San Diego Gas and Electric 2023 Demand Response Executive Summary

April 1st, 2024

Contents

1. Background and Introduction

1.1 Background

San Diego Gas & Electric (SDG&E) presents this Executive Summary for its Demand Response (DR) activities for program year 2023 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 required the preparation of a voluminous number of tables resulting in the load impact reports that were 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 requested two things: 1) the removal of the requirement to file the load impact reports in their entirety and 2) providing the reports to the Energy Division of the Commission.

On April 8th, 2010, Decision (D.) 10-04-006[2] granted the utilities requests and added an Executive Summary requirement. These executive summaries were to include an overview of the evaluation findings, recommendations for changes to the demand response resource, and 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. Additionally, the IOUs should report the regression model specifications for each demand response program.

On June 24, 2010, Decision (D.) 10-06-036 stated that Protocol 22 requires the use of 1-in-2 weather year for the monthly system peak day. The 1-in-10 weather year, typical event day, or an average weekday for each month are not needed for Qualifying Capacity (QC) calculation or Resource Adequacy (RA).

On March 7th, 2014, Decision (D.) 14-03-026[3] directed that supply resources are defined as resources that are integrated into the California Independent System Operators energy markets. Additionally,

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

[2] Decision (D.) 10-04-006, OP 1 and OP2.

[3] Decision (D.) 14-03-026, OP3

in 2014, SDG&E was directed to include weather scenarios for load impacts that were coincident with the CAISO's system peak.[4]

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

- Time Of Use (TOU) periods were changed in Decision (D) 17-08-030[5].
- The 2018-2022 Demand Response programs were approved in Decision (D) 17-12-003.
- Decision (D) 18-06-030[6] adopted Local Capacity Obligations for 2019.
- The Default Residential TOU Decision (D) 18-12-004[7] approved Mass TOU Default Migration Plan for 2019.
- Decision (D) 17-01-006 and Decision (D) 17-10-018 allowed Grandfathering for certain NEM customers.

In August 2017, Decision (D) 17-08-030[8] 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 Decision (D.) 17-12-003, which provided approval of SDG&E's DR program application and among other things, directed the Peak Time Rebate program[9] and Permanent Load Shifting (PLS) program[10] 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 Decision (D) 18-06-030, Adopting Local Capacity Obligations for 2019 and refining the CPUC's Resource Adequacy Program. Ordering Paragraphs 13 and 14 address changes to the

[4] 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 for CAISO's system peak to be used for establishing RA.
[5] Decision (D.) 17-08-030, OP8. The time-of-use periods defined in Tables 1 and 2 herein must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.
[6] Decision (D.) 18-06-030, OP12, 13 and 14.
[7] Decision (D.) 18-12-004, OP3
[8] Decision (D.) 17-08-030, OP1
[9] Decision (D.) 17-12-003 OP11
[10] Decision (D.) 17-12-003 OP36

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 Decision (D) 18-12-004[11] which allowed SDG&E to default all eligible residential customers onto TOU rates in 2019. Approximately 800,000 of SDG&E's residential customers were transitioned to TOU rates by December 2019. However, 2020 was the last year to identify shifts or load reductions due to the changed TOU and/or default TOU, as over 100,000 small commercial and industrial customers were placed onto TOU rates. Additionally, 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. Furthermore, Electric Vehicle TOU rates were added to the load impact studies that SDG&E conducted in Program Year (PY) 2019.

SDG&E grandfathered certain residential and commercial customers per Decision (D) 17-01-006 and Decision (D) 17-10-018. Under these decisions, eligible behind-the-meter solar customers are permitted to continue billing under previous TOU hours. 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[12], 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. The August and September months of 2020 were extremely warm in southern California and these 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 following a modified work and school schedules, energy usage patterns tended to revert back to a new "normal". Due to 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) prior to the summer of 2021. These new emergency programs aimed to offset the need for any further rolling blackouts in 2021. Both programs were up and

[11] Decision (D.) 18-12-004 OP3

[12] Grandfathering for residential customers ended on July 31st, 2022

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.[13] The purpose of the document was to establish consistent due dates for Investor-Owned Utilities IOU's and Third party demand response providers (DRPs), along with a schedule for filing the Load Impact reports. The document also emphasized the need for QC updates 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, as per Decision (D) 20-06-031[14]. Amount other things, the Guide stated that updates to QC are warranted if changes varied by more than 20% or 10MWs. Additionally, the Guide provided "Best Practices" for Load Impact Protocol Filings.

In 2022, all ex-ante load impact summaries were averaged over the current Resource Adequacy (RA) hours of 4 pm to 9 pm for all programs and/or dynamic rates. The CPUC clarified the quarterly testing report requirements and moved the RA measurement hours during the months of March and April from 4-9 PM to 5-10 PM. Therefore, 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).[15]

In August 2022, Decision (D) 22-08-039 said it was reasonable to use the existing LIP methodology to establish RA for 2023. However, the CPUC recognized that Load Serving Entities (LSEs) would need further guidance on how to utilize the LIP outputs under the new RA 24-hour slice framework. Parties were directed to submit proposals in Workstream 2 of R.21-10-002.11.[16] This process resulted in Decision (D.) 23-04-010[17], which made updates to the Demand Response (DR) RA counting methodology under the 24-hour slice-of-day framework for the 2024 RA test year.

On December 1, 2022, Decision (D.) 22-12-009 approved SDG&E 's residential CBP Pilot for the 2023 Bridge Year. On May 2, 2022, SDG&E (A.22-05-003) and the other IOUs filed 2023-2027 DR portfolio applications. However, given the late filing of these applications, the Utilities requested the CPUC to initially consider on an expedited schedule their requests for 2023 Bridge Funding (Phase I), in order to ensure the continued

[13] Guide to CPUC's Load Impact Protocols (LIP) Process, Version 3.0. (Jan 06, 2022) pg. 3, 5-6
[14] Decision (D.) 20-06-031 OP15
[15] D22-06-050, OP5
[16] D.22-08-039, OP 2-3, at 15
[17] Decision (D.) 23-04-010, OP2 and 23.

operation of their DR programs through 2023, while leaving consideration of the 2024-2027 program year budgets until a later time (Phase II).

On June 29th, 2023, Decision (D.) 23-06-029 authorized two parallel Working Groups (WGs) led by Energy Division staff. The first WG would continue the work initiated by the California Energy Commission (CEC) Supply-Side Demand Response (SSDR) Qualifying Capacity (QC) WG to refine elements in the CEC's incentive-based supply-side DR QC proposal by December 2024.[18] The second WG would propose how to simplify the load impact protocols using a stakeholder process[19] by January 19, 2024.[20] Both Working Groups were scoped into R.23-10-011, the new RA proceeding.[21]

In addition, Decision (D.) 23-06-029[22] states that the Resource Adequacy (RA) measurement hours are modified to 5:00pm-10:00 p.m. for March, April, and May, and 4:00pm–9:00 p.m. for all other months. The modified RA hours shall be effective beginning in the 2024 RA compliance year.

On December 14, 2023, Decision (D.) 23-12-005[23] (Demand Response Programs, Pilots, and Budgets for the years 2024-2027 DR Application) ordered SDG&E the following:

1) Eliminate its Capacity Bidding Program Prescribed product option[24] within 60 days of the date of issuance of this decision.

2) Sunset the Base Interruptible Program (BIP) at the end of 2023.

3) Terminate the current Smart Energy Programs (SEP) formerly named as AC Saver programs (Day Of and Day Ahead), at the end of 2023 and decline to fund the SEP for future years.

4) Continue ELRP Group A (excluding sub-group A.6 PSR) and Group B pilot through 2027.

5) Continue ELRP sub-group A.6 (residential) pilot through 2025.

6) Authorized SDG&E to submit a Tier 2 advice letter seeking to make its CBP Residential Pilot permanent, contingent upon a showing of a Total Resource Cost (TRC) test of 1.0 or greater be cost effective.

7) Authorize SDG&E to submit a Tier 3 advice letter by December 31, 2024, seeking additional budget for its CBP Residential Program, if necessary.

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[18] Decision (D.) 23-06-029, OP 23, at 143-144.
More information about the SSDR QC WG can be found here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops. Or email David.Oliver@cpuc.ca.gov.

[19] Decision (D.) 23-06-029, COL 17, at 134.
For more information about the LIP Simplification WG, please email Andrew.Magie@cpuc.ca.gov and LoadImpactProtocolsInfo@cpuc.ca.gov.

[20] Order Instituting Rulemaking R.23-10-011, at 6.

[21] Order Instituting Rulemaking R.23-10-011, preliminary scoping issue 6, at 5.

[22] Decision (D.) 23-06-029, OP5

[23] Decision (D.) 23-12-005, OP 28, 31, 35, and 50. Conclusion of Law 20 and 113.

[24] The Capacity Bidding Program Prescribed product option includes CBP Day Ahead and Day Of 11am-7pm and 1pm-9pm.

1.2 Introduction

This Executive Summary provides all relevant information regarding the load impact evaluations as prescribed in Decision (D.) 10-04-006. Included are program descriptions, program options, ex-post load impact methodology, program year 2023 event results, ex-ante forecasts, methodology and ex-ante load impacts. Much of the information presented in the executive summary is excerpted directly from the individual load impact reports. The following reports are included in this executive summary.

