San Diego Gas and Electrics 2022 Demand Response Executive Summary

Redacted (in black) – Public Version

April 1st, 2023

Contents

1. Background and Introduction

A) Background

San Diego Gas & Electric (SDG&E) presents this Executive Summary for its Demand Response (DR) activities for program year 2022 in accordance with (D.) 08-4-050. In Decision (D.) 08-04-050 the California Public Utility Commission (Commission) required the Investor-Owned Utilities (IOUs) - San Diego Gas & Electric Company (SDG&E), Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) to perform annual studies of their DR activities in accordance with the load impact protocols[1] and to file the load impact reports by April 1st each year. The original load impact protocols require the preparation of a voluminous number of tables that resulted in the load impact reports being too large to be filed in hard copy. On April 6th, 2009, the Investor Owned Utilities (IOUs) filed a petition to modify D.08-41-050. The petition asked for two things: 1) the removal of the requirement to file the load impact reports in their entirety and 2) to provide the reports to the energy division of the Commission. On April 8th, 2010, D.10-04-006 granted the utilities requests and added an Executive Summary requirement. The executive summaries were to include an overview of the evaluation findings, recommendations for changes to the demand response resource. Additionally, the executive summaries were to include brief descriptions of the methodology, the enrollment forecast, and the inputs and assumptions used for calculating both the ex-post and ex-ante load impact estimates. The IOUs should also report the regression model specifications for each demand response program.

In 2014 SDG&E was directed to include weather scenarios for load impacts that were coincident with the CAISO's system peak.[2]

In 2017 and 2018 Six CPUC decisions made changes that affected SDG&E's Demand Response Activities:

- TOU periods were changed in D.17-08-030
- 2018-2022 Demand Response programs were approved in D.17-12-003
- D.18-06-030 Adopting Local Capacity Obligations for 2019
- Default Residential TOU D.18-12-004 approved mass default for 2019
- D.17-01-006 and D.17-10-018 allowed Grandfathering for certain NEM customers

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[1] On April 24, 2008 D.08-04-050 adopted the protocols used in estimation of demand response load impacts.

[2] In October of 2014 SDG&E received a letter from the Director the CPUC's Energy Division. The letter informed the IOUs that they needed to include ex-ante forecasts that are to be used for RA should be with respect to the CAISO's system peak.

In August 2017 D.17-08-030 provided GRCP2 approval and directed SDG&E to file an advice letter by December 1, 2017 for implementation of time of use period changes for the 2018 calendar year. Since TOU period definitions changed for all SDG&E's existing TOU customers, the 2018 load Impact studies that estimated dynamic rate reductions also attempted to estimate load impacts associated with the change in TOU periods.

On January 17, 2017, SDG&E filed its 2018-2022 Demand Response Program Application. In this application SDG&E proposed several modifications to its existing DR programs and proposed two new DR pilots. Among those modifications were requests to improve the Capacity Bidding Program (CBP) by reducing the number of products offered and simplifying the program. On December 13, 2017, the CPUC issued D.17-12-003 that provided approval of SDG&E's DR program application and among other things directed the Permanent Load Shifting (PLS) program to be suspended after 2018. Additionally, SDG&E was directed to file Advice Letters for the modifications to its CBP program.

In June of 2018, the CPUC issued D.18-06-030 Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program. Ordering Paragraphs 13 and 14 address changes to the Resource Adequacy measurement hours. Specifically, they were modified from 1:00 pm to 6:00 pm to 4:00 pm to 9:00 pm (HE17-HE21) for each month of the year beginning in 2019. Additionally, combined storage and demand response projects became eligible to participate in the Resource Adequacy program.

In December of 2018 SDG&E received D.18-12-004 which allowed SDG&E to default all eligible residential customers onto TOU rates in 2019. About 800,000 of SDG&E's residential customers were transitioned to TOU rates by December 2019. However, 2020 would be the last year to try to identify shifts or load reductions due to the changed TOU and/or default TOU as over 100,000 small commercial and industrial customers have been placed onto TOU rates, and nearly 900,000 of SDG&E's residential customers have now embedded those TOU impacts/changes in their current loads and there were no control groups available. Additionally, Electric vehicle TOU rates were added to the load impact studies that SDG&E conducted in PY2019.

SDG&E grandfathered certain SDG&E residential and commercial customers per D.17-01-006 and D.17-10-018. Under these decisions those customers who TOU period definitions were allowed to use the old TOU rates "grandfathered" TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions for a specific period of time after new TOU Periods are implemented. Generally, these customers had to have opted into a TOU tariff prior to July 31, 2017 in order to preserve the “old” TOU time periods. Residential customers were grandfathered up to 5 years[3], and commercial customers up to 10 years.

Due to the Covid-19 pandemic in 2020, SDG&E observed about a 5-8% reduction in its commercial and industrial reference loads in mid-March 2020, and an opposite 10-12% increase to its residential reference loads. SDG&E made assumptions for the forecasting of the 2020 load impacts that were affected by Covid-19.[4] The August and September months of 2020 were extremely warm in southern California and the extreme conditions led to rolling blackouts on August 14th.

The Covid-19 pandemic continued into 2021, although many people were still sheltering at home or on a modified work and school schedules, energy usage patterns tended to revert back to a new “normal”. Prior to the summer of 2021, because of the extreme weather conditions and rolling blackouts that occurred in 2020, the State of California developed two emergency DR programs developed: the Emergency Load Reduction Program (ELRP) and the California State Emergency Program (CSEP). These new emergency programs would offset the need for any further rolling blackouts in 2021. Both programs were up and available during 2021, and combined with the mild summer weather, California was able avoid rolling blackouts.

In February of 2021, the CPUC’s Energy Division (ED) issued a Load Impact Protocol Guidance Document.[5] The purpose of the document was to establish consistent due dates for IOU’s and 3rd parties with a schedule for filing the LIP reports. It also called attention to Qualified Capacity (QC) update for market-integrated DR resources up to two times a year to reflect significant changes in customer enrollments during the Resource Adequacy (RA) compliance year per D.20-06-031. Amount other things, the Guide provided that updates to QC are warranted if changes varied by more than 20% or 10MWs. The Guide also provided “Best Practices” for Load Impact Protocol Filings.

In 2022, all ex-ante load impact summaries are averaged over the current Resource Adequacy (RA) hours of 4 pm to 9 pm for all programs and/or dynamic rates. Starting in 2023, the RA AAH will be updated for March and April to be 5pm – 10pm (HE18 – HE22). The remaining months are 4pm – 9pm (HE17 – HE21).[6]

In August 2022, D.22-08-039 said it was reasonable to use the existing LIP methodology to establish RA for 2023. However, the CPUC recognized that LSEs would need further guidance on how to utilize the LIP outputs under the new RA 24-hour slice framework, and parties were directed to submit proposals in Workstream 2 of

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[3] Grandfathering for residential customers ended on July 31st, 2022
[4] The assumptions used were included in Section 4: Methodology is available in SDG&E’s 2020 Demand Response Executive Summary.
[5] Guided to CPUC’s Load Impact Protocol Process, Feb 10th, 2021, page 3, 5-6
[6] D22-06-050, OP5

R.21-10-002.11.[7] A decision refining the test year framework is expected in Q1, 2023 and may have implications for Filing Year 2023.[8]

B) Introduction

This Executive Summary provides all relevant information regarding the load impact evaluations as prescribed in D10-04-006. Included are program descriptions, program options, ex-post load impact methodology, program year 2022 event results, ex-ante forecasts, methodology and ex-ante load impacts. Much of the information presented in the executive summary are excerpts taken directly from the individual load impact reports. The following reports are included in this executive summary.

A) Statewide DR Programs

1. 2022 Statewide Load Impact Evaluation of California's Capacity Bidding Programs, Ex-post and Ex-ante Impacts, Applied Energy Group, April 1st, 2023.
2. 2022 Statewide Load Impact Evaluation of California's Critical Peak Pricing Programs, Ex-post and Ex-ante Impacts, Christensen Associates, April 1st, 2023.
3. 2022 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report, Christensen Associates, April 1st, 2023.

B) SDG&E DR Programs

1. 2022 Load Impact Evaluation of San Diego Gas and Electric's AC Saver Day Of Program, Resource Innovations[9], April 1st, 2023.
2. 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2023.
3. 2022 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Time-of-Use rates and Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2023.
4. 2022 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates, Christensen Associates, April 1st, 2023.

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[7] D.22-08-039, OP 2-3, at 15
[8] Guide to CPUC's Load Impact Protocols (LIP) Process Version 3.0, January 6, 2023
[9] Nexant is the original consultant that SDG&E contracted with, and during the contract, Nexant started doing business as Resource Innovations.

5. 2022 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates, Demand Side Analytics LLC, April 1st, 2023.

C) SDG&E DR Pilots

1. 2022 Load Impact Evaluation for San Diego Gas and Electric's Non-Residential ELRP
2. 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential ELRP
3. 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential CBP

This Executive Summary report provides the results from SDG&E's Demand Response activities and is organized in the following way:

Supply Side Resources

Emergency Programs:

Base Interruptible Program (BIP)

Aggregator Programs:

Capacity Bidding Program (CBP)

Price Responsive Programs:

AC Saver Day Of Residential and Commercial

AC Saver Day Ahead Residential

AC Saver Day Ahead Commercial

Load Modifying Rates/Programs

Price Responsive Programs:

Critical Peak Pricing Default (CPP-D)

Default Small Commercial CPP and TOU

Voluntary Residential CPP and TOU

Electric Vehicle Time of Use

DR Pilots

Non-Residential ELRP (A.1., A.2., A.3, A.4, B.2 subgroups)

Residential ELRP

Residential CBP

SDG&E presents its public version of the Program Year 2022 ex-post and ex-ante estimates. Tables that contain confidential information are "blacked out". The totals in the tables reflect public information only.

Table 2-1 presents the Program Year (PY) 2022 ex-post estimates for the average event day Load Impact in MWs across all SDG&E DR Programs events. The table presents the ex-post estimates by DR category – Supply Side or Load Modifying and are statistically significant unless otherwise noted. Supply Side resources are bid into the CAISO market during the event season which typically runs from April 1st through October 31st. Dynamic and time of use rates are Load Modifying resources. In 2022 SDG&E's system peaked 4,816 MW on September 7th, 2022, at 5:23pm. However, CAISO hit its all-time peak on September 6th, 2022 at 4:57pm. with 52,061 MWs and no rolling blackouts. SDG&E can trigger a CPP Event if the day-ahead system load forecast for the potential event day is greater than 4,000 MW.

Table 2-1: Program Year (PY) 2022 Ex-post estimates for DR Programs

Program Type and Name	Customers on Average Event Day	Event Window Average Event Day HE [a]	Average Event Day Load Impact (MW)
Supply Side Demand Response	**28,209**		**11.96**
BIP	0	-	0
AC Saver Day Ahead Residential[g]	17,528	HE19-HE20	8.65
AC Saver Day Ahead Commercial (including Quasi-Residential)	-	HE19-HE20	-
AC Saver Day Of Commercial	2,377	HE19-HE20	0.23
AC Saver Day Of Residential	8,241	HE19-HE20	1.68
CBP DA (Product 11am-7pm)	0	-	0
CBP DA (Product 1pm-9pm)	0	-	0
CBP DA Elect $200 (Including products 1pm-9pm)	0	-	0
CBP DA Elect $400 (Including products 1pm-9pm)	0	-	0
CBP DA Elect $600 (Including products 1pm-9pm)	[redacted]		
CBP DO (Product 11am-7pm)	0	-	0
CBP DO (Product 1pm-9pm)	0	-	0
CBP DO Elect $200 (Product 1pm-9pm)	0	-	0
CBP DO Elect $400 (Product 1pm-9pm)	63	HE19	1.40
CBP DO Elect $600 (Product 1pm-9pm)	0	-	0
Load Modifying	**123,574**		**8.95**
CPPD Large (Excluding TD)	533	HE17-HE21	2.49
CPPD Medium (Excluding TD)	4,324	HE17-HE21	-3.22
Default Small Commercial TOU and CPP Rates (Excluding TD)[f]	44,306	HE17-HE21	0.75
Small Agricultural CPP[f]	56	HE17-HE21	0.65
EVTOU2 (Including NEM plus Non-NEM) [bc]	8,081	HE17-HE21	3.76
EVTOU5 (Including NEM plus Non-NEM [bc]	22,504	HE17-HE21	5.71
Technology Deployment (TD) on Small Commercial CPP plus CPP (Large and Medium)[f]	215	HE17-HE21	0.15
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU[f]	668	HE17-HE21	0.10
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU[f]	42,887	HE17-HE21	4.27
Total	**151,783**		**20.91**

a HE means hour ending

b The load impacts for EVTOU2 (Including NEM plus Non-NEM), EVTOU5 (Including NEM plus Non-NEM), energy reported is the average consumption over the RA window for the August average weekday.

c The customer counts are based on 2022 ex-ante 1-in-2 weather August system peak

f In 2022, there were five CPP Events. The customer counts are based on 2022 ex-post combined TOU and CPP Load Impact -Typical Weekday Event

g In 2022, 7 out of 12 ACSDA Res events took place during the period HE19-HE20

Table 2-2 presents the Program Year (PY) 2022 ex-post estimates for the average event day Load Impact in MWs across all SDG&E DR Pilot events.

Table 2-2: Program Year (PY) 2022 Ex-post estimates for DR Pilots

Program Type and Name	Customers on Average Event Day	Event Window Average Event Day HE [a]	Average Event Day Load Impact (MW)
Residential ELRP	525,382	HE17-HE21	11.91
Residential CBP[a]	99	HE19-HE21	-0.03[a]
Non-Residential A.1 ELRP	412	HE17-HE21	36.45[b]
Non-Residential A.2 ELRP	17	HE17-HE21	-0.01
Non-Residential A.3 ELRP	[redacted]	[redacted]	[redacted]
Non-Residential A.5 ELRP	[redacted]	[redacted]	[redacted]
Non-Residential B.2 ELRP	[redacted]	[redacted]	[redacted]
Total Residential and Non-Residential	**525,910**		**48.35**

a The average event day load impact is based on delivered load. Nearly all sites (98%) also had PV collocated with their storage systems and 17% of sites were also on EV rates. Reductions were not statistically significant for the average weekday event. Early dispatch challenges / increased load impact over season.

b The average event day load impact is based on 4pm-9pm event window. Three of the nine events were triggered from 4pm-9pm event window.

In 2022, all ex-ante load impact summaries are averaged over the current Resource Adequacy (RA) hours of 4 pm to 9 pm for all programs and/or dynamic rates. Starting in 2023, the RA AAH will be updated for March and April to be 5pm – 10pm (HE18 – HE22). The remaining months are 4pm – 9pm (HE17 – HE21).[10]

SDG&E updated SDG&E and CAISO weather scenarios in 2022 due to long-term warming trend. SDG&E and CAISO weather scenarios are an input for the PY22 Ex-ante estimates.

It should also be noted that ex-post weather conditions are typically not the same as the 1-in-2, or 1-in-10 weather scenarios used in the ex-ante tables. In other words, the actual weather conditions when DR activities are called can be different than a 1-in-2 or 1-in-10 conditions. For example, an event could be called on a 1 in 4 peak weather condition or even during much cooler weather than a 1-in-2 peak condition. It is for these reasons that the ex-post load impact estimates don't always align with the ex-ante forecasts required in this submittal.

Located in Appendix A are the model specifications for each of the studies, ex-post, and ex-ante. The ex-ante tables located in Appendix B[11] contain both SDG&E and CAISO load impacts. Appendix B is a separate document provided in pdf and excel formats. The ex-ante tables include the following:

[10] D22-06-050, OP5

[11] File names are: AppendixB.TablesforExecutiveSummary_formatted_Mar312022.pdf and AppendixB.TablesforExecutiveSummary_formatted_Mar312022.xls

- 1-in-2 weather scenario for individual programs
- 1-in-2 weather scenario for the portfolio,
- 1-in-10 weather scenario for individual programs, and
- 1-in-10 weather scenario for the portfolio

Table 2-3 presents SDG&E's 2022 ex-ante estimates for all DR Activities: DR Programs, Dynamic and TOU rates. The MW load impacts are for SDG&E 1-in-2 weather conditions for September 2023. SDG&E's AC Saver Day Ahead Program is expected to contribute about 4 MWs of load reduction in August 2023. SDG&E's AC Saver Day Of program continues to decline in enrollment as it is not being marketed.

