

San Diego Gas and Electric's 2021 Demand Response Executive Summary

Redacted – Public Version

April 1st, 2022



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1. Background

San Diego Gas & Electric (SDG&E) presents this Executive Summary for its Demand Response (DR) activities for program year 2021 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 protocols¹ and to file the load impact reports by April 1st each year. The original load impact protocols require the preparation of a voluminous number of tables that resulted in the load impact reports being too large to be filed in hard copy. On April 6th, 2009 the Investor Owned Utilities (IOUs) filed a petition to modify D.08-41-050. The petition asked for two things: 1) the removal of the requirement to file the load impact reports in their entirety and 2) to provide the reports to the energy division of the Commission. On April 8th, 2010, D.10-04-006 granted the utilities requests and added an Executive Summary requirement. The executive summaries were to include an overview of the evaluation findings, recommendations for changes to the demand response resource. Additionally, the executive summaries were to include brief descriptions of the methodology, the enrollment forecast, and the inputs and assumptions used for calculating both the ex-post and ex-ante load impact estimates. The IOUs should also report the regression model specifications for each demand response program.

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

Six CPUC decisions over a two-year period made changes that affected SDG&E's Demand Response Activities.

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

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

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

In August 2017 D.17-08-030 provided GRCP2 approval and directed SDG&E to file an advice letter by December 1, 2017 for implementation of time of use period changes for the 2018 calendar year. Since TOU period definitions changed for all SDG&E's existing TOU customers, the 2018 load Impact studies that estimated dynamic rate reductions also attempted to estimate load impacts associated with the change in TOU periods. Additionally, SDG&E implemented its residential default TOU rate in 2019. At the end of 2019 nearly 800,000 residential customers had been moved from their tiered rate structure to a TOU rate structure. However, 2020 will be the last year to try to identify shifts or load reductions due to the changed TOU and/or default TOU as over 100,000 small commercial and industrial customers have been placed onto TOU rates, and nearly 900,000 of SDG&E's residential customers have now embedded those TOU impacts/changes in their current loads.

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

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

In December of 2018 SDG&E received D.18-12-004 which allowed SDG&E to default all eligible residential customers onto TOU rates in 2019. About 800,000 of SDG&E's residential customers were transitioned to TOU rates by December 2019. At the end of 2020 SDG&E had nearly 900,000 of its residential customers on one of its 2 default TOU rates.³ Electric vehicle TOU rates were added to the load impact studies that SDG&E conducted in PY2019.

³ On March 18, 2021, the Commission granted SDG&E a two-month extension for filing the *2020 Load Impact Evaluation for San Diego Gas and Electric's Residential Default Time of Use* (2020 Residential Default TOU LIP Report). The draft version of the 2020 Residential Default TOU LIP Report is now due on May 19, 2021 and the final version of the report is due on May 27, 2021.

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

During 2020, the Covid-19 pandemic 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. More information about the assumptions used in forecasting the 2020 load impacts that were affected by Covid-19 are included in Section 4: Methodology is available in SDG&E’s 2020 Demand Response Executive Summary.

The Covid-19 pandemic continued into 2021, although many people were still sheltering at home or on a modified work and school schedules, energy usage patterns tended to revert back to a new “normal”. The August and September months of 2020 were extremely warm in southern California and the extreme conditions led to rolling blackouts on August 14th. In preparation for the summer of 2021, two emergency DR programs developed: the Emergency Load Reduction Program (ELRP) and the California State Emergency Program (CSEP). These new emergency programs would offset the need for any further rolling blackouts in 2021. Both programs were up and available during 2021, and combined with the mild summer weather, California was able to avoid rolling blackouts.

In February of 2021, the CPUC’s Energy Division (ED) issued a Load Impact Protocol Guidance Document.⁴ The purpose of the document was to establish consistent due dates for IOU’s and 3rd parties with a schedule for filing the LIP reports. It also called attention to Qualified Capacity (QC) update for market-integrated DR resources up to two times a year to reflect significant changes in customer enrollments during the RA compliance year per D.20-06-031. Updates to QC are warranted if changes varied by more than 20% or 10MWs. The Guide also provided “Best Practices” for Load Impact Protocol Filings.

⁴ Guided to CPUC’s Load Impact Protocol Process, Feb 10th, 2021, page 3, 5-6

2. Introduction

This Executive Summary provides all relevant information regarding the load impact evaluations as prescribed in D10-04-006. Included are program descriptions, program options, ex-post load impact methodology, program year 2021 event results, ex-ante forecasts, methodology and ex-ante load impacts. Much of the information presented in the executive summary are excerpts taken directly from the individual load impact reports. The following reports are included in this executive summary.

