant Percent Impacts by Enrollment Year



[redacted]

Table 4-7 shows the per-customer and aggregate ex-post impacts by event day for the AutoDR and TA/TI participants for the CBP DO 1-4 hour product. For comparison, the table also includes

[41] The DO graph shows data for participants who enrolled in AutoDR or TA/TI in 2011 or later. There are also some DO participants (not shown) who enrolled in 2007.

the aggregate impact results calculated using the 10-in-10 baseline approach used for settlement, as well as the aggregate load shed test results. In the 10-in-10 baseline approach, the baseline is calculated at the individual customer level by averaging the customer's usage during 10 prior non-event weekdays (excluding holidays) and then applying a day-of adjustment to calibrate the baseline load to account for event day conditions (e.g., hotter weather). Then, the observed load is subtracted from the adjusted baseline to get the load reduction on the event day. The total load reduction of all the AutoDR and TA/TI customers is the sum of the load reduction of each AutoDR and TA/TI customer based on their individual baseline. While the regression-based ex-post analysis yielded higher aggregate impacts than those estimated using the 10-in-10 baseline approach, the performance for DO is still generally below the load shed test MW regardless of the metric for load reduction.

Table 4-7 PG&E CBP Day-Of 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Aggregate Impact with 10-in-10 Baseline (MW)	Temp (˚F)
		Ref. Load	Impact	Ref. Load	Impact				
Avg. Event	195	157.7	41.6	30.7	8.1	26%	10.9	5.6	92
05/22/17	196	135.3	39.2	26.5	7.7	29%	11.8	4.4	86
05/23/17	131	133.5	30.3	17.5	4.0	23%	7.9	3.3	77
06/16/17	46	203.8	39.8	9.4	1.8	20%	3.1	1.1	90
06/19/17	206	154.0	40.3	31.7	8.3	26%	11.9	5.9	94
06/20/17	206	156.4	38.7	32.2	8.0	25%	11.9	4.7	92
06/22/17	206	157.7	40.6	32.5	8.4	26%	11.9	5.8	94
06/23/17	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
07/07/17	212	153.8	39.8	32.6	8.4	26%	12.1	6.7	96
07/27/17	212	144.0	30.4	30.5	6.4	21%	12.1	6.3	90
07/31/17	212	141.8	32.8	30.1	7.0	23%	12.1	6.1	87
08/01/17	226	156.1	43.1	35.3	9.8	28%	13.4	8.3	92
08/02/17	226	162.9	44.5	36.8	10.1	27%	13.4	9.1	93
08/28/17	226	168.2	44.1	38.0	10.0	26%	13.4	7.3	96
08/29/17	226	152.4	40.9	34.4	9.2	27%	13.4	8.6	90
08/31/17	226	154.8	43.2	35.0	9.8	28%	13.4	7.7	96
09/01/17	226	173.3	45.7	39.2	10.3	26%	12.5	6.3	103
09/05/17	226	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
09/11/17	226	156.9	37.0	35.5	8.4	24%	12.5	7.2	87
09/26/17	226	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
09/27/17	226	148.6	30.0	33.6	6.8	20%	12.5	2.7	85
10/06/17	177	142.4	34.8	25.2	6.2	24%	10.5	4.9	78
10/16/17	167	133.6	37.5	22.3	6.3	28%	9.6	4.3	78
10/17/17	167	132.5	36.9	22.1	6.2	28%	9.6	4.4	74
10/18/17	167	126.0	31.9	21.0	5.3	25%	9.6	4.7	66
10/23/17	167	136.2	37.6	22.7	6.3	28%	9.6	4.3	80

Table 4-8 shows the per-customer and aggregate ex-post impacts by event day for the AutoDR and TA/TI participants for the CBP DA 1-4 hour product. For comparison, the table also includes the aggregate impact results calculated using the 10-in-10 baseline approach, as well as the aggregate load shed test results. On average, the regression-based ex-post analysis yielded lower aggregate impacts than those estimated using the 10-in-10 baseline approach. The load shed test results show higher values than were achieved using either impact analysis method. Therefore, the performance for DA is generally below the load shed test MW regardless of the metric used to estimate load reduction.

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Aggregate Impact with 10-in-10 Baseline (MW)	Temp (˚F)
		Ref. Load	Impact	Ref. Load	Impact				
Avg. Event	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
05/22/17	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
05/23/17	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
06/19/17	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
06/20/17	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
06/22/17	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
08/01/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
08/02/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
08/28/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
08/29/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
08/31/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
09/01/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104
09/27/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
09/28/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
10/17/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
10/18/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
10/24/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
10/25/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/26/17	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84

SCE

Events for SCE CBP

Table 4-9 and Table 4-10 present summaries of the PY2017 events for SCE's CBP program by product for DO and DA, respectively.[42] The table includes definitions of average summer and non-summer event days. The DO participants experienced a total of 65 event days over the course of the program year, while DA participants experienced 47 event days. Events were called with a wide variety of event hours.

Table 4-9 SCE CBP Day-Of 1-4 Hour Event Summary

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour
Avg. Summer	-	16-19	348
Avg. Non-Summer	-	18-19	341
11/7/2016	Monday	18-19 19-19	79 5
11/8/2016	Tuesday	17-19 19-19	79 5
11/9/2016	Wednesday	17-19 18-19 19-19	79 5 3
11/10/2016	Thursday	17-19 18-18 18-19	79 5 3
11/14/2016	Monday	17-18 17-19 18-18	5 79 3
11/15/2016	Tuesday	18-18 18-19	8 79
11/16/2016	Wednesday	17-18 18-18	50 29
11/17/2016	Thursday	17-19 18-19	50 29
11/18/2016	Friday	17-19 18-19	50 29
11/21/2016	Monday	18-18	79
11/22/2016	Tuesday	18-18 18-19	58 29
11/23/2016	Wednesday	18-18	50
11/25/2016	Friday	18-18	50
11/28/2016	Monday	18-18	79
11/29/2016	Tuesday	18-18 18-19	58 29

[42] SCE's PY2017 evaluation period is from Nov. 1, 2016 through Oct. 31, 2017.

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour
11/30/2016	Wednesday	18-18	29
12/7/2016	Wednesday	18-18	4
3/7/2017	Tuesday	19-19	7
3/9/2017	Thursday	19-19	7
5/3/2017	Wednesday	19-19	246
5/4/2017	Thursday	19-19	206
5/22/2017	Monday	18-19 19-19	206 40
5/23/2017	Tuesday	19-19	246
6/19/2017	Monday	16-19 17-19	130 246
6/20/2017	Tuesday	16-19	376
6/21/2017	Wednesday	16-19	376
6/22/2017	Thursday	16-19	376
7/6/2017	Thursday	19-19	368
7/7/2017	Friday	17-19	368
7/10/2017	Monday	19-19	368
7/27/2017	Thursday	19-19	368
7/31/2017	Monday	18-19	368
8/1/2017	Tuesday	16-19	331
8/2/2017	Wednesday	16-19	331
8/3/2017	Thursday	16-19	331
8/10/2017	Thursday	19-19	288
8/11/2017	Friday	19-19	331
8/28/2017	Monday	16-19	331
8/29/2017	Tuesday	16-19	331
8/30/2017	Wednesday	19-19	331
8/31/2017	Thursday	17-19	331
9/1/2017	Friday	16-19	350
9/5/2017	Tuesday	18-19	350
9/6/2017	Wednesday	19-19	350
9/7/2017	Thursday	19-19	175
9/11/2017	Monday	18-19	350
9/12/2017	Tuesday	19-19	350
9/13/2017	Wednesday	19-19	120
9/26/2017	Tuesday	19-19	350
9/27/2017	Wednesday	19-19	295
9/28/2017	Thursday	19-19	295
10/6/2017	Friday	19-19	294

Date	Day of Week	Event Hours (HE) DO 1-4 Hour	# Accts DO 1-4 Hour
10/9/2017	Monday	19-19	294
10/10/2017	Tuesday	19-19	294
10/11/2017	Wednesday	19-19	19
10/12/2017	Thursday	19-19	19
10/16/2017	Monday	18-19	341
10/17/2017	Tuesday	18-19	341
10/18/2017	Wednesday	18-19 19-19	169 172
10/23/2017	Monday	17-19 18-19	275 66
10/24/2017	Tuesday	16-19	341
10/25/2017	Wednesday	18-19	341
10/26/2017	Thursday	19-19	341
10/27/2017	Friday	18-19	341
10/31/2017	Tuesday	19-19	307

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 4-8 Hour	# Accts DA 4-8 Hour
Avg. Event	-	19-19	30	16 - 19	18
5/3/2017	Wednesday	19-19	26	-	-
5/4/2017	Thursday	19-19	22	-	-
5/23/2017	Tuesday	19-19	26	-	-
6/20/2017	Tuesday	16-19	25	16 - 19	18
6/21/2017	Wednesday	16-19	25	15 - 19	18
6/22/2017	Thursday	16-19	25	16 - 19	18
6/26/2017	Monday	18-18	25	-	-
7/3/2017	Monday	19-19	26	-	-
7/6/2017	Thursday	19-19	26	-	-
7/7/2017	Friday	17-19	26	-	-
7/10/2017	Monday	19-19	26	-	-
7/27/2017	Thursday	19-19	26	-	-
7/31/2017	Monday	17-19	26	-	-
8/1/2017	Tuesday	16-19	42	-	-
8/2/2017	Wednesday	16-19	42	-	-
8/3/2017	Thursday	16-19	42	-	-
8/7/2017	Monday	19-19	42	-	-
8/10/2017	Thursday	19-19	38	-	-
8/11/2017	Friday	19-19	42	-	-
8/28/2017	Monday	16-19	42	-	-

Date	Day of Week	Event Hours (HE) DA 1-4 Hour	# Accts DA 1-4 Hour	Event Hours (HE) DA 4-8 Hour	# Accts DA 4-8 Hour
8/29/2017	Tuesday	16-19	42	-	-
8/30/2017	Wednesday	19-19	42	-	-
8/31/2017	Thursday	17-19	42	-	-
9/1/2017	Friday	16-19	26	14 - 19	18
9/5/2017	Tuesday	16-19	26	16 - 19	18
9/6/2017	Wednesday	19-19	26	-	-
9/7/2017	Thursday	19-19	14	-	-
9/11/2017	Monday	17-19	26	-	-
9/12/2017	Tuesday	19-19	26	-	-
9/13/2017	Wednesday	19-19	9	-	-
9/26/2017	Tuesday	19-19	26	-	-
9/27/2017	Wednesday	19-19	21	-	-
9/28/2017	Thursday	19-19	21	-	-
10/6/2017	Friday	19-19	21	-	-
10/10/2017	Tuesday	19-19	21	-	-
10/11/2017	Wednesday	19-19	1	-	-
10/12/2017	Thursday	19-19	1	-	-
10/16/2017	Monday	19-19	26	-	-
10/17/2017	Tuesday	18-19	26	-	-
10/18/2017	Wednesday	18-19 19-19	14 12	-	-
10/23/2017	Monday	18-19	26	-	-
10/24/2017	Tuesday	16-19	26	13 - 19	18
10/25/2017	Wednesday	18-19	26	-	-
10/26/2017	Thursday	19-19	26	-	-
10/27/2017	Friday	18-19	26	-	-
10/30/2017	Monday	18-19 19-19	5 21	-	-
10/31/2017	Tuesday	19-19	22	-	-

Summary Load Impacts

Table 4-11 to Table 4-13 below show the average event-hour impacts for the three CBP products, respectively: DO 1-4 hour, DA 1-4 hour, and DA 4-8 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)[1]	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
Avg. Summer	16-19	348	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
Avg. Non-Summer	18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
11/7/2016	18-19 19-19	84	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
11/8/2016	17-19 19-19	84	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
11/9/2016	17-19 18-19 19-19	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
11/10/2016	17-19 18-18 18-19	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
11/14/2016	17-18 17-19 18-18	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
11/15/2016	18-18 18-19	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
11/16/2016	17-18 18-18	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/17/2016	17-19 18-19	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
11/18/2016	17-19 18-19	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
11/21/2016	18-18	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
11/22/2016	18-18 18-19	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
11/23/2016	18-18	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/25/2016	18-18	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
11/28/2016	18-18	79	2.7	293.3	27.2	23.2	2.1	9%	58
11/29/2016	18-18 18-19	87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
11/30/2016	18-18	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
12/7/2016	18-18	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
3/7/2017	19-19	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
3/9/2017	19-19	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
5/3/2017	19-19	246	6.1	200.3	14.3	49.3	3.5	7%	79
5/4/2017	19-19	206	5.6	217.2	14.9	44.7	3.1	7%	70