I. Statewide DR Programs

1. 2023 Statewide Load Impact Evaluation of California's Capacity Bidding Programs, Ex-post and Ex-ante Impacts, Applied Energy Group, April 1st, 2024.
2. 2023 Statewide Load Impact Evaluation of California's Critical Peak Pricing Programs, Ex-post and Ex-ante Impacts, Christensen Associates, April 1st, 2024.
3. 2023 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report, Christensen Associates, April 1st, 2024. However, SDG&E had no customers enrolled in BIP in 2023. Therefore, the executive summary does not include ex-post and ex-ante results.

II. SDG&E DR Programs

1. 2023 Load Impact Evaluation of San Diego Gas and Electric's AC Saver Day Of Program, Resource Innovations, April 1st, 2024.
2. 2023 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2024.
3. 2023 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, 2024.
4. 2023 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, 2024.
5. 2023 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates, Demand Side Analytics LLC, April 1st, 2024.

III. SDG&E DR Pilots

1. 2023 Load Impact Evaluation for San Diego Gas and Electric's Non-Residential ELRP.

2. 2023 Load Impact Evaluation for San Diego Gas and Electric's Residential ELRP.
3. 2023 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): In accordance with Decision (D.) 23-12-005, the BIP was terminated at the end of 2023. In addition, SDG&E had no customers enrolled in BIP in 2023. Therefore, the executive summary does not include ex-post and ex-ante results.

Aggregator Programs:

Capacity Bidding Program (CBP): In accordance with Decision (D.) 23-12-005, Capacity Bidding Program Prescribed products option were eliminated within 60 days of the date of issuance of this Decision. In addition, there were no customers enrolled in the CBP Prescribed product option in 2023. Therefore, the executive summary does not include ex-post and ex-ante results for these products.

Price Responsive Programs:

In accordance with Decision (D.) 23-12-005, AC Saver Day Of Residential and Commercial AC Saver Day Ahead Residential and Commercial programs were terminated at the end of 2023. Therefore, the executive summary does not include the AC Saver Day Ahead and Day Of ex-ante results.

Decision (D.) 23-12-005 states that "*SDG&E calculated a TRC of just 0.7 for the SEP based on PY22 SEP Ex-ante estimates. The TRC ratios presented by SDG&E's SEP program are too low, and SDG&E has not presented any compelling evidence to suggest that the SEP program as designed will remedy this issue. We therefore direct SDG&E to terminate the current AC Saver program at the end of 2023 and decline to fund the SEP for future years.*"

However, the TRC calculation was based on the PY22 average ex-post estimates (6pm-8pm) which showed a load impact of 8.65MW (17,528 accounts) and in PY23 average ex-post estimates (6pm-8pm) showed a load impact of 14.02MW (32,280 accounts). This represents a load impact increase of 62% and a customer increase of 84% from PY22 to PY23.

AC Saver Day Ahead

AC Saver Day Of

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

In accordance with Decision (D.) 23-12-005, ELRP Group A (excluding sub-group A.6 PSR) and Group will continue through 2027, and ELRP sub-group A.6 pilot will continue through 2025. Therefore, the executive summary report includes Non-Residential ELRP ex-ante results for the years of 2023 through 2027 and ELRP sub-group A.6 ex-ante results for the years of 2023 through 2025.

In accordance with Decision (D.) 22-12-009, SDG&E 's Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the executive summary report does not include Residential CBP ex-ante results.

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

Residential ELRP

Residential CBP

Table 1-1 presents the Program Year (PY) 2023 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 2023 SDG&E's system peaked at 4,397 MW on August 28th, 2023, at 5:38pm. However, CAISO hit its all-time peak on August 16th, 2023 at 5:59pm. with

44,534 MWs and no rolling blackouts. SDG&E can trigger a CPP Event if the day-ahead system load forecast for the potential event day exceeds 4,000 MW.

Table 1-1: Program Year (PY) 2023 Ex-post estimates for DR Programs

Program Type and Name	Customers on Average Event Day	Event Window Average Event Day HE *	Average Event Day Load Impact (MW)
Supply Side Demand Response	**39,621**		**14.28**
BIP	N/A	-	-
AC Saver Day Ahead Residential**	30,019	HE20-HE21	11.06+
AC Saver Day Ahead Commercial (including Quasi-Residential)	N/A	-	-
AC Saver Day Of Commercial	2,099	HE19-HE20	.004
AC Saver Day Of Residential	7,348	HE19-HE20	0.59+
CBP DA (Product 11am-7pm)	N/A	-	-
CBP DA (Product 1pm-9pm)	N/A	-	-
CBP DA Elect $200 (Including products 1pm-9pm)	N/A	-	-
CBP DA Elect $400 (Including products 1pm-9pm)	70	HE20-HE20	.77+
CBP DA Elect $600 (Including products 1pm-9pm)	34	HE20-HE20	0.15+
CBP DO (Product 11am-7pm)	N/A	-	-
CBP DO (Product 1pm-9pm)	N/A	-	-
CBP DO Elect $200 (Product 1pm-9pm)	N/A	-	-
CBP DO Elect $400 (Product 1pm-9pm)	51	HE20-HE20	1.71+
CBP DO Elect $600 (Product 1pm-9pm)	N/A	-	-
Load Modifying	**106,610**		**19.7**
CPPD Large (Excluding TD)	316	HE17-HE21	3.21+
CPPD Medium (Excluding TD)	2,545	HE17-HE21	1.23
Default Small Commercial TOU and CPP Rates (Excluding TD)****	23,372	HE17-HE21	0.24
Small Agricultural CPP****	73	HE17-HE21	0.05
EVTOU2 (Including NEM plus Non-NEM) **	8,422	HE17-HE21	1.81+
EVTOU5 (Including NEM plus Non-NEM **	31,861	HE17-HE21	6.92+
Technology Deployment (TD) on Small Commercial CPP plus CPP (Large and Medium)****	93	HE17-HE21	0.04+
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU****	555	HE17-HE21	0.12+
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU****	39,373	HE17-HE21	6.10+
Total	**146,231**		**33.28**

* HE means hour ending

** In 2023, there were 18 ACSDA Residential events. Eight events took place from 7-9 pm, five events took place from 6-8 pm, and five events took place from 5-9 pm. Results are shown for the average 7-9 pm event. There were no ACSDA Commercial or Quasi-Residential events.
*** 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. The customer counts are based on 2023 ex-ante 1-in-2 weather August system peak
**** In 2023, there was only one CPP Event on August 29.
+ Statistically significant at 90% confidence

Table 1-2 presents the Program Year (PY) 2023 ex-post estimates for the average event day Load Impact in MWs across all SDG&E DR Pilot events.

Table 1-2: Program Year (PY) 2023 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*	N/A	-	-
Residential CBP	117	HE18-HE21	0.07+
Non-Residential A.1 ELRP	455	HE20-HE21	-9.48
Non-Residential A.2 ELRP	[redacted]	[redacted]	[redacted]
Non-Residential A.3 ELRP			
Non-Residential A.4 ELRP	327	HE19-HE20	1.11+
Non-Residential A.5 ELRP	[redacted]	[redacted]	[redacted]
Non-Residential B.2 ELRP	145	HE20-HE21	1.05+
Total Residential and Non-Residential	**1,049**		**-7.14**

* No events were called for PY23 Residential –ELRP A.6.
+ Statistically significant at 90% confidence

In 2022, all ex-ante load impact summaries were averaged over the Resource Adequacy (RA) hours of 4 pm to 9 pm for all programs and/or dynamic rates. In 2023, the RA AAH was updated for March and April to be 5pm – 10pm (HE18 – HE22). The remaining months are 4pm – 9pm (HE17 – HE21).[25]

SDG&E updated SDG&E and CAISO peak weather scenarios in 2022 to reflect the long-term warming trend that California has had. SDG&E and CAISO weather scenarios are an input for the PY23 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 peak condition. 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.

[25] D22-06-050, OP5

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[26] 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 peak conditions:

- 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 1-3 presents SDG&E's 2023 ex-ante estimates for all DR Activities. The MW load impacts are for SDG&E 1-in-2 weather conditions for August2024. Load impact evaluations for Electric Vehicle (EV) time of use studies have been conducted for five years PY2019-PY2023 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 19 MWs for the August peak day in 2024.

[26] File names are: AppendixB.TablesforExecutiveSummary_formatted_Mar312022.pdf and AppendixB.TablesforExecutiveSummary_formatted_Mar262023.xls

Table 1-3 presents the Program Year (PY) 2023 ex-ante estimates for August 2024 Load Impact in MWs across all SDG&E DR Programs.

Table 1-3: Program Year (PY) 2023 Portfolio Ex-ante estimates* for all DR Programs based on 1-in-2 August SDG&E weather scenarios for the year of 2024.