1. 2021 Statewide Load Impact Evaluation of California's Capacity Bidding Programs, Ex-post and Ex-ante Impacts, Applied Energy Group, April 1st, 2022
2. 2021 Statewide Load Impact Evaluation of California's Critical Peak Pricing Programs, Ex-post and Ex-ante Impacts, Christensen Associates, April 1st, 2022
3. 2021 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report, Christensen Associates, April 1st, 2022
4. 2021 Load Impact Evaluation of San Diego Gas and Electric's AC Saver Day Of Program, Resource Innovations⁵, April 1st, 2022
5. 2021 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2022
6. 2021 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, 2022
7. 2021 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, 2022
8. 2021 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates, Demand Side Analytics LLC, April 1st, 2022

⁵ Nexant is the original consultant that SDG&E contracted with, and during the contract, Nexant started doing business as Resource Innovations.

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

Supply Side Resources

Emergency Programs:

Base Interruptible Program (BIP)

Aggregator Programs:

Capacity Bidding Program (CBP)

Price Responsive Programs:

AC Saver Day Of

AC Saver Day Ahead Residential

AC Saver Day Ahead Commercial

Load Modifying Rates/Programs

Price Responsive Programs:

Critical Peak Pricing Default (CPP-D)

Default Small Commercial CPP and TOU

Voluntary Residential CPP and TOU

Electric Vehicle Time of Use

Table 2-1 presents the Program Year (PY) 2021 ex-post estimates for the average event day Load Impact in MWs across all SDG&E 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 2021 SDG&E's system peaked on August 26th at 5:53p.m. at 3,860 MWs. 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. The weather during the summer of 2021 was significantly milder than the summer of 2020. Because of the milder weather, SDG&E did not have the need to call its load modifying DR, and therefore there are no ex-post results for any of SDG&E's CPP rates.

Table 2-1: Program Year (PY) 2021 Ex-post estimates

Program Type and Name	Customers on Average Event Day	Event Window Average Event Day HE ^a	Average Event Day Load Impact (MW)
Supply Side Demand Response			
BIP			
AC Saver Day Ahead Residential	14,839	HE19-HE20	6.02
AC Saver Day Ahead Commercial (including Quasi-Residential)	676	HE19-HE20	-
AC Saver Day Of Commercial	2,312	HE19-HE20	0.22
AC Saver Day Of Residential	7,798	HE19-HE20	0.44
CBP DA (Including products 11am-7pm)	22	HE19	0.20
CBP DA (Including products 1pm-9pm)	24	HE19	0.06
CBP DO (Including products 11am-7pm)	11	HE19	0.06
CBP DO (Including products 1pm-9pm)	122	HE19	0.97
Load Modifying			
CPPD Large (Excluding TD) ^f	448	HE15-HE18	-
CPPD Medium (Excluding TD) ^f	4,243	HE15-HE18	-
Default Small Commercial TOU and CPP Rates (Excluding TD) ^f	52,081	HE15-HE18	-
Small Agricultural CPP ^f	166	HE15-HE18	-
EVTU2 (Including NEM plus Non-NEM) ^b	7,863	HE17-HE21	1.49
EVTU5 & EVTU2 to EVTU5 (Including NEM plus Non-NEM) ^b	16,009	HE17-HE21	2.71
Technology Deployment (TD) on Small Commercial CPP plus CPP (Large and Medium)	383	HE15-HE18	-
Voluntary Residential grandfathered CPP on Technology Deployment (TD) ^{ef}		HE15-HE18	-
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU ^{fc}	713	HE15-HE18	-
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU ^{fc}	33,626	HE15-HE18	-
Voluntary Residential grandfathered CPP excluding Technology Deployment (TD) customers plus TOU ^{fc}	366	HE15-HE18	-
Total^g	141,703		12.24

^a HE means hour ending

^b The load impacts for EVTU2 (Including NEM plus Non-NEM), EVTU5 (Including NEM plus Non-NEM), energy reported is the average consumption over the RA window for the August average weekday.

^c The customer counts are based on 2021 ex-ante 1-in-2 weather August system peak

^d The average ex-post estimates are statistically significant for some of event hours but not at the aggregate level.

^e In 2021, there were no customers under Voluntary Residential grandfathered CPP on Technology Deployment (TD). Therefore, the impacts are intentionally left in blank.

^f In 2021, there were no CPP events called. Therefore, the impacts are intentionally left in blank.

^g The total excludes the number of customers and MWs for BIP.

All ex-ante load impact summaries are averaged over the current Resource Adequacy (RA) hours of 4 p.m. to 9 p.m. for all programs and/or dynamic rates. It should also be noted that ex-post weather conditions are typically not the same as the 1-in-2, or 1-in-10 weather scenarios used in the ex-ante tables. In other words, the actual weather conditions when DR activities are called can be different than a 1-in-2 or 1-in-10

conditions. For example, an event could be called on a 1 in 4 peak weather condition or even during much cooler weather than a 1-in-2 peak condition. It is for these reasons that the ex-post load impact estimates don't always align with the ex-ante forecasts required in this submittal.