Event	Event Hrs (HE)[1]	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
5/22/2017	18-19 19-19	246	6.1	218.7	17.9	53.8	4.4	8%	84
5/23/2017	19-19	246	6.1	213.7	14.3	52.6	3.5	7%	78
6/19/2017	16-19 17-19	376	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
6/20/2017	16-19	376	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
6/21/2017	16-19	376	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
6/22/2017	16-19	376	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
7/6/2017	19-19	368	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
7/7/2017	17-19	368	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
7/10/2017	19-19	368	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
7/27/2017	19-19	368	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
7/31/2017	18-19	368	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
8/1/2017	16-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
8/2/2017	16-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
8/3/2017	16-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
8/10/2017	19-19	288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
8/11/2017	19-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
8/28/2017	16-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
8/29/2017	16-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
8/30/2017	19-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
8/31/2017	17-19	331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
9/1/2017	16-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100
9/5/2017	18-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
9/6/2017	19-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
9/7/2017	19-19	175	3.2	104.3	16.3	18.3	2.9	16%	79
9/11/2017	18-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
9/12/2017	19-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
9/13/2017	19-19	120	2.4	116.6	18.6	14.0	2.2	16%	69
9/26/2017	19-19	350	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
9/27/2017	19-19	295	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
9/28/2017	19-19	295	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
10/6/2017	19-19	294	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
10/9/2017	19-19	294	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
10/10/2017	19-19	294	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
10/11/2017	19-19	19	0.3	123.1	15.9	2.3	0.3	13%	71
10/12/2017	19-19	19	0.3	121.7	15.9	2.3	0.3	13%	72

Event	Event Hrs (HE)[1]	# of Accts	Nom. Cap. (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
				Ref. Load	Impact	Ref. Load.	Impact		
10/16/2017	18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
10/17/2017	18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
10/18/2017	18-19 19-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
10/23/2017	17-19 18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
10/24/2017	16-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/25/2017	18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
10/26/2017	19-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
10/27/2017	18-19	341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
10/31/2017	19-19	307	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

[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-Ahead 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. Event	19-19	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
5/3/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
5/4/2017	19-19	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
5/23/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
6/20/2017	16-19	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
6/21/2017	16-19	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
6/22/2017	16-19	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
6/26/2017	18-18	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
7/3/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
7/6/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
7/7/2017	17-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
7/10/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
7/27/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
7/31/2017	17-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
8/1/2017	16-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
8/2/2017	16-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
8/3/2017	16-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92

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)
8/7/2017	19-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
8/10/2017	19-19	38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
8/11/2017	19-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
8/28/2017	16-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
8/29/2017	16-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	99
8/30/2017	19-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
8/31/2017	17-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
9/1/2017	16-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101
9/5/2017	16-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
9/6/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
9/7/2017	19-19	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
9/11/2017	17-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
9/12/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
9/13/2017	19-19	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
9/26/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
9/27/2017	19-19	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
9/28/2017	19-19	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
10/6/2017	19-19	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/10/2017	19-19	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
10/11/2017	19-19	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
10/12/2017	19-19	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
10/16/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/17/2017	18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/18/2017	18-19 19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
10/23/2017	18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
10/24/2017	16-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/25/2017	18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
10/26/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
10/27/2017	18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
10/30/2017	18-19 19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
10/31/2017	19-19	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

Table 4-13 SCE CBP Day-Ahead 4-8 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. Event	16 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
6/20/2017	16 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
6/21/2017	15 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
6/22/2017	16 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
9/1/2017	14 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104
9/5/2017	16 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
10/24/2017	13 - 19	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96

Table 4-14 and Table 4-15 present the impacts for an average summer event day by Industry and LCA, respectively, for the CBP products.[43]

[43] The results in Table 4-14 and Table 4-15 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 4-14 SCE CBP Impacts by Industry and Notice

	Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Event Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact		
DO 1-4 Hr.	Manufacturing	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
	Wholesale, Transport, other Utilities	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
	Retail Stores	315	120.7	18.1	38.0	5.7	15%	90
	Offices, Hotels, Finance, Services	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
	Schools	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
	Institutional/Government	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
	Total DO 1-4 Hr.	**348**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**90**
DA 1-4 Hr.	Manufacturing	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
	Wholesale, Transport, other Utilities	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
	Retail Stores	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
	Total DA 1-4 Hr.	**30**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**86**
DA 4-8 Hr.	Wholesale, Transport, other Utilities	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
	Total DA 4-8 Hr.	**18**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**90**

Table 4-15 SCE CBP Impacts by LCA and Notice

	LCA	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Event Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact		
DO 1-4 Hr.	LA Basin	273	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
	Outside LA Basin	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
	Ventura / Big Creek	46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
	Total DO 1-4 Hr.	**348**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**90**
DA 1-4 Hr.	LA Basin	24	330.2	63.5	7.9	1.5	19%	86
	Outside LA Basin	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
	Ventura / Big Creek	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
	Total DA 1-4 Hr.	**30**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**86**
DA 4-8 Hr.	LA Basin	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
	Total DA 4-8 Hr.	**18**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**90**

Table 4-16 to Table 4-20 show the average event day impacts for two additional geographical areas in SCE's service territory: South of Lugo and Southern Orange County. (Note that there were no South Orange County participants for the CBP DA 4-8 Hour events.)

Table 4-16 South of Lugo 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		
11/7/2016	25	155.7	13.1	3.9	0.3	8%	78
11/8/2016	25	164.2	15.5	4.1	0.4	9%	86
11/9/2016	25	168.3	15.5	4.2	0.4	9%	87
11/10/2016	25	161.3	15.5	4.0	0.4	10%	85
11/14/2016	25	155.2	15.5	3.9	0.4	10%	82
11/15/2016	25	148.1	13.1	3.7	0.3	9%	73
11/16/2016	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
11/17/2016	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
11/18/2016	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
11/21/2016	25	138.0	10.7	3.4	0.3	8%	63
11/22/2016	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/23/2016	19	128.7	8.5	2.4	0.2	7%	67
11/25/2016	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
11/28/2016	25	131.2	10.7	3.3	0.3	8%	58
11/29/2016	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
11/30/2016	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
5/3/2017	69	102.8	18.5	7.1	1.3	18%	82
5/4/2017	69	100.1	18.5	6.9	1.3	18%	75
5/22/2017	69	107.3	19.3	7.4	1.3	18%	85
5/23/2017	69	104.4	18.5	7.2	1.3	18%	83
6/19/2017	135	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
6/20/2017	135	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
6/21/2017	135	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
6/22/2017	135	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
7/6/2017	133	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
7/7/2017	133	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
7/10/2017	133	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
7/27/2017	133	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
7/31/2017	133	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
8/1/2017	113	143.5	22.3	16.2	2.5	16%	87
8/2/2017	113	134.8	22.3	15.2	2.5	17%	91
8/3/2017	113	152.2	22.3	17.2	2.5	15%	92
8/10/2017	113	133.6	17.4	15.1	2.0	13%	86
8/11/2017	113	139.5	17.4	15.8	2.0	12%	88

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
8/28/2017	113	147.5	22.3	16.7	2.5	15%	99
8/29/2017	113	155.8	22.3	17.6	2.5	14%	100
8/30/2017	113	137.8	17.4	15.6	2.0	13%	98
8/31/2017	113	150.5	21.2	17.0	2.4	14%	87
9/1/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	103
9/5/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
9/6/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
9/7/2017	32	134.9	15.9	4.3	0.5	12%	77
9/11/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
9/12/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
9/13/2017	32	127.1	15.9	4.1	0.5	13%	69
9/26/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
9/27/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
9/28/2017	131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
10/6/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
10/9/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
10/10/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
10/16/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
10/17/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
10/18/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
10/23/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/24/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/25/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
10/26/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
10/27/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
10/31/2017	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

Table 4-17 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		
11/7/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
11/8/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
11/9/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
11/10/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
11/14/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
11/15/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
11/16/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/17/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/18/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
11/21/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
11/22/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
11/28/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
11/29/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
11/30/2016	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
5/3/2017	26	107.4	17.7	2.8	0.5	16%	71
5/4/2017	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
5/22/2017	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
5/23/2017	26	106.5	17.7	2.8	0.5	17%	68
6/19/2017	36	154.0	22.0	5.5	0.8	14%	76
6/20/2017	36	150.3	22.0	5.4	0.8	15%	78
6/21/2017	36	139.8	22.0	5.0	0.8	16%	72
6/22/2017	36	136.9	22.0	4.9	0.8	16%	70
7/6/2017	36	134.6	15.7	4.8	0.6	12%	81
7/7/2017	36	148.8	20.5	5.4	0.7	14%	82
7/10/2017	36	128.8	15.7	4.6	0.6	12%	77
7/27/2017	36	129.1	15.7	4.6	0.6	12%	76
7/31/2017	36	140.1	18.8	5.0	0.7	13%	75
8/1/2017	33	154.2	22.6	5.1	0.7	15%	79
8/2/2017	33	145.1	22.6	4.8	0.7	16%	79
8/3/2017	33	157.1	22.6	5.2	0.7	14%	82
8/10/2017	33	126.0	16.4	4.2	0.5	13%	74
8/11/2017	33	129.4	16.4	4.3	0.5	13%	76
8/28/2017	33	151.4	22.6	5.0	0.7	15%	83
8/29/2017	33	156.9	22.6	5.2	0.7	14%	84
8/30/2017	33	129.9	16.4	4.3	0.5	13%	85
8/31/2017	33	156.1	20.8	5.1	0.7	13%	84

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
9/1/2017	34	168.1	21.9	5.7	0.7	13%	93
9/5/2017	34	135.6	17.3	4.6	0.6	13%	79
9/6/2017	34	124.2	14.5	4.2	0.5	12%	73
9/7/2017	34	125.5	14.5	4.3	0.5	12%	76
9/11/2017	34	139.2	17.3	4.7	0.6	12%	79
9/12/2017	34	120.7	14.5	4.1	0.5	12%	73
9/13/2017	34	116.6	14.5	4.0	0.5	12%	69
9/26/2017	34	117.0	14.5	4.0	0.5	12%	73
9/27/2017	34	119.3	14.5	4.1	0.5	12%	74
9/28/2017	34	118.1	14.5	4.0	0.5	12%	78
10/6/2017	34	120.5	14.5	4.1	0.5	12%	82
10/9/2017	34	117.0	14.5	4.0	0.5	12%	72
10/10/2017	34	115.5	14.5	3.9	0.5	13%	72
10/16/2017	34	135.0	17.3	4.6	0.6	13%	86
10/17/2017	34	138.0	17.3	4.7	0.6	13%	79
10/18/2017	34	141.7	17.3	4.8	0.6	12%	74
10/23/2017	34	152.4	20.1	5.2	0.7	13%	94
10/24/2017	34	168.0	21.9	5.7	0.7	13%	101
10/25/2017	34	143.7	17.3	4.9	0.6	12%	88
10/26/2017	34	119.4	14.5	4.1	0.5	12%	76
10/27/2017	34	128.1	17.4	4.4	0.6	14%	73
10/31/2017	34	109.5	14.5	3.7	0.5	13%	64

Table 4-18 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		
5/3/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
5/4/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
5/23/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
6/20/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	98
6/21/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
6/22/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
6/26/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
7/3/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
7/6/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
7/7/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101
7/10/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
7/27/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
7/31/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
8/1/2017	20	254.8	52.3	5.1	1.0	21%	89
8/2/2017	20	226.7	52.3	4.5	1.0	23%	96
8/3/2017	20	259.4	52.3	5.2	1.0	20%	97
8/7/2017	20	203.2	24.2	4.1	0.5	12%	89
8/10/2017	20	218.9	24.2	4.4	0.5	11%	91
8/11/2017	20	207.1	24.2	4.1	0.5	12%	93
8/28/2017	20	272.9	52.3	5.5	1.0	19%	104
8/29/2017	20	220.8	52.3	4.4	1.0	24%	105
8/30/2017	20	268.3	24.2	5.4	0.5	9%	102
8/31/2017	20	220.0	56.4	4.4	1.1	26%	84
9/1/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	105
9/5/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
9/6/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
9/7/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
9/11/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
9/12/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
9/13/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
9/26/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
9/27/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
9/28/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
10/6/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
10/10/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
10/16/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
10/17/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
10/18/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
10/23/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
10/24/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/25/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
10/26/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
10/27/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
10/30/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
10/31/2017	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65

Table 4-19 South Orange County 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		
5/3/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
5/4/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
5/23/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
6/20/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
6/21/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
6/22/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
6/26/2017	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
7/3/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
7/6/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
7/7/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
7/10/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
7/27/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
7/31/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
8/1/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
8/2/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
8/3/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
8/7/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
8/10/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
8/11/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
8/28/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
8/29/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
8/30/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
8/31/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
9/1/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
9/5/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
9/6/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
9/7/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
9/11/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
9/12/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
9/13/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
9/26/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
9/27/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
9/28/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
10/6/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
10/10/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
10/16/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
10/17/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
10/18/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
10/23/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
10/24/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101
10/25/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
10/26/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
10/27/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
10/30/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
10/31/2017	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

Table 4-20 South of Lugo Event Day Impacts: CBP DA 4-8 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
		Ref. Load	Impact	Ref. Load.	Impact		
6/20/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104
6/21/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	103
6/22/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
9/1/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	109
9/5/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
10/24/2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93

Hourly Load Impacts

Figure 4-4 through Figure 4-6 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each of the SCE CBP products on an average summer event day. The event window is 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 4-4 SCE CBP Day-Of 1-4 Hour: Average Hourly Per-Customer Impact, 2017

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-5 SCE CBP Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2017

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-6 SCE CBP Day-Ahead 4-8 Hour: Average Hourly Per-Customer Impact, 2017

Figure redacted to protect customer or aggregator confidentiality.