Program Type and Name	Forecasted Customers in August 2024	Ex-ante estimates for the month of August 2024 (MW) over the RA hours [a]
Supply Side Demand Response	**160**	**2.47**
CBP DA Elect $200 (Including products 1pm-9pm)	0	0
CBP DA Elect $400 (Including products 1pm-9pm)	70	0.38
CBP DA Elect $600 (Including products 1pm-9pm)	34	0.42
CBP DO Elect $200 (Product 1pm-9pm)	0	0
CBP DO Elect $400 (Product 1pm-9pm)	51	1.60
CBP DO Elect $600 (Product 1pm-9pm)	[redacted]	[redacted]
Load Modifying Demand Response	**130,825**	**27.71**
CPPD Large (Excluding TD)	181	2.03
CPPD Medium (Excluding TD)	2,288	1.19
Default Small Agricultural TOU and CPP Rates (Excluding TD)	51	0.00
Default Small Commercial TOU and CPP Rates (Excluding TD)	17,317	0.29
EVTOU2 (Including NEM plus Non-NEM) **	13,636	4.32
EVTOU5 (Including NEM plus Non-NEM) **	65,512	14.89
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	112	0.06
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	568	0.13
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH plus TOU	31,160	4.80
Total	**130,985**	**30.18**

* Ex-ante estimates are for the month of August as that was the 2023 peak day month from 2023.

** EVTOU are non-event estimates and correspond to August Peak Day

Table 1-4 presents the Program Year (PY) 2023 ex-ante estimates for August 2024 Load Impact in MWs across all SDG&E DR Pilots.

Table 1-4: Program Year (PY) 2023 Portfolio Ex-ante estimates* for all DR Pilots based on 1-in-2 August SDG&E weather scenarios for the year of 2024.

Program Type and Name	Forecasted Customers in August 2024	Ex-ante estimates for the month of August 2024 (MW) over the RA hours [a]
Non-Residential A.1 ELRP	650	26.65
Non-Residential A.2 ELRP	[redacted]	[redacted]
Non-Residential A.3 ELRP	[redacted]	[redacted]
Non-Residential A.4 ELRP	503	1.15
Non-Residential A.5 ELRP	[redacted]	[redacted]
Non-Residential B.2 ELRP	166	1.61
Residential ELRP	576,812	13.35
Residential CBP**	N/A	N/A

* Ex-ante estimates are for the month of August as that was the 2023 peak day month from 2023.
** Per Decision (D.) 22-12-009, SDG&E 's Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the ex-ante section was not included.

2. Program Descriptions

2.1 Supply Side Demand Response

2.1.1 Emergency Programs

2.1.1.1 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.[27]

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 2023.On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the BIP program at the end of 2023.

2.1.2 Aggregator Programs

2.1.2.1 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 2-1. 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

[27] https://www.sdge.com/sites/default/files/elec_elec-scheds_bip.pdf

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 2-2.

CBP has its own tariff, Schedule CBP.[28] 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.

On December 14, 2023, Decision (D.) 23-12-005 ordered SDG&E to eliminate its Capacity Bidding Program Prescribed product option (Day Ahead and Day Of 11am-7pm and Day Ahead 1pm-9pm) within 60 days of the date of issuance of this decision. Therefore, in 2024 SDG&E will offer only the following products: Elect DA 1-9 hour ($200/MWh, $400/MWh, $600/MWh) and Elect DO 1-9 hour ($200/MWh, $400/MWh, $600/MWh).

Table 2-1: 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 2-2: 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	$80/MWh
	Presc DA 1-9 Hour	1 PM–9 PM	$80/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	$95/MWh
	Presc DO 1-9 Hour	1 PM–9 PM	$110/MWh
	Elect DO 1-9 Hour	1 PM–9 PM	$200/MWh, $400/MWh, $600/MWh

[28] https://tariff.sdge.com/tm2/pdf/tariffs/ELEC_ELEC-SCHEDS_CBP.pdf

2.1.3 Price Response Programs

2.1.3.1 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.

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.[29] 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 on the AC Saver Day Ahead program receive an end of year $20 participation credit. (however, customers on a TOU+ rate based thermostat program do not receive a credit). No credits are given to any commercial customers. 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.

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

On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023.

2.2 Load Modifying Demand Response

2.2.1 Pricing Programs (Critical Peak Pricing Rates)

2.2.1.1 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 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.[30] 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.[31]

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.[32] There was one CPP event called in 2023, on August 29.

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[30] CPP rates are commodity rates and are not available to Direct Access or Community Choice Aggregator customers.

[31] 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.

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

2.2.1.2 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 the major distinction that SDG&E's small commercial and industrial customers do not have demand charges, so 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 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's CPP-TOU rates.[33]

2.2.1.3 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. Like 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 two 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 the TOU and CPP rates are voluntary rates that became active in February 2015.

The TOU periods for the two rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super

[33] SDG&E's CPP rate is a commodity rate. If a customer is defaulted into a Community Choice Aggregator (CCA) they will receive their commodity rate from the CCA. Therefore CCA customers can not enroll in SDG&E's CPP-TOU rates.

off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. The analysis includes Net Energy Metered ("NEM") customers. Load impacts for these customers are estimated separately but included in the results for each rate using a customer-weighted average. The protocol tables contain separate results for NEM and Non-NEM customers, along with combined results of all customers regardless of NEM status.

Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. The CPP event window coincides with the resource adequacy window in all months except March, April, and May, when the RA window is 5 to 10 p.m. In 2023, SDG&E called one CPP event on August 29th.[34]

[34] 2023 Load Impact Evaluation of Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates for San Diego Gas & Electric, p 1, CA Consulting

2.3. Nonevent based Programs

2.3.1 Electric Vehicles Time-of-Use (TOU) Rates (EVTOU2 and EVTOU5)

SDG&E has two primary EV-TOU rates, the whole-home rates EV-TOU-2 and EV-TOU-5, and a small number of sub-meter homes on an EV-TOU rate that are not included in this evaluation. Nearly all new enrollments are on the EV-TOU-5 rate. All of the rates include a peak period from 4-9 pm, super off-peak rates from 12-6 am, and off-peak rates in all other hours. The main differences between the two whole premise rates are in the super off-peak rates, the monthly billing fee, and rates during weekends. Overall, the EV-TOU-5 rate has a lower super-off peak price, a higher monthly fixed charge, and the same rates for weekdays and weekends.

2.4. Pilots

2.4.1. Non-Residential ELRP

The Emergency Load Reduction Program (ELRP) pilot is a demand response program with direct settlements and performance payments to participant sites designed to access additional incremental load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Two distinct groups of customers are eligible for ELRP participation: (Group A) directly enrolled non-residential customers and aggregators, and (Group B) third-party demand response providers (DRPs) with market-integrated proxy DR (PDR) resources.

Group A: Direct enrolled residential and non-residential customers and aggregators:

- A.1. Non-Residential Customers (BIP, Non-Res CPP, SCE's RTP, AP-I, SDP-C allowed).
- A.2. Non-Residential Aggregation (BIP + Non-BIP Aggregators).
- A.3. Rule 21 Exporting Distributed Energy Resources (DER).
- A.4. Virtual Power Plant (VPP) Aggregators (AC Cycling allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.5. Vehicle-Grid-Integration (VGI) Aggregators (AC Cycling Allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).

Group B: Market-integrated PDR resources:

- B.1. Third-party DR Providers.
- B.2. IOU Capacity Bidding Program (CBP) Aggregators.

2.4.2 Residential ELRP (A.6)

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 additional residential emergency load reduction resources. ELRP A.6 is a behavioral demand response program with direct settlements and performance payments to participants. On December 14, 2023, Decision (D.) 23-12-005 ordered that ELRP Group A (excluding sub-group A.6 PSR) and Group B pilot will continue through 2027, and ELRP sub-group A.6 pilot will continue through 2025. All ELRP groups remunerate participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, settlement payments for A.6 will decrease in 2024 and 2025 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

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 17,400 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 2023 evaluation includes CCA customers. The Residential ELRP pilot had a large number of participants. As of August

2023, there were a total of 567,613 program participants. Of these, more than 99% were BDR or CARE/FERA participants.

2.4.3 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, PY 2022, and PY 2023 one residential battery storage aggregator enrolled. Swell enrolled 10 residential sites in PY 2021, 99 residential sites in PY 2022, and 214 unique sites in PY2023. In PY 2023 enrolled sites had one to three 5-kW Tesla Powerwall battery systems per site with an average of 7.5 kW of storage and the average site had 8.7 kW of interconnected battery storage. PY2023 was the third year of the residential pilot designed to assess the pilot's cost-effectiveness, load reduction capability, and feasibility as a full-scale residential program. To assess the pilot's load reduction capability under varying weather conditions and hours, twenty 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 sites enrolled and set up for event participation during each event. PY2021 saw delivered load per site being dropped to 0 kW upon dispatch of the storage resources. Due to dispatch issues, PY2022 events on average did not see significant load reductions at the site level or in aggregate. PY2023 events demonstrated statistically significant reductions for most events. Export events produced similar impacts as reduction events when analyzing delivered load only and substantially greater impacts when analyzing net loads. SDG&E will file and Advice Letter (AL) by December 2024 to convert the CBP Residential Pilot into the CBP Residential Program.