Located in Appendix A are the model specifications for each of the studies, ex-post, and ex-ante. The ex-ante tables located in Appendix B⁶ 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:

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

Table 2-2 presents SDG&E's 2021 ex-ante estimates for all DR Activities: DR Programs, Dynamic and TOU rates. The MW load impacts are for SDG&E 1-in-2 weather conditions for August 2022. SDG&E's AC Saver Day Ahead Program is expected to contribute about 4 MWs of load reduction in August 2022. SDG&E's AC Saver Day Of program continues to decline in enrollment as it is not being marketed.

Residential Default TOU studies were conducted for 2018, 2019 and 2020. The challenge of not having a residential control group was supposed to be the major obstacle in the 2020 study – as SDG&E had withheld customers to be used as controls in the 2018 and 2019 load impact studies. However, 2020 presented larger challenges due to effects on customer usage because of Covid-19 stay at home orders and two significant heat storms during the summer when many residential customers were confined to their homes. As a result, the 2020 Residential Default TOU study did not yield statistically significant load reductions. Although the Covid-19 pandemic continued during 2021, customers began to get back to "normal" activities. Therefore, SDG&E did not conduct a Default Residential TOU load impact evaluation in 2021. 2021 was the 4th year of being on TOU for the first phase of residential customers and the 3rd year for the rest of the residential customers.

Load impact evaluations for Electric Vehicle (EV) time of use studies have been conducted for three years, 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 11 MWs for the August peak day in 2022.

⁶ File names are: AppendixB.TablesforExecutiveSummary_formatted_Mar312021.pdf and AppendixB.TablesforExecutiveSummary_formatted_Mar312021.xls

Table 2-2: Program Year (PY) 2021 Portfolio Ex-ante estimates* based on 1-in-2 August^a SDG&E weather scenarios for the year of 2022

Program Type and Name	Forecasted Customers in August 2022	Ex-ante estimates for the month of August 2022 (MW) over the RA hours ^a
Supply Side Demand Response		
BIP		
AC Saver Day Ahead Commercial (including Quasi-Residential)	650	0.60
AC Saver Day Ahead Residential	18,829	3.42
AC Saver Day Of Commercial	1,963	0.31
AC Saver Day Of Residential	7,160	1.62
CBP DA (Including products 11am-7pm)	11	0.05
CBP DA (Including products 1pm-9pm)	0	0.00
CBP DA Elect (Including products 1pm-9pm)	94	2.27
CBP DO with new TI (Including products 11am-7pm)	9	0.02
CBP DO with new TI (Including products 1pm-9pm)	0	0.00
CBP DO Elect with new TI (Including products 1pm-9pm)	199	3.50
Load Modifying Demand Response		
CPPD Large (Excluding TD)	406	1.75
CPPD Medium (Excluding TD)	3,724	0.40
Default Small Agricultural TOU and CPP Rates (Excluding TD)	164	0.03
Default Small Commercial TOU and CPP Rates (Excluding TD)	51,393	0.17
EVTU2 (Including NEM plus Non-NEM) ^b	9,612	3.61
EVTU5 (Including NEM plus Non-NEM) ^b	23,437	7.48
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	415	0.37
Voluntary Residential grandfathered CPP customers on Technology Deployment (TD) ^{c,d}		
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU	713	0.18
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH plus TOU	20,699	1.87
Total^d	139,478	27.80

^a Ex-ante estimates are for the month of August as that was the 2021 peak day month from 2021.

^b EVTU are non-event estimates and correspond to August Peak Day

^c There are no customers on Voluntary Residential grandfathered CPP customers on Technology Deployment (TD), therefore is intentionally left in blank

^d The total excludes the number of customers and MWs for BIP.

3. Program Descriptions

3.1 Supply Side Demand Response

3.1.1 Emergency Programs

3.1.1.1 Base Interruptible Program

The Base Interruptible Program (BIP) is an emergency demand response (DR) program intended to provide load reduction on a “day-of” basis when the California Independent System Operator (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 Investor Owned Utilities (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 p.m. – 9 p.m. 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.⁷

Participation in SDG&E’s program has been low, consistent with the California Public Utilities Commission (“Commission” or “CPUC”) direction to focus marketing efforts on price responsive programs.

3.1.2 Aggregator Programs

3.1.2.1 Capacity Bidding Program (CBP)

⁷ http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_BIP.pdf

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 runs yearly 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 four CBP products: two Day-Ahead and two Day-Of products as shown in Table 3-1. CBP events can only be called during the products’ hours, which are between 11 a.m. – 7p.m. and 1 p.m. – 9 p.m. The aggregator selects a product to nominate their customer(s) into.