Load Impacts of TA/TI and AutoDR Participants

Table 4-21 presents the ex-post load impacts achieved in PY2017 by SCE CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years. Only the DO 1-4 hour product had AutoDR or TA/TI participants in 2017.

Table 4-21 SCE CBP Day-Of 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Event Hrs (HE)	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact			
Avg. Summer	16-19	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
Avg. Non-Summer	18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
11/7/2016	18-19 19-19	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
11/8/2016	17-19 19-19	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
11/9/2016	17-19 18-19 19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
11/10/2016	17-19 18-18 18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
11/14/2016	17-18 17-19 18-18	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
11/15/2016	18-18 18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
11/16/2016	17-18 18-18	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/17/2016	17-19 18-19	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
11/18/2016	17-19 18-19	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
11/21/2016	18-18	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
11/22/2016	18-18 18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
11/23/2016	18-18	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
11/25/2016	18-18	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
11/28/2016	18-18	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
11/29/2016	18-18 18-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
11/30/2016	18-18	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
5/3/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80

Event	Event Hrs (HE)	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact			
5/4/2017	19-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
5/22/2017	18-19 19-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
5/23/2017	19-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
6/19/2017	16-19 17-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
6/20/2017	16-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
6/21/2017	16-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
6/22/2017	16-19	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
7/6/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
7/7/2017	17-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
7/10/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
7/27/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
7/31/2017	18-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
8/1/2017	16-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
8/2/2017	16-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
8/3/2017	16-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
8/10/2017	19-19	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
8/11/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
8/28/2017	16-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
8/29/2017	16-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
8/30/2017	19-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
8/31/2017	17-19	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
9/1/2017	16-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	99
9/5/2017	18-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
9/6/2017	19-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
9/7/2017	19-19	27	61.1	9.5	1.6	0.3	16%	0.5	80
9/11/2017	18-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
9/12/2017	19-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
9/13/2017	19-19	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
9/26/2017	19-19	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
9/27/2017	19-19	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
9/28/2017	19-19	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
10/6/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
10/9/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
10/10/2017	19-19	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
10/11/2017	19-19	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
10/12/2017	19-19	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72

Event	Event Hrs (HE)	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact			
10/16/2017	18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
10/17/2017	18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
10/18/2017	18-19 19-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
10/23/2017	17-19 18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
10/24/2017	16-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
10/25/2017	18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
10/26/2017	19-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
10/27/2017	18-19	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
10/31/2017	19-19	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

SDG&E

Events for SDG&E CBP

Table 4-22 presents a summary of the 2017 events for SDG&E's CBP program by product. Over the course of the program year, the DO 1-4 hour and DO 2-6 hour participants experienced 9 event days, the DA 1-4 hour participants experienced 20 events, and the DA 2-6 hour participants experienced 12 events. Events were called with various event windows. An average event is defined as one called during hours-ending 16-19.

Table 4-22 SDG&E CBP Event Summary

Date	Day of Week	Event Hours (HE)	# Accounts DO 1-4 Hour	# Accounts DO 2-6 Hour	# Accounts DA 1-4 Hour	# Accounts DA 2-6 Hour
Avg. Event	-	16-19	170	4	41	62
6/20/2017	Tuesday	16-19	-	-	6	60
6/21/2017	Wednesday	16-19	-	-	6	60
6/22/2017	Thursday	16-19	-	-	6	60
7/7/2017	Friday	16-19	-	-	6	65
8/1/2017	Tuesday	16-19	170	4	69	-
8/2/2017	Wednesday	16-19	170	4	69	-
8/3/2017	Thursday	16-19	-	-	69	-
8/22/2017	Tuesday	16-19	-	-	69	-
8/28/2017	Monday	17-19 16-19	170 -	4 -	- 69	- -
8/29/2017	Tuesday	16-19	-	-	69	-
8/30/2017	Wednesday	18-19 16-19	170 -	4 -	- 69	- -
8/31/2017	Thursday	16-19	170	4	69	-
9/1/2017	Friday	16-19	174	4	4	65
9/11/2017	Monday	18-19	-	-	4	65
10/16/2017	Monday	18-19	-	-	4	65
10/17/2017	Tuesday	18-19	-	-	4	65
10/23/2017	Monday	18-19 17-19	169 -	4 -	- 4	- 65
10/24/2017	Tuesday	16-19	169	4	4	65
10/25/2017	Wednesday	18-19	169	4	4	65
10/27/2017	Friday	18-19	-	-	4	65

Summary Load Impacts

Table 4-23 through Table 4-26 show the average event-hour impacts for the four CBP products. 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 4-23 SDG&E CBP Day-Of 1-4 Hour Product: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (°F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	170	4.6	147.2	18.5	25.0	3.1	13%	85
8/1/2017	170	4.6	141.6	19.0	24.1	3.2	13%	79
8/2/2017	170	4.6	144.2	19.0	24.5	3.2	13%	83
8/28/2017	170	4.6	138.0	14.3	23.5	2.4	10%	78
8/30/2017	170	4.6	152.7	21.7	26.0	3.7	14%	82
8/31/2017	170	4.6	148.4	19.1	25.2	3.2	13%	84
9/1/2017	174	4.9	149.7	17.2	26.0	3.0	11%	88
10/23/2017	169	4.6	148.3	21.6	25.1	3.6	15%	88
10/24/2017	169	4.6	151.4	18.2	25.6	3.1	12%	93
10/25/2017	169	4.6	146.7	21.6	24.8	3.6	15%	80

Table 4-24 SDG&E CBP Day-Of 2-6 Hour Product: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (°F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	4	0.2	20.3	13.4	0.1	0.1	66%	89
8/1/2017	4	0.1	43.2	12.0	0.2	<0.1	28%	82
8/2/2017	4	0.1	12.4	12.0	<0.1	<0.1	97%	87
8/28/2017	4	0.1	25.1	24.6	0.1	0.1	98%	81
8/30/2017	4	0.1	39.5	39.2	0.2	0.2	99%	87
8/31/2017	4	0.1	12.2	12.0	<0.1	<0.1	99%	90
9/1/2017	4	0.2	16.7	14.4	0.1	0.1	87%	92
10/23/2017	4	0.2	39.4	39.2	0.2	0.2	99%	89
10/24/2017	4	0.2	16.9	16.4	0.1	0.1	97%	94
10/25/2017	4	0.2	39.4	39.2	0.2	0.2	99%	82

Table 4-25 SDG&E CBP Day-Ahead 1-4 Hour: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	41	0.1	268.0	11.5	11.0	0.5	4%	77
6/20/2017	6	0.1	623.6	32.9	3.7	0.2	5%	72
6/21/2017	6	0.1	610.5	32.9	3.7	0.2	5%	71
6/22/2017	6	0.1	587.7	32.9	3.5	0.2	6%	69
7/7/2017	6	0.1	650.9	31.2	3.9	0.2	5%	76
8/1/2017	69	0.3	234.4	9.5	16.2	0.7	4%	76
8/2/2017	69	0.3	239.9	9.5	16.6	0.7	4%	80
8/3/2017	69	0.3	257.3	9.7	17.8	0.7	4%	75
8/22/2017	69	0.3	222.3	9.5	15.3	0.7	4%	73
8/28/2017	69	0.3	238.7	9.5	16.5	0.7	4%	76
8/29/2017	69	0.3	232.3	9.5	16.0	0.7	4%	78
8/30/2017	69	0.3	245.6	9.5	16.9	0.7	4%	81
8/31/2017	69	0.3	249.6	9.5	17.2	0.7	4%	79
9/1/2017	4	0.1	844.6	90.0	3.4	0.4	11%	84
9/11/2017	4	0.1	783.9	47.8	3.1	0.2	6%	77
10/16/2017	4	<0.1	693.3	47.8	2.8	0.2	7%	84
10/17/2017	4	<0.1	705.6	47.8	2.8	0.2	7%	77
10/23/2017	4	<0.1	778.2	39.8	3.1	0.2	5%	87
10/24/2017	4	<0.1	845.5	56.1	3.4	0.2	7%	91
10/25/2017	4	<0.1	790.4	47.8	3.2	0.2	6%	79
10/27/2017	4	<0.1	762.0	47.8	3.0	0.2	6%	71

Table 4-26 SDG&E CBP Day-Ahead 2-6 Hour: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (˚F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	62	0.2	203.6	7.6	12.6	0.5	4%	77
6/20/2017	60	0.2	206.5	7.5	12.4	0.5	4%	72
6/21/2017	60	0.2	201.9	7.5	12.1	0.5	4%	71
6/22/2017	60	0.2	189.5	7.5	11.4	0.5	4%	69
7/7/2017	65	0.2	191.5	0.7	12.4	<0.1	0%	76
9/1/2017	65	0.2	209.6	12.0	13.6	0.8	6%	84
9/11/2017	65	0.2	180.6	5.6	11.7	0.4	3%	77
10/16/2017	65	0.2	164.3	5.6	10.7	0.4	3%	84
10/17/2017	65	0.2	166.5	5.6	10.8	0.4	3%	77
10/23/2017	65	0.2	183.2	3.7	11.9	0.2	2%	87
10/24/2017	65	0.2	212.0	9.8	13.8	0.6	5%	91
10/25/2017	65	0.2	175.5	5.6	11.4	0.4	3%	79
10/27/2017	65	0.2	160.1	5.6	10.4	0.4	4%	71

Table 4-27 presents the impacts for an average event day by industry group.[44,45]

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

[45] The results in Table 4-27 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.

Table 4-27 SDG&E CBP Impacts by Industry and Notice

	Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Event Temp (˚F)
			Ref. Load	Impact	Ref. Load	Impact		
DA	Retail Stores	3	338.4	23.3	1.0	0.1	7%	77
DA	Offices, Hotels, Finance, Services	63	206.3	6.2	13.0	0.4	3%	77
DA	Institutional/Government	1	2,384.8	213.1	2.4	0.2	9%	77
DA	**Total DA**	68	241.1	9.9	16.4	0.7	4%	77
DO	Agriculture, Mining & Construction	4	20.3	13.4	0.1	0.1	66%	89
DO	Manufacturing	1	1,328.1	173.5	1.3	0.2	13%	89
DO	Retail Stores	151	137.5	18.3	20.8	2.8	13%	85
DO	Offices, Hotels, Finance, Services	17	150.9	9.3	2.6	0.2	6%	89
DO	Institutional/Government	1	372.7	44.4	0.4	<0.1	12%	82
DO	**Total DO**	174	144.3	18.4	25.1	3.2	13%	85
Total CBP		**130**	195.1	14.0	25.4	1.8	7%	78

Hourly Load Impacts

Figure 4-7 and Figure 4-8 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for SDG&E's CBP DO and DA products, respectively, on an average event day. In both the DO and DA figures, results for the 1-4 hour and 2-6 hour products are combined. 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 4-7 SDG&E CBP All Day-Of: Average Hourly Per-Customer Impact, 2017