3. Methodology

A summary of ex-post and ex-ante methods are provided in Table 3-1 and Table 3-2. 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 2020 and 2021, an adjustment factor for the effect of the Covid-19 pandemic was applied to customer loads. This adjustment factor was removed in 2022 as customer behavior returned to a "normal" state. SDG&E continued to see significant CCA activity in 2023. SDG&E also expects to lose more CPP customers in 2024 and beyond as they migrate over to CCAs.

Table 3-1: Summary of 2023 Analysis Methodologies by Program

Supply Side Demand Response Programs			
Program	**Method**	**Evaluation**	**Key Assumptions**
AC Saver Day Ahead Commercial	Ex-Post: There were no ACSDA commercial events called in PY2023. Ex-Ante: On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023. Therefore, the program year 2023 AC Saver Day Ahead Load Impact Evaluation Report does not include ex-ante analysis.	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.	N/A
AC Saver Day Ahead Residential	Ex-Post: Difference-in-Differences analysis of means using matched control groups. Ex-Ante: On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023. Therefore, the program year 2023 AC Saver Day Ahead Load Impact Evaluation Report does not include ex-ante analysis.	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 an 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 3-1 continued: Summary of 2023 Analysis Methodologies by Program

Program	Method	Evaluation	Key Assumptions
AC Saver Day of Commercial	Ex-Post: Statistical matching design Ex-Ante: On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023. Therefore, the program year 2023 AC Saver Day Of Load Impact Evaluation Report does not include ex-ante analysis.	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.
AC Saver Day Of Residential	Ex-Post: Statistical matching design using a random sample of Residential population Ex-Ante: On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the AC Saver program at the end of 2023. Therefore, the program year 2023 AC Saver Day Of Load Impact Evaluation Report does not include ex-ante analysis.	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.	• Snapback for residential customers was calculated based on cycling strategy.

Table 3-1 continued: Summary of 2023 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 2023 program year. Ex-Ante: On December 14, 2023, Decision (D.) 23-12-005 OP28 ordered SDG&E to terminate the BIP program at the end of 2023. Therefore, the program year 2023 BIP Load Impact Evaluation Report does not include ex-ante analysis.	BIP had no customers or events in 2023.	• N/A
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 3% growth per year from 2024-2027 due to SDG&E's proposed program improvements. The enrollment forecasts for both programs show a flat trend from 2028-2034 • 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.

Table 3-1 continued: Summary of 2023 Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Critical Peak Pricing CPP	Ex-post: Within-subjects customer-specific regressions or panel regressions Ex-Ante: 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.
Default Small Commercial CPP	Ex-post: Agricultural & Commercial: Difference-in-differences with matched controls Ex-ante: 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 23,000 non-residential Small CPP sites among a matched control candidate pool of roughly 5,000 small commercial CPP opt-outs and 900 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.	The historical load patterns and performance during actual events are used to estimate the reductions for a standardized set of weather conditions.

Table 3-1 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	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.

Table 3-1 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: Apply the PY23 ex-post CPP event load impacts to reference loads calculated using PY23 customer load data. Load impacts for different weather scenarios are developed by applying the estimated load impact from the ex-post analysis to weather-sensitive reference loads. For the TOU rate and the TOU portion of the CPP rate, hourly percentage load impacts from the ex-post analysis are applied to weather-sensitive reference loads that are developed as described above.	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. The reference loads are estimated by obtaining weather-specific coefficients using regression models like those used in the ex-post analysis and applying the coefficients to four alternative weather scenarios. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these customers.	• One CPP event was called in 2023.

Table 3-2: 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 3-2 continued: Summary of Analysis Methodologies by Pilot

Program	Method	Evaluation	Key Assumptions
Residential ELRP	Ex-Post: There were no Residential ELRP events called in PY2023. 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: Difference in difference with out of sample matched control selection. Simple difference for supplemental analysis of telemetry data. Ex-Ante: In accordance with Decision (D.) 22-12-009, SDG&E 's Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the ex-ante section was not included in this report	Reference loads, developed using a pool of 16,000 residential sites with solar and storage, weighted to the full territory population of storage interconnections. Impact assumptions based on	• The enrollment forecast based on historical growth in interconnections and assumptions regarding enrollment rate, described above.

4.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 4-1 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 4-1: Summary of 2023 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*	N/A						
AC Saver Day Ahead Residential**	47.15	36.10	0.37	23.5%	11.06	30,128	18
AC Saver Day Of Commercial	13.48	13.38	.05	0.7%	.09	2,099	15
AC Saver Day Of Residential	12.33	11.81	-.03	4.9%	0.59	7,348	15
Base Interruptible Program***	N/A						
Capacity Bidding Program****	17.77	15.22	18.94	9.0%	2.55	135	5

* No AC Saver Day Ahead Commercial or Quasi-Residential events were called in PY 2023.
** AC Saver Day Ahead Residential called 8 events from 7-9 PM, 5 events from 6-8 PM, and 5 events from 5-9 PM. The average DR LI Ex-Post estimates are reported for days with the event window of 7-9 PM.
*** No BIP events were called in PY 2023.
**** SDG&E triggered Elect DA 1-9 Hour ($400) for 5 events, and Elect DA 1-9 Hour ($600)for 2 events, and the Elect DO 1-9 Hour ($400) for 5 events

Table 4-1 continued: Summary of 2023 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	139.0	134.6	1.55	3.2%	4.4	2861	1
CPP customers on Technology Deployment (TD)	0.40	0.34	2.73	13.7%	0.05	20	
Default Small Commercial CPP	56.76	56.52	0.01	0.24%	0.24	23,372	1
Small Agricultural CPP	0.72	0.67	0.70	7.1%	0.05	73	
PSW customers on Technology Deployment (TD)	0.37	0.33	0.45	11.4%	0.04	93	
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	1.06	0.95	0.21	11.0%	0.12	555	1
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU	65.17	59.07	0.15	7.0%	6.09	39,373	
Electric Vehicle Time-Of-Use: EVTOU2*****	7.52	5.53	0.24	26.4%	1.99	8,422	TOU
Electric Vehicle Time-Of-Use: EVTOU5*****	45.21	38.29	0.22	15.3%	6.92	31,861	TOU

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

Table 4-2: Summary of 2023 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*	178.81	188.29	-20.86	-5.3%	-9.48	455	3
Non-Residential A.2 ELRP *	[redacted]						
Non-Residential A.3 ELRP *	[redacted]						
Non-Residential A.4 ELRP*	0.12	-0.99	-.038	918.8%	1.11	327	2
Non-Residential A.5 ELRP**	[redacted]						
Non-Residential B.2 ELRP*	16.63	15.58	7.22	6.3%	1.05	145	3
Residential ELRP **	N/A	N/A	N/A	N/A	N/A	N/A	0
Residential CBP	0.05	-0.01	0.57	125.4%	0.07	117	20

* Non-Residential ELRP groups: A1,A2,A3,A5 and B2 are based off of an 8-9 PM event, while the A4 group is based on 6-8pm

** No PY23 events were called for Res-ELRP

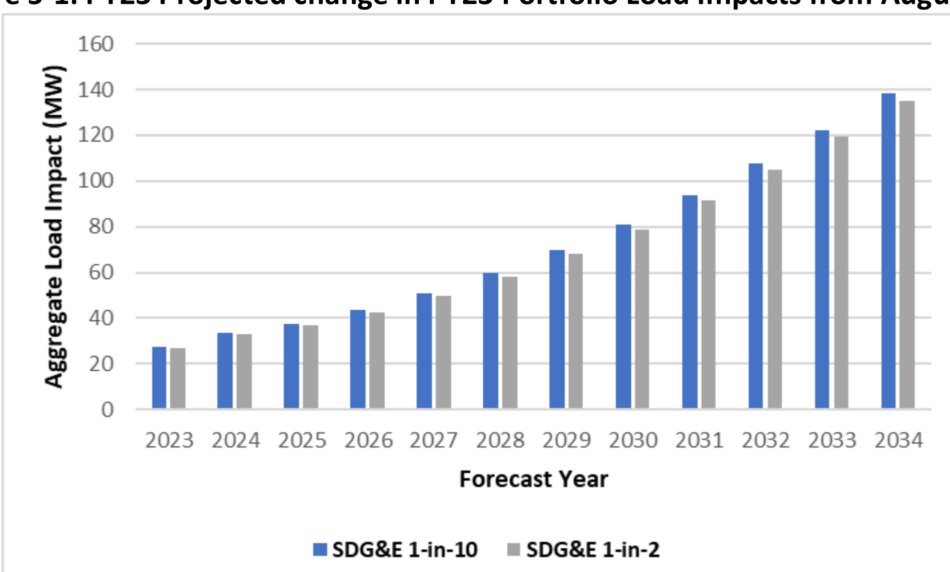
5. Ex-Ante Load Impacts

This section presents PY23 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.[35] 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.

5.1 Projected Change in PY23 Portfolio Load Impacts from 2023–2034

Figure 5-1 presents the portfolio-adjusted aggregate load impact estimates for the August 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 311% from 2024 to 2034 (from 34MW in 2024 to 139MW in 2034) under 1-in-10 weather conditions. On the other hand, SDG&E's portfolio is projected to increase by 309% from 2024 to 2034 (from 33MW in 2024 to 135MW in 2034) under 1-in-2 weather conditions.