The Utility may call a day-ahead event whenever the day ahead market price is equal to or greater than \$80/MWh or as utility system conditions warrant. Day-ahead market price is defined as California Independent System Operator (CAISO) Default Load Aggregated Point (DLAP) or applicable Pricing Node (pnode) SDG&E- Aggregated Pricing Node (APND) day-ahead market locational marginal price (DAM LMP). The Utility may call a day-of event whenever the forecasted real-time price is equal or greater than \$95/MWh for the 11-7 p.m. product or \$110/MWh for the 1-9 p.m. product, or as utility system conditions warrant. Real-time price is defined as the CAISO DLAP or applicable pnode SDGE-APND average hourly real-time market locational marginal price (LMP).

CBP has its own tariff, Schedule CBP.⁸ 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 in TI. 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.⁹

⁸ http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_misc.html

⁹ 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.

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

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

Note: CBP Elect products will be available only from 1p.m. to 9p.m. starting in 2022.

3.1.3 Price Response Programs

3.1.3.1 AC Saver Program

AC Saver is a supply side Demand Response (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.¹⁰ 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.

¹⁰ "Day-Of" refers to programs in which customers are notified the day of an event, formerly known as Summer Saver.

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. Residential customers receive an annual capacity payment of \$20.

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

3.2 Load Modifying Demand Response

3.2.1 Pricing Programs (Critical Peak Pricing Rates)

3.2.1.1 Critical Peak Pricing – Default (CPP-D)

CPP is a statewide price responsive rate that qualifies as load modifying demand response. California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when an event is called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers benefit financially 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. 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.¹¹

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 p.m. and can be triggered up to 18 CPP days a year and the CPP period in 2021 was from 2 p.m. to 6 p.m. There were no CPP events called in 2021. In 2022 SDG&E will be changing its CPP period from 2 p.m.- 6 p.m. to 4 p.m. - 9 p.m. per D.21-03-056.¹²

¹¹ 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.

¹² D.21-03-056, p 16 and Conclusion of Law #3, Attachment 1.

3.2.1.2 Default Small Commercial Critical Peak Pricing and Time of Use

This dynamic rate is similar to SDG&E's Large and Medium CPP rates with a major distinction, SDG&E's small commercial and industrial customers do not have demand charges, therefore there are no demand components. Between November 2015 and April 2016, SDG&E transitioned over 120,000 small business customers onto time of use rates with a critical peak component (CPP-TOU). While customers were defaulted onto TOU-CPP rates, they could elect to opt-out to a time-of-use (TOU) rate and approximately 5% of them did. In tandem, SDG&E also transitioned small agricultural customers from flat rates onto time of use rates and offered a CPP-TOU rate on a voluntary (opt-in) basis. By April 2016, electricity rates without a time varying component were no longer available for small commercial and agricultural customers. In the years leading up to and after the rate transition, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices. In subsequent years, the portion of non-residential sites opting out of CPP-TOU rates onto TOU only rates continued to be in the low single digits and about 112,000 small commercial customers were on CPP-TOU rates at the end of 2020. However, in the spring of 2021, all commercial sites in the City of San Diego were defaulted onto a Community Choice Aggregation (CCA) energy supply option which precludes staying on SDG&E CPP-TOU rates.¹³ As of the PY 2021 event season, about 51,000 small commercial sites (45%) remain on the CPP-TOU rate. The CCA transition also affected Technology Deployment (TD) sites on CPP rates as they will no longer be signaled during CPP events. The CCA transition does not affect TD sites in ACSDA programs since those participants are not on CPP-TOU rates.

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

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

The TOU periods for all non-Grandfathered rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an

¹³ SDG&E's CPP rate is a commodity rate. Therefore, if a customer is defaulted onto a Community Choice Aggregator (CCA) they will be receiving their commodity rate from the CCA.

overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year. Starting June 1st 2022, the CPP event window will coincide with the RA window of 4 p.m. to 9 p.m.

For residential Grandfathered customers, the summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. The grandfathering term expires on July 31, 2022.

3.3.1 Nonevent based programs

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

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

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

4. Methodology

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

During 2021 the Covid-19 pandemic continued however, much of the customer loads returned to a "normal" state. SDG&E did not provide any adjustment factors to its ex-ante estimates for 2022 and beyond. SDG&E continues to see significant CCA activity in 2022. It is expected that SDG&E's CPP residential program will see a significant additional reductions starting in the 2nd quarter of 2022. SDG&E also expects to lose more CPP customers in 2023 and 2024 due to CCAs.