Residential Default TOU studies were conducted for 2018, 2019 and 2020. The challenge of not having a residential control group was supposed to be the major obstacle in the 2020 study – as SDG&E had withheld customers to be used as controls in the 2018 and 2019 load impact studies. However, 2020 presented larger challenges due to effects on customer usage because of Covid-19 stay at home orders and two significant heat storms during the summer when many residential customers were confined to their homes. As a result, the 2020 Residential Default TOU study did not yield statistically significant load reductions. Although the Covid-19 pandemic continued during 2021, customers began to get back to "normal" activities. Therefore, SDG&E did not conduct a Default Residential TOU load impact evaluation starting in PY2021. In 2022 the first phase of default TOU customers have been on TOU rates for 5 years, and the 2nd phase of default TOU customers have been on the rate for 4 years.

Load impact evaluations for Electric Vehicle (EV) time of use studies have been conducted for four years PY2019-PY2022 and SDG&E continues to evaluate three of the residential EV time of use rates. EV growth continues to be significant in SDG&E's service territory, and the load impacts attributed to non-event EV time of use rates is expected to be over 21 MWs for the September peak day in 2023.

Table 2-3 presents the Program Year (PY) 2022 ex-ante estimates for September 2023 Load Impact in MWs across all SDG&E DR Programs.

Table 2-3: Program Year (PY) 2022 Portfolio Ex-ante estimates* for all DR Programs based on 1-in-2 September SDG&E weather scenarios for the year of 2023.

Program Type and Name	Forecasted Customers in September 2023	Ex-ante estimates for the month of September 2023 (MW) over the RA hours [a]
Supply Side Demand Response	**32,130**	**8.67**
BIP	[redacted]	[redacted]
AC Saver Day Ahead Commercial (including Quasi-Residential)	374	0.31
AC Saver Day Ahead Residential	22,473	4.93
AC Saver Day Of Commercial	2,160	0.18
AC Saver Day Of Residential	7,001	1.75
CBP DA (Product 11am-7pm)	0	0
CBP DA (Product 1pm-9pm)	0	0
CBP DA Elect $200 (Including products 1pm-9pm)	0	0
CBP DA Elect $400 (Including products 1pm-9pm)	48	0.2
CBP DA Elect $600 (Including products 1pm-9pm)	[redacted]	[redacted]
CBP DO (Product 11am-7pm)	0	0
CBP DO (Product 1pm-9pm)	0	0
CBP DO Elect $200 (Product 1pm-9pm)	[redacted]	[redacted]
CBP DO Elect $400 (Product 1pm-9pm)	73	1.2
CBP DO Elect $600 (Product 1pm-9pm)	[redacted]	[redacted]
Load Modifying Demand Response	**134,384**	**31.00**
CPPD Large (Excluding TD)	457	2.35
CPPD Medium (Excluding TD)	2,265	0.01
Default Small Agricultural TOU and CPP Rates (Excluding TD)	57	1.09
Default Small Commercial TOU and CPP Rates (Excluding TD)	44,068	3.69
EVTOU2 (Including NEM plus Non-NEM) [b]	11,743	8.69
EVTOU5 (Including NEM plus Non-NEM) [b]	41,516	12.61
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	243	0.05
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	625	0.32
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH plus TOU	33,410	2.19
Total	**166,514**	**39.67**

[a] Ex-ante estimates are for the month of September as that was the 2022 peak day month from 2022.
[b] EVTOU are non-event estimates and correspond to September Peak Day

Table 2-4: Program Year (PY) 2022 Portfolio Ex-ante estimates* for all DR Pilots based on 1-in-2 September SDG&E weather scenarios for the year of 2023.

Program Type and Name	Forecasted Customers in September 2023	Ex-ante estimates for the month of September 2023 (MW) over the RA hours [a]
Non-Residential A.1 ELRP	485	29.01
Non-Residential A.2 ELRP	17	0.04
Non-Residential A.3 ELRP	[redacted]	[redacted]
Non-Residential A.4 ELRP	1,298	2.54
Non-Residential A.5 ELRP	[redacted]	[redacted]
Non-Residential B.2 ELRP	[redacted]	[redacted]
Residential ELRP	542,446	13.28
Residential CBP	1,134	0.79

[a] Ex-ante estimates are for the month of September as that was the 2022 peak day month from 2022.

2. Program Descriptions

3.1 Supply Side Demand Response

3.1.1 Emergency Programs

3.1.1.1 Base Interruptible Program

The Base Interruptible Program (BIP) is an emergency DR program intended to provide load reduction on a “day-of” basis when the CAISO issues a notice that loads should be curtailed on the same day because of a statewide emergency (e.g., a shortage of electricity). SDG&E can also call a BIP event when extreme temperature conditions are impacting system demand. If SDG&E does not foresee a CAISO statewide emergency each year, it will call a yearly test event on what it believes will be the highest load day of the year. BIP is a statewide program, offered by PG&E and SCE as well, with minor differences in the tariffs across the three IOUs.

BIP offers a monthly bill credit as a capacity payment to customers or aggregators that can commit to curtail 15% of their Monthly Average Peak Demand, calculated by the customer’s energy usage during the hours from 4 pm – 9 pm The Committed Load is the difference of the Monthly Average Peak Demand minus the contracted Firm Service Level (FSL). The capacity payment is a monthly flat rate of $6.30 per kW of Committed Load. BIP was designed to be an emergency program where large customers (and aggregators who can mimic large customers) are able to shed large amounts of load on short notice (no less than 20 minutes) of a load shed event. It is available to be called year-round, not to exceed four (4) hours for any calendar day, or 10 Interruption Periods per calendar month, or 120 hours during any calendar year. Customers are given at least 20-minute notice and must curtail their load down to their contracted Firm Service Level (their FSL) when events are initiated. Otherwise, customers will pay an excess energy charge of $4.50 kWh for every 15-minute interval during the event period for any usage in excess of their contracted FSL. The program's tariff with full details can be found at SDG&E's website.[12]

Participation in SDG&E's program has historically been low, consistent with the California Public Utilities Commission ("Commission" or "CPUC") direction to focus marketing efforts on price responsive programs. There were no participants in 2022, SDG&E is forecasting 1 new BIP participant for 2023 with a very modest load impact.

3.1.2 Aggregator Programs

3.1.2.1 Capacity Bidding Program (CBP)

CBP is a statewide price-responsive program launched in 2007. The Capacity Bidding Program (CBP) is a supply side DR program that provides incentives to aggregators to sign up commercial customers who commit to shed load when triggered. CBP is a seasonal DR program that is available on non-holiday weekdays each year from May 1 to October 31. The program is open to bundled, Direct Access (DA) customers and Community Choice Aggregation ("CCA") customers. SDG&E has six CBP products: three Day-Ahead and three Day-Of products as shown in Table 3-1. SDG&E implemented two new Elect Products: Elect DA 1-9 Hour and Elect DO 1-9 Hour, each with three price trigger options: $200/MWh, $400/MWh, $600/MWh. CBP events can only be called during the products' hours, which are between 11 am – 7pm and 1 pm – 9 pm The aggregator selects a product to nominate their customer(s) into.

The Utility may call an event whenever the day-ahead market price is equal to or greater than the product price trigger or as utility system conditions warrant. The day-ahead market price is defined as CAISO DLAP or applicable pnode SDG&E-APND day-ahead market locational marginal price (DAM LMP). SDG&E may call an event whenever the forecasted real-time price is equal to or greater than the product price trigger or as utility system conditions warrant. The Real-time price is defined as the CAISO DLAP or applicable pnode SDG&E-APND average hourly real-time market locational marginal price (LMP). A summary of the price triggers is shown below in Table 3-2.

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[12] https://tariff.SDG&E.com/tm2/pdf/tariffs/ELEC_ELEC-SCHEDS_BIP.pdf

CBP has its own tariff, Schedule CBP.[13] Customers on the CBP tariffs offered by the IOUs are also eligible to participate in Technology Incentives (TI) and Automated Demand Response (AutoDR) programs but currently there are no TI customers enrolled.

Table 3-1: Summary of the Capacity Bidding Program (CBP) for Elect and Non-Elect Products

Day-Ahead Products	Hours	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration Per Operational Month	Maximum Events Per Day	Maximum Events Per Month
2 to 4 hours	11am to 7pm	2 hours	4 hours	24	1	6
2 to 4 hours	1pm to 9pm	2 hours	4 hours	24	1	6
Day-Of Products	**Hours**	**Minimum Duration per Event**	**Maximum Duration per Event**	**Maximum Cumulative Event Duration Per Operational Month**	**Maximum Events Per Day**	**Maximum Events Per Month**
2 to 4 hours	11am to 7pm	2 hours	4 hours	24	1	6
2 to 4 hours	11am to 9pm	2 hours	4 hours	24	1	6

Table 3-2: Summary of the Capacity Bidding Program (CBP) Price Triggers

Program	Product	Operating Hours	Price Trigger
Non-Res DA	Presc DA 11-7 Hour	11 AM–7 PM	$90/MWh
	Presc DA 1-9 Hour	1 PM–9 PM	$90/MWh
	Elect DA 1-9 Hour	1 PM–9 PM	$200/MWh, $400/MWh, $600/MWh
Non-Res DO	Presc DO 11-7 Hour	11 AM–7 PM	$115/MWh
	Presc DO 1-9 Hour	1 PM–9 PM	$125/MWh
	Elect DO 1-9 Hour	1 PM–9 PM	$200/MWh, $400/MWh, $600/MWh

3.1.3 Price Response Programs

3.1.3.1 AC Saver Program

AC Saver is a supply side DR program available to all qualifying customers with air conditioning (AC) units with SDG&E-approved and installed technology capable of curtailing the customer's AC use. AC Saver offers two products to customers to choose from. Those products are: (1) "Day-Ahead", meaning the customer is typically notified the day before the event based on a forecasted grid need; and (2) "Day-Of" which refers to the fact the customer is notified to drop load on the same day the load is needed.

[13] http://regarchive.SDG&E.com/tm2/ssi/inc_elec_rates_misc.html

Apart from the types of products, there are different types of technologies used to signal to customers that load must be dropped. The types of technologies that the program currently uses are direct load control switches and thermostats. Events last between two and four hours and may be called between April and October. Residential net energy metering (NEM) customers with self-generation (usually solar) installed at the premise are not eligible for the program.

Customers with direct load control switches participate in the AC Saver Day-Of product.[14] Within the Day-Of product there are two options available to residential customers: (1) a 50% cycling option, meaning that the customer's air conditioning run-time is reduced by 50%; and (2) a 100% cycling option where the AC is turned off for the entire duration of the event. Commercial customers may choose between a 30% cycling and a 50% cycling option. Customers enrolled on the Day-Of option are not permitted to override individual events. Customers receive an annual capacity payment based on the size of their air-conditioner and the cycling option that they choose.

Customers with Honeywell, Nest or Ecobee thermostats participate in the AC Saver Day-Ahead product. For customers enrolled on AC Saver Day-Ahead, the vendor either increases the customer's thermostat's setpoint by 4-degrees Fahrenheit or uses some other comparable strategy. Customers may override individual events. Starting in 2022, customers whose thermostats were disconnected from the internet (and therefore non-responsive to dispatched events) for one year or more have been unenrolled from the program. Residential customers receive an annual capacity payment of $20.

The program is usually activated when SDG&E bids in and then receives an award from the CAISO market. SDG&E bids the program into the CAISO market daily using an energy price based on the tariff-specified heat rate.

3.2 Load Modifying Demand Response

3.2.1 Pricing Programs (Critical Peak Pricing Rates)

3.2.1.1 Critical Peak Pricing – Default (CPP-D)

CPP is a statewide price responsive rate that qualifies as load modifying demand response. California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when an event is called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers benefit financially

[14] "Day-Of" refers to programs in which customers are notified the day of an event, formerly known as Summer Saver.

from the longer periods of the lower rates for electricity consumed outside of the CPP periods. Customers newly enrolled on the program may also be eligible for bill protection for an initial period, such as 12 months, so that their energy costs on CPP do not exceed their pre-CPP costs while they learn how to respond. SDG&E has implemented CPP as the default rate for its medium and large nonresidential customers since 2008.

All CPP tariffs are designed for bundled service customers.[15] Like CBP customers, customers on SDG&E's CPP tariffs are also eligible to participate in Technology Incentives (TI) which includes Automated Demand Response (AutoDR) programs. SDG&E's Technology Incentives Program offers incentives for the purchase and installation of qualified automated demand-response measures that provide verified, dispatchable, on-peak load reduction at customer-owned facilities. Eligible customers can receive up to $200 per kilowatt (kW) of verified, dispatchable, fully automated on-peak load reduction. The total incentive is limited to 75% of the total project cost.[16]

SDG&E started defaulting its large commercial and industrial customers onto CPP rates in 2008. SDG&E's CPP rate is year-round, customers are notified the day before by 2 pm and can be triggered up to 18 CPP days a year. In 2022 SDG&E changed its CPP period from 2 pm- 6 pm to 4 pm - 9 pm per D.21-03-056.[17] There were five CPP events called in 2022. All five events took place during a heat wave in September which spanned the Labor Day weekend.

3.2.1.2 Default Small Commercial Critical Peak Pricing and Time of Use

This dynamic rate is similar to SDG&E's Large and Medium CPP rates with a major distinction, SDG&E's small commercial and industrial customers do not have demand charges, therefore there are no demand components. Between November 2015 and April 2016, SDG&E transitioned over 120,000 small business customers onto time of use rates with a critical peak component (CPP-TOU). While customers were defaulted onto TOU-CPP rates, they could elect to opt-out to a time-of-use (TOU) rate and approximately 5% of them did. In tandem, SDG&E also transitioned small agricultural customers from flat rates onto time of use rates and offered a CPP-TOU rate on a voluntary (opt-in) basis. By April 2016, electricity rates without a time varying component were no longer available for small commercial and agricultural customers. In the years leading up to and after the rate transition, SDG&E offered customers smart thermostats, free of charge, to help them

15 CPP rates are commodity rates and are not available to customers that are Direct Access or Community Choice Aggregator customers.

[16] The TI program requires customers receiving incentives to enroll in a qualified DR program for 3 years after installation. Qualifying programs for TI enrollment are the Capacity Bidding Program (CBP), Critical Peak Pricing (CPP) or other eligible pilots such as DRAM.

[17] D.21-03-056, p 16 and Conclusion of Law #3, Attachment 1.

manage their energy bills and automate response to critical peak prices. In subsequent years, the portion of non-residential sites opting out of CPP-TOU rates onto TOU only rates continued to be in the low single digits and about 112,000 small commercial customers were on CPP-TOU rates at the end of 2020. However, in the spring of 2021, all commercial sites in the City of San Diego were defaulted onto a Community Choice Aggregation (CCA) energy supply option which precludes staying on SDG&E CPP-TOU rates.[18]

3.2.1.3 Voluntary Residential Critical Peak Pricing (CPP) and Time of Use (TOU)

SDG&E's voluntary residential CPP is considered a dynamic rate with an underlying TOU rate structure. Similar to the commercial and industrial CPP rates, these "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers benefit financially from the longer periods of the lower rates for electricity consumed outside of the CPP periods. The (non-grandfathered) TOU and CPP rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both rates are voluntary and became active in February 2015.