Figure 5-1: PY23 Projected change in PY23 Portfolio Load Impacts from August 2023-2034



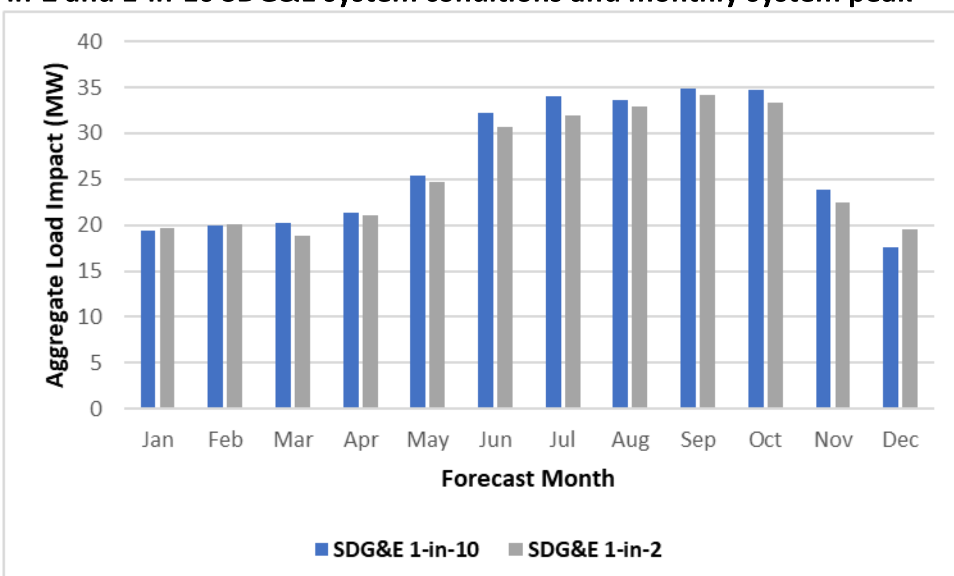
[35] DR Load Impact Protocols and Regulatory Guidance (Protocols 17-23) by CPUC (Apr 2008) - page 93-110

a. Portfolio Aggregate Load Impacts by Month for the year of 2024

Figure 5-2 shows the 2024 load impact estimates under 1-in-2 and 1-in-10 SDG&E weather conditions for 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 2024, SDG&E's DR portfolio estimates nearly 34 MW of load reduction during the August monthly system peak day under SDG&E's 1-in 10 weather conditions. The months of September and October load impacts are slightly higher than the month of August delivering about 35 MW respectively under SDG&E's 1-in-10 conditions.

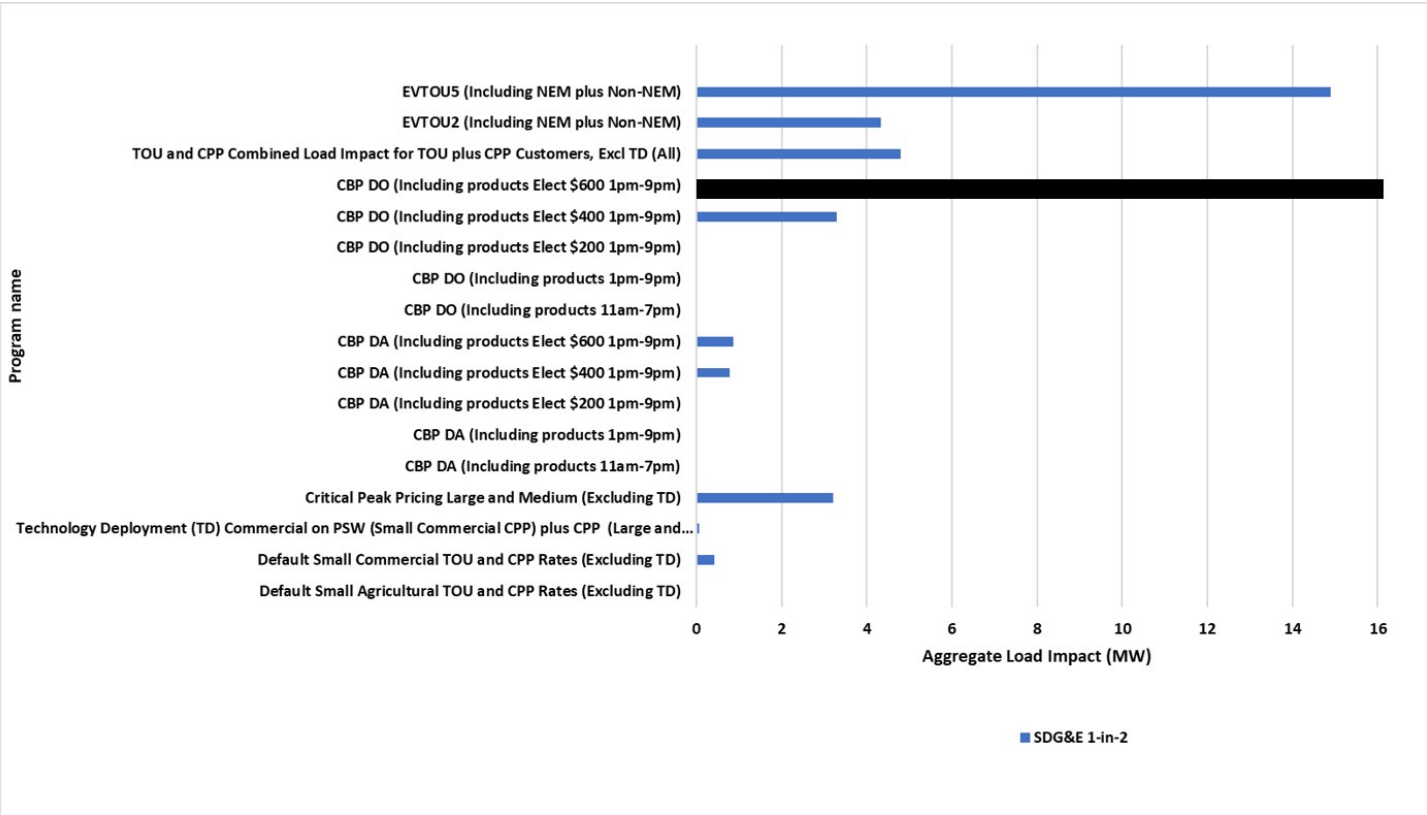
Figure 5-2: PY23 Portfolio Aggregate Ex-ante Load Impact Estimates (MW) for the year of 2024 by 1-in-2 and 1-in-10 SDG&E system conditions and monthly system peak



b. Portfolio Load Impacts by Program Type for the year of 2024

Figure 5-3 shows the distribution of portfolio aggregate load impacts by program type in August 2024 for all DR Supply Side and Load Modifying programs. In August 2024, the load impacts from price responsive programs are forecast to comprise 26% of SDG&E's DR portfolio, 59% from non-event programs, 16% from aggregator, and 0% from emergency programs under 1-in-2 weather conditions. A greater percentage of load impacts are projected to come from EVTOU5 followed by EVTOU2 in the coming years.

Figure 5-3: Distribution of PY23 Portfolio Aggregate Load Impacts by Program Type for August 2024 System Peak Day under 1-in-2 SDG&E-specific System Conditions



c. Portfolio Load Impacts by Program from 2023-2034

Table 5-1 summarizes the portfolio load impacts by program for 2023 through 2034 under 1-in-2 SDG&E weather conditions all DR Supply Side, Load Modifying programs and DR pilots.

In August 2034, the load impacts from load modifying programs are forecast to comprise 98% of SDG&E's DR portfolio, 2% from supply side programs, and 0% of SDG&E's Pilots.

Historically, the supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. However, on December 14, 2023, Decision (D.) 23-12-00536 ordered that the following programs sunset at the end of 2023; AC Saver Day Ahead, AC Saver Day Of, and BIP, therefore eliminating the emergency and price responsive supply side programs. The aggregator DR represents 100%, the majority of this percentage is attributable to CBP DO (Including products Elect $400 1pm-9pm).

Table 5-1: Portfolio Aggregate PY23 Load Impact Estimates (MW) for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Aggregator DR	**2.47**	**2.54**	**2.63**	**2.70**	**2.78**	**2.78**	**2.78**	**2.78**	**2.78**	**2.78**	**2.78**	**2.78**
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)	0.38	0.39	0.41	0.42	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
CBP DA Elect $600 (Including products 1pm-9pm)	0.42	0.43	0.45	0.46	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
CBP DO Elect $200 (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 $400 (Product 1pm-9pm)	1.60	1.65	1.70	1.75	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
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 forecasted to comprise 4% of SDG&E's DR load modifying portfolio in August 2034 where the greater percentage of load impacts are projected to come from Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU . The load impacts from non-event based are forecast to embrace 96% of SDG&E's DR load modifying portfolio; most of this percentage is related to EVTOU5 (Including NEM plus Non-NEM).