Table 4-1: Summary of Analysis Methodologies by Program

Supply Side Demand Response Programs			
Program	Method	Evaluation	Key Assumptions
AC Saver Day Ahead Commercial	<u>Ex-Ante</u> : Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The 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.	<ul style="list-style-type: none"> Shift of roughly half of existing CPP-TD participants to ACSDA in 2021 reflecting expected defaulting of customers to a Community Choice Aggregation provider. CCA supplied customers must be unenrolled from CPP rates but can continue to participate in ACSDA assumed their device(s) remain(s) connected. Note there is no ex-post analysis to describe for PY2021. So historical impacts from PY 2020 events were used as inputs to ex-ante modeling.
AC Saver Day Ahead Residential	<u>Ex-Post</u> : Panel Regression with a multiple matched control group <u>Ex-Ante</u> : Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The 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.	<ul style="list-style-type: none"> Analysis showed that COVID-19 effects have largely subsided, and any remaining effects are small. Loads are assumed as a “new normal”.

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

Program	Method	Evaluation	Key Assumptions
AC Saver Day Of Commercial	<p><u>Ex-Post:</u> Statistical matching design</p> <p><u>Ex-Ante:</u> Ex-ante load impacts fit a single model that estimates the weather responsiveness of average ex-post load impacts</p>	<p>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.</p>	<ul style="list-style-type: none"> • Commercial snapback is assumed to be zero. • Enrollment is projected to decrease over the next few program years. • Chose not to compare to 2020 due to the impact from the COVID-19 pandemic
AC Saver Day Of Residential	<p><u>Ex-Post:</u> Randomized Controlled Trial (RCT)</p> <p><u>Ex-Ante:</u> Ex-ante load impacts fit a single model that estimates the weather responsiveness of average ex-post load impacts</p>	<p>Random samples of residential AC Saver Day Of customers were selected from each cycling strategy.</p>	<ul style="list-style-type: none"> • Enrollment is projected to decrease over the next few program years. • Snapback for residential customer was calculated based on cycling strategy. • Chose not to compare to 2020 due to the impact from the COVID-19 pandemic

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

Program	Method	Evaluation	Key Assumptions
Base Interruptible Program	<p><u>Ex-Post:</u> Regression analysis of customer-level hourly load data</p> <p><u>Ex-ante:</u> Scenarios of ex-ante load impacts are developed by combining enrollment forecasts with per-customer reference loads and load impacts, which were developed using the results of the ex-post load impact evaluation.</p>	<p>BIP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models.</p>	<ul style="list-style-type: none"> Average program FSL achievement rate is assumed. For PY2021, assumes no COVID-19 adjustment because the program appears to have returned to pre-COVID-19 levels.
Capacity Bidding Commercial CBP	<p><u>Ex-Post:</u> Customer-specific hourly regression models as the primary evaluation method.</p> <p><u>Ex-ante:</u> 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.</p>	<p>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.</p>	<ul style="list-style-type: none"> The enrollment forecast assumes a 2% growth per year from 2022-2027 due to SDG&E's proposed program improvements. In addition, SDG&E forecasts the CBP DO program enrollment will increase by another 1% per year starting in 2022-2023 due to growth in the Technical Incentives (TI) program. The enrollment forecasts for both programs show a flat trend from 2027-2032 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 4-1 continued: Summary of Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	Method	Evaluation	Key Assumptions
Critical Peak Pricing CPP	<u>Ex-Ante</u> : Weather-Adjusted, per-customer Impacts	Ex-ante estimates are based on ex-post percentage load impacts (adjusted for changes in event hours as needed), with the reference loads simulated to represent the range of weather and day types required by the Protocols.	The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios. Forty percent of Large & Medium CPP was removed starting with 2021 program year due to CCA migration.
Default Small Commercial CPP	<u>Ex-ante</u> : Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The distance matching approach used selected five matched control sites for each of the roughly 108,000 non-residential Small CPP sites among a matched control candidate pool of roughly 13,500 small commercial and small agricultural TOU sites who were selected in PY 2020.	Note there is no ex-post analysis to describe for PY2021. So historical impacts from PY 2020 events and PY 2021 ex-ante reference loads were used as inputs to ex-ante modeling.

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

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	Method	Evaluation	Key Assumptions
Electric Vehicle Time-Of-Use: EVTOU2, EVTOU5 & VGI	<p><u>Ex-Post</u>: Panel regression difference-in-differences method.</p> <p><u>Ex-ante</u>: 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.</p>	<p>EVTUO: 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.</p> <p>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.</p>	<ul style="list-style-type: none"> The EVTUO approach relies more heavily on selecting a comparable matched control group than the model specification. We conducted a tournament to identify the model that performed best at identifying the control pool with electric vehicles, but not on EV TOU rates. For the evaluation, we used a standard difference-in-differences panel regression with customer fixed effects, date-time effects, and weather explanatory variables. To calculate the VGI Pilot customer response we ran linear regressions with multiple fixed effects and multi-way clustering. The regressions treated station ID, date, day of week and hour as categorical regressors, and captured Station ID and date as fixed effects in each panel.