As of August 1st 2022, the TOU periods for all residential customers are centered around an on-peak period of 4 pm to 9 pm on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 4 pm to 9 pm period on any day (including weekends) throughout the year. Starting June 1st 2022, the CPP event window coincided with the RA window of 4 pm to 9 pm

For residential Grandfathered customers, the summer TOU on-peak period is 11 am to 6 pm on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 pm to 8 pm, with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. There were approximately 380 customers on the grandfathering TOU periods, that expired on July 31, 2022.

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[18] SDG&E's CPP rate is a commodity rate. Therefore, if a customer is defaulted onto a Community Choice Aggregator (CCA) they will be receiving their commodity rate from the CCA.

3.3.1 Nonevent based programs

3.3.1.1 Electric Vehicle Time of Use 2 (EVTOU2) and Electric Vehicle Time of Use 5 (EVTOU5) and Vehicle to Grid Integration (VGI)

SDG&E has three residential TOU rates for electric vehicles. Nearly all new enrollments are on the EVTOU5 rate. All the rates include a peak period from 4 pm - 9 pm, super off-peak rates from 12 am - 6 am, and off-peak rates in all other hours. The main differences are in the super off-peak rates, the monthly billing fee, and rates during weekends. Overall, the EVTOU5 rate has a lower super off-peak price, a higher monthly fixed charge, and the same rates for weekdays and weekends.

The Power Your Drive Pilot Vehicle Grid Integration Rate (VGI) was designed to reduce greenhouse gas ("GHG") and criteria pollutants emissions, increase adoption of electrical vehicles ("EVs"), and integrate EV charging with the electric grid through a day-ahead hourly electric rate. The Commission authorized SDG&E to install Level 2 charging stations through the Pilot at workplaces and multi-unit dwellings ("MUDs") such as apartments and condominiums. SDG&E installed, owns, and maintains 3,118 charging ports at 254 locations. A total of 35% of the chargers are located in multi-family dwellings, and 36% of sites are located in disadvantaged communities. The pilot offers a unique Rate-to-Driver billing option where drivers' charging costs appear directly on their SDG&E bill. It also relies on a unique dynamic rate, which consists of five main components. These components are day-ahead hourly market prices, a delivery component, a system adder that targets the top 150 system load hours, a circuit adder that targets the top 200 load hours of the distribution circuit and an excess supply adder.

3.4.1 Pilots

3.4.1.1 Non-Residential ELRP

The Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participants. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency load reduction resources beyond those available in CAISO capacity markets and utility specific emergency resources such as Critical Peak Pricing. ELRP. As its name implies, ELRP is an out of market emergency resource. It includes multiple subgroups (Groups A.1, A.2, A.3, A.4, A.5 for customers and aggregators not participating in Demand Response, and Groups B.1 and B.2 for demand response providers) designed for both large commercial and industrial customers and aggregators of residential and non-residential resources including battery storage and other behind the meter dispatchable generation. There is also a residential subgroup (A.6) which has been evaluated separately and is not the focus of this report. All ELRP groups remunerate participant performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, the eligibility, targeting, and rollout of the each subgroup are entirely different.

3.4.1.2 Residential ELRP

The Residential Emergency Load Reduction Program (ELRP) pilot is a behavioral demand response program with direct settlements and performance payments to participants. The pilot was rolled out in May of 2022 upon direction by the Commission to capture residential emergency load reduction resources and is currently planned to operate from 2022 through 2025. The Residential ELRP pilot, like other ELRP pilot programs, renumerate participant performance via a $2/kWh payment, determined using baseline settlement rules specific to each pilot program. Residential ELRP is currently marketed to SDG&E residential customers as the Power Saver Rewards Program.

Participants in the Residential ELRP pilot either opted in or were defaulted onto the program across three basic eligibility groups. Customers receiving Behavioral Demand Response (BDR) treatment, as well as those on CARE or FERA rates, were defaulted onto Residential ELRP on May 1, 2022. Over 550,000 customers were defaulted into Residential ELRP. Approximately 4,000 residential customers opted into the pilot program. All Residential ELRP pilot participants were subject to the following eligibility criteria:

- The customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party DRP, or CCA;
- The customer is not served by a CCA which has elected to exclude its customers from participation in ELRP; and
- The customer must have hourly meter data.

No CCAs have yet elected to exclude their customers from Residential ELRP, so SDG&E's PY 2022 evaluation includes CCA customers. The Residential ELRP pilot had a large number of participants. As of August 2022, there were a total of 540,636 program participants. Of these, more than 99% were BDR or CARE/FERA participants.

3.4.1.3 Residential CBP

The Residential Capacity Bidding Program is a pilot rolled out in PY2021 to facilitate residential participation in a similar program to SDG&E's commercial Capacity Bidding Program. As with commercial CBP the Residential CBP is a capacity-based market program which compensates participants for monthly capacity nominations plus energy-based performance payments at market based rates established in the CBP tariff. The goal of Residential CBP is to enable aggregators of residential customers with dispatchable resources to bid their resources into a capacity market in a similar manner.

Program participation is open to aggregators of dispatchable residential resources. In PY 2021 and PY 2022 one residential battery storage aggregator enrolled. Swell enrolled 10 residential sites in PY 2021 and 99 residential sites in PY 2022. In PY 2022 enrolled sites had one to three 5-kW Tesla Powerwall battery systems per site and the average site had 6.96 kW of interconnected battery storage.

PY2022 was the second year of the residential pilot and thus the pilot's cost-effectiveness, load reduction capability, and feasibility as a full-scale residential program are still being assessed. In order to assess the pilot's load reduction capability under varying weather conditions and hours, ten events were called for differing evening hours (anywhere from 4 to 9 pm) and on differing days of the week. During the events, Swell dispatched the energy storage resources of the 99 enrolled sites. PY2021 saw delivered load per site being dropped to 0 kW upon dispatch of the storage resources, but due to dispatch issues, PY2022 events on average did not see significant load reductions at the site level or in aggregate.

4. Methodology

A summary of ex-post and ex-ante methods are provided in Table 4-1. Each DR activity uses its unique method to analyze results. Ex-post methods are used to calculate reductions for actual demand response events. Many factors go into each result such as weather conditions, day of the week, season, whether the customer received notification, number of participants, and connected versus disconnected devices for technology deployment programs. Additionally, all events have different hours and days of when they were called. While ex-post methods are used for actual events, ex-ante methods are used to get load reductions for each month under two peak weather planning conditions: 1-in-2 and 1-in-10 for both SDG&E and CAISO. The ex-ante estimates are used in establishing Resource Adequacy (RA) credit for supply side demand response activities. Supply side resources are bid into the CAISO market during the event season which typically runs from April 1st through October 31st. Dynamic and Time of Use rates are Load Modifying resources, and those ex-ante estimates are utilized and accounted for in SDG&E's peak forecast.

During 2022 the Covid-19 pandemic continued however, much of the customer loads returned to a "normal" state. SDG&E did not provide any adjustment factors to its ex-ante estimates for 2022 and beyond. SDG&E continues to see significant CCA activity in 2022. SDG&E also expects to lose more CPP customers in 2023 and 2024 as they migrate over to CCAs.

Table 4-1: Summary of Analysis Methodologies by Program

Supply Side Demand Response Programs			
Program	**Method**	**Evaluation**	**Key Assumptions**
AC Saver Day Ahead Commercial	Ex-Ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads.	Note there is no ex-post analysis to describe for PY2022. So, weather normalized customer regressions by segment for reference loads and regression of historical event percent impacts versus weather for percent reductions were used as inputs to ex-ante modeling for 2023 and beyond.
AC Saver Day Ahead Residential	Ex-Post: Difference-in-Differences analysis of means using matched control groups. Ex-Ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	Matched control groups are identified by comparing behavior of participants and non-participants on event-like non-event days. Control groups' behavior during events acts as estimate of participants' counterfactual non-event behavior. The difference between participants and non-participants, net of the prediction error for non-event days, is the program's ex-post load impact.	• The behavior of treated and untreated households must differ during event days *only* because of the program being dispatched. Evidence for this assumption is found in the degree of similarity between each treated customer and its matched control group on non-event days.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Program	Method	Evaluation	Key Assumptions
AC Saver Day Of Commercial	Ex-Post: Statistical matching design Ex-Ante: Ex-ante load impacts fit a single model that estimates the weather responsiveness of average ex-post load impacts.	Under the matching design, a matched control selected for all the commercial AC Saver Day Of program participants. This approach was chosen for the commercial segment due to the smaller size of the program population and the larger relative effect of holding back a control group from program from program dispatch.	• Commercial snapback is assumed to be zero. • Enrollment is projected to decrease over the next few program years.
AC Saver Day Of Residential	Ex-Post: Randomized Controlled Trial (RCT) Ex-Ante: Ex-ante load impacts fit a single model that estimates the weather responsiveness of average ex-post load impacts.	Under the matching design, a matched control selected for all the commercial AC Saver Day Of program participants. Previous evaluations used random samples of residential AC Saver Day Of customers to be selected from each cycling strategy which ultimately withheld some load impacts from the program's performance.	• Enrollment is projected to decrease over the next few program years. • Snapback for residential customer was calculated based on cycling strategy.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Program	Method	Evaluation	Key Assumptions
Base Interruptible Program	Ex-Post: SDG&E had no customers enrolled in BIP and therefore did not call any events during the 2022 program year. Ex-ante: "For SDG&E, the load impact is assumed to be 0.1 MWh/h for each hour during the event window."[19]	BIP had no customers or events in 2022. The ex-ante forecast is conducted for a single customer in 2023.	• Average program FSL achievement rate is assumed. [redacted] • For PY2022, assumes no COVID-19 adjustment because the program appears to have returned to pre-COVID-19 levels.
Capacity Bidding Commercial CBP	Ex-Post: Customer-specific hourly regression models as the primary evaluation method. Ex-ante: Based on 4 primary steps: 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.	Customer-specific regressions allow for granularity in the results and can readily be used to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects.	• The enrollment forecast assumes a 2% growth per year from 2023-2027 due to SDG&E's proposed program improvements. The enrollment forecasts for both programs show a flat trend from 2027-2033 • CBP is an aggregator nomination-based program, which often results in dramatic changes in the underlying participant population from year to year. Therefore, it was determined the most appropriate approach was not to make any assumptions or adjustments to reflect COVID-19 conditions.

[19] 2022 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1, 2023) – page 15

Table 4-1 continued: Summary of Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Critical Peak Pricing CPP	<u>Ex-post:</u> Within-subjects customer-specific regressions or panel regressions <u>Ex-Ante:</u> Weather-Adjusted, per-customer Impacts	Ex-ante estimates are based on ex-post percentage load impacts (adjusted for changes in event hours as needed), with the reference loads simulated to represent the range of weather and day types required by the Protocols.	The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios. Forty percent of Large & Medium CPP was removed starting with 2021 program year due to CCA migration.
Default Small Commercial CPP	<u>Ex-post:</u> Commercial: Difference-in-differences with matched controls Agricultural: Panel regression with multiple matched control groups <u>Ex-ante:</u> Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The distance matching approach used selected one matched control site for each of the roughly 44,000 non-residential Small CPP sites among a matched control candidate pool of roughly 7,000 small commercial CPP opt-outs and 3,300 small agricultural CPP opt-outs. These customers were not enrolled in CPP or other DR programs which might influence energy use and excluded sites that were recently defaulted to a CCA. The difference-in-differences model was then used to assess impacts and standard errors for each event and each study segment. Small CPP Agricultural impacts were estimated using a panel regression.	The historical load patterns and performance during actual events are used to estimate the reductions for a standardized set of weather conditions.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Electric Vehicle Time-Of-Use: EVTOU2, EVTOU5 & VGI	Ex-Post: Panel regression difference-in-differences method. Ex-ante: Based on analyses of per-customer load impact findings from ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.	EVTOU: Panel regression difference-in-differences with fixed customer effects, daily time effects, and weather were used to isolate the load impact. Regressions were run for like days. For example, when we estimated impacts for the top 10 highest system load days, we included only the top 10 highest load days in the year before and after EV TOU enrollment. This ensures the difference in differences adjustment was calibrated to correct day types. PYD: Panel regression by charging station with multiple fixed effects. Regressions were run in relation to both Price response and Event responses. The Price model related price changes on the program to hourly charging kWh. The Event based model flagged hours with circuit or system Critical Peak Pricing adders as events. The coefficients of these models demonstrate the magnitude of customer response to measured changes in pricing as well as event hours.	• The EVTOU approach relies more heavily on selecting a comparable matched control group than the model specification. A tournament was conducted to identify the model that performed best at identifying the control pool with electric vehicles, but not on EV TOU rates. For the evaluation, we used a standard difference-in-differences panel regression with customer fixed effects, date-time effects, and weather explanatory variables. • To calculate the VGI Pilot customer response we ran linear regressions with multiple fixed effects and multi-way clustering. The regressions treated station ID, date, day of week and hour as categorical regressors, and captured Station ID and date as fixed effects in each panel.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Voluntary Residential CPP & TOU	Ex-Post: Difference-in-Difference analysis method using data for TOU and CPP participants and matched control group customer. Ex-Ante: Since no residential CPP events took place in 2021, the ex-ante analysis for CPP events applies CPP event load impacts from PY2020 to reference loads calculated using PY2021 customer load data.	The difference-in-differences evaluation is a quasi-experimental approach that compares the usage of treatment and matched control group customers on relevant days or time periods, adjusted by their usage differences on pre-treatment or non-event days.	• Five CPP events were called in 2022. • Starting June 1, 2022, the CPP event window coincided with the RA window, such that ex-ante results beginning in 2022 reported load impacts over the 4 to 9 pm period. This means that the ex-post load impacts, which occurred between 2 and 6 pm, were shifted forward to span the updated event window beginning in 2022.

Table 4-2: Summary of Analysis Methodologies by Pilot

Pilot Programs			
Program	**Method**	**Evaluation**	**Key Assumptions**
Non-Residential ELRP	Ex-Post: Site specific regression models with synthetic controls Ex-Ante: Top down enrollment model based on projections for interconnected capacity and feasible enrollment levels. Load reductions are assumed to be a function of dispatchable generation capacity not weather sensitive load curtailment and therefore the same for all weather specifications.	Key modeling design components are Matched Control Tournament and Out of sample regression model tournament to select most accurate model for each participant site.	• Historical load patterns were not used to derive the ex-ante forecast and the forecast is not differentiated by weather conditions. Rather, capacity enrollments were forecast as a portion of total interconnected dispatchable generation that can feasibly be enrolled. Enrollments are derated for performance during actual events, relative to nominated reductions specified by enrollees at the time of enrollment.

Table 4-2 continued: Summary of Analysis Methodologies by Pilot

Program	Method	Evaluation	Key Assumptions
Residential ELRP	Ex-Post: Difference-in-Differences analysis of means using matched control groups. Within-subjects time-series model for participants to estimate statewide emergency alert effects Ex-Ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	Matched control groups are identified by comparing behavior of participants and non-participants on event-like non-event days. Control groups' behavior during events acts as estimate of participants' counterfactual non-event behavior. The difference between participants and non-participants, net of the prediction error for non-event days, is the program's ex-post load impact.	• The behavior of treated and untreated households must differ during event days *only* because of the program being dispatched. Evidence for this assumption is found in the degree of similarity between each treated customer and its matched control group on non-event days.
Residential CBP	Ex-Post: Average customer time series with out of sample model selection for the average customer Ex-Ante: Weather normalized customer regressions by climate zone for reference loads. Consideration of PY 2021 and PY 2022 performance for percent reductions	Reference loads, developed using a sample of 2,600 residential sites with solar and storage, weighted to the full territory population of storage interconnections. Impact assumptions based on PY 2021 ex-post conclusions that battery storage is dispatched to keep whole building loads at 0 kW during events.	• No statistically significant load reductions were observed for PY 2022. • The enrollment forecast based on historical growth in interconnections and assumptions regarding enrollment rate, described above. • All ex-ante impacts are derated by 50% to reflect the dispatch uncertainty observed in the PY 2022 test events. Aggregate impacts are expected to grow with enrolled residential storage capacity until flattening after 2028.