Table 5-1 Continued: Portfolio Aggregate PY23 Load Impact Estimates (MW) for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Load Modifying	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Modifying Total MWs	**22.69**	**28.7**	**32.41**	**38.47**	**45.86**	**54.68**	**64.7**	**76.28**	**88.94**	**103.19**	**118.34**	**134.57**
Price Responsive	**12.29**	**8.65**	**6.99**	**6.85**	**6.70**	**6.67**	**6.52**	**6.38**	**5.92**	**6.08**	**5.93**	**5.77**
Critical Peak Pricing Large and Medium (Excluding TD)	5.38	3.22	2.29	2.30	2.30	2.42	2.43	2.44	2.44	2.45	2.45	2.46
Default Small Agricultural TOU and CPP Rates (Excluding TD)	0	0	0	0	0	0	0	0	0	0	0	0
Default Small Commercial TOU and CPP Rates (Excluding TD)	0.58	0.43	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	0.06	0.06	0.05	0.05	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.02
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU	6.13	4.80	4.17	4.03	3.89	3.74	3.59	3.44	3.28	3.13	2.98	2.82
Non-event based	**10.40**	**20.05**	**25.42**	**31.62**	**39.16**	**48.01**	**58.18**	**69.90**	**83.02**	**97.11**	**112.41**	**128.8**
EVTOU2 (Including NEM plus Non-NEM) *	2.66	4.86	6.08	7.50	9.22	11.24	13.56	16.24	19.24	22.46	25.96	29.72
EVTOU5 (Including NEM plus Non-NEM) *	7.74	15.19	19.34	24.12	29.94	36.77	44.62	53.66	63.78	74.65	86.45	99.16
Pilots	**41.68**	**42.71**	**44.27**	**30.9**	**32.09**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Non-Residential A.1 ELRP**	26.65	26.65	26.65	26.65	26.65	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Residential A.2 ELRP	[redacted]											
Non-Residential A.3 ELRP												
Non-Residential A.4 ELRP	0.77	1.15	1.73	2.69	3.88	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Residential A.5 ELRP	[redacted]											
Non-Residential B.2 ELRP	1.61	1.61	1.61	1.61	1.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Residential ELRP***	12.70	13.35	14.33	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Supply Side plus Load Modifying plus Pilots Total MWs	**66.84**	**73.95**	**79.31**	**72.07**	**80.73**	**57.46**	**67.48**	**79.06**	**91.72**	**105.97**	**121.12**	**137.35**

*EVTOU2 and EVTOU5 rates have a substantial growth from previous years due to an increase in the CEC's EV adoption forecast.
** Non-Residential ELRP is planned to be sunset after PY27
***Residential ELRP is planned to be sunset after PY25.
****Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the ex-ante values were not produced.
***** In 2021 - 2023, SDG&E saw a substantial decrease in participants due to the migration of bundled customers to DA/CCA service.

Table 5-2 summarizes the portfolio number of customers forecasted by program for 2023 through 2034 under 1-in-2 SDG&E weather conditions.

The supply side programs were previously divided into three groups: emergency programs, price responsive and aggregator DR, however only aggregator DR remains in SDG&E's service territory. In August 2034, the number of customers from load modifying programs are forecast to comprise 98% of SDG&E's DR portfolio, 2% from supply side programs, and 0% from pilots.

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 7% of SDG&E's DR load modifying portfolio in August 2034 with the remaining 93% from non-event based programs where the greater percentage of customers is projected to come from EVTOU5

Table 5-2 Portfolio Aggregate PY23 number of customers forecasted for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Supply Side Total number of customers	**160**	**165**	**169**	**174**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**
Aggregator DR	**160**	**165**	**169**	**174**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**
CBP DA Elect $200 (Including products 1pm-9pm)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DA Elect $400 (Including products 1pm-9pm)	70	72	74	76	79	79	79	79	79	79	79	79
CBP DA Elect $600 (Including products 1pm-9pm)	34	35	36	37	38	38	38	38	38	38	38	38
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)	0	0	0	0	0	0	0	0	0	0	0	0
CBP DO Elect $400 (Product 1pm-9pm)	51	53	54	56	57	57	57	57	57	57	57	57
CBP DO Elect $600 (Product 1pm-9pm)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 5-2 Continued: Portfolio Aggregate PY23 number of customers forecasted for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Modifying	**107,712**	**130,826**	**143,539**	**166,252**	**194,531**	**227,914**	**266,352**	**310,814**	**360,628**	**414,254**	**472,549**	**535,345**
Price Responsive	**66,535**	**51,678**	**43,608**	**42,324**	**41,441**	**40,541**	**39,622**	**38,681**	**37,753**	**36,811**	**35,864**	**34,891**
Critical Peak Pricing Lrg & Med (Excluding TD)	2,778	2,469	2,270	2,284	2,296	2,308	2,320	2,320	2,341	2,352	2,363	2,373
Default Small Agricultural TOU and CPP Rates (Excluding TD)	70	52	40	39	39	40	40	40	40	40	40	40
Default Small Com TOU and CPP Rates (Excluding TD)	23,374	17,317	13,489	13,123	13,171	13,217	13,261	13,300	13,336	13,372	13,407	13,419
TD Commercial on PSW (Sm Com CPP) + CPP (Lrg & Med)	116	112	106	100	94	89	84	82	82	82	82	82
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	582	568	568	568	568	568	568	568	568	568	568	568
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU ***	39,615	31,160	27,135	26,210	25,273	24,319	23,349	22,371	21,386	20,397	19,404	18,409
Non-event based	**41,177**	**79,148**	**99,931**	**123,928**	**153,090**	**187,373**	**226,730**	**272,133**	**322,875**	**377,443**	**436,685**	**500,454**
EVTOU2 (Including NEM plus Non-NEM) *	8,441	13,636	16,532	19,883	23,964	28,768	34,289	40,664	47,793	55,463	63,793	72,763
EVTOU5 (Including NEM plus Non-NEM) *	32,736	65,512	83,399	104,045	129,126	158,605	192,441	231,469	275,082	321,980	372,892	427,691
Pilots	**568,769**	**578,136**	**592,088**	**1,952**	**2,517**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Non-Residential A.1 ELRP **	650	650	650	650	650	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Residential A.2 ELRP	[redacted]											
Non-Residential A.3 ELRP	[redacted]											

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Non-Residential A.4 ELRP	335	503	754	1,131	1,696	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Residential A.5 ELRP	[redacted]											
Non-Residential B.2 ELRP	166	166	166	166	166	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Residential ELRP ***	567,613	576,812	590,513	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Supply Side plus Load Modifying plus Pilots Total number of customers	**676,641**	**709,127**	**735,796**	**168,378**	**197,228**	**228,094**	**266,532**	**310,994**	**360,808**	**414,434**	**472,729**	**535,525**

*EVTOU2 and EVTOU5 rates have a substantial growth from previous years due to an increase in the CEC's EV adoption forecast.

** Non-Residential ELRP is planned to be sunset after PY27

***Residential ELRP is planned to be sunset after PY25.

****Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the ex-ante values were not produced.

***** In 2021 - 2023, SDG&E saw a substantial decrease in participants due to the migration of bundled customers to DA/CCA service.

6. Recommendations

The 2023 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. On December 14, 2023, Decision (D.) 23-12-005[36] ordered that the following programs sunset at the end of 2023, therefore no recommendations have been included for AC Saver Day Ahead, AC Saver Day Of, and BIP.

6.1.1 Aggregator Programs

6.1.1.1 Capacity Bidding Program (CBP)

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs: [37]

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

- Consider including irradiance data. Based on the observed strong interest from customers with net metering, especially residential customers, we highly recommend incorporating irradiance data into the analysis. While it's understood that energy production from solar panels is affected by multiple factors beyond just temperature, integrating irradiance data will significantly improve the accuracy of our predictions.
- Identify customers with battery storage. The customers with battery storage have the capability to utilize charged batteries during the CBP events, presenting a challenge in accurately estimating load reduction from meter data. By pinpointing these specific customers and understanding their behavior and patterns during the events will help us to refine our predictions.
- Re-evaluate the approach of estimating Ex-Ante per-customer impact. Considering that the ex-ante per-customer impact is derived from the Ex-Post but assumes a system-wide event is called. In reality, events are typically called at the Sub-LAP level (applicable to PG&E and SCE, as SDG&E is one Sub-LAP). Thus, the per-customer impact from the ex-post reporting hour may underestimate the actual impact. Therefore, reassessing the ex-ante impact based on the current Ex-Post is essential to ensure a more accurate estimation of the impact on individual customers.

[36] Decision (D.) 23-12-005, OP 28, 31, 35, and 50. Conclusion of Law 20 and 113.
[37] 2023 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 27, 2024) – page 46-47

6.2 Load Modifying DR

6.2.1 Price responsive Programs

6.2.1.1 Critical Peak Pricing (CPP)

Christensen made the following recommendation:

For SDG&E, the only event was called during the hottest day of the year. 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.[38]

6.2.1.2 Default Small Commercial CPP

DSA made the following recommendations:[39]

- **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, 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 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.

[38] 2023 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs by Christensen (April 1st, 2024) – page 40
[39] 2023 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program (April 1, 2024) – page 52-53.

6.2.1.3 Voluntary Residential CPP and TOU

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

One CPP event was called August 29th, which was a weekday event. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures, months, and days of week.

6.2.2 Nonevent Based Programs

6.2.2.1 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 with incentives and tools to manage charging to lower bills and reduce use during peak hours.