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

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	Method	Evaluation	Key Assumptions
Voluntary Residential CPP & TOU	<p><u>Ex-Post:</u> Difference-in-Difference analysis method.</p> <p><u>Ex-Ante:</u> Since no residential CPP events took place in 2021, the ex-ante analysis for CPP events applies CPP event load impacts from PY2020 to reference loads calculated using PY2021 customer load data.</p>	<p>Selects a quasi-experimental matched control groups, comparing the usage of treatment and control group customers on relevant days or time periods, comparisons are then adjusted by usage difference on pre-treatment or non-event days.</p>	<ul style="list-style-type: none"> • Fifty five percent of the customers were removed starting in 2022 program year due to CCA migration • No CPP events were called in 2021. • Starting June 1, 2022, the CPP event window will coincide with the RA window, such that ex-ante results beginning in 2022 will report load impacts over the 4 to 9 p.m. period. This means that the ex-post load impacts, which occurred between 2 and 6 p.m., were shifted forward to span the updated event window beginning in 2022.

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

Table 5-1: Summary of 2021 SDG&E Average DR LI Ex-post estimates by Program

Program	Supply Side Demand Response						
	Reference Load (MW)	Observed Event Load (MW)	Load Impact per Customer (kW)	% Load Impact	Aggregate Impact (MW)	Number of Accounts	Number of Events
AC Saver Day Ahead Commercial**	-	-	-	-	-	-	-
AC Saver Day Ahead Residential	24.38	18.36	0.41	24.7%	6.02	14,839	5
AC Saver Day Of Commercial	13.51	13.30	0.09	1.6%	0.22	2,312	7
AC Saver Day Of Residential	10.66	10.23	0.06	4.1%	0.44	7,798	7
Base Interruptible Program							
Capacity Bidding Program*	18.8	17.5	7.3	7%	1.3	179	69*

* SDG&E triggered 26 CBP-DA 11 a.m.-7 p.m. events, 11 CBP-DA 1 p.m.-9 p.m. events, 12 CBP-DO 11 a.m.-7 p.m. events, and 20 CBP-DO 1 p.m.-9 p.m. events.

** No AC Saver Day Ahead Commercial events were called in PY 2021.

Table 5-1 continued: Summary of 2021 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***	-	-	-	-	-	-	-
CPP customers on Technology Deployment (TD)***	-	-	-	-	-	-	
Default Small Commercial CPP***	-	-	-	-	-	-	-
Small Agricultural***	-	-	-	-	-	-	
PSW customers on Technology Deployment (TD)***	-	-	-	-	-	-	
Voluntary Residential grandfathered CPP customers on Technology Deployment (TD) plus TOU***	-	-	-	-	-	-	-
Voluntary Residential CPP customers on Technology Deployment (TD) plus TOU***	-	-	-	-	-	-	
Voluntary Residential CPP excluding Technology Deployment (TD) customers plus TOU***	-	-	-	-	-	-	
Voluntary Residential grandfathered CPP excluding Technology Deployment (TD) customers plus TOU***	-	-	-	-	-	-	
Electric Vehicle Time-Of-Use: EVTOU2**	11.56	9.67	0.24	16.4%	1.89	7,863	TOU
Electric Vehicle Time-Of-Use: EVTOU5 & EVTOU2 to EVTOU5**	27.05	24.48	0.28	9.42%	2.55	16,009	TOU

*There are no Voluntary Residential grandfathered CPP customers on Technology Deployment (TD), therefore the impacts are intentionally left in blank.

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

*** No CPP events were called in PY 2021.

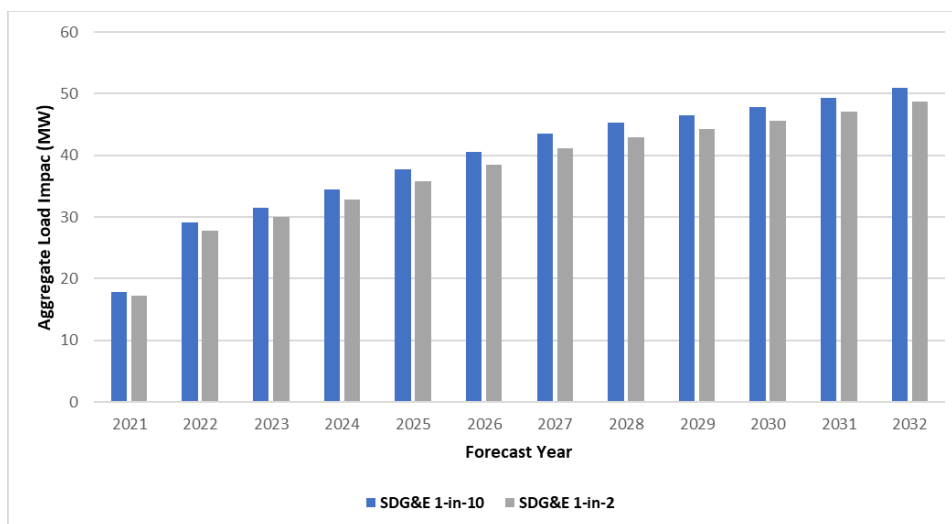
5. Ex-Ante Load Impacts

This section presents PY21 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.¹⁴ 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). The load impact estimates for each program align with the peak period now used for resource adequacy planning, which is 4 p.m. to 9 p.m. year-round.