5. Ex-Post Load Impact Estimates

Ex-post load impact results are calculated for each demand response event that was initiated during the previous event year. Table 5-1 below shows the average load reduction for each demand response activity. When looking at these results it's important to keep in mind that each DR activity is unique, and dispatches can be based on multiple factors. DR activities vary in the number of participants, the number of events called and not all of SDG&E's DR is weather sensitive. Though some load impacts might be smaller than others, each DR activity faces challenges. For instance, SDG&E's AC Saver Day Ahead program's impacts only measure connected devices which is only a subset of all the participants. SDG&E has learned that devices can be disconnected for a variety of reasons. It can be simple as a change in a Wi-Fi password, or the customer installs a new router and forgets to set up the communicating thermostat. As a result, in those cases the thermostats are not dispatched and therefore add no value to the load impacts.

Table 5-1: Summary of 2022 SDG&E Average DR LI Ex-post estimates by Program

Supply Side Demand Response							
Program	**Reference Load (MW)**	**Observed Event Load (MW)**	**Load Impact per Customer (kW)**	**% Load Impact**	**Aggregate Impact (MW)**	**Number of Accounts**	**Number of Events**
AC Saver Day Ahead Commercial**	-	-	-	-	-	-	-
AC Saver Day Ahead Residential*	33.19	24.54	0.49	26.1%	8.65	17,528	12
AC Saver Day Of Commercial	7.83	7.76	0.10	1.2%	0.23	2,377	11
AC Saver Day Of Residential	17.74	16.07	0.20	9.4%	1.68	8,241	11
Base Interruptible Program***	-	-	-	-	-	-	-
Capacity Bidding Program	12.0	10.6	21.6	12%	1.4	66	9****

* AC Saver Day Ahead Residential called 2 events from 5-7 PM, 7 events from 6-8 PM, and 3 events from 5-9 PM. The average DR LI Ex-Post estimates are reported for days with the event window of 6-8 PM excluding August 17th, which had a dispatch error that prevented thermostats from being activated.
** No AC Saver Day Ahead Commercial events were called in PY 2022.
*** No BIP events were called in PY 2022.
****SDG&E triggered 6 Elect DO 1-9 Hour ($400) events and 3 Elect DA 1-9 Hour ($600) events

Table 5-1 continued: Summary of 2022 SDG&E Average DR LI Ex-post estimates by Program

Load Modifying Demand Response (Dynamic and TOU rates)							
Program	**Reference Load (MW)**	**Observed Event Load (MW)**	**Load Impact per Customer (kW)**	**% Load Impact**	**Aggregate Impact (MW)**	**Number of Accounts**	**Number of Events**
Critical Peak Pricing excluding TD**	240.25	241.0	-0.15	-0.30%	-0.72	4,857	5
CPP customers on Technology Deployment (TD)**	2.38	2.23	0.70	6.3%	0.15	215	
Default Small Commercial CPP***	112.53	111.77	0.02	0.7%	0.75	44,306	5
Small Agricultural***	1.84	1.19	11.57	35.2%	0.65	56	
PSW customers on Technology Deployment (TD)	0.81	0.76	0.26	5.5%	0.04	172	
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	1.52	1.04	0.71	31.5%	0.47	668	5
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU	76.45	72.17	0.10	5.5%	4.27	42,887	
Electric Vehicle Time-Of-Use: EVTOU2*	10.74	6.98	0.46	35.0%	3.76	8,081	TOU
Electric Vehicle Time-Of-Use: EVTOU5*	33.17	27.46	0.25	17.2%	5.71	22,504	TOU

*EVTOU2 and EVTOU5 ex-post estimates are based on August Average Weekday

** Five CPP events were called for Medium & Large Commercial customers in PY 2022

***Small Commercial CPP and Agricultural are based on average weekday

Table 5-2: Summary of 2022 SDG&E Average DR LI Ex-post estimates by Pilot

Program	Reference Load (MW)	Observed Event Load (MW)	Load Impact per Customer (kW)	% Load Impact	Aggregate Impact (MW)	Number of Accounts	Number of Events
Non-Residential A.1 ELRP	195.41	158.96	88.53	18.7%	36.45	412	9
Non-Residential A.2 ELRP [a]	4.60	4.72	-7.40	-2.7%	-0.12	17	10
Non-Residential A.3 ELRP [a]	[redacted]						
Non-Residential A.4 ELRP	-	-	-	-	-	-	0
Non-Residential A.5 ELRP	[redacted]						
Non-Residential B.2 ELRP							
Residential ELRP	628.16	616.26	0.02	1.9%	11.91	525,382	10
Residential CBP [a]	0.05	0.06	-0.03	-5.2%	0.00	99	10

[a] The aggregate impacts are not statistically significant 90%.

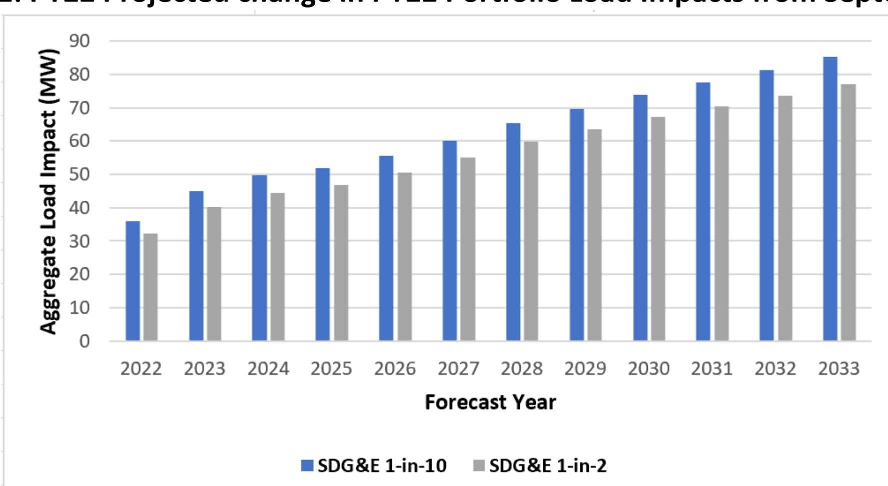
6. Ex-Ante Load Impact Estimates

This section presents PY22 ex-ante load impact estimates for SDG&E's portfolio. Ex-ante load impacts represent weather conditions under normal (1-in-2 year) and extreme (1-in-10 year) conditions when SDG&E system peaks according to DR Load Impact Protocols and Regulatory Guidance.[20] Normal conditions are defined as those that would be expected to occur once every 2 years (1-in-2 conditions) and extreme conditions are defined as those that would be expected to occur once every 10 years (1-in-10 conditions). Staring in 2023, Resource Adequacy Availability Assessment Hours are 5pm – 10pm (HE18 – HE22) for March and April and 4pm – 9pm (HE17 – HE21) for the remaining months.

6.1 Projected Change in PY22 Portfolio Load Impacts from 2022–2033

Figure 6-1 presents the portfolio-adjusted aggregate load impact estimates for the September system peak day under 1-in-2 and 1-in-10 SDG&E weather conditions for all DR Supply Side and Load Modifying programs. Overall, SDG&E's portfolio is projected to increase by 90% from 2023 to 2033 (from 45 MW in 2023 to 85 MW in 2033) under 1-in-10 weather conditions. On the other hand, SDG&E's portfolio is projected to increase by 92% from 2023 to 2033 (from 40 MW in 2023 to 77 MW in 2033) under 1-in-2 weather conditions.

Figure 6-1: PY22 Projected change in PY22 Portfolio Load Impacts from September 2022-2033



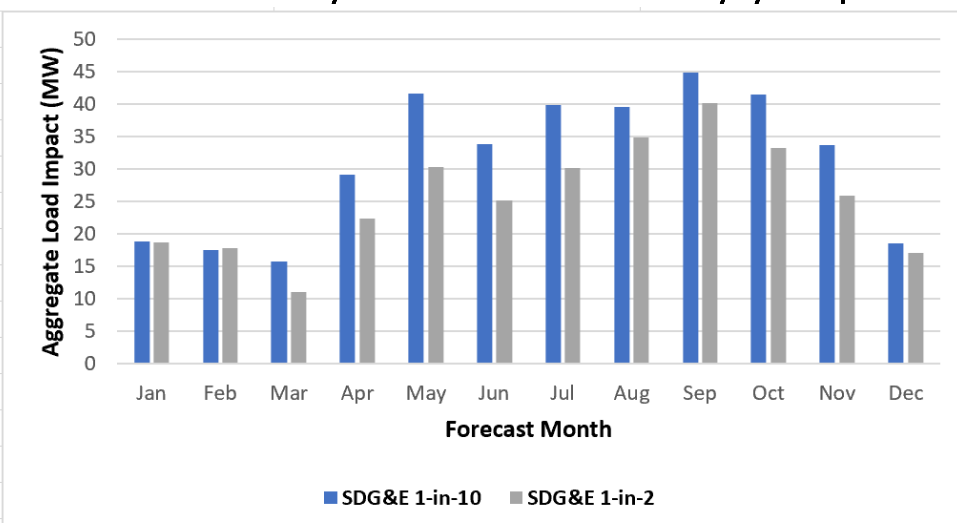
[20] DR Load Impact Protocols and Regulatory Guidance (Protocols 17-23) by CPUC (Apr 2008) - page 93-110

a. Portfolio Aggregate Load Impacts by Month for the year of 2023

Figure 6-2 shows the 2023 load impact estimates under 1-in-2 and 1-in-10 SDG&E weather conditions all DR Supply Side and Load Modifying programs. The impacts across the 12 months vary for summer versus winter months. Winter months show a lower reduction due to load modifying and supply side programs provide significant load impact reductions only during summer months.

In 2023, SDG&E's DR portfolio estimates nearly 45 MW of load reduction during the September monthly system peak day under SDG&E's 1-in 10 weather conditions. The months of May, July, and October load impacts are slightly lower than the month of September delivering 42, 40, and 42MW respectively under SDG&E's 1-in-10 conditions.

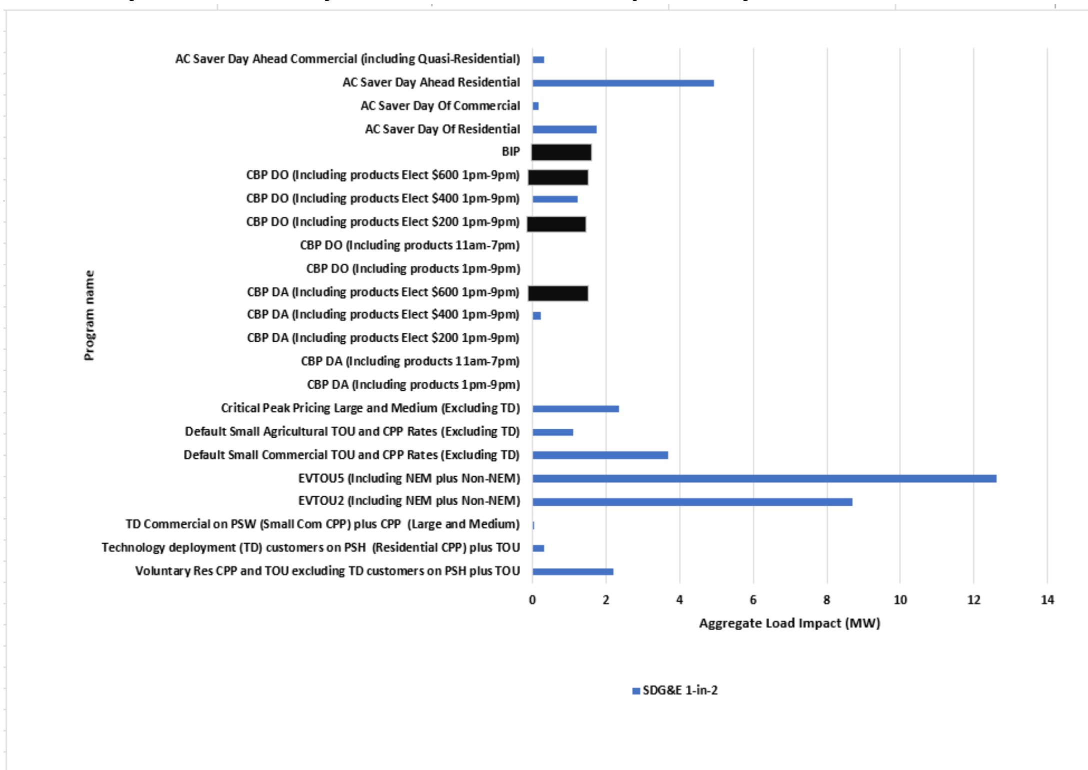
Figure 6-2: PY22 Portfolio Aggregate Ex-ante Load Impact Estimates (MW) for the yar of 2023 by 1-in2 and 10n10 SDG&E system conditions and monthly system peak



b. Portfolio Load Impacts by Program Type for the year of 2023

Figure 6-3 shows the distribution of portfolio aggregate load impacts by program type in September 2023 for all DR Supply Side and Load Modifying programs. In September 2023, the load impacts from price responsive programs are forecast to comprise 42% of SDG&E's DR portfolio, 53% from non-event programs, [redacted] under 1in2 weather conditions. A greater percentage of load impacts are projected to come from EVTOU5 followed by EVTOU2 in the coming years.

Figure 6-3: Distribution of PY22 Portfolio Aggregate Load Impacts by Program Type for September 2023 System Peak Day under 1-in-2 SDG&E-specific System Conditions



c. Portfolio Load Impacts by Program from 2022-2033

Table 6-1 summarizes the portfolio load impacts by program for 2022 through 2033 under 1-in-2 SDG&E weather conditions all DR Supply Side, Load Modifying programs and DR pilots.

In September 2033, the load impacts from load modifying programs are forecast to comprise 43% of SDG&E's DR portfolio, [redacted].

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. The load impacts from emergency programs are forecast to comprise [redacted] of SDG&E's DR supply side portfolio. The price responsive programs represent 85% of SDG&E's DR supply side portfolio and most of this percentage is derived from AC Saver Day Ahead Residential. The aggregator DR represents [redacted], the majority of this percentage is attributable to CBP DO (Including products Elect $400 1pm-9pm).

Table 6-1: Portfolio Aggregate PY22 Load Impact Estimates (MW) for the September System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Supply Side Total MWs	**7.70**	**8.62**	**9.47**	**10.4**	**11.48**	**12.65**	**14.03**	**14.26**	**14.12**	**13.97**	**13.83**	**13.68**
Emergency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BIP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Price Responsive	**6.65**	**7.17**	**7.98**	**8.89**	**9.93**	**11.08**	**12.46**	**12.69**	**12.55**	**12.4**	**12.26**	**12.11**
AC Saver Day Ahead Commercial (including Quasi-Residential)	0.36	0.31	0.25	0.20	0.16	0.13	0.11	0.09	0.09	0.08	0.08	0.07
AC Saver Day Ahead Residential	4.06	4.93	6.04	7.21	8.46	9.80	11.20	11.45	11.31	11.17	11.03	10.89
AC Saver Day Of Commercial	0.20	0.18	0.17	0.15	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.13
AC Saver Day Of Residential	2.03	1.75	1.52	1.33	1.17	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Aggregator DR	**1.05**	**1.45**	**1.49**	**1.51**	**1.55**	**1.57**	**1.57**	**1.57**	**1.57**	**1.57**	**1.57**	**1.57**
CBP DA (Product 11am-7pm)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DA (Product 1pm-9pm)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DA Elect $200 (Including products 1pm-9pm)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DA Elect $400 (Including products 1pm-9pm)	0.03	0.22	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
CBP DA Elect $600 (Including products 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBP DO (Product 11am-7pm)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DO (Product 1pm-9pm)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DO Elect $200 (Product 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBP DO Elect $400 (Product 1pm-9pm)	1.02	1.23	1.26	1.28	1.31	1.33	1.33	1.33	1.33	1.33	1.33	1.33
CBP DO Elect $600 (Product 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The load modifying programs are divided into two groups: price responsive programs and non-event based. The load impacts from price responsive programs are forecast to comprise 8% of SDG&E's DR load modifying portfolio where the greater percentage of load impacts are projected to come from Default Small Commercial TOU and CPP Rates (Excluding TD). The load impacts from non-event based are forecast to embrace 92% of SDG&E's DR load modifying portfolio; most of this percentage is related to EVTOU5 (Including NEM plus Non-NEM).