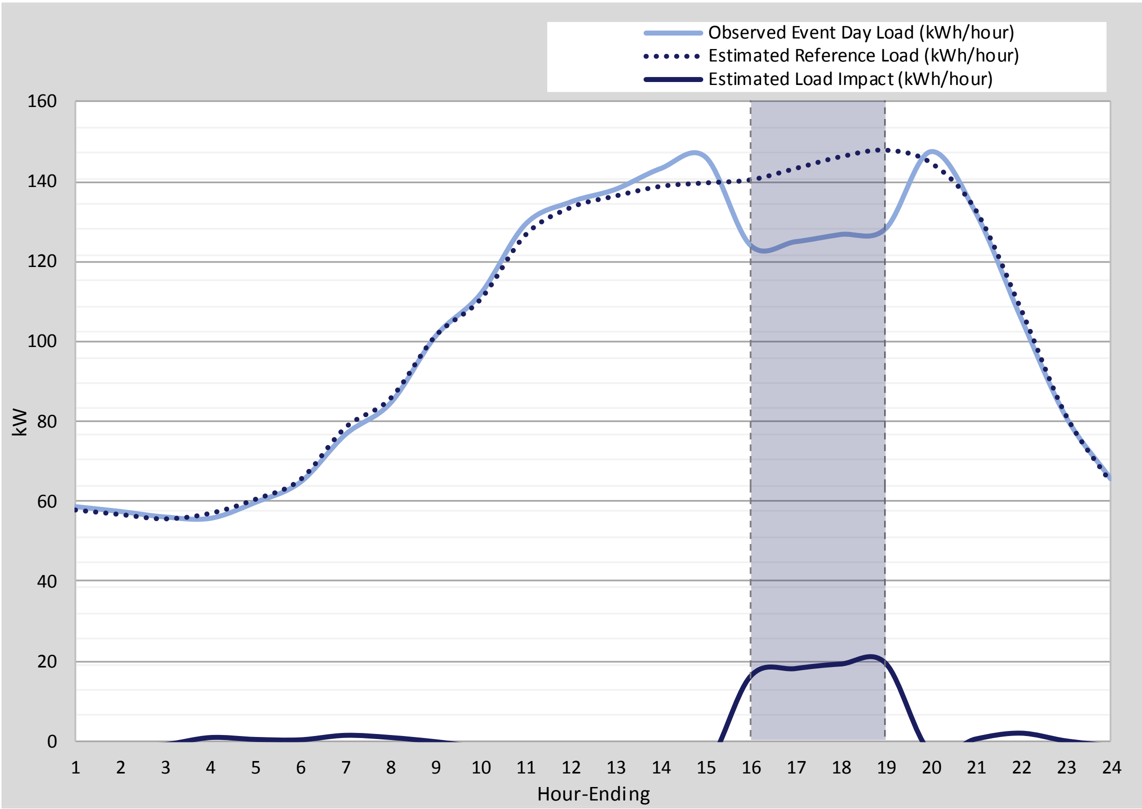
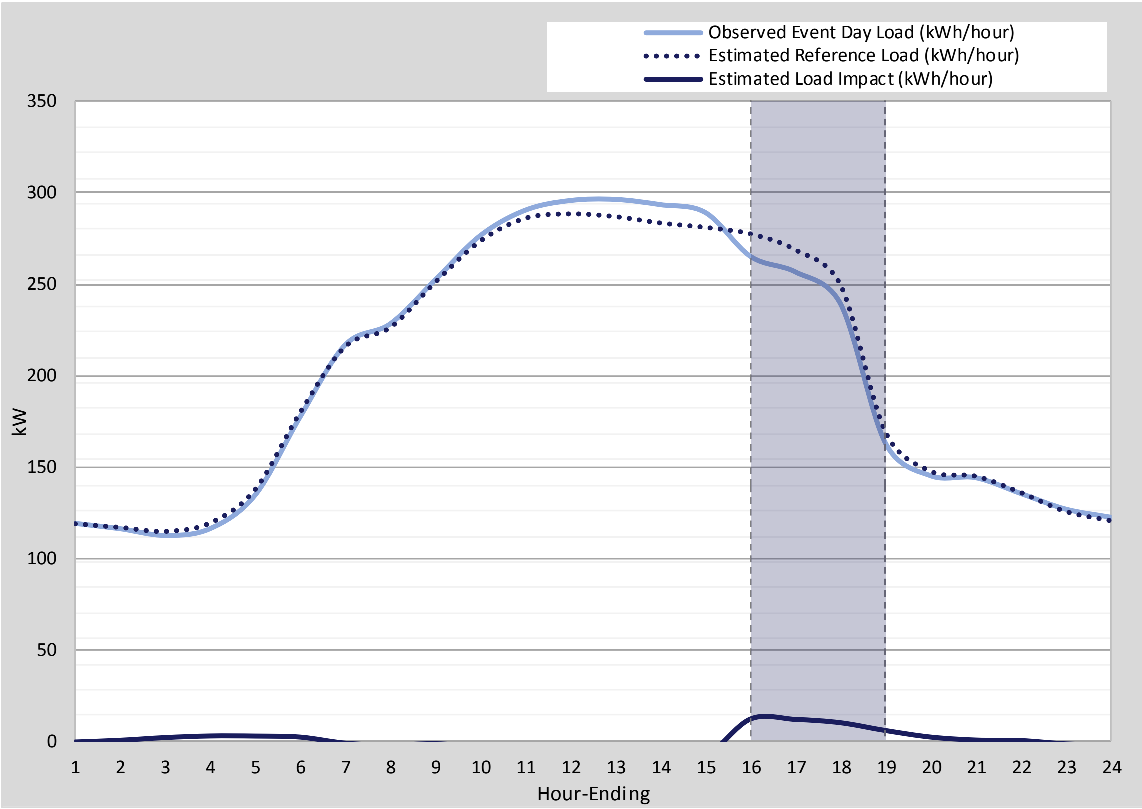


Figure 4-8 SDG&E CBP All Day-Ahead: Average Hourly Per-Customer Impact, 2017



Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved in PY2017 by SDG&E CBP customers that enrolled in AutoDR or TA/TI 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 4-28 presents the average event-hour impacts and aggregate load shed test results for the CBP DO 1-4 hour product by event. There were no AutoDR or TA/TI participants in any of the events for the CBP DO 2-6 hour product.

Table 4-28 SDG&E CBP Day-Of 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Number of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Event	31	96.1	25.1	3.0	0.8	26%	1.4	84
8/1/2017	30	94.3	26.4	2.8	0.8	28%	1.4	78
8/2/2017	30	94.0	26.4	2.8	0.8	28%	1.4	82
8/28/2017	30	88.8	21.5	2.7	0.6	24%	1.4	77
8/30/2017	30	92.5	26.3	2.8	0.8	28%	1.4	81
8/31/2017	30	96.9	26.4	2.9	0.8	27%	1.4	82
9/1/2017	35	95.7	20.0	3.3	0.7	21%	1.5	87
10/23/2017	30	95.8	26.3	2.9	0.8	27%	1.4	87
10/24/2017	30	99.9	27.2	3.0	0.8	27%	1.4	92
10/25/2017	30	90.3	26.3	2.7	0.8	29%	1.4	80

Table 4-29 presents the average event-hour impacts for the CBP DA 1-4 hour participants.

Table 4-29 SDG&E CBP Day-Ahead 1-4 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Number of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Event	15	481.3	16.8	7.2	0.3	3%	2.1	77
8/1/2017	15	467.1	16.8	7.0	0.3	4%	2.1	76
8/2/2017	15	482.1	16.8	7.2	0.3	3%	2.1	80
8/3/2017	15	498.4	16.8	7.5	0.3	3%	2.1	75
8/22/2017	15	453.7	16.8	6.8	0.3	4%	2.1	73
8/28/2017	15	479.6	16.8	7.2	0.3	4%	2.1	76
8/29/2017	15	472.1	16.8	7.1	0.3	4%	2.1	78
8/30/2017	15	497.2	16.8	7.5	0.3	3%	2.1	81
8/31/2017	15	500.4	16.8	7.5	0.3	3%	2.1	79

Table 4-30 presents the average event-hour impacts for the CBP DA 2-6 hour participants.

Table 4-30 SDG&E CBP Day-Ahead 2-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	Number of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (˚F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Event	15	460.2	19.2	6.9	0.3	4%	2.1	77
6/20/2017	15	452.7	14.5	6.8	0.2	3%	2.1	72
6/21/2017	15	443.8	14.5	6.7	0.2	3%	2.1	71
6/22/2017	15	421.1	14.5	6.3	0.2	3%	2.1	69
7/7/2017	15	451.8	8.2	6.8	0.1	2%	2.1	76
9/1/2017	15	489.4	34.1	7.3	0.5	7%	2.1	84
9/11/2017	15	417.1	16.4	6.3	0.2	4%	2.1	77
10/16/2017	15	386.4	16.4	5.8	0.2	4%	2.1	84
10/17/2017	15	389.0	16.4	5.8	0.2	4%	2.1	77
10/23/2017	15	437.8	14.5	6.6	0.2	3%	2.1	87
10/24/2017	15	502.4	29.2	7.5	0.4	6%	2.1	91
10/25/2017	15	411.0	16.4	6.2	0.2	4%	2.1	79
10/27/2017	15	370.0	16.4	5.5	0.2	4%	2.1	71

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 did the matching and DID analysis at the product level and at the program level. The only results that were statistically significant were for the CBP DO 1-4 hour product.

Figure 4-9 shows the treatment and control-group match for the CBP DO 1-4 hour product on an average event day. The graph compares the average per-customer load profile of each group. There were 35 control-group matches for the incremental analysis, and there were 31 participating accounts on the average event day.[46]

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

Figure 4-9 SDG&E CBP DO 1-4 Hour: AutoDR and TA/TI Event Day Match, kW

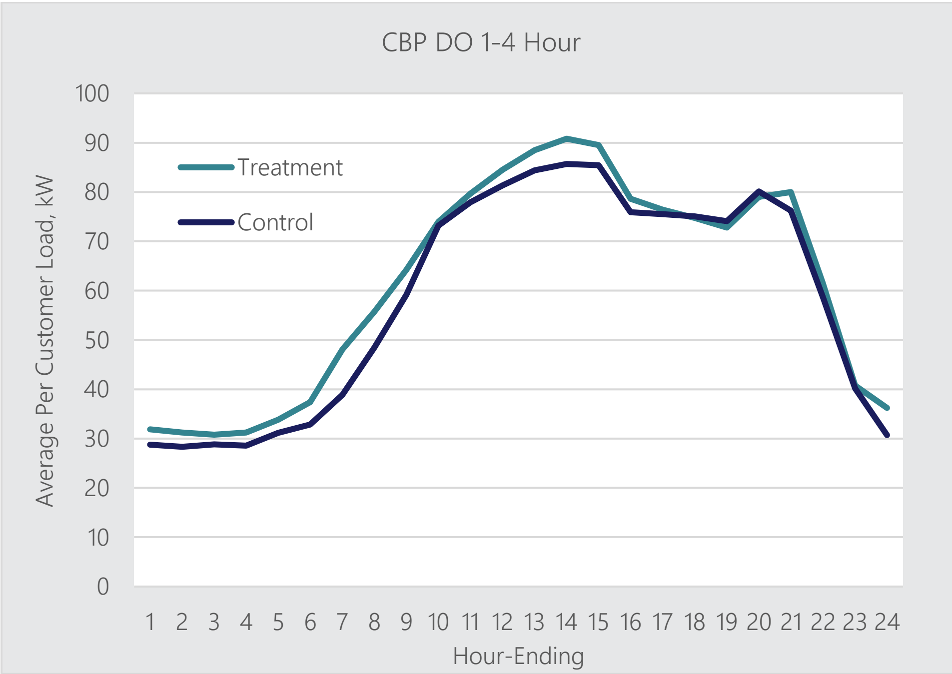


Figure 4-10 illustrates the incremental impacts for the DO 1-4 hour product. The figure shows the average per-customer incremental impact for each hour of an average event day. It also includes the upper and lower confidence intervals at the 95th percentile. For CBP DO, the incremental impacts are very small, and often insignificant during non-event hours. However, during the HE16 to HE19 event window, we do see significant incremental impacts of 5.6 kW per enabled customer, on average.

Figure 4-10 SDG&E CBP DO 1-4 Hour: AutoDR and TA/TI Average Event Day Incremental Impacts, kW

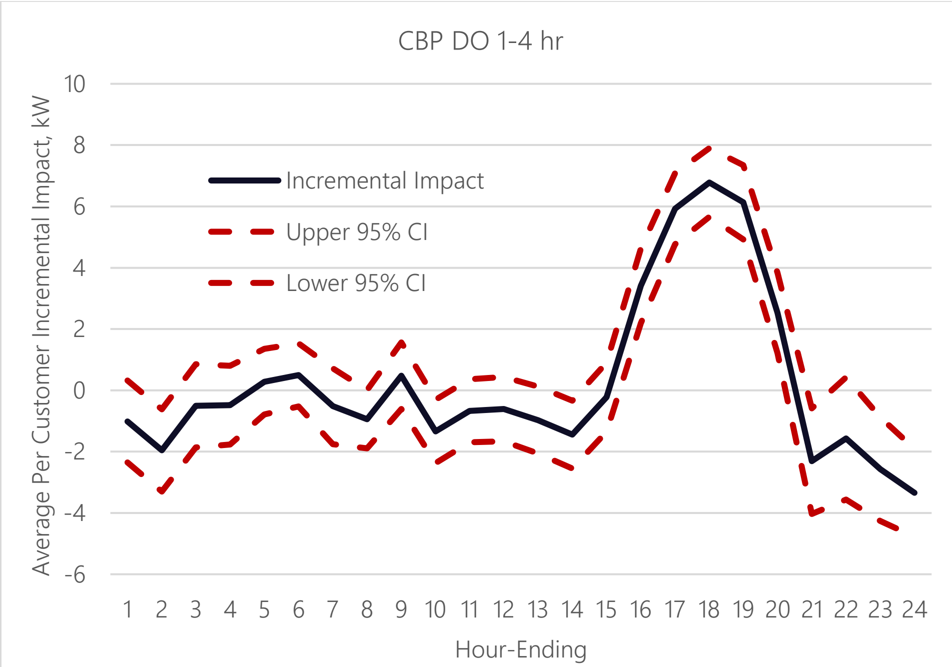


Table 4-31 summarizes the average on-peak per customer and aggregate incremental impacts associated with the AutoDR and TA/TI participants of the CBP DO 1-4 hour product. As noted previously, the incremental impacts were not statistically significant for the other products.