Key recommendations from the evaluation are:

- Evaluate and report impacts for all sites that reached a full year of experience with electric vehicle time-of-use rates (1st year impacts). This is our preferred approach and will be possible again in next year’s evaluation. 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.

- Continue to 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 consumption levels. Without sufficient data on EV charging patterns without the EV-TOU-5 and EV-TOU-2 rates, it is impossible to estimate the TOU effect on load patterns. The same applies to the installation of solar or battery storage. These technologies 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 EV-TOU-5 or EV-TOU-2. 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. [44]

6.2.3 Pilot Programs

6.2.3.1 Non-Residential ELRP

DSA made the following recommendation for non-residential only[40]:

- **Reserve ELRP dispatch for clear emergency conditions. Significant load reductions were observed for PY2022 and largely not for PY2023 events.** PY 2022 events were also dispatched under more extreme conditions and may be more a function of the emergency conditions under which the event is called. Unlike in PY 2022, in PY 2023 there were no emergency conditions or resulting public service announcements to improve customer awareness of the events. Reserving dispatch to clear emergency conditions which are clearly communicated to participants may be more in line with participant expectations and understanding of the program and may deliver greater impacts when it is called. This may include not calling event in years where extreme weather conditions are not experienced.
- **Improve dispatch advance notice.** PY2022 events were also with day-ahead notice, compared to day-of and even hour-ahead notice in PY2023. The advance notice received by participants, which is a function of when CAISO Emergency Energy Alerts are triggered may also indirectly be a function of extremity of emergency conditions at the time of the alert. To the extent possible, earlier advance notice, ideally day ahead, should improve the response to ELRP event notifications.
- **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 participant sites are paid 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. Further, to avoid payment for noise with baseline settlements, the settlement rules could incorporate a buffer or

[40] 2023 Load Impact Evaluation for San Diego Gas and Electric's Emergency Load Reduction Pilot by Demand Side Analytics. (Apr 1, 2024) – page 52-53

minimum percent impact which must be achieved for a settlement baseline to qualify for payment. This minimum would ideally be set above the noise observed in loads.

6.2.3.2 Residential ELRP

Due to no events being called for Residential ELRP in PY23, the following recommendations from DSA in PY22 are still applicable for the program made the following recommendation for residential only[41]:

- **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.

[41] 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

6.2.3.3 Residential CBP

DSA made the following recommendation for residential only[42]:

- **For performance-based settlements, consider using net load or telemetry data.** Settlements based on delivered load are problematic for two reasons in the context of battery storage. First, settlement baselines perform best with large impacts but censoring net loads diminishes the signal to noise ratio. This results in noise being mistaken for impacts, and effectively compensating noise. This is especially the case for reduction only events which reduce loads less than export events and which delivered load settlements tend to systematically underestimate. Second, the greatest load reduction potential for battery storage systems lies in leveraging available capacity to export energy to the grid. Delivered load ignores exports, making it impossible to measure and compensate this value.
- **For maximal benefit, design a program which compensates for exports.** The load reduction potential for battery storage in the Residential CBP pilot was about 9 kWh per event, or 3 kW per hour for a 3-hour event, for sites averaging 7.5 kW of battery storage. This is about ten-fold the reduction potential for a reduction only event. The cost of recruiting, enrolling, connecting, and administering participant sites is a relatively fixed per site cost. Therefore, maximizing the benefit per participant, especially increase by ten-fold, will substantially improve cost-effectiveness and may be the difference between a cost-effective and a cost-ineffective program.
- **Thoroughly test and validate load dispatch ahead of the event season.** 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 events so load reductions or lack thereof can be clearly identified. Events should be evaluated soon after dispatch to identify and correct any issues.
- **As an alternative to compensating energy exports, consider a program design option that counts exports as demand reductions but only includes capacity payments (i.e., does not include energy payments).** The batteries in Residential CBP do not receive compensation for exports due to CAISO rules. As a result, there is untapped potential. While a battery may have the capability to deliver 3 kW, it is only compensated for offsetting part of whole building load (e.g., 0.3 kW). The CAISO reasoning for excluding imports is that battery storage customers may get double payment, once from the DR

[42] 2023 Load Impact Evaluation for San Diego Gas and Electric's Residential Capacity Bidding Pilot by Demand Side Analytics. (Apr 1, 2024) – page 25-26

payment and once through NEM credits. By only paying for capacity, SDG&E can incentivize additional, untapped peaking capacity, while avoiding double-payment for energy. Further, energy only programs such as ELRP could have unpredictable aggregator payments from year to year. The alternative is to create a load modifying DR product, explicitly for battery storage, that allows batteries to receive compensation for export capacity. This may still include a performance based element to ensure that nominated reductions are reflective of capacity actually delivered.

Appendix A: Regression Specifications

A.1 Supply Side Demand Response

A.1.2 Aggregator Programs

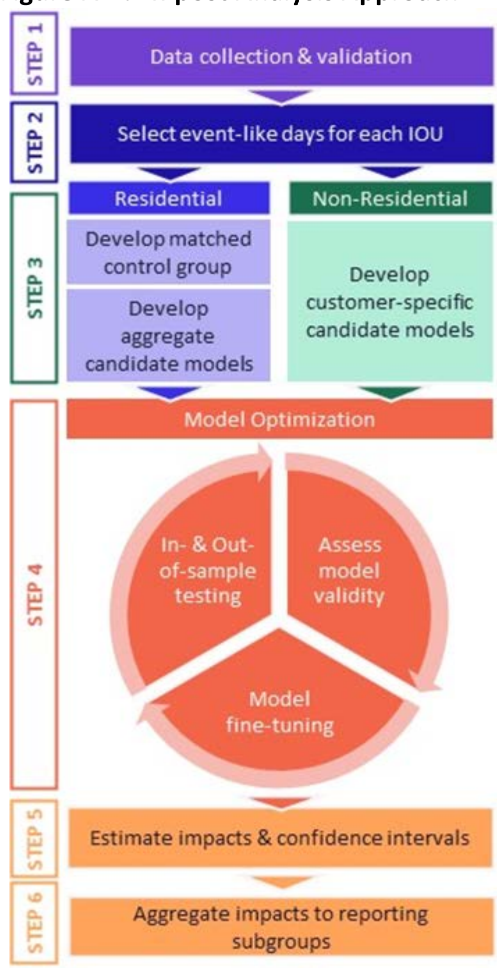
A.1.2.1 Capacity Bidding Program (CBP)

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

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



[43] 2023 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 27, 2024)

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.

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.

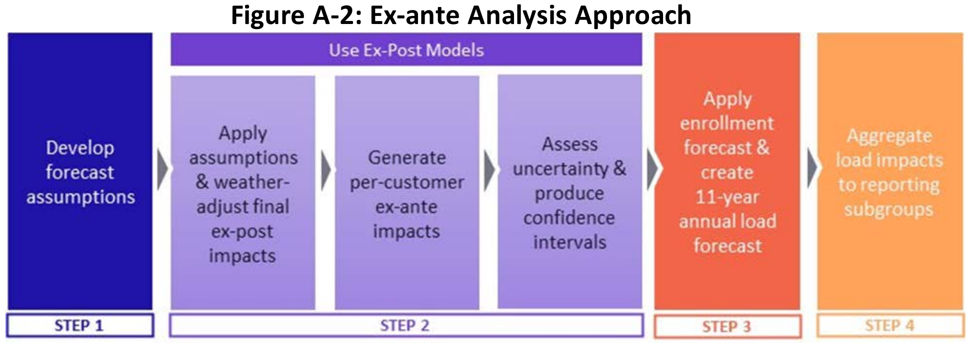
Table A-3: Explanatory Variables Included in Candidate Regression Models

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 2023 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 2023 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[44]:

b) Ex-post

The primary task in developing ex-post load impacts is to estimate the reference load for each event. The reference load represents the counterfactual (a measure of what participant demand would have been in the absence of CAC cycling during an event). 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 percentage of the enrolled residential population be held back during events to serve as a control group, reducing the total load impacts of the program. Beginning in the 2021 evaluation, Resource Innovations has utilized a statistical matching framework for the residential sector.

Dissimilarity Statistic for Matching

$$Dissimilarity_i = \sum_{k=0}^{E_s-1}\left(EventDayHour_{k,i} - EventDayHour_{k,j}\right)^2 + \sum_{k=E_s}^{E_e}\left(ProxyDayHour_{k,i} - ProxyDayHour_{k,j}\right)^2$$

Table A-4: Dissimilarity Statistic for Customer Matching

Variable	Definition
$EventDayHour_k$	Hourly demand of the k^{th} hour of the event day
$ProxyDayHour_k$	Hourly demand of the k^{th} hour of the proxy day
E_s	Event start hour
E_e	Event end hour
j	AC Saver Day Of participant to be matched
i	Index of the pool of control customers

[44] 2023 Load Impact evaluation of San Diego Gas & Electric's AC Saver Day Of Program by Resource Innovations (Mar 1, 2024)

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 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

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

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

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:[45]

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 was one event called in the summer of 2023, on August 29. 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.

[45] 2023 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates by Christensen (Apr 1, 2024)

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;
- *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 2034 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[46]:

a) Ex-post

<u>Small CPP & Agricultural</u>

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.