Table 6-1 Continued: Portfolio Aggregate PY22 Load Impact Estimates (MW) for the September System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Load Modifying	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Modifying Total MWs	**24.28**	**30.99**	**34.54**	**36.05**	**38.7**	**41.84**	**45.18**	**48.73**	**52.53**	**55.92**	**59.35**	**62.94**
Price Responsive	**11.54**	**9.69**	**9.07**	**6.53**	**5.85**	**5.72**	**5.62**	**5.52**	**5.4**	**5.31**	**5.23**	**5.13**
Critical Peak Pricing Large and Medium (Excluding TD)	2.70	2.36	2.09	1.82	1.74	1.63	1.55	1.47	1.36	1.28	1.21	1.14
Default Small Agricultural TOU and CPP Rates (Excluding TD)	1.09	1.09	1.09	0.68	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Default Small Commercial TOU and CPP Rates (Excluding TD)	3.67	3.68	3.68	2.29	1.84	1.84	1.84	1.84	1.85	1.85	1.85	1.85
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	0.05	0.05	0.05	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.02
Technology deployment (TD) customers on PSH (Residential CPP)	0.48	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
Voluntary Residential CPP and TOU excluding TD customers on PSH plus TOU	3.55	2.19	1.84	1.38	1.36	1.34	1.33	1.31	1.29	1.28	1.27	1.25
Non-event based	**12.74**	**21.3**	**25.47**	**29.52**	**32.85**	**36.12**	**39.56**	**43.21**	**47.13**	**50.61**	**54.12**	**57.81**
EVTOU2 (Including NEM plus Non-NEM)	5.42	8.69	10.28	11.83	13.10	14.35	15.67	17.06	18.56	19.89	21.23	22.61
EVTOU5 (Including NEM plus Non-NEM)	7.32	12.61	15.19	17.69	19.75	21.77	23.89	26.15	28.57	30.72	32.89	35.20
Pilots	**41.09**	**45.66**	**52.21**	**57.7**	**61.64**	**64.99**	**68.32**	**68.45**	**68.48**	**68.51**	**68.55**	**68.58**
Non-Residential A.1 ELRP	28.01	29.01	29.88	30.74	31.77	32.77	33.59	33.59	33.59	33.59	33.59	33.59
Non-Residential A.2 ELRP	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Non-Residential A.3 ELRP	[redacted]											
Non-Residential A.4 ELRP	0.00	2.54	6.63	9.95	11.89	13.39	15.01	15.01	15.01	15.01	15.01	15.01
Non-Residential A.5 ELRP	[redacted]											
Non-Residential B.2 ELRP	[redacted]											
Residential ELRP	12.97	13.28	13.71	14.14	14.57	15.01	15.44	15.57	15.60	15.63	15.67	15.70
Residential CBP	0.07	0.79	1.95	2.83	3.36	3.77	4.23	4.23	4.23	4.23	4.23	4.23
Supply Side plus Load Modifying plus Pilots Total MWs	**73.07**	**85.27**	**96.22**	**104.15**	**111.82**	**119.48**	**127.53**	**131.44**	**135.13**	**138.40**	**141.73**	**145.20**

* In 2021 and 2022, SDG&E saw a substantial decrease in participants due to the migration of bundled customers to DA/CCA service.

Table 6-2 summarizes the portfolio number of customers forecasted by program for 2022 through 2033 under 1-in-2 SDG&E weather conditions.

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. In September 2032, the number of customers from load modifying programs are forecast to comprise 23% of SDG&E's DR portfolio, [redacted]

In September 2032, the customers from emergency programs are forecast to comprise [redacted] of SDG&E's DR supply side portfolio. The price responsive programs represent [redacted] of SDG&E's DR supply side portfolio and most of this percentage is derived from AC Saver Day Ahead Residential. The aggregator DR represents [redacted] the majority of this percentage is attributable to CBP DO (Including products Elect $400 1pm-9pm).

As was presented in the ex-ante load impacts, the load modifying programs are divided into two groups: price responsive programs and non-event based. The customers from price responsive programs are forecast to comprise 23% of SDG&E's DR load modifying portfolio where the greater percentage of the number of customers are projected to come from Default Small Commercial TOU and CPP Rates (Excluding TD).

Table 6-2 Portfolio Aggregate PY22 number of customers forecasted for the September System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Supply Side Total number of customers	**29,145**	**32,129**	**36,769**	**41,874**	**47,576**	**53,843**	**61,274**	**63,159**	**63,159**	**63,159**	**63,159**	**63,159**
Emergency												
BIP												
Price Responsive	**29,027**	**32,008**	**36,645**	**41,748**	**47,447**	**53,712**	**61,143**	**63,028**	**63,028**	**63,028**	**63,028**	**63,028**
AC Saver Day Ahead Commercial (including Quasi-Residential)	415	374	324	281	244	212	184	177	177	177	177	177
AC Saver Day Ahead Residential	18,049	22,473	28,247	34,338	40,898	47,914	55,373	57,265	57,265	57,265	57,265	57,265
AC Saver Day Of Commercial	2,372	2,160	1,991	1,835	1,691	1,559	1,559	1,559	1,559	1,559	1,559	1,559
AC Saver Day Of Residential	8,191	7,001	6,083	5,294	4,614	4,027	4,027	4,027	4,027	4,027	4,027	4,027
Aggregator DR	**118**	**121**	**124**	**126**	**129**	**131**	**131**	**131**	**131**	**131**	**131**	**131**
CBP DA (Product 11am-7pm)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DA (Product 1pm-9pm)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DA Elect $200 (Including products 1pm-9pm)	0	0	0	0	0	0	0	0	0	0	0	0

Table 6-2 Continued: Portfolio Aggregate PY22 number of customers forecasted for the September System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CBP DA Elect $400 (Including products 1pm-9pm)	57	48	49	50	51	52	52	52	52	52	52	52
CBP DA Elect $600 (Including products 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBP DO (Product 11am-7pm)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DO (Product 1pm-9pm)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DO Elect $200 (Product 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBP DO Elect $400 (Product 1pm-9pm)	61	73	75	76	78	79	79	79	79	79	79	79
CBP DO Elect $600 (Product 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6-2 Continued: Portfolio Aggregate PY22 number of customers forecasted for the September System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Modifying	**124,631**	**134,383**	**141,526**	**130,736**	**132,098**	**138,874**	**146,147**	**153,995**	**162,546**	**170,095**	**177,737**	**185,985**
Price Responsive	**92,373**	**81,124**	**78,049**	**57,327**	**50,524**	**49,298**	**48,134**	**47,037**	**45,988**	**44,995**	**44,055**	**43,168**
Critical Peak Pricing Lrg & Med (Excluding TD)***	4,631	2,722	2,136	1,396	1,326	1,261	1,199	1,142	1,076	1,013	954	899
Default Small Agricultural TOU and CPP Rates (Excluding TD)	57	57	57	35	28	28	28	29	29	29	29	29
Default Small Com TOU and CPP Rates (Excluding TD)***	43,880	44,067	43,962	27,393	21,943	21,986	22,019	22,044	22,068	22,091	22,114	22,138
TD Commercial on PSW (Sm Com CPP) + CPP (Lrg & Med)	215	243	242	228	215	203	192	189	189	189	189	189
TD customers on PSH (Residential CPP) plus TOU	909	625	625	625	625	625	625	625	625	625	625	625
Voluntary Residential CPP and TOU excluding TD customers on PSH***	42,681	33,410	31,027	27,650	26,387	25,195	24,071	23,008	22,001	21,048	20,144	19,288
Non-event based	**32,258**	**53,259**	**63,477**	**73,409**	**81,574**	**89,576**	**98,013**	**106,958**	**116,558**	**125,100**	**133,682**	**142,817**
EVTOU2 (Including NEM plus Non-NEM)	8,168	11,743	13,482	15,173	16,563	17,925	19,361	20,884	22,518	23,972	25,433	26,947
EVTOU5 (Including NEM plus Non-NEM)	24,090	41,516	49,995	58,236	65,011	71,651	78,652	86,074	94,040	101,128	108,249	115,870
Pilots	**541,226**	**545,380**	**551,611**	**557,093**	**561,414**	**565,433**	**569,494**	**569,207**	**567,976**	**566,768**	**565,586**	**564,430**
Non-Residential A.1 ELRP	474	485	492	497	503	509	514	514	514	514	514	514
Non-Residential A.2 ELRP	17	17	18	18	18	18	18	18	18	18	18	18
Non-Residential A.3 ELRP	[redacted]											
Non-Residential A.4 ELRP	0	1,298	3,390	5,071	6,041	6,792	7,606	7,606	7,606	7,606	7,606	7,606
Non-Residential A.5 ELRP	[redacted]											
Non-Residential B.2 ELRP	[redacted]											
Residential ELRP	540,636	542,446	544,909	547,438	550,032	552,693	555,283	554,996	553,765	552,557	551,375	550,219
Residential CBP	99	1,134	2,802	4,069	4,820	5,421	6,073	6,073	6,073	6,073	6,073	6,073
Supply Side plus Load Modifying plus Pilots Total number of customers	**695,002**	**711,892**	**729,906**	**729,703**	**741,088**	**758,150**	**776,915**	**786,361**	**793,681**	**800,022**	**806,482**	**813,574**

* In 2021 and 2022, SDG&E saw a substantial decrease in participants due to the migration of bundled customers to DA/CCA service.

7. Recommendations

The 2022 DR program evaluations contain the evaluators' recommendations for each program. The recommendations pertain to steps that can be taken to improve the measurement and evaluation of DR resources and to improve program performance. This section summarizes the recommendations for each program.

7.1 Supply Side Demand Response

7.1.1 Emergency Programs

7.1.1.1 Base interruptible program (BIP)

In 2022, SDG&E had no participants in BIP and no BIP events were called. Christensen had no recommendations specific to SDG&E's implementation of this program.[21]

7.1.2 Aggregator Programs

7.1.2.1 Capacity Bidding Program (CBP)

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs:[22]

a) Reevaluate the approach to reporting delivery performance. Three considerations for future reports:

- Produce an average event hour for reporting delivery performance. Given CBP's need-based nature of dispatching events (Sub-LAP level CAISO market awards), reporting the average load impacts for a coincident hour (i.e., the most dispatched hour) produces a "watered-down" average load impact. We've attempted to reconcile this by including an adjusted delivery performance metric, but it can still be improved. We recommend producing an average event hour strictly for reporting delivery performance, which can directly be measured against the nominated capacity without needing an adjustment.
- Maintain the existing approach to the average event day due to limitations of the CPUC LIP, which requires reporting a 24-hour load profile for an average event day.

[21] 2022 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1, 2023) – page 51

[22] 2022 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Apr 1, 2023) – page 41

- Consider including dispatched capacity in the Ex-Post table generators (MS Excel-based Protocol) as available to each reporting customer segment.

7.1.3 Price Responsive Programs

7.1.3.1 AC Saver Day Ahead commercial and residential programs

DSA made the following recommendation for residential only[23]:

- **If possible, avoid bidding sites that lack connected thermostats into the CAISO markets**. Sites with loads that cannot be controlled or dispatched do not deliver any detectable demand reduction. They simply dilute the demand reductions and make them harder to detect. SDG&E should continue efforts to remove thermostats disconnected for prolonged periods from the dispatch portal.
- **Review dispatch strategy to optimize load reductions.** Dispatch strategies can be designed to maintain more consistent impacts across multiple event hours and potentially produce higher average impacts across event hours by producing greater impacts in later event hours, e.g. in hour 3 or 4.

DSA made the following recommendation for commercial only:[24]

- **Continue disenrolling thermostats with prolonged disconnections.** Thermostats which are not connected cannot respond to dispatch signals or produce reductions. However, they still cause the program to incur technology costs which accrue on a per enrolled device basis.
- **Consider planning a transition for the small number of remaining participants.** Aggregate load reductions across all TD programs are now below 0.1 MW and are expected to continue to substantially decline over the next five years. Programs with low participation and societal benefits relative to the costs to maintain and evaluate a program can be good candidates for sunsetting. Part of this process can include identifying alternative programs that may be more cost effective for participants.

7.1.3.2 AC Saver Day Of commercial and residential programs

Resource Innovations made the following recommendations: [25]

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[23] 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program by Demand Side Analytics. (Apr 1, 2023) – page 38

[24] 2022 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program by Demand Side Analytics. (Apr 1, 2023) – page 48

[25] AC Saver Day Of 2022 Load Impact Program Evaluation by Nexant (Mar 2023) -page 53 and 54

- Continue to implement the matched control methodology for both the residential and non-residential segments in future years. The matched control approach yielded statistically-robust load impact estimates for the residential customer segment and allowed all residential program participants to provide load impacts without the need to hold back a fraction of the customers to serve as a control group
- Continue to employ a difference-in-differences framework to estimate ex-post impacts in future AC Saver Day Of evaluations. This methodology has the advantage of being robust to large-scale differences in weather between event and proxy days and time-invariant differences in consumption between treatment and control customers.
- To ensure that the program's direct load control devices are dispatching during events and producing load reductions, a field study should be conducted that examines the fleet of devices for functionality, prioritizing devices for commercial customers. Alternatively, a data-based analysis could be designed that uses clustering or similar techniques to identify specific devices that do not exhibit evidence of cycling during program events.

7.2 Load Modifying DR

7.2.1 Price responsive Programs

7.2.1.1 Critical Peak Pricing (CPP)

Christensen made the following recommendation:

Five events were called during the September heat wave, including weekends. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures and months.[26]

7.2.1.2 Default Small Commercial CPP

DSA made the following recommendation:[27]

- **Assess if additional communications encouraging response improve reductions using randomized controlled trials.** The magnitude of demand reductions during events is small on a percentage basis,

[26] 2022 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates by Christensen (April 1st, 2023) – page 40

[27] 2022 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program (April 1, 2023) – page 48

with ample room to improve reductions. Most reductions were delivered by sites receiving event notifications. Additional communications require resources and their effectiveness at improving price response is unknown. Because of the potential, however, we recommend testing the effectiveness of more education regarding event response. It is critical, however, for the test to be implemented using randomized control trials, so it is possible to assess if the communications had any impact on price response.

- **Notification rates for small CPP can be improved. Customers elect whether or not to sign up for notifications and by which channels they receive notification.** Because notification is closely linked to response, additional efforts to improve notification rates are recommended. Sites receiving event notifications tend to produce greater impacts so an increase in notification rates has the potential to meaningfully increase load reductions.

7.2.1.3 Voluntary Residential CPP and TOU

The treatment group among CPP customers will decrease in enrollment as customers migrate to Community Choice Aggregator programs. As a result, finding valid incremental treatment customers will become more difficult in future years. The reduction of incremental customers limits the experimental leverage of estimating TOU load impacts for future program years.

Five CPP events were called during the September heat wave, including weekends and a holiday. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures and months.

7.2.2 Nonevent Based Programs

7.2.2.1 Electric Vehicle Time of Use

Electric vehicles have the potential to transform the electric grid fundamentally. They are a new, incremental, flexible, and critical load. As the residential electric vehicle market grows, it will impact all aspects of the electric grid. The efforts to ensure electric vehicles are a flexible load over the next few years will be vital as the market share increases. There are over 2.8M vehicles in SDG&E territory and the implications of transportation electrification for the electric grid are large. Moreover, electric vehicles are quickly maturing to an early adopter technology to mass adoption. The transformation is most evident for new vehicles, where electric vehicles constitute 18.8% of the market in San Diego County and 25% of the new vehicle market in

Orange County. Thus, it has become increasingly important to provide customers incentives and tools to manage charging to lower bills and reduce use during peak hours.