Table 4-31 SDG&E CBP DO 1-4 Hour: Incremental AutoDR and TA/TI Impacts

Product	Number of Accounts	Incremental Impact Per Customer (kW)	Incremental Impact Aggregate (kW)	Statistically Significant
CBP DO 1-4 Hour	31	5.6	172.5	Yes

Aggregator Managed Portfolio

SCE was the only utility to offer AMP in PY2017.

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

5

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 the following:

- How current ex-post results differ from last year's ex-post results.
- How current ex-post results differ from last year's forecast.
- How current ex-ante results differ from last year's forecast.
- How 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 non-residential CBP nominations will remain constant throughout the forecast horizon (2018-2028), with an estimated 700 customers for the DA product. The DO product will not be offered, but the forecast assumes the current DO customers will participate in DA instead beginning in 2018.

The ex-ante impact results forecast annual CBP load impacts for the non-residential DA product that are commensurate with the PY2017 per-customer impacts and with the 2018-2028 enrollment forecast. The impacts are estimated to remain constant across the months of May through October.

Table 5-1 summarizes the average event-hour load impact forecasts for non-residential CBP DA on an August peak day in 2018.[47] 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.

[47] Though labeled as an August peak day in 2018, the results in Table 5-1 would be identical for each month, May through October, and each year, 2018 through 2028, in the forecast.

Table 5-1 PG&E Non-Residential CBP DA: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2018

	Size	# of Accts	Per Customer Impact (kW)				Aggregate Impact (MW)			
			Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
			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	44	2.3	2.9	1.8	2.5	0.1	0.1	0.1	0.1
	20 to < 200 kW	435	14.7	15.8	14.3	15.1	6.4	6.9	6.2	6.6
	≥ 200 kW	222	65.4	65.2	62.4	69.1	14.5	14.5	13.8	15.3
	Total DA	**700**	**30.0**	**30.6**	**28.7**	**31.4**	**21.0**	**21.5**	**20.1**	**22.0**

Figure 5-1 illustrates the average event-hour load impacts distributed by LCA for non-residential CBP DA on an August peak day in 2018. The results shown are for 1-in-2 weather conditions for the utility peak. Results for Humboldt are redacted to protect customer or aggregator confidentiality.

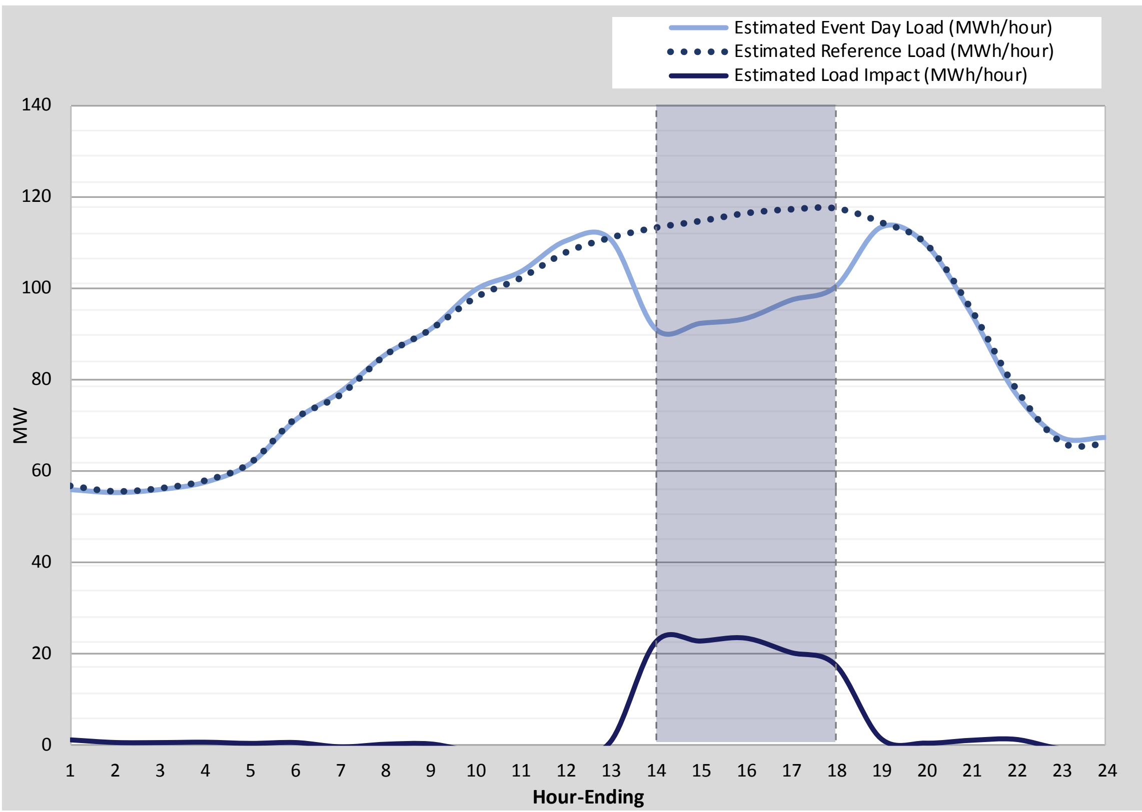
Figure 5-1 PG&E Non-Residential CBP DA: Average Event-Hour Aggregate Load Impacts by LCA for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions

Figure redacted to protect customer or aggregator confidentiality.

Hourly Reference Loads and Load Impacts

Figure 5-2 compares the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2018 for PG&E's non-residential CBP DA product. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-2 PG&E Non-Residential CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment and Load Impact Summary

SCE proposed several changes to CBP that were adopted by the Commission. The changes are anticipated to increase CBP enrollment over time, beginning in 2018. The changes include streamlining CBP offerings from six products to two products, changing the event window from 11 AM – 7 PM to 1 PM – 7PM, and establishing a monthly five event maximum.

SCE forecasts CBP DA enrollment to increase to 90 customers in 2018 and then to stay at 90 customers until 2022. In 2023, SCE expects CBP DA enrollment to increase to 3,321 customers due to an influx of residential customers following full opening of the program to the residential class.[48] Subsequently, enrollment is projected to hold steadily at 3,321 participants for the

[48] However, residential CBP enrollment may occur earlier than 2023, pending the 2020 mid-cycle filing required in D.17-12-003.

remainder of the forecast horizon (2023-2028). For the CBP DO product, SCE forecasts the enrollment to increase to 1,250 customers in 2018 due to the closure of AMP, and then to stay constant at that value throughout the forecast horizon (2018-2028).

The ex-ante impact results forecast annual non-residential CBP load impacts for the DA and DO products that are commensurate with the PY2017 per-customer impacts and the non-residential 2018-2028 enrollment forecast. In addition, SCE assumes a constant aggregate residential CBP forecast of 3 MW throughout the forecast horizon starting in 2023 due to the expected influx of residential customers.

Table 5-2 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2018. 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, 2018

Notice	# of Accts	Per Customer Impact (kW)				Aggregate Impact (MW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
		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	90	68.5	68.5	68.5	68.5	6.2	6.2	6.2	6.2
Total DO	1,250	18.5	18.5	18.5	18.5	23.1	23.1	23.1	23.1

Hourly Reference Loads and Load Impacts

Figure 5-3 and Figure 5-4 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2018 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-3 SCE CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions

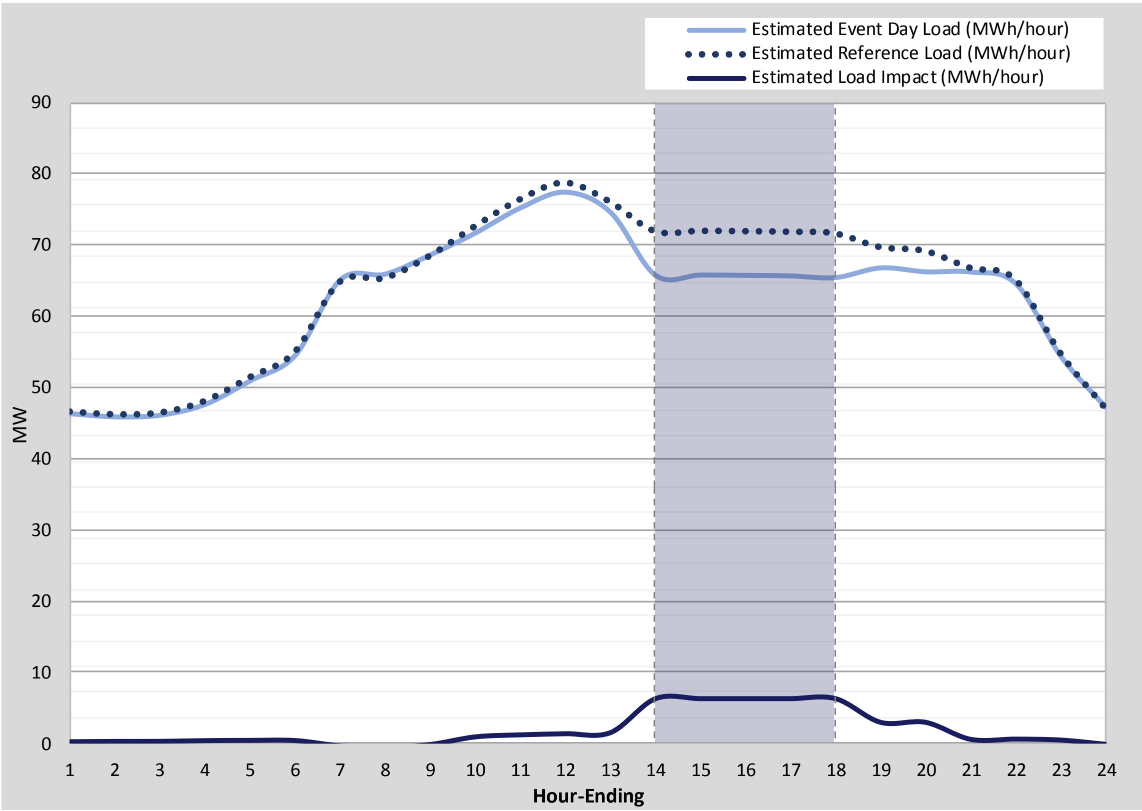
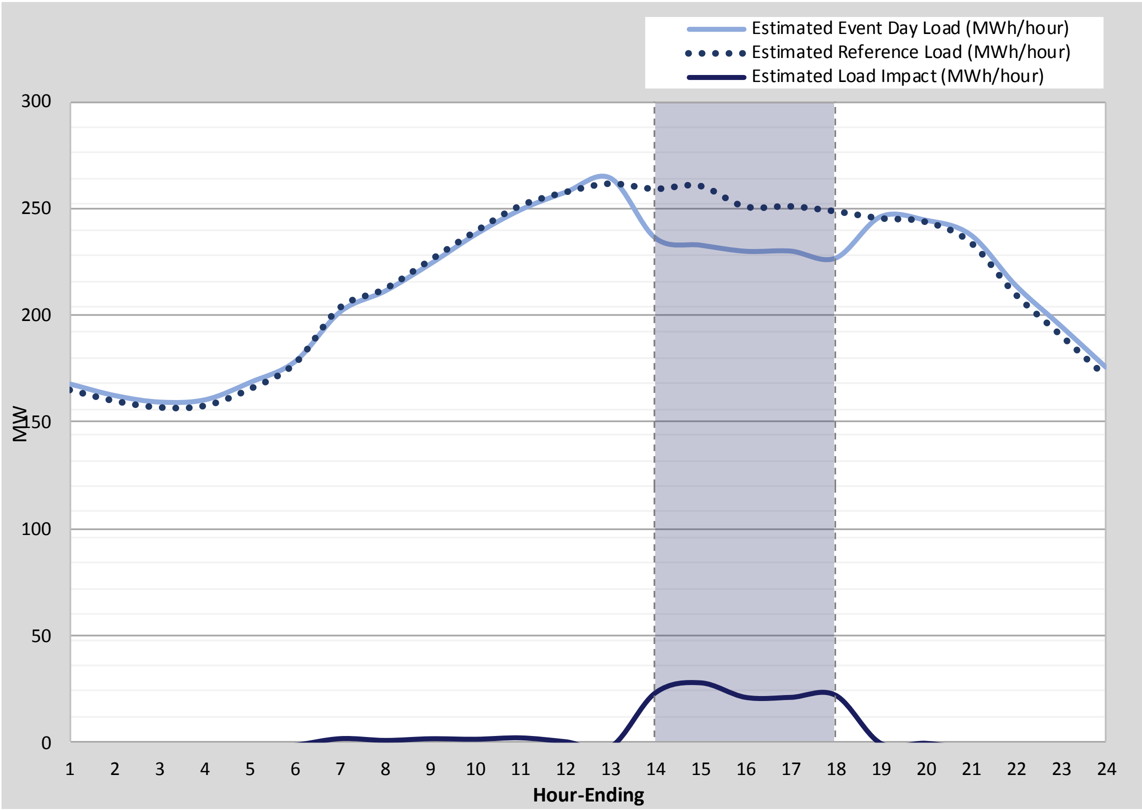


Figure 5-4 SCE CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions



SDG&E

Enrollment and Load Impact Summary

The Commission approved several CBP changes requested by SDG&E. As a result, SDG&E is reducing its number of CBP products from nine to four beginning in 2018. There will be two DA 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1 PM - 9 PM. Similarly, there will be two DO 2-4 hour products, one with the hours of 11 AM - 7 PM and the other with the hours of 1 PM - 9 PM. SDG&E has also proposed simplifying the trigger by basing it on price only, instead of on price and heat rate. The Commission will adopt final price triggers in a future decision, pending a proposal from SDG&E to describe methods of determining the price triggers.