6.1 Projected Change in PY20 Portfolio Load Impacts from 2021–2032

Figure 6-1 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. Overall, SDG&E's portfolio is projected to increase by 75% from 2022 to 2032 (from 29 MW in 2022 to 51 MW in 2032) under 1-in-10 weather conditions. On the other hand, SDG&E's portfolio is projected to increase by 75% from 2022 to 2032 (from 28 MW in 2022 to 49 MW in 2032) under 1-in-2 weather conditions.

Figure 6-1: Projected Change in PY21 Portfolio Load Impacts from August 2022–2032



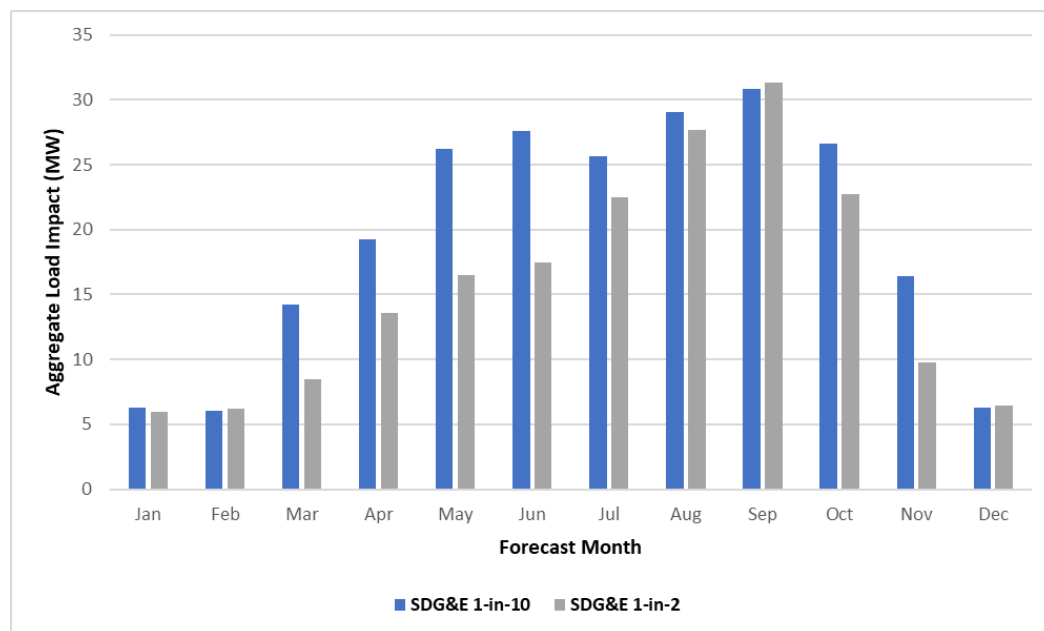
¹⁴ DR Load Impact Protocols and Regulatory Guidance (Protocols 17-23) by CPUC (Apr 2008) - page 93-110

5.2 Portfolio Aggregate Load Impacts by Month for the year of 2022

Figure 6-2 shows the 2022 load impact estimates under 1-in-2 and 1-in-10 SDG&E weather conditions. 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 2022, SDG&E's DR portfolio estimates nearly 31 MW of load reduction during the September monthly system peak day under SDG&E's 1-in-10 weather conditions. The months of June, July, and August load impacts are slightly lower than the month of September delivering 27, 25, and 29MW respectively under SDG&E's 1-in-10 conditions.