Key recommendations from the evaluation are:

- Continue to evaluate and report impacts for all sites that reached a full year of experience with electric vehicle time-of-use rates (1st year impacts). Using a rolling enrollment approach leads to few incremental sites in October but grows during the study period. The approach creates two challenges, however. First, the sample size for early months is inherently small. Second, there is little data regarding behavior with TOU rates for sites that enroll towards the end of the study period. Shifting to analyzing sites that reached a full year of experience under TOU rates addresses these challenges. It ensures a large enough number of sites are analyzed each month and ensures we fully factor in the behavior of each new enrollment.
- Remove from the analysis sites whose enrollment on electric vehicle TOU rates coincides with the introduction of the electric vehicle into the home. Electric vehicles fundamentally change whole home load patterns and consumptions levels. Without sufficient data on EV charging patterns without the EVTOU5 and EVTOU2 rates, it is impossible to estimate the TOU effect on load patterns. The same applies to the installation of solar or battery storage. They fundamentally change whole home loads, and sites with installations over the study period (or the pre-intervention year) should be removed from the analysis.
- Assess whether SDG&E can incorporate California Department of Motor Vehicle (DMV) registration data to identify control sites – sites with electric vehicles that are not enrolled on EVTOU5 or EVTOU2. The DMV makes vehicle registration data available for public use but with limitations on how it is used and requirements regarding public notices and data security. While algorithms to identify electric vehicles using AMI data are helpful, vehicle registration data is a better source of information.
- Consider offering automated demand management to customers who enroll on electric vehicle rates. We recommend SDG&E make the offer immediately after a customer enrolls on an electric vehicle rate. Vehicle charging now can be managed via direct communication with vehicle on-board computers, an approach known as telematics, which does not require installations of devices. Currently, SDG&E does not directly manage vehicle charging. Instead, the TOU rates encourage customers to shift load from higher-price peak hours to lower-price off-peak and super off-peak hours.

A TOU rate is considered a "passive" form of demand response, leaving it up to the customer to take action. Not all customers modify the vehicle settings to charge during super off-peak periods. Telematics can be used to incorporate customer preferences, set default charge settings, lower customer bills, and reduce grid impacts via managed charging. It can also be used to actively respond to grid prices and events, making the electric vehicle a truly flexible load. The use of telematics fundamentally shifts the paradigm from behavioral prices response to prices-to-devices that respond based on user preference settings.

- Consider modifying the building blocks used for ex-ante impacts. Currently, the ex-ante impacts are based on four types of sites, customers on EV-TOU-5 and EV-TOU-2 with and without solar. Few new sites are enrolling on EV-TOU-2 and most new enrollment are on EV-TOU-5. As a result, the EV-TOU-2 analysis relies on an estimating sample that is small. For future years, we recommend that SDG&E build its ex-ante forecast based on sites on electric vehicle TOU rates with and without solar, eliminating the distinction between EV-TOU-5 and EV-TOU-2.

7.2.2.2 VGI Pilot Program

The Power-Your-Drive charging app has a key feature – the ability to restrict charging when prices exceed a threshold – that is rarely used. We recommend changing the default settings. To enable this feature, customers have to change the default settings and define a price threshold to automate the response. We recommend an A/B test to assess how changing the default settings affects charging behavior. In specific, we recommend testing a default that avoids charging when prices are high (above $0.50/kWh), provides users a push notice that prices are high, and allows drivers to "charge anyway" via the push of a button.[28]

7.2.3 Pilot Programs

7.2.3.1 Non-Residential ELRP

DSA made the following recommendation for non-residential only[29]:

- **Collect data to inform assumptions regarding percent of dispatchable generation capacity available for participation in ELRP**. Load reductions observed for PY 2022 events did not appear correlated with weather conditions and may be more a function of the availability of generation capacity for

[28] 2022 Load Impact Evaluations for San Diego Gas and Electric's Electric Vehicles Time-of-Use (TOU) Rates by Demand Side Analytics (Apr 2023)

[29] 2022 Load Impact Evaluation for San Diego Gas and Electric's Non-Residential Emergency Load Reduction Pilot by Demand Side Analytics. (Apr 1, 2023) – page 43

reductions. A better understanding of resource availability will better inform load reduction forecasting. This may include process surveys or interviews with the large non-residential customers that comprise most of ELRP participants.

- **Consider updates to baseline adjustment rules.** While a load impact evaluation approach which incorporates controls for exogenous factors provides the most robust estimate of actual load reductions, ELRP participants are remunerated for reductions based on baseline methodology. This includes a pre-event adjustment which is asymmetrical because it can only adjust the baseline upwards, not downwards. Incorporating a post event adjustment may somewhat reduce the gap observed between the adjusted baseline and observed loads in post event hours. Incorporating symmetrical adjustment rules would allow for downwards adjustment for better alignment with post-event loads.

7.2.3.2 Residential ELRP

DSA made the following recommendation for residential only[30]:

- **Do not default any additional BDR sites on TOU and consider converting BDR sites on TOU rates to opt-in**. While this group represents about third of reductions, the smaller percent reductions are also less likely to be distinguishable from noise using the baseline settlement approaches used to compensate participants, and therefore more likely to result in overpayment. To still retain engaged sites opt-in messaging could be sent to BDR sites on TOU rates requiring them to opt-in to stay enrolled.
- **Possibly tailor BDR outreach message to TOU vs non-TOU customers.** Defaulted BDR sites that are not on TOU rates still retain a load shape with a peak concentrated from 4 to 6pm and their load reductions are concentrated during these hours, indicating that there may be more discretionary load that can be shed for these customers during these hours.

[30] 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential Emergency Load Reduction Pilot by Demand Side Analytics. (Apr 1, 2023) – page 36

7.2.3.3 Residential CBP

DSA made the following recommendation for residential only[31]:

- **Thorough test and validate load dispatch ahead of the event season**. Test events with clear validation protocols should be run ahead of each season to confirm that load control is being effectively dispatched. Evaluation methodology criteria for validating effective load reductions should be defined ahead of the test events so load reductions or lack thereof can be clearly identified. Test events should be evaluated soon after dispatch to identify and correct any issues. This should help avoid the dispatch issues observed in PY 2022.
- **Recruit aggregators and participants ahead of the summer demand response season.** For PY 2021 and PY 2022 delayed enrollment resulted in test events only occurring in the fall (October and November). Resource potential for Residential CBP is the highest in the summer months and the pilot is expected to yield the greatest benefits in these months. It is also important to test load reduction performance in the summer.

[31] 2022 Load Impact Evaluation for San Diego Gas and Electric's Residential Capacity Bidding Pilot by Demand Side Analytics. (Apr 1, 2023) – page 36

Appendix A: Regression Specifications

A.1 Supply Side Demand Response

A.1.1 Emergency Programs

A.1.1.1 Base interruptible program (BIP)

The paragraphs below describe the ex-post and ex-ante methodologies[32]:

a) Ex-post

The following is a general form of the model that would be separately estimated for an enrolled BIP customer. Table A.1-1 below describes the terms included in this equation for the observed demand in a given hour *h* and date *d:*

$$
\begin{aligned}
Q_t \; = \; & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=1}^{24}(b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t}) \\
& + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{i=6}^{10}(b_i^{MONTH} \times MONTH_{i,t}) + \sum_{i=2}^{24}(b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + e_t
\end{aligned}
$$

[32] 2022 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1st, 2023)

Table A-1: Descriptions of Variables included in the Ex-post Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a BIP customer
The various b's	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10 (may be excluded via model screening)
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday (Sunday hourly indicator variable is included in models that include weekend dates)
$MONTH_{j,t}$	a series of indicator variables for each month (model screening may include separate hourly profiles by month)
$SUMMER_t$	an indicator variable for the summer pricing season[33]
e_t	the error term

B) Ex-ante

Because BIP events may be called in any month of the year, separate regression models were estimated to allow for simulated winter reference loads. The winter model is shown below. This model is estimated separately from the summer *ex-ante* model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table A-2 describes the terms included in the equation.

$$
\begin{aligned}
Q_t \; = & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) \\
& + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{j=2-4,11-12}(b_j^{MONTH} \times MONTH_{j,t}) + e_t
\end{aligned}
$$

[33] The summer pricing season is May through October for SDG&E.

Table A-2: Descriptions of Terms included in the Ex-ante Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour t for a customer enrolled in BIP prior to the last event date
The various b's	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g., *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday (Sunday hourly indicator variables are included in models that include weekend dates)
$MONTH_{j,t}$	an indicator variable for Monday and Friday (Sunday hourly indicator variables are included in models that include weekend dates)
e_t	the error term

A.1.2 Aggregator Programs

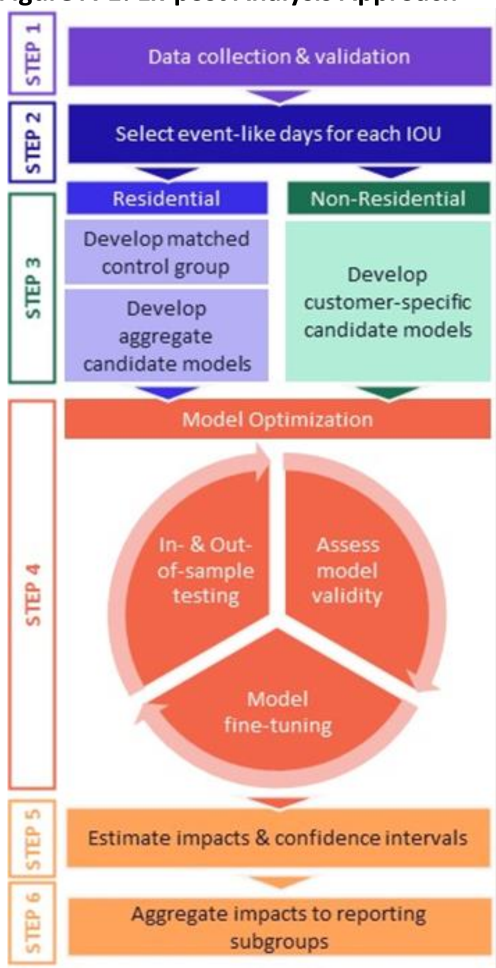
A.1.2.1 Capacity Bidding Program (CBP)

The paragraphs below describe the ex-post and ex-ante methodologies:[34]

a) Ex-post

Figure A-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 A-1: Ex-post Analysis Approach



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.

[34] 2022 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2023)

In this simple example below, α_t, δ_t, and CDH_t, make up the baseline blocks of the model, and explain variation in kwh_{it} unrelated to demand response events. The remaining variables, $EVNT$, and the interaction term $(\alpha_t * EVNT)$ are the impact blocks and explain the variation in kwh_t related to a CBP event. An hourly model like the equation below can be equivalently estimated as one model with hourly dummy variables or as 24 separate hourly models.

$$kwh_{it} = \beta_0 + \beta_1 \alpha_t + \beta_2 \delta_t + \beta_3 CDH_t + \beta_4 EVNT + \beta_5 (\alpha_t * EVNT) + \varepsilon_{it}$$

Where:

kwh_{it} is the consumption of customer i in hour t.

β_0 is the intercept.

β_n is the coefficient associated with each explanatory variable.

α_t is a vector of baseline explanatory variables (e.g., average load, baseline interactions, etc.).

δ_t is a vector of calendar variables (i.e., month, year, and day of the week).

CDH_t represents the cooling degree hours for hour t.

$EVNT$ is a dummy variable indicating that hour t was on a CBP event day.

$(\alpha_t * EVNT)$ is an interaction between the event indicator and baseline explanatory variables.

ε_{it} is the error for customer i in time t.

Table A.3 presents the different explanatory variables used to create candidate models for the CBP.

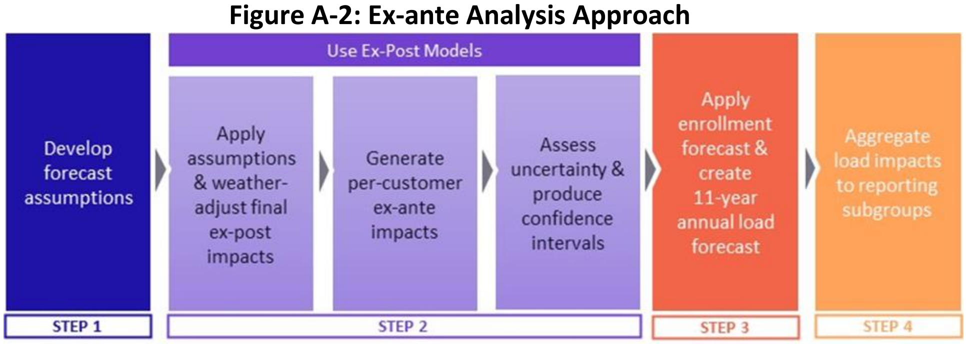
Table A-3: Explanatory Variables Included in Candidate Regression Models

Variable Name	Variable Description
	Baseline Variables
$Weather_{i,d}$	Weather-related variables including average daily temperature, cooling degree hour (CDH) terms with base value of 70, heating degree hour (HDH) with base value of 60, 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
$OtherEvt_{i,d}$	Equals one on event days of other demand response programs in which the customer is enrolled
$AvgLoad_{i,d}$	The average of each day's load in specified window
	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
$P*EventWindow_{i,d}$	An indicator variable for aggregator program event days interacted with an indicator for the window the event is called

b) Ex-ante

Figure A.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 A-2: Ex-ante Analysis Approach



A.1.3 Price Responsive Programs

A.1.3.1 AC Saver Day Ahead commercial and residential programs

a) Ex-post

The 2022 Residential DR Evaluation does not use a regression model for ex-post results. Instead, a matched control group is identified and used to estimate how program participants would have behaved in the counterfactual where they were not enrolled in AC Saver Day Ahead. The procedure for identifying the matched control group compares treated and untreated customers on non-event days; customers with similar load shapes on non-event days act as a proxy for what participants would have done if the event had not been called. Several matching algorithms (e.g. Euclidean distance, propensity matching) and site characteristics were compared. The winning matching process minimizes the error between treated and control group customers on these non-event days. On event days, the control group's behavior establishes a reference load. The load impact of the ACSDA Residential program is computed as the difference between the control group and the program participants, net of the (minimized) error on non-event days.

b) Ex-ante

A key objective of the 2022 evaluation is to quantify the relationship between demand reduction, temperature, and hour of day. Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events use the reductions for a standardized set of weather conditions.

At a fundamental level, the process of estimating ex-ante impacts includes five main steps:

1. Estimate the relationship between cooling load per thermostat (absent DR) and weather by hour of day
2. Estimate the relationship between cooling load percent reduction, temperature, and hours into an event using historical event data
3. Predict cooling loads and percent reductions for 1-in-2 and 1-in-10 weather year conditions
4. Combine the loads and percent reductions to estimate impacts per connected thermostat
5. Incorporate the enrollment/device forecast and device connectivity forecast

A.1.3.2 AC Saver Day Of commercial and residential programs

The paragraphs below describe the ex-post and ex-ante methodologies:[35]

b) Ex-post

In previous years, a randomized controlled trial (RCT) framework was utilized to estimate ex-post reference loads for the residential segment. However, the implementation of this framework was associated with technical challenges and sampling error due to changes in customer load between the two control groups from one season to the next. Further, the RCT framework requires a fraction of the enrolled residential population be held back during events to serve as a control group, reducing the total load impacts of the program. In the 2021 evaluation, Resource Innovations recommended utilizing a statistical matching framework for the residential sector, which was implemented for the 2022 program year.

Dissimilarity Statistic for Matching

$$Dissimilarity_i = \left(PeakProxy_i - PeakProxy_j\right)^2 + \left(EventMorn_i - EventMorn_j\right)^2 + \left(EventMidday_i - EventMidday_j\right)^2$$

Table A-4: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$PeakProxy$	Average demand across the 2022 proxy days during the event window hours
$EventMorn$	Average demand on the event day from midnight to 10 am
$EventMidday$	Average demand on the event day from 10 am to the start of the event
j	AC Saver Day Of participant to be matched
i	Index of the pool of control customers

Ex-post event impacts were estimated for a broad collection of program segments including customer class, cycling strategy, NEM status, climate zone, industry, and status of dual-enrollment in other pricing and demand response programs at SDG&E.