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 2028 show a flat trend at the 2022 values.

The ex-ante load impact forecast follows the 2018-2028 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 2018.[49] 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 5-3 SDG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2018

Notice	# of Accts	Per Customer Impact (kW)				Aggregate Impact (MW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
		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	69	9.8	9.8	9.8	9.8	0.7	0.7	0.7	0.7
Total DO	171	18.5	18.5	18.4	18.5	3.2	3.2	3.1	3.2

Hourly Reference Loads and Load Impacts

Figure 5-5 and Figure 5-6 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2018 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

[49] Though labeled as an August peak day in 2018, the results in Table 5-3 would be identical for each month, May through October, in the 2018 forecast.

Figure 5-5 SDG&E CBP DA: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions

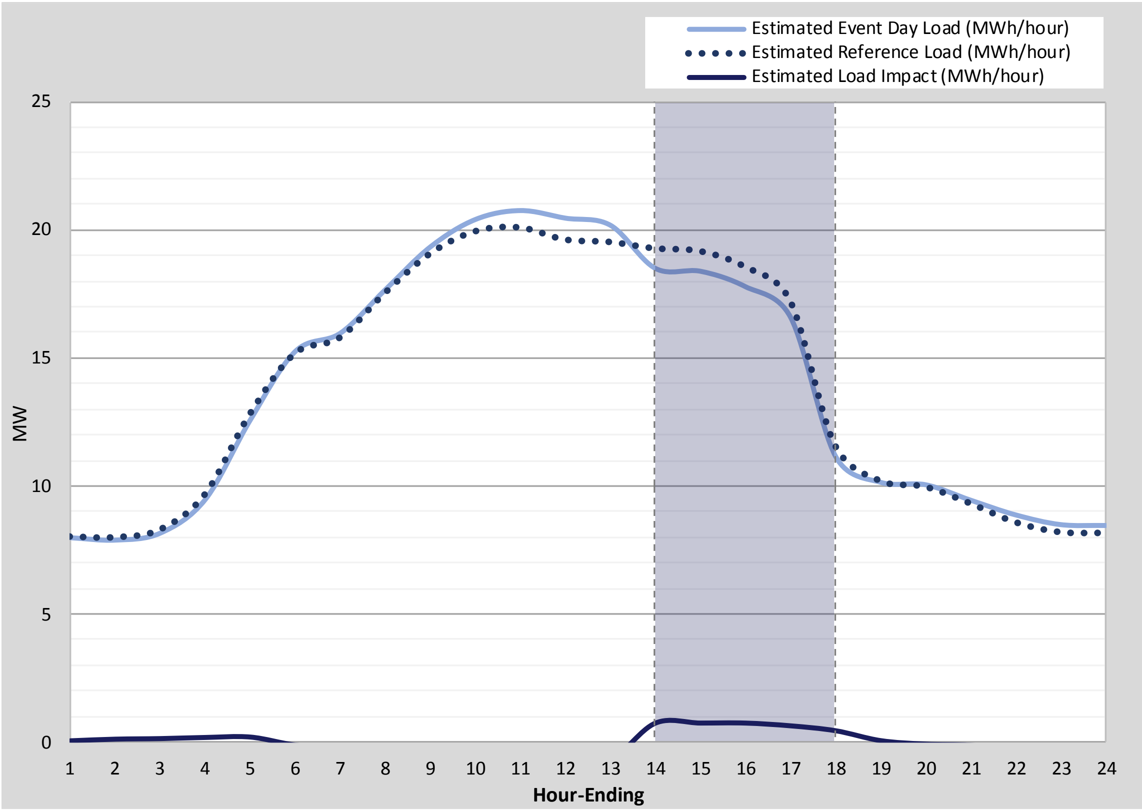
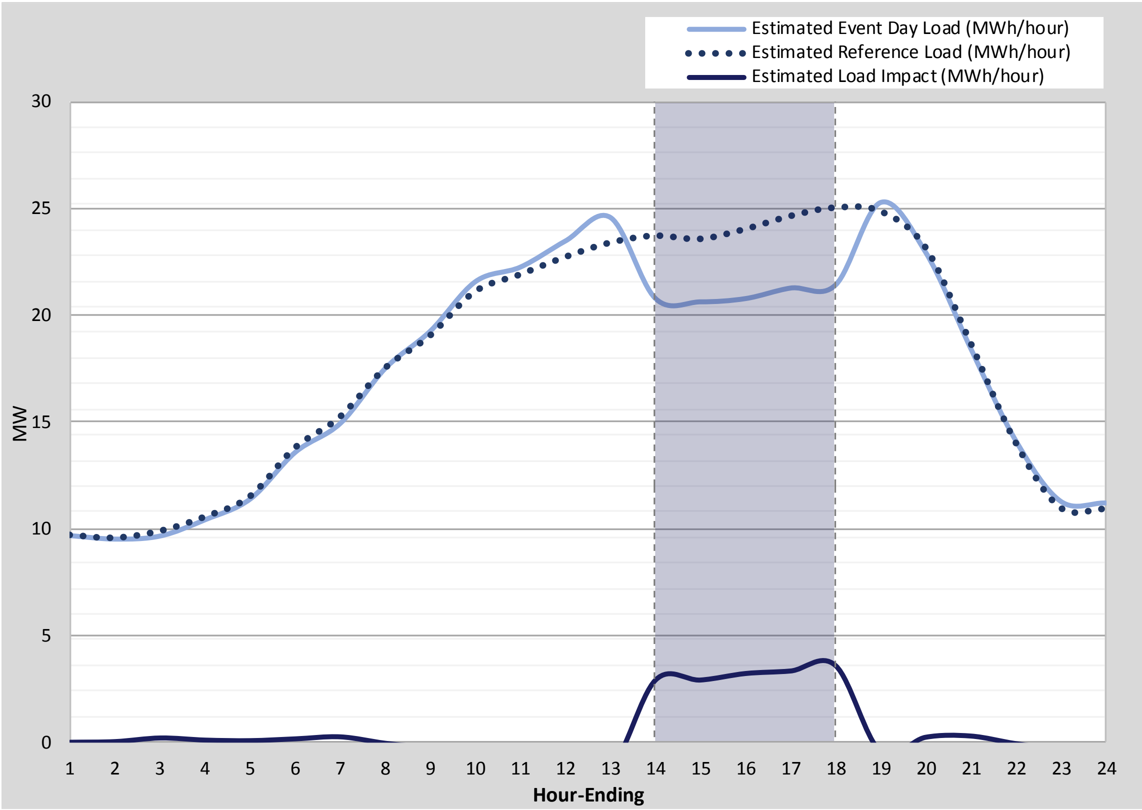


Figure 5-6 SDG&E CBP DO: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2018, 1-in-2 Utility Peak Weather Conditions



Aggregator Managed Portfolio

PG&E discontinued AMP as of the end of PY2016, and SCE discontinued AMP as of the end of PY2017. Therefore, there are no ex-ante impacts for 2018-2028.

Comparisons of Ex-Post and Ex-Ante Results

PG&E

Previous and Current Ex-Post: CBP

Table 5-4 summarizes the non-residential CBP DA and DO average event-hour ex-post load impact results for the past three 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 Non-Residential CBP: Previous and Current Ex-Post, Average Event Day

	Ex-Post Year	# of Accts	Per Customer (kW)		Aggregate (MW)		% Impact	Event Temp (˚F)
			Reference Load	Load Impact	Reference Load	Load Impact		
DA	2015	200	425.5	79.7	85.1	15.9	19%	90
	2016	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
	2017	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
DO	2015	569	177.8	34.7	101.2	19.8	20%	90
	2016	406	156.0	22.6	63.3	9.2	14%	88
	2017	811	138.1	26.8	112.0	21.8	19%	91

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

Table 5-5 compares the current year's analysis with the previous year's analysis of non-residential 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.[50] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.

[50] 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 5-5 PG&E Non-Residential CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

Model		Year	Day	# of 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 2017	Aug 31	20	1,361.6	293.9	27.2	5.9	22%	97
		Ex-Ante 2018	Aug Peak	700	165.4	30.0	115.8	21.0	18%	92
	Previous	Ex-Post 2016	Aug 17	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
		Ex-Ante 2017	Aug Peak	50	626.7	138.1	31.1	6.9	22%	92
		Ex-Ante 2018	Aug Peak	50	626.7	138.1	31.1	6.9	22%	92
DO	Current	Ex-Post 2017	Aug 31	911	137.7	26.6	125.4	24.2	19%	95
		Ex-Ante 2018	Aug Peak	-	-	-	-	-	-	-
	Previous	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
		Ex-Ante 2018	Aug Peak	611	154.7	22.2	94.5	13.6	14%	92

Table 5-5 shows the following trends for the non-residential CBP DA and DO products on an August peak day:

- Current Ex-Post Compared with Previous Ex-Ante: The aggregate ex-post impacts for DA were lower in PY2017 (5.9 MW) than projected to be in the previous ex-ante forecast (6.9 MW) due to lower than forecasted enrollment. In contrast, the aggregate ex-post impacts for DO were higher in PY2017 (24.2 MW) than projected to be in the previous ex-ante forecast (13.6 MW) due to higher than forecasted enrollment.
- Current Ex-Ante Compared with Previous Ex-Ante: Since the DO product will no longer be offered, the current ex-ante analysis for DA forecasts higher impacts (21.0 MW) than did the previous ex-ante analysis (6.9 MW) due to higher expected enrollment from some former DO participants moving to DA. The current ex-ante analysis for the DO product forecasts zero impacts, while the previous ex-ante analysis estimated impacts of 13.6 MW.
- Current Ex-Ante Compared with Current Ex-Post: For DA, the current ex-ante estimates for PY2018 (21.0 MW) and the current ex-post estimates for PY2017 (5.9 MW) differ due to the expected increase in DA enrollment beginning in 2018. For DO, the current ex-ante impacts are estimated to be zero for PY2018 since the DO product will not be offered. However, with DO MW forecast to migrate to DA, non-residential CBP as a whole maintains its load impacts.

SCE

Previous and Current Ex-Post: CBP

Table 5-6 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past six 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 5-6 SCE CBP: Previous and Current Ex-Post, Average Summer Event Day

	Ex-Post Year	# of Accts	Per Customer (kW)		Aggregate (MW)		% Impact	Event Temp (˚F)
			Reference Load	Load Impact	Reference Load	Load Impact		
DA	2012	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
	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	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
	2017	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
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	243	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
	2017	348	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90

Previous and Current Ex-Post: AMP

Table 5-7 summarizes SCE's AMP DO average event-hour ex-post load impact results for the past six 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 AMP: Previous and Current Ex-Post, Average Summer Event Day

	Ex-Post Year	# of Accts	Per Customer (kW) Reference Load	Per Customer (kW) Load Impact	Aggregate (MW) Reference Load	Aggregate (MW) Load Impact	% Impact	Event Temp (˚F)
DO	2012	1,648	334.1	97.2	550.6	160.1	29%	91
	2013	1,531	293.8	80.1	449.6	122.6	27%	85
	2014	920	331.0	98.2	304.5	90.3	30%	82
	2015	1,186	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
	2016	1,571	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
	2017	722	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90

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.