[46] 2023 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, 2024)

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

b) Ex-ante

A key objective of the 2023 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 Residential CPP and TOU rates[47]:

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).

- <u>Ex-post models for estimating CPP load impacts:</u> 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

[47] 2023 Load Impact Evaluation of Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates for San Diego Gas & Electric by Christensen (Mar 11, 2024)

event days, adjusted for differences on non-event days). The primary customer-level fixed-effects 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:

$$kWh_{c,d} = \beta_0 + \sum_{Evts(i)}(\beta_{1,i} \times NonDual_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)}(\beta_{2,i} \times Dual_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)}(\beta_{3,i} \times NonDual\ Control_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)}(\beta_{4,i} \times Dual\ Control_{c,d} \times Evt_{i,d}) + \beta_5 \times CPP_{c.d} + \beta_6 \times ACSDO\_Evt_{c.d} + C_c + D_d + \varepsilon_{c.d}$$

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).[48]

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*
$NonDual_{c,d}$	Variable indicating whether customer *c* is a non-dual *CPP* customer on date *d* (1 = yes, 0 if not)
$Dual_{c,d}$	Variable indicating whether customer *c* is a dually enrolled *CPP* customer on date *d (*1 = yes, 0 if not)
$NonDual\_Control\text{-}_{c,d}$	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)
$Dual\_Control_{c,d}$	Variable indicating whether customer *c* is a control customer matched to a dually enrolled *CPP* 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)
$ACSDO\_Evt_{c,d}$	Variable indicating that date *d* is *an AC Saver Day-Of* ("ACSDO")event day (1=event, 0 if not) for customer *c*
C_c	Customer Fixed Effects

[48] 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.

Symbol	Description
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
$\beta_{1,i}$	Estimated load impact for event *i* for non-dual *CPP* customers
$\beta_{2,i}$	Estimated load impact for event *i* for dually enrolled *CPP* customers
$\beta_{3,i}$	Estimated load impact for event *i* for control customers matched to non-dual *CPP* customers
$\beta_{4,i}$	Estimated load impact for event *i* for control customers matched to dually enrolled *CPP* customers
β_5	Estimated non-event day response for incremental *CPP* customers
β_6	Estimated average ACSDO event load impact

- <u>Ex-post models for estimating TOU load impacts:</u>

  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:[49]

$$kWh_{c,d} = \beta_0 + \beta_1 \times TOU_c \times Post_{c,d} + \beta_2 \times Post_{c,d} + \beta_3 \times Weather_{c,d} + \beta_4 \times TOU_c \times Weather_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

  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 in TOU (1) or Control (0) customer
$Post_{c,d}$	Variable indicating that date *d* is in the post-enrollment period for customer *c*
$Weather_{c,d}$	Weather conditions on day *d* for customer *c*
C_c	Customer Fixed Effects
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
β_1	Estimated load impact for TOU
β_2	Estimated load impact for control customers during post-enrollment period
β_3	Estimated coefficient for weather variable
β_4	Estimated load impact of TOU interacted with weather

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 per-customer load impacts from the ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

[49] 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.

CPP events are usually called during extreme weather scenarios. Weather-sensitive ex-ante load impacts for the relevant weather scenarios are constructed by applying percentage load impacts from ex-post to simulated weather-sensitive reference loads. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these customers. SDG&E called one CPP event in 2023. The ex-ante analysis uses load impacts from this event as a basis for PY2023 ex-ante forecasts. Different ex-post percentage load impacts (or level load impacts in the case of NEM customers) by climate zone, dual enrollment in either ACSDA or ELRP, and for customers who receive notifications are applied to simulated reference loads.

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[50]:

a) EVTOU - Ex-post

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

Methodology Component	Description
1. Population or sample analyzed	The evaluation focused only on incremental sites that enrolled between October 1, 2022 and April 30, 2023 thereby reaching their full first summer of savings on May 1, 2023. It excluded sites who had a change in electric vehicle, solar, or battery status that coincided with the study period. The full population of incremental participants with a full year of data before and a full summer of data after electric vehicle TOU rate adoption. The evaluation included approximately 25% of the incremental enrollments as customers often enroll on TOU rates for electric vehicles shortly after getting their electric 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 a control group of customers with electric vehicles but that were not on SDG&E's TOU rates for electric vehicles. The process to find this control group 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 we also identified the approximate date the electric vehicle(s) arrived at the household. Once control candidates with electric vehicles had been identified, we matched customers using pre-treatment hourly AMI data. The matching on pre-treatment loads used Euclidian distance matching and matches were selected only from customers with similar electric vehicle scores. Participants were paired to the matched control site and the control site was assigned the same "treatment date" as the participant.

[50] 2023 Load Impact evaluation of San Diego gas and Electric's Electric Vehicles Time-of-Use (TOU) Rates by Demand Side Analytics (Apr 1, 2024)

4.	**Evaluation Method**	Simple difference-in-differences was used to isolate the load impact. The process involved the following steps: 1. Aggregate (or average) the data to the relevant time unit of analysis. This was done for both participants and control and for the year before and after the treatment. 2. The difference between the before and after period was calculated for the treatment group 3. The difference between the before and after time period was calculated for the control group. 4. The difference observed in the control group was netted out of the participant difference to produce the difference-in-differences.
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 (least percent bias and relative RMSE) at identifying the control pool.
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

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.

A.2.3 Pilot Programs

A.2.3.1 Non-Residential ELRP

The paragraphs below describe the ex-post and ex-ante methodologies[51]:

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 2023 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 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 functional form of the regression with synthetic controls differs from a panel difference in difference regression in that usage for the control or controls are specified as right hand predictor variables. This enables the incorporation of multiple controls and the magnitude of coefficients for each control essentially weights the effect of each control in the regression which directly estimates the counterfactual load. In a difference in difference regression, usage for the single matched control is structured on a separate record from the treatment site and a treatment effect is instead estimated. The counterfactual load is then derived by adding back the treatment effect to the observed load. The model equation including the full set up

[51] 2023 Load Impact Evaluations for San Diego Gas and Electric's Electric Emergency Load Reduction Pilot by Demand Side Analytics (Apr 1, 2024)

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

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

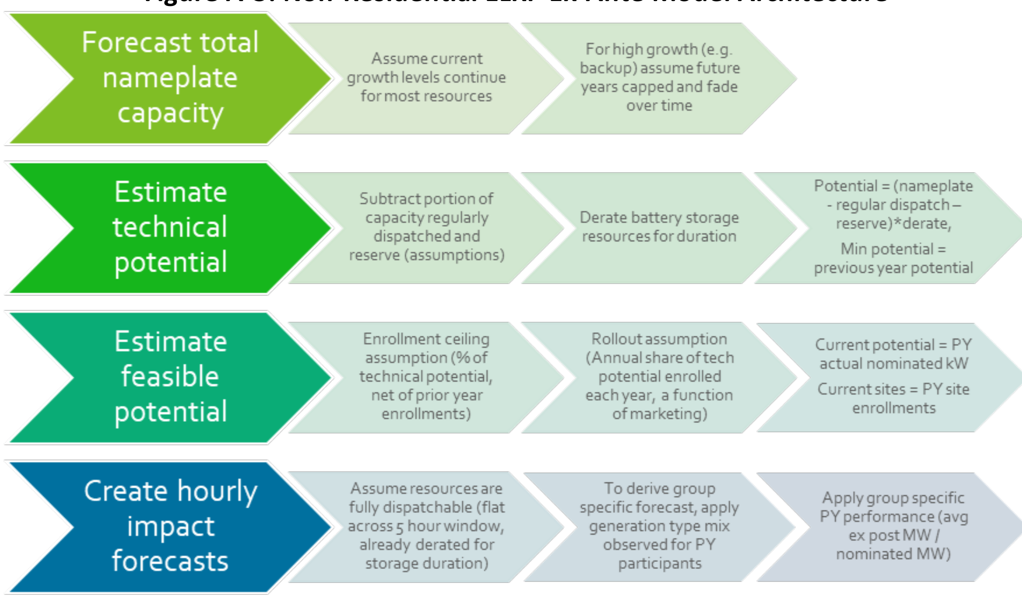
Table A-14 Ex-Post Regression Elements for Non-Residential ELRP

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 2023 are tied to the reduction capacity nominated by participant sites in PY 2023. 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[52]:

A) Ex-Post

There were no Residential ELRP events in PY23, therefore Ex-Post analysis was not conducted.

B) Ex-Ante

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
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[53]:

A) Ex-Post:

A time series regression with synthetic controls were used as the primary method for estimating load impacts for PY 2023 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

[52] 2023 Load Impact Evaluations for San Diego Gas and Electric's Electric Emergency Load Reduction Pilot by Demand Side Analytics (Apr 1, 2024)
[53] 2023 Load Impact Evaluation for San Diego Gas & Electric's Residential Capacity Bidding Pilot by Demand Side Analytics (Apr 1, 2024)

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

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

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:

In accordance with Decision (D.) 22-12-009, SDG&E 's Residential CBP Pilot was approved for the 2023 Bridge Year. Therefore, the ex-ante section was not included in this report

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