In previous years, a lagged dependent variable (LDV) regression model was used to estimate load impacts in both the residential and non-residential segments. Since a statistical matching framework was used for both segments in this evaluation, a difference-in-differences (DiD) regression methodology was employed to better control for inherent differences that likely exist between the treatment and control customers. This methodology assumes that the program impact is equal to the difference in usage between the treatment and

[35] AC Saver Day Of 2022 Load Impact Program Evaluation by Resource Innovations (Mar 2023)

the control groups during the event window period, minus any pre-existing difference between the two groups. When using a DiD methodology, the matched control group does not need to perfectly match the treatment group on non-event days. Subtracting any difference between treatment and control customers on non-event days adjusts for any difference between the two groups that might occur due to random chance. Therefore, any further change between the groups in the post-treatment period can be measured as the impact of treatment. The regression specification for estimating load impacts is shown below.

Difference-in-Differences Model for Estimating Impacts

$$kwh_{i,t} = \alpha_i + \delta \ \mathrm{treat}_i + \gamma \ \mathrm{post}_t + \beta(\mathrm{treat} \times \mathrm{post})_{i,t} + u_t + v_i + \varepsilon_{i,t}$$

Table A-5: Explanatory Variables included in Regression Models

Variable Name	Variable Description
i, t	Indicate observations for each individual i, date t, and event number n
α	The model constant
δ	Pre-existing difference between treatment and control customers
γ	The difference between event and proxy days common to both treatment and control group members
β	The net difference between treatment and control group customers during event days– this parameter represents the difference-in-differences
μ	Time effects for each date that control for unobserved factors that are common to all treatment and control customers but unique to the date
υ	Customer fixed effects that control for unobserved factors that are time-invariant and unique to each customer
ε	The error for each individual customer and time period
treat	A binary indicator or whether or not the customer is part of the treatment or control group (in practice this is absorbed by the individual customer fixed effects)
post	A binary indicator that equals 0 in the pre-treatment period and 1 in the post-treatment period (in practice this is absorbed by the individual date fixed effects)
*treat*post*	A binary indicator of whether an event occurred that day–impacts are only observed if the customer is on PTS (Treatment = 1) and it was an event day

b) Ex-ante

Table A-6 presents the model that is used to estimate reference load and load impacts as a function of weather. This model is estimated separately by customer class (residential and commercial) and cycling strategy. The estimated parameters from the models are used to predict reference loads under 1-in-2 and 1-in-10-year ex-ante weather conditions for all months of the year that the program may be dispatched.

Table A-6: Ex-ante Model for Reference Loads and Load Impacts

$$impact_d = b_0 + b_1 \times mean17_d + \varepsilon_d$$

Variable Name	Variable Description
$impactd$	Core 2019,2021 and 2022 ex-post impacts
b_0	Estimated constant
b_1	Estimated parameter coefficient
$mean17_d$	Average temperature over the first 17 hours of the day for each event day
ε_d	The error term for each day d

A.2 Load Modifying DR

A.2.1 Price responsive Programs

A.2.1.1 Critical Peak Pricing (CPP)

The paragraphs below describe the ex-post and ex-ante methodologies for large and medium nonresidential customers:[36]

a) Ex-post

SDG&E can trigger a CPP Event if the day-ahead system load forecast for the potential event day is greater than 4,000 MW. There were 5 events called in the summer of 2022, during the heat wave at the beginning of September (including the weekend of Labor Day). Ex-post load impacts for these events are computed using a panel regression model given by:

$$Q_t = a + \Sigma_{Evt=1}^{E}(b^{Evt} \times CPP_t) + b^{MornLoad} \times MornLoad_t + b^{Wth} \times Wth_t + b^{othDR} \times OthDR_t + \Sigma_{j=days\ of\ week} b^j \times DayType_t^j + \Sigma_{j=months} b^j \times Month_t^j + e_t$$

The variables are explained in the following table:

Table A-7: Ex-Post Regression Model Variables for CPP Panel Regression

Variable Name / Term	Variable / Term Description
Q_t	the customer's usage on day *t*
a and the various *b*s	the estimated parameters
CPP_t	an indicator variable for CPP event days
Wth_t	weather conditions on day *t* (e.g., measured by CDD, CDH, or THI)
E	the number of event days that occurred during the program year
$MornLoad_t$	variables equal to the average of the day's load in hours-ending 1 through 7 and separately for hours-ending 8 through 14.
$DayType^j_t$	an indicator variable for day of week *j* on date *t*
$Month^j_t$	a series of indicator variables for each month
$OthDR_t$	a series of indicator variables representing event days for other DR programs in which the service account is enrolled
e_t	the error term.

b) Ex-ante

Estimating ex-ante load impacts for future years requires three key pieces of information:

- A utility-provided *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;

[36] 2022 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing (CPP) Rates by Christensen (Feb 2023)

- *Reference loads* by customer type;
- A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions (if applicable), as determined in the ex-post evaluation.

The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios.

Load impacts are provided for the years 2023 through 2033 for a variety of day types and weather scenarios, including the following:

- A typical event day under the four weather scenarios, defined by both utility-specific and CAISO peaking conditions in both 1-in-2 (normal) and 1-in-10 (extreme) scenarios; and
- The monthly system peak load day of each month, again under the above four weather scenarios.

A.2.1.2 Default Small Commercial CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies:[37]

a) Ex-post

Small CPP

The change in energy use patterns was estimated using difference-in-differences with a control site matched to each participant. Key modeling design components are as follows:

- Matched control tournament: In order to identify the control pool sites that best matched each participant's energy use patterns on event-like proxy days (similar in weather and system conditions to event days), several matching methods were tested. These methods included different matching algorithms (e.g. Euclidean and propensity matching) and different site characteristics to be used in the matching. Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and site weather sensitivity. Control candidates were also "hard-matched" on climate zone, net metering status, and size.
- Difference in-differences model with event and non-event days and participants and matched controls: The data was structured with participant loads pre- and post-intervention and control loads pre- and post-intervention side by side. Per site load impacts were estimated with difference-in-differences to net out exogenous differences between treatment and control that existed prior to the intervention. This approach was used as the primary method for event impacts for critical

[37] 2022 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program by DSA (Mar 2023)

peak events delivered by Small CPP participants and Technology Deployment program participants[38].

Small CPP Agricultural

Panel regressions with multiple control groups were used as the primary method for estimating load impacts for PY 2022 impacts for Small CPP Agricultural. The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads with a panel model, one should observe:

- Very similar energy use patterns for participant and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of a panel model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. The equation for the model is presented below. A separate model was estimated for each intervention and hour of the day. Pre and post event terms (single hour with two-hour buffer) were added to the Small CPP Ag models to implement the same calibration for these load control programs.

Equation Ex-Post Regression Model for Small CPP Ag

$$kW_{i,t} = \mathrm{a} + \mathrm{b} \cdot kW\_1 - kW\_5_i + \sum_{n=1}^{max} \mathrm{c}_n \cdot Event_n + \mathrm{d} \cdot CDH_{i,t} + \delta_t + \varepsilon_{i,t}$$

[38] Due to the very small sample size, a panel regression model was used for Small CPP Agricultural participants.

Table A-8: Ex-Post Regression Elements for Small CPP Ag

Variable Name / Term	Variable / Term Description
$kW_{i,t}$	Is the usage for each individual customer and time period
a	Is the model intercept
b	Loads for the five most closely matched control sites based on Euclidean distance matching. They did not experience the treatment and are weighted based on their predictive power.
c	Controls for differences between event and non-event days
d	Is the parameter for weather sensitivity of loads
Event	Is a binary variable indicating if day is an event. Separate variables are used for each event so impacts are estimated for each event. It has a value of zero on event-like proxy days. The five closest non-event days were included as proxy days for each event. Separate proxy days were selected for each event using Euclidean distance matching.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

b) Ex-ante

A key objective of the 2022 evaluation is to quantify the relationship between demand reductions, temperature and hour of day. Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used to estimate the reductions for a standardized set of weather conditions.

At a fundamental level, the process of estimating ex-ante impacts included five main steps:

1. Estimate the relationship between customer loads (absent DR) and weather
2. Use the models to predict customers loads (absent DR) for 1-in-2 and 1-in-10 weather year conditions
3. Apply the average percent reductions, at an hourly level, from historical events. The average reduction was employed because experience with small business default CPP is limited and there is less of a history of program performance across events.
4. Estimate reductions for 1-in-2 and 1-in-10 weather year conditions
5. Incorporate the enrollment forecast

A.2.1.3 Voluntary Residential CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies for and TOU rates:[39]

a) Ex-post

The ex-post impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that involve selecting quasi-experimental matched control groups and then comparing the usage of treatment and control group customers on relevant days or time periods, where the comparisons are then adjusted by usage differences on pre-treatment or non-event days. The control groups were selected by matching each treatment customer to one of an initial sample of eligible non-treatment customers in relevant population segments (e.g., climate zone, CARE status, and solar PV size), based on the closest match of load profiles.

The formal ex-post load impact estimates are based on fixed-effects panel regression models. Two versions of fixed-effects models were estimated. The first version was used to estimate residential CPP event-day hourly load impacts. Weekend CPP events were estimated separately from weekday events, as load usage may vary between weekdays and weekend days. The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR and TOU-DR-P customers). In addition to estimating each load impact type separately by rate, the load impacts were estimated separately for NEM customers within each rate. In the first model, which addresses the objective of estimating hourly ex-post load impacts at the program level, a set of twenty-four separate fixed-effects models were estimated, one for each hour of the day. These models allow customer-specific constant terms, but estimate the same coefficient, effectively representing an average load impact across the included treatment customers, for variables that do not vary across customers (e.g., the occurrence of an event day).

- Ex-post models for estimating CPP load impacts: The load impact estimation model for CPP accounts for customer-specific and date-specific fixed effects (which include weather and day-type factors) and effectively estimates the CPP load impact as the difference between CPP and control-group customer loads on event days, controlling for the aforementioned fixed effects. This can be described as a difference-in-differences estimate (the difference between treatment and control group usage on event days, adjusted for differences on non-event days). The primary customer-level fixed-effects

[39] 2022 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates by Christensen (April 2023)

regression model used in the analysis is shown below, where the equation is estimated separately for each of the 24 hours. This model produces load impact estimates for each hour of every event:

$$kWh_{c,d} = \beta_0 + \Sigma_{Evts(i)} (\beta_{1,i} \times CPP_{c,d} \times Evt_{i,d}) + \Sigma_{Evts(i)} (\beta_{2,i} \times TD_{c,d} \times Evt_{i,d}) + \Sigma_{Evts(i)} (\beta_{3,i} \times CPP\_Control_{c,d} \times Evt_{i,d}) + \Sigma_{Evts(i)} (\beta_{4,i} \times TD\_Control_{c,d} \times Evt_{i,d}) + \beta_5 \times \mathrm{CPP}_{c,d} + \beta_6 \times SS\_Evt_{c,d} + \Sigma_{Cust} (\beta_{7,Cust} \times C_c) + \Sigma_{date} (\beta_{8,date} \times D_{date,d}) + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in table A-9. Results are scaled to enrollment numbers because a portion of residential CPP customers are removed from the analysis based upon load quality and NEM customer restrictions. We also use a similar specification to estimate CPP load impact among specific subsets of customers (e.g., notified vs non-notified, dual enrollment).[40]

[40] For example, in the case of notification status, each event day will have a separate coefficient estimated for notified and non-notified customers. Similar to how the above specification separates each event day load impact coefficient for CPP customers not on TD versus CPP customers on TD.

Table A-9: Description of Variables Used in the CPP Analysis Regressions

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
$CPP_{c,d}$	Variable indicating whether customer *c* is only a *CPP* customer (*i.e.*, not also dually enrolled in *TD*) on date *d* (1 = yes, 0 if not)
$TD_{c,d}$	Variable indicating whether customer *c* is a dually enrolled *CPP* and *TD* customer on date *d* (1 = yes, 0 if not)
$CPP\_Control_{c,d}$	Variable indicating whether customer *c* is a control customer matched to a *CPP* customer who is not dually enrolled, on date *d* (1 = yes, 0 if not)
$TD\_Control_{c,d}$	Variable indicating whether customer *c* is a control customer matched to a dually-enrolled *CPP* and *TD* customer, on date *d* (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date *d* is the i^{th} event day (1=i^{th} event, 0 if not)
$SS\_Evt_{c,d}$	Variable indicating that date *d* is *a Summer Saver* event day (1=event, 0 if not) for customer *c*
β_0	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event *d* for *CPP* only customers
$\beta_{2,d}$	Estimated load impact for event *d* for dually enrolled *CPP* and *TD* customers
$\beta_{3,d}$	Estimated load impact for event *d* for control customers matched to *CPP* only customers
$\beta_{4,d}$	Estimated load impact for event *d* for control customers matched to dually enrolled *CPP* and *TD* customers
β_5	Estimated non-event day response for incremental *CPP* customers
β_6	Estimated average *Summer Saver* load impact
$\beta_{7,Cust}$ and $\beta_{8,date}$	Customer and date fixed effects
C_c	Variable indicating that the observation is for customer *c*
$D_{date,d}$	Date indicator variable (1 = date *d* equals date *day*)
$\varepsilon_{c,d}$	Error term

- Ex-post models for estimating TOU load impacts:

The model is estimated separately by rate (*e.g.,* TOU-DR, TOU-DR-P, GTOU-DR-P), hour, month, day-type (*i.e.*, average weekday versus peak month day), and applicable customer groups (*e.g.*, climate zone, NEM). The customer-level fixed-effects models are of the following form:[41]

$$kWh_{c,d} = \beta_0 + \beta_1 \times (TOU_c \times Post_{c,d}) + \Sigma_{Cust} (\beta_{2,Cust} \times C_c) + \Sigma_{dates} (\beta_{3,dates} \times D_{dates}) + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table A-10. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

Table A-10: Description of Variables Used in the TOU Analysis Regressions

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
TOU_c	Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer
$Post_{c,d}$	Variable indicating that date *d* is in the post-enrollment period for customer *c*
β_0	Estimated constant coefficient
β_1	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
C_c	Variable indicating that the observation is associated with customer *c*
D_{date}	Variable indicating that the observation is for date *d*
$\varepsilon_{c,d}$	Error term

b) Ex-ante

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on analyses of per-customer load impact findings from ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments. The ex-ante analysis for CPP events applies CPP event load impacts from the ex-post analysis to simulated reference loads using PY2022 customer load data.

[41] Note that the customer and date fixed effects remove the need for us to include stand-alone TOU_c and $Post_{c,d}$ variables. The former is perfectly collinear with the customer's fixed effect and the latter is perfectly collinear with a combination of date fixed effects.