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

	Model	Year	Day	# of 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 2017	Summer	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
		Ex-Ante 2018	Aug Peak	90	798.6	68.5	71.9	6.2	9%	96
	Previous	Ex-Post 2016	Summer	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
		Ex-Ante 2017	Aug Peak	30	419.2	52.8	12.6	1.6	13%	94
		Ex-Ante 2018	Aug Peak	90	419.2	52.8	37.7	4.7	13%	94
DO	Current	Ex-Post 2017	Summer	348	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
		Ex-Ante 2018	Aug Peak	1,250	203.2	18.5	254.0	23.1	9%	94
	Previous	Ex-Post 2016	Summer	243	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
		Ex-Ante 2017	Aug Peak	814	202.4	36.1	164.8	29.3	18%	92
		Ex-Ante 2018	Aug Peak	1,250	202.4	36.1	253.0	45.1	18%	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 higher aggregate impacts ([redacted] MW) than the previous ex-ante projections for PY2017 (1.6 MW) due to greater enrollment and larger per-customer impacts than expected. For DO, the current ex-post results show lower aggregate impacts ([redacted] MW) than the previous ex-ante projections for PY2017 (29.3 MW) due to lower realized enrollment and smaller per-customer impacts.

- Current Ex-Ante Compared with Previous Ex-Ante: The current ex-ante analysis for DA (6.2 MW) projects higher impacts than did the previous ex-ante analysis (4.7 MW) due to higher expected per-customer impacts in PY2018. The current PY2018 ex-ante estimates for DO (23.1 MW) are lower than the previous ex-ante impacts for PY2018 (45.1 MW) due to lower expected per-customer impacts.
- Current Ex-Ante Compared with Current Ex-Post: For DA, the current ex-ante estimates for PY2018 (6.2 MW) are higher than the current ex-post estimates for PY2017 ([redacted] MW) because of lower enrollment in PY2017 than expected for PY2018. For DO, the current ex-ante estimates for PY2018 (23.1 MW) show higher aggregate impacts than the current ex-post estimates for PY2017 ([redacted] MW) due mainly to higher expected enrollment.

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

Since SCE's AMP has been discontinued as of the end of PY2017, there are no ex-ante impacts for the program.

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 six 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

	Ex-Post Year	# of Accts	Per Customer (kW)		Aggregate (MW)		% Impact	Event Temp (˚F)
			Reference Load	Load Impact	Reference Load	Load Impact		
DA	2012	78	320.3	81.6	25.0	6.4	25%	83
DA	2013	142	304.8	75.9	43.2	10.8	25%	88
DA	2014	163	247.0	60.6	40.4	9.9	25%	87
DA	2015	122	148.0	64.1	18.1	7.8	43%	80
DA	2016	69	276.3	51.4	19.1	3.5	19%	79
DA	2017	68	241.1	9.9	16.4	0.7	4%	77
DO	2012	321	229.7	30.5	73.7	9.8	13%	86
DO	2013	260	234.5	40.2	61.1	10.5	17%	87
DO	2014	237	228.5	37.0	54.1	8.8	16%	87
DO	2015	223	208.4	25.6	46.4	5.7	12%	82
DO	2016	200	189.9	24.0	38.0	4.8	13%	84
DO	2017	174	144.3	18.4	25.1	3.2	13%	85

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.[51] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.

[51] 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	# of 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 2017	Aug 2	69	239.9	9.5	16.6	0.7	4%	80
DA	Current	Ex-Ante 2018	Aug Peak	69	248.9	9.8	17.2	0.7	4%	80
DA	Previous	Ex-Post 2016	Aug 16	72	309.2	93.9	22.3	6.8	30%	78
DA	Previous	Ex-Ante 2017	Aug Peak	70	264.2	12.1	18.5	0.8	5%	83
DA	Previous	Ex-Ante 2018	Aug Peak	70	264.2	12.1	18.5	0.8	5%	83
DO	Current	Ex-Post 2017	Aug 31	174	145.2	18.9	25.3	3.3	13%	84
DO	Current	Ex-Ante 2018	Aug Peak	171	141.3	18.5	24.2	3.2	13%	84
DO	Previous	Ex-Post 2016	Aug 15	200	198.6	22.2	39.7	4.4	11%	83
DO	Previous	Ex-Ante 2017	Aug Peak	199	180.6	25.5	35.9	5.1	14%	85
DO	Previous	Ex-Ante 2018	Aug Peak	199	180.6	25.5	35.9	5.1	14%	85

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 similar aggregate impacts (0.7 MW) as the previous ex-ante projections for PY2017 (0.8 MW). For DO, the current aggregate ex-post impacts (3.3 MW) are lower than the previous ex-ante projections for PY2017 (5.1 MW) due to lower enrollment and lower per-customer impacts realized in 2017 than previously expected.
- Current Ex-Ante Compared with Previous Ex-Ante: The current PY2018 aggregate ex-ante impacts for DA (0.7 MW) are similar to previous ex-ante impacts for PY2018 (0.8 MW). The current ex-ante analysis for DO projects lower impacts in PY2018 (3.2 MW) than did the previous ex-ante analysis (5.1 MW) due to lower expected per-customer impacts and lower enrollment.
- Current Ex-Ante Compared with Current Ex-Post: For DA, the current ex-ante estimates for PY2018 show comparable aggregate impacts (0.7 MW) to the current ex-post estimates for PY2017 (0.7 MW). For DO, the current ex-ante estimates for PY2018 (3.2 MW) show fairly comparable aggregate impacts to the current ex-post estimates for PY2017 (3.3 MW), although the ex-ante impacts are projected to be slightly smaller.

6

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:

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

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, 2015, and 2016.
- 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 2017. 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

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.

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

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

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

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. As a final check, we also try to select event-like days that represent a similar distribution of day types as the event days. For example, if there are more event days in August and more event days on a Tuesday, we try to account for that in the selected event-like days.

In Figure 6-1 to Figure 6-3 below we show comparisons of the distributions of average daily temperature of event days and event-like days. We show one comparison for each utility, because we do this selection at the utility level instead of the program or product level. We use this approach to accommodate customer moves between products or programs and the automation process of running individual customer regression models.

Figure 6-1 PG&E Average Daily Temperatures of Event Days v. Event-Like Days

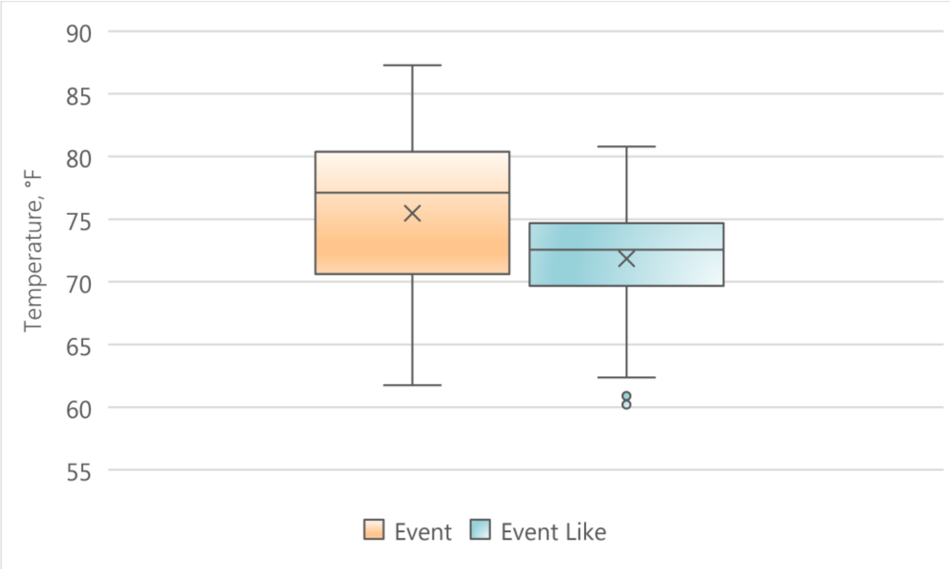


Figure 6-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

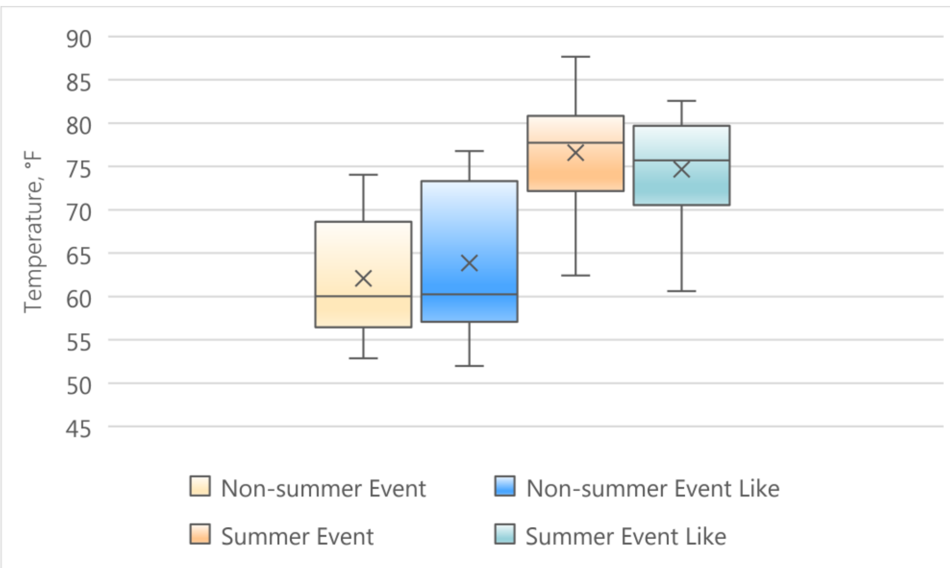
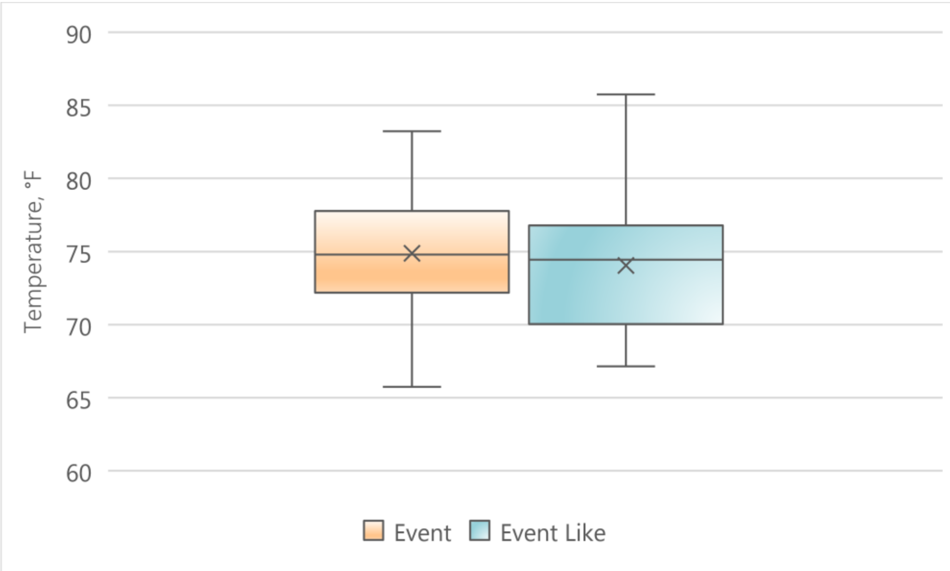


Figure 6-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



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:

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

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.

Table 6-1 presents the weighted average MAPE and MPE for the final set of per customer models for each utility, by product.[52,53] Across all three IOUs, programs, and products, all MAPE and MPE estimates are below 10%; in addition, they tend to be lower for the CBP programs across the board, with all MPE and MAPE values being less than 6%. All 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 6-1 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	0.2%	0.0%	1.1%	-0.2%
		DO	5.5%	-4.2%	4.6%	-2.8%
SCE	CBP	DA	2.0%	-1.8%	2.6%	-1.8%
		DO	2.2%	-1.8%	1.9%	-1.4%
	AMP	DO	9.2%	-8.0%	6.3%	-3.3%
SDG&E	CBP	DA	0.5%	-0.4%	0.2%	-7.9%
		DO	2.0%	-1.5%	1.3%	-0.7%

Figure 6-4 to Figure 6-7 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 6-4 PG&E Actual and Predicted Loads on Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

Figure 6-5 SCE Actual and Predicted Loads on Summer Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

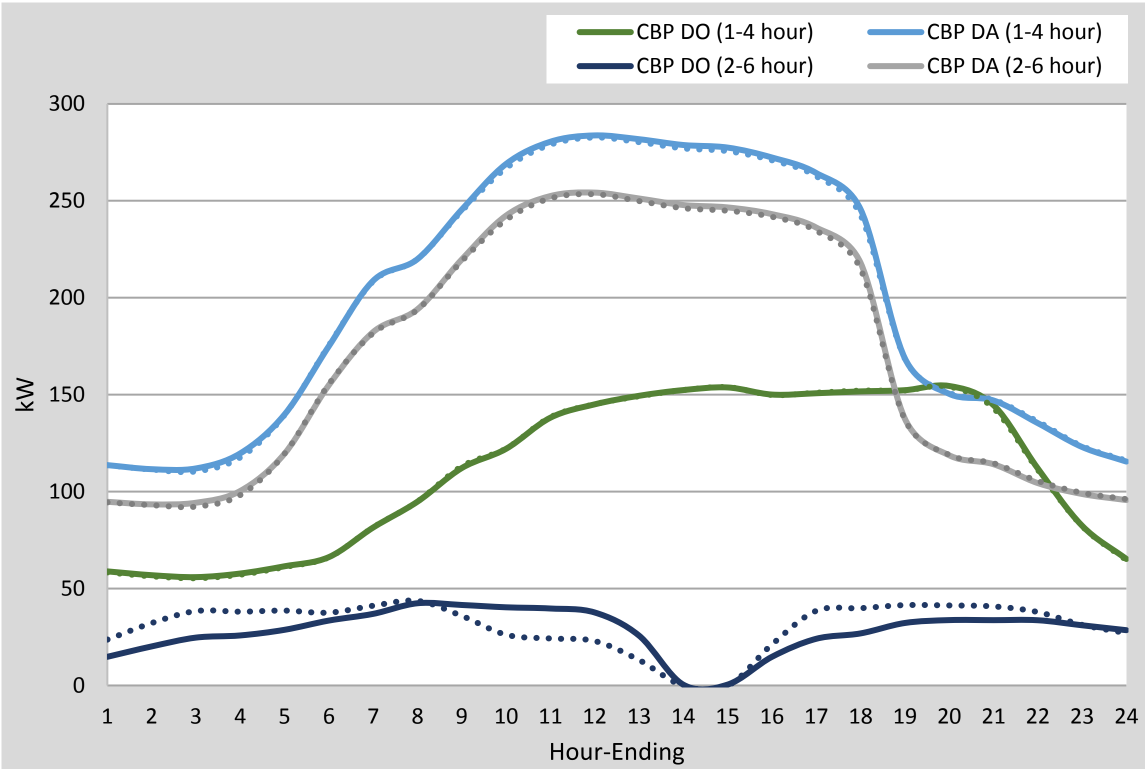
Figure 6-6 SCE Actual and Predicted Loads on Non-Summer Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

[52] 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.

[53] 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 6-7 SDG&E Actual and Predicted Loads on Event-Like Days



To address PG&E's concerns of modeling bias within the AutoDR and TA/TI customers, we perform a similar test for this group. Figure 6-8 and Figure 6-9 show the average event-like day predicted and actual loads from the out-of-sample tests for the AutoDR and TA/TI customers for CBP DO and CBP DA, respectively. Again, the predicted load is very close to the actual load, which tells us that, on average, the customer-specific regression models are performing well and do not show any indication of over- or under-predicting bias.

Figure 6-8 PG&E CBP DO: Actual and Predicted Loads on Event-Like Days (AutoDR & TA/TI Customers)

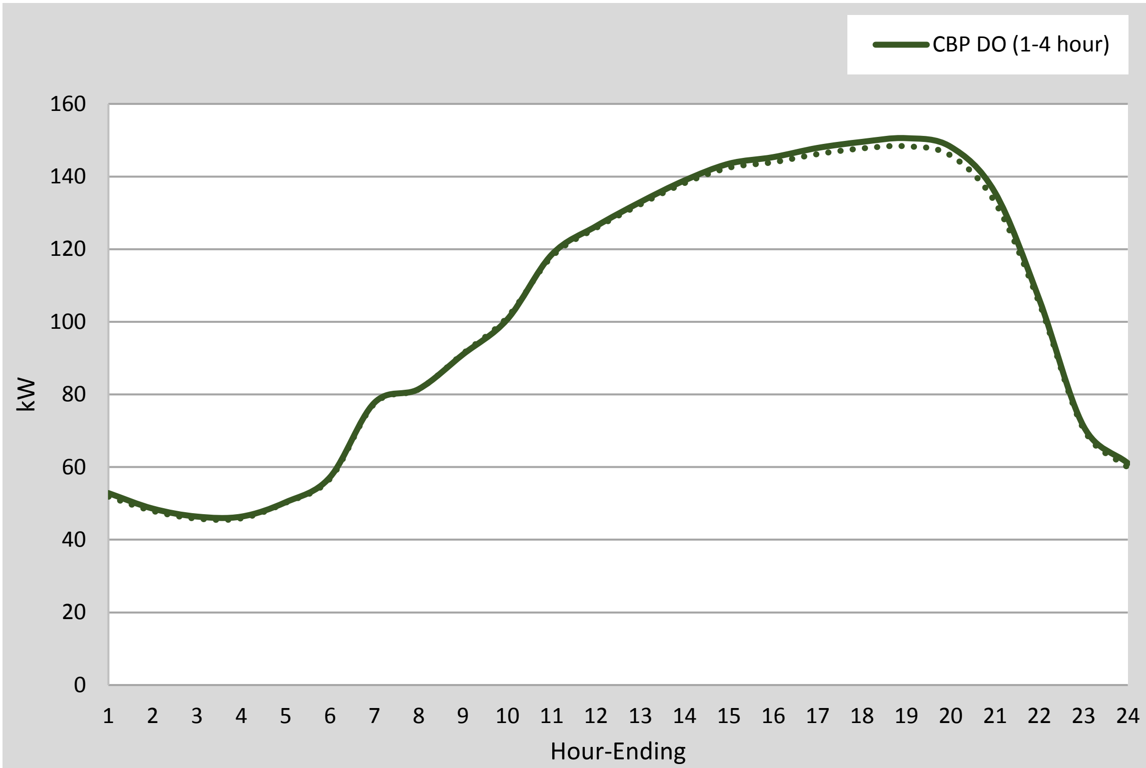


Figure 6-9 PG&E CBP DA: Actual and Predicted Loads on Event-Like Days (AutoDR & TA/TI Customers)

Figure redacted to protect customer or aggregator confidentiality.

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.

7

KEY FINDINGS AND RECOMMENDATIONS

Key Findings

Below we present key findings for each IOU.

PG&E

Figure 7-1 summarizes the average event-hour load impacts for PG&E's non-residential CBP DA and DO products. The figure includes the average event day ex-post impacts for 2012 through 2017 and the August peak ex-ante impacts projected for 2018 for CBP under the utility 1-in-2 weather condition. The blue-green bars are aggregate impacts (left y-axis) and the orange 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 ex-post 2016 and 2017 impacts for DA have been redacted to protect customer or aggregator confidentiality. The figure illustrates several key findings:

- CBP DA per-customer impacts projected for 2018 are lower than in previous years because of an expected change in the customer make-up as some former DO customers begin participating in DA. The aggregate impacts are higher in 2018 due to DO no longer being offered.
- CBP DO aggregate impacts increased in 2017 relative to 2016 because of greater enrollment; however, they are expected to drop to zero in 2018 since the DO product will not be offered.
- CBP DO percent impacts increased in 2017 compared with 2016.
- Historically, CBP DO has outperformed DA in aggregate impacts, but underperformed in per-customer impacts.
- Residential CBP is forecast to provide a meaningful amount of load impacts (4 MW) starting in 2019.

Figure 7-1 PG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2018

Figure redacted to protect customer or aggregator confidentiality.

SCE

Figure 7-2 and Figure 7-3 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 2017 (CBP and AMP) and the August peak ex-ante impacts projected for 2018 under the utility 1-in-2 weather condition (CBP only). The blue-green bars are aggregate impacts (left y-axis) and the orange 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. Some of the data has been redacted to protect customer or aggregator confidentiality. The figures illustrate several key findings:

- CBP DA aggregate and per-customer impacts were [redacted] in 2017 than 2016 and are expected to be [redacted] in 2018 due to an expected increase in enrollment.
- CBP DO aggregate impacts in 2017 were comparable to 2016, [redacted] in 2018 due to a much higher forecasted enrollment.
- As in past years, CBP DO is expected to outperform DA in aggregate impacts, but lower per-customer impacts are projected for DO than DA.
- AMP DO aggregate and per-customer impacts were [redacted] in 2017 than in 2016.
- 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 7-2 SCE CBP: Comparison of Average Event-Hour Load Impacts, 2012-2018

Figure redacted to protect customer or aggregator confidentiality.

Figure 7-3 SCE AMP: Comparison of Average Event-Hour Load Impacts, 2012-2018

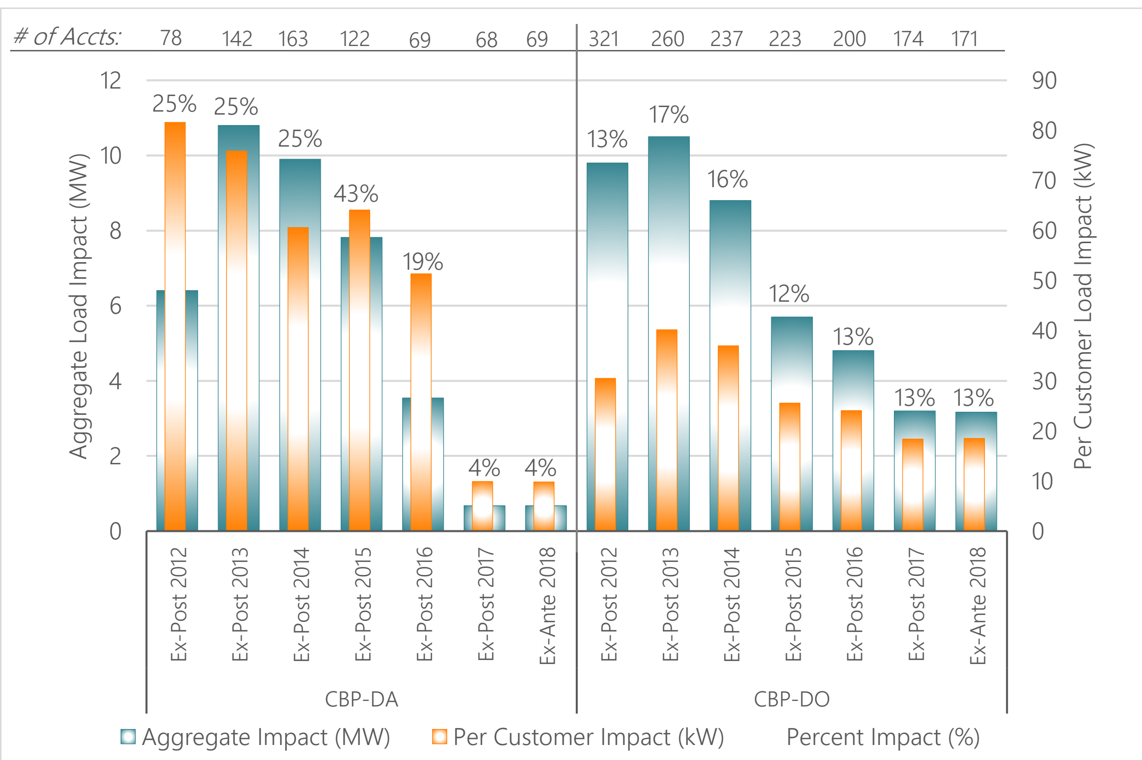
Figure redacted to protect customer or aggregator confidentiality.

SDG&E

Figure 7-4 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 2017 and the August peak ex-ante impacts projected for 2018 under the utility 1-in-2 weather condition. The blue-green bars are aggregate impacts (left y-axis) and the orange 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 per-customer and aggregate impacts fell in 2017 due to loss of one large account that had previously responded with a significant load impact. The 2018 impacts are expected to be comparable to 2017.
- CBP DO impacts in 2017 and projected for 2018 are lower than 2016 impacts due to lower enrollment and loss of some previously nominated customers that had larger-than-average per-customer impacts.
- CBP DO outperformed DA in per-customer and aggregate impacts in 2017 and is expected to do so again in 2018.

Figure 7-4 SDG&E CBP: Comparison of Average Event-Hour Load Impacts, 2012-2018



Recommendations

- In the next evaluation cycle, conduct analysis to estimate the ex-ante impacts for residential CBP customers for all IOUs.
- Further investigate the performance of AutoDR customers to determine the reasons for underperformance relative to load shed test results.

A

APPENDICES

PG&E CBP Ex-Post Table Generator

PG&E CBP Ex-Ante Table Generator (Non-Residential)

SCE CBP Ex-Post Table Generator

SCE CBP Ex-Ante Table Generator (Non-Residential)

SDG&E CBP Ex-Post Table Generator

SDG&E CBP Ex-Ante Table Generator

SCE AMP Ex-Post Table Generator (Note: entire file is redacted from public posting to protect customer or aggregator confidentiality)

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