A.2.2 Nonevent Based Programs

A.2.2.1 Electric Vehicle Time Of Use and Power Your Drive

The paragraphs below describe the ex-post and ex-ante methodologies:[42]

a) EVTOU - Ex-post

Table A-11: EV TOU Ex-Post Evaluation Approach Summary

Methodology Component	Description
1. Population or sample analyzed	The full population of incremental participants, along with a matched control group, was analyzed. The evaluation focused only on incremental sites that enrolled on EVTOU in 2022 and excluded sites who had a change in electric vehicle, solar, or battery status that coincided with the study period. The evaluation includes 25% of the new enrollments because it is common for customer to enroll on TOU rates for electric vehicles when they first get their vehicle.
2. Data included in the analysis	The analysis included up to year of pre and post TOU data. The same data was included for participants and matched control. In all cases, we ensured that both the participant and control had pre and post TOU data for the same day of year.
3. Use of control groups	We relied on control group of customers with electric vehicles but who were not on SDG&E's TOU rates for electric vehicles. The process involves two steps. First, we build electric vehicle propensity using AMI data to identify unique load patterns that indicate the presence of electric vehicles (but avoiding variables about load shape and overall consumption). As part of the analysis, DSA will also identify the date the electric vehicle(s) arrived at the household. Once control candidates with electric vehicles had been identified, we matched customers who enrolled on TOU rates for electric vehicles in 2021 using 2020 (pre-treatment) hourly AMI data. The matching on pre-treatment loads used Euclidian distance matching and matched were selected only from customers with similar electric vehicle propensity scores.
4. Evaluation Method	Panel regression difference-in-differences with fixed customer effects, daily time effects, and weather were used to isolate the load impact. Regressions were run for like days. For example, when we estimated impacts for the top 10 highest system load days, we included only the top 10 highest load days in the year before and after EV TOU enrollment. This ensures the difference in differences adjustment was calibrated to correct day types.
5. Model selection	The approach relies more heavily on selecting a comparable matched control group than the model specification. We conducted a tournament to identify the model that performed best at identifying the control pool with electric vehicles, but not on TOU rates for electric vehicles. For the evaluation, we used a standard difference-in-differences panel regression with customer fixed effects, date-time effects, and weather explanatory variables.
6. Segmentation of impact results	The results were segmented by: ▪ Rate ▪ Region in SDG&E territory (based on 3-digit zip code) ▪ Solar status ▪ Low income

[42] 2022 Load Impact Evaluations for San Diego Gas and Electric's Electric Vehicles Time-of-Use (TOU) Rates by Demand Side Analytics (Apr 2023)

b) EVTOU - Ex-ante

Table A-12: EV TOU Ex-Ante Evaluation Approach Summary

Methodology Component	Description
1. Years of historical data	Data from the year prior to the adoption of EVTOU rates for each customer was used to develop reference loads. The load reductions for a full year with EVTOU participation were used to model ex-ante load impacts
2. Process for producing ex-ante impacts	The key steps were: ▪ Segment customers by rate type (EV TOU5 and EVTOU2) and solar status ▪ Estimate the relationship between reference loads and weather on a per household basis. ▪ Use the models to predict reference loads for 1-in-2 and 1-in-10 weather year conditions. ▪ Estimate the relationship between EVTOU load impacts and weather. ▪ Predict the reductions for 1-in-2 and 1-in-10 weather year conditions. ▪ Combine per customers reference loads and load impacts with an incremental forecast of enrollment on EV TOU rated developed by SDG&E.
3. Accounting for changes in the participant mix	The ex-ante load impacts accounts for changes in the participant mix across the two main rate types – EVTOU2 and EVTOU5 – and due to rooftop solar status.
4. Producing busbar level impacts	Granular results for distribution planning have been required for the last few years. A key consideration in the approach is that there is more data about customer loads than there is data on the percent reductions delivered during events. To develop ex-ante impacts at the busbar level, we use the load impacts by segment and the current mix of customers at the busbar level to estimate the granular impacts.

c) Power Your Drive

Table A-13: Power Your Drive Evaluation Approach

Methodology Component	Description
1. Population or sample analyzed	Charging data from all PYD charging sessions from the program's launch in 2017 through December 2021 were provided for evaluation. We analyzed charging sessions from January 2019 through December 2022. Until 2019, the program was still quickly bringing stations online and aggressively enrolling participants.
2. Data included in the analysis	For the PYD evaluation, we utilized: ▪ Charging session level kWh consumption data ▪ Driver Enrollment Data ▪ Site and Station characteristics ▪ Charging $/kWh prices by day, hour, and station ▪ Historical weather patterns from Weather station records
3. Evaluation Method	Panel regression by charging station with multiple fixed effects. Regressions were run in relation to both Price response and Event responses. The Price model related price changes on the program to hourly charging kWh. The Event based model flagged hours with circuit or system Critical Peak Pricing adders as events. The coefficients of these models demonstrate the magnitude of customer response to measured changes in pricing as well as event hours.
4. Model selection	To estimate customer response DSA ran linear regressions with multiple fixed effects and multi-way clustering. The regressions treated station ID, date, day of week and hour as categorical regressors, and captured Station ID and date as fixed effects in each panel.
5. Segmentation of impact results	The results will be segmented by: ▪ Site type: Workplace vs. Multi-Unit Dwellings ▪ Rate to Host vs. Rate to Driver

A.2.3 Pilot Programs

A.2.3.1 Non-Residential ELRP

The paragraphs below describe the ex-post and ex-ante methodologies:[43]

a. Ex-Post

Individual site regressions with synthetic controls and site-specific specifications were used as the primary method for estimating load impacts for PY 2022 impacts for Non-Residential ELRP. The approach is implemented on hourly participant site loads. It relies on control sites that did not experience the intervention (up to five matched to each participant site), lagged participant site usage, an industry usage profile, solar irradiance, plus weather and time characteristics, to estimate the counterfactual. The model estimates a

[43] 2022 Load Impact Evaluations for San Diego Gas and Electric's Electric Non-Residential Emergency Load Reduction Pilot by Demand Side Analytics (Apr 2023)

counterfactual load using weather and these various synthetic controls and predictors. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed participant site and predicted counterfactual loads. With a regression model with synthetic controls, one should observe:

- Very similar energy use patterns for participant site and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of individually specified site specific regression models allows for incorporation of a subset of possible parameters that best predict out of sample loads for each site and does not rely on finding a single ideal match. The model equation including the full set up possible parameters is presented in equation and table below. In practice the model used for each site and included a varying subset of these parameters. A separate model was estimated for each hour of the day.

Ex-Post Regression Model for Non-Residential ELRP

$$kW_t = \mathrm{a} + \sum_{n=1}^{max} \mathrm{b} \cdot kW\_0_{n,t} + \sum_{n=1}^{max} \mathrm{c}_n \cdot kW\_1_{t-n} + \sum_{n=1}^{max} \mathrm{d}_n \cdot month_n + \sum_{n=1}^{max} \mathrm{e}_n \cdot dow_n + \mathrm{f} \cdot solar_t + \mathrm{g} \cdot industry_t + \sum_{n=1}^{max} \mathrm{h}_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

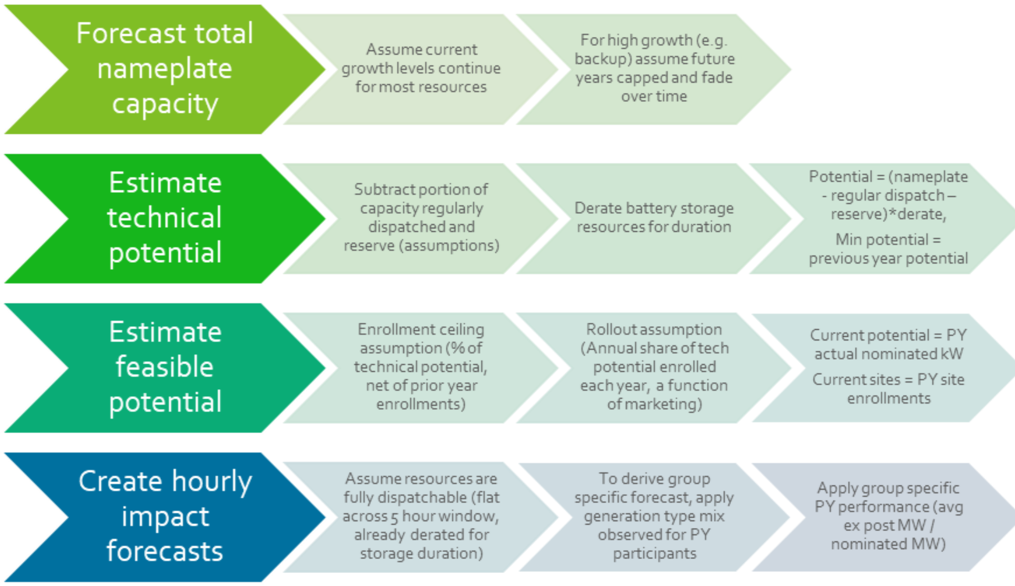
Table A-14 Ex-Post Regression Elements for Non-Residential ELRP

kW_t	Is the site usage for each time period.
kW_0_t	Is the synthetic control usage for up to 5 matched controls for each time period. The specific number of controls used varied by site. These synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
kW_1_{t-n}	Is the lagged participant site usage and could by one of: no lags, 1 day, 1 week, 2 weeks, 1 day and 1 week, and 1 and 2 weeks. The specific lags used varied by site.
a	Is the model intercept.
b	Coefficients for the synthetic control loads. The specific number of controls used varied by site.
c	Coefficients for the participant site usage lags. The specific lags used varied by site.
d	Coefficients for each month.
e	Coefficients for each day of week.
f	Coefficient for solar irradiance across for each time period. Inclusion of this parameter varied by site.
g	Coefficient for industry load profile: normalized hourly loads (scaled from 0 to 1) for control sites in the same industry as the participant site. Industry grouping developed using NAICS code and customer names indicative of industry activity. Inclusion of this parameter varied by site.
h	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 24 hour moving average of temperature, averaged across participant sites for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{(i,t)}$	Represents the error term for each individual customer and time period.

b. Ex-Ante:

The figure below summarized ex-ante forecast model uses historical interconnection data to derive the ex-ante load reduction estimates. Essentially, historical interconnected capacity and growth rates are used to project future interconnected capacity. The technical potential for the program is deemed to be the remainder of forecasted interconnection capacity after subtracting the portion of capacity assumed to be typically used for daily operations the portion expected to be reserved for on-site back-up of other purposes. The feasible potential incorporates expected limits on enrollment. Enrollments for PY 2022 are tied to the reduction capacity nominated by participant sites in PY 2022. The expected impacts further incorporate derating of battery storage capacity to reflect duration limits. Forecasted reductions for PY 2022 are tied to average MW reductions across all events. They are not tied to the average weekday event because no clear pattern was observed by weather, day type, duration or event window. Actual PY 2022 reductions are used to derive a performance factor, relative to nominated capacity. This performance factor is then carried through subsequent years.

Figure A-3: Non-Residential ELRP Ex-Ante Model Architecture



A.2.3.2 Residential ELRP

The paragraphs below describe the ex-post and ex-ante methodologies:[44]

A) Ex-Post

The 2022 ELRP Residential Pilot load impact report does not use a regression model to determine ex-post results. Instead, a matched control group is identified and used to estimate how program participants would have behaved in the counterfactual where they were not enrolled in AC Saver Day Ahead. The procedure for identifying the matched control group compares treated and untreated customers on non-event days; customers with similar load shapes on non-event days act as a proxy for what participants would have done if the event had not been called. Several matching algorithms (e.g. Euclidean distance, propensity matching) and site characteristics were compared. The winning matching process minimizes the error between treated and control group customers on these non-event days. On event days, the control group's behavior establishes a reference load. The load impact of the ACSDA Residential program is computed as the difference between the control group and the program participants, net of the (minimized) error on non-event days.

For the statewide flex alert, which exposed all customers to a 'treatment,' the procedure of difference in differences with a matched control group was not feasible. Instead, a within customer time series model was necessary to estimate the effect of the statewide emergency alert. A spline weather model was constructed using a primary weather variable selected from among ten variables.

B) Ex-Ante

A key objective of the 2022 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used as the reductions for a standardized set of weather conditions. At a fundamental level, the process of estimating ex-ante impacts included five main steps:

1. Estimate the relationship between customer loads (absent DR) and weather by hour of day

[44] 2022 Load Impact Evaluations for San Diego Gas and Electric's Residential Emergency Load Reduction Pilot by Demand Side Analytics (Apr 2022)

2. Estimate the relationship between customer load percent reduction, temperature, and hours into an event using historical event data
3. Predict cooling loads and percent reductions for 1-in-2 and 1-in-10 weather year conditions
4. Combine the loads and percent reductions to estimate impacts per customer
5. Incorporate the enrollment forecast

A.2.2.3 Residential CBP

The paragraphs below describe the ex-post and ex-ante methodologies:[45]

A) Ex-Post:

A time series regression with synthetic controls were used as the primary method for estimating load impacts for PY 2022 impacts for Residential CBP. The approach is implemented on a time series of average customer loads. It relies on control sites that did not experience the intervention (one matched to each participant site), solar irradiance, plus weather and month characteristics, to estimate the counterfactual. The time series model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed participant and predicted counterfactual loads. With a time series model with synthetic controls, one should observe:

- Very similar energy use patterns for participant and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of a time series model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. Inclusion of multiple matches was testing in the model selection tournament but the winning model only included a single matched control (the closest match for each participant). The equation for the model is presented below. A separate model was estimated for each hour of the day.

Equation: Ex-Post Regression Model for Residential CBP

$$kW_t = \mathrm{a} + \mathrm{b} \cdot kW_{0_t} + \sum_{n=1}^{max} \mathrm{c}_n \cdot month_n + \mathrm{d} \cdot solar_t + \mathrm{e} \cdot CDH_t + \sum_{n=1}^{max} \mathrm{f}_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

45 2022 Load Impact Evaluations for San Diego Gas & Electric's Residential Capacity Bidding Pilot by Demand Side Analytics (Apr 2023)

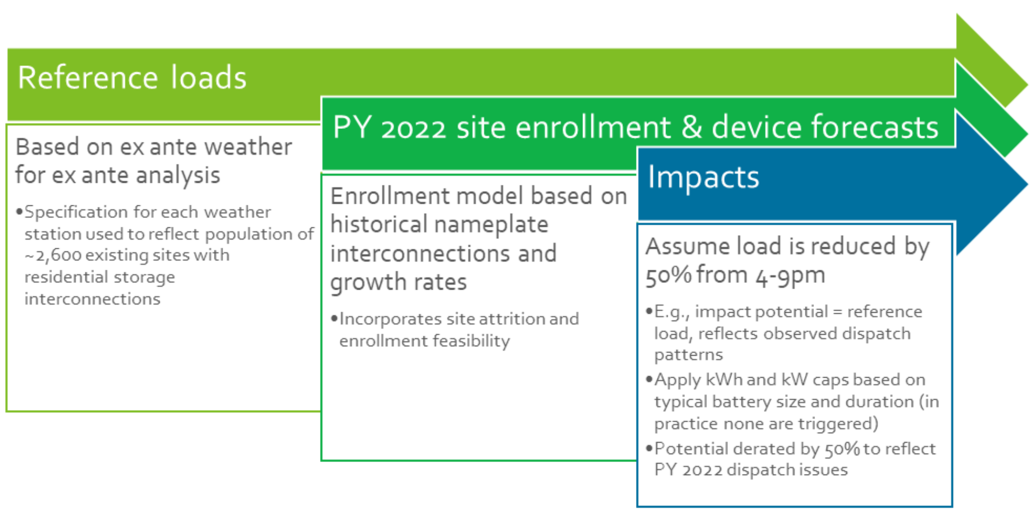
Table A-15: Ex-Post Regression Elements for Residential CBP

kW_t	Is the average usage across participants for each time period.
kW_0_t	Is the average synthetic control usage across matched controls for each time period. Synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
a	Is the model intercept.
b	Coefficient for the synthetic control load.
c	Coefficients for each month.
d	Coefficient for average solar irradiance across participants for each time period.
e	Coefficient for weather sensitivity of loads, based on CDH above 65F.
f	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 18 hour moving average of temperature, averaged across participants for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{(i,t)}$	Represents the error term for each individual customer and time period.

B) Ex-Ante:

The ex-ante capacity forecast for Residential CBP was derived by combining the three key inputs shown below. Essentially, reference loads were developed using 2022 loads for about the roughly 2,600 residential sites with storage. Average impacts were derived by applying impact assumptions from the PY 2021 ex-post evaluation[46], which essentially showed that loads are dropped to 0 kW during events. Aggregate impacts were developed by applying an enrollment forecast based on historical battery storage growth and other key assumptions discussed below.

Figure A-4: Ex-Ante Inputs and Assumptions



[46] Based on PY2021 PG&E residential battery pilot

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