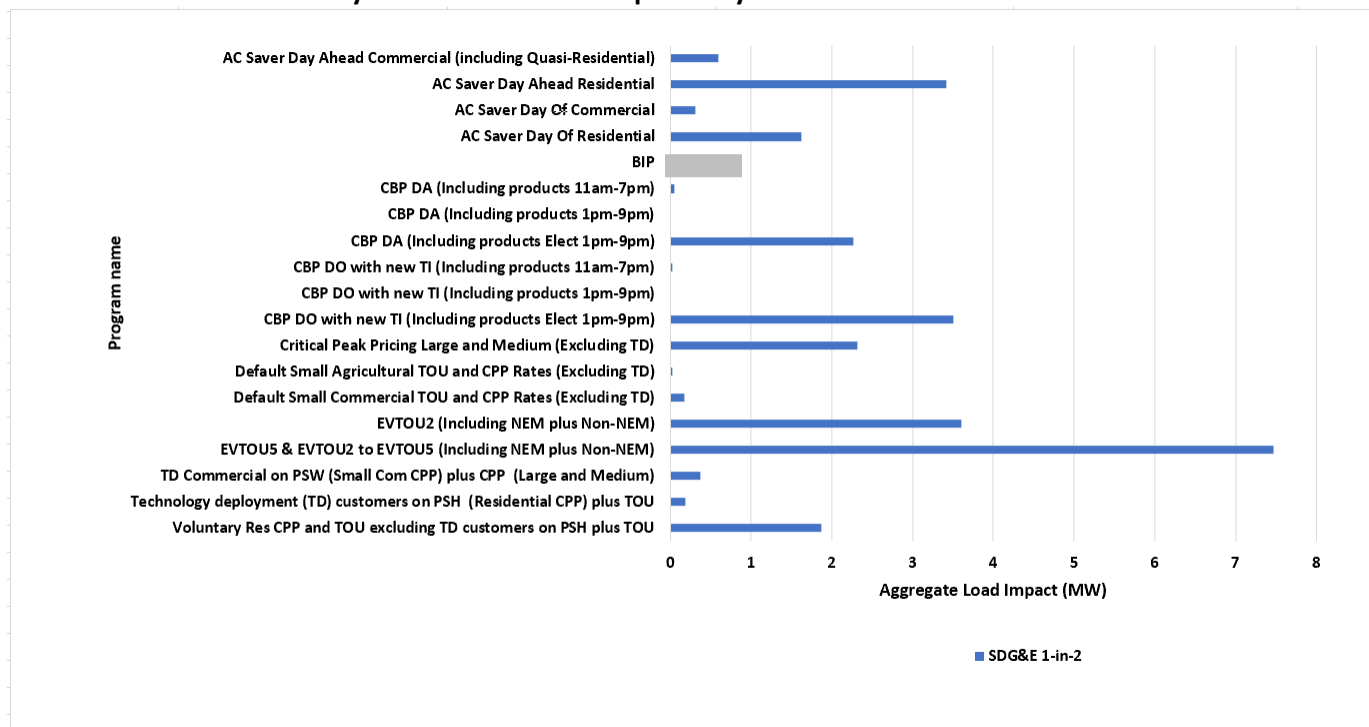
Figure 6-2: PY21 Portfolio Aggregate Ex-ante Load Impact Estimates (MW) for the year of 2022 by 1-in-2 and 1-in-10 SDG&E-specific System Conditions and Monthly System Peak Day



5.3 Portfolio Load Impacts by Program Type for the year of 2021

Figure 6-3 shows the distribution of portfolio aggregate load impacts by program type in August 2021. In August 2021, the load impacts from price responsive programs are forecast to comprise 39% of SDGE's DR portfolio, 40% from non-event programs and 21% from aggregator and less than 1% from emergency programs. A greater percentage of load impacts are projected to come from EVTOU5 followed by AC Saver Day Ahead Residential. The smaller impacts come from BIP and Default Small Agricultural TOU and CPP Rates (Excluding TD).

Figure 6-3: Distribution of PY20 Portfolio Aggregate Load Impacts by Program Type 2022 August System Peak Day under 1-in-2 SDG&E-specific System Conditions



5.4 Portfolio Load Impacts by Program from 2021-2032

Table 6-4 summarizes the portfolio load impacts by program for 2021 through 2032 under 1-in-2 SDG&E weather conditions.

In August 2032, the load impacts from load modifying programs are forecast to comprise 68% of SDGE's DR portfolio and 32% from supply side programs.

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. The load impacts from emergency programs are forecast to comprise 0.5% of SDG&E's DR supply side portfolio. The price responsive programs represent 58% of SDGE's DR supply side portfolio and most of this percentage is derivate from AC Saver Day Ahead Residential. The aggregator DR represents 42%, the majority of this percentage is attribute of CBP DO with new TI (Including products 11 a.m.-7 p.m. and 1 p.m.- 9 p.m.).

Table 6-4: Portfolio Aggregate PY21 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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Supply Side Total MWs**	6.42	11.78	12.66	13.52	14.50	15.53	16.62	16.73	16.35	16.00	15.65	15.33
Emergency												
BIP												
Price Responsive	5.47	5.95	6.70	7.49	8.34	9.25	10.22	10.32	9.95	9.59	9.25	8.92
AC Saver Day Ahead Commercial (including Quasi-Residential)	0.63	0.60	0.55	0.51	0.48	0.44	0.41	0.39	0.39	0.38	0.37	0.37
AC Saver Day Ahead Residential	2.72	3.42	4.41	5.39	6.41	7.48	8.58	8.70	8.33	7.98	7.64	7.32
AC Saver Day Of Commercial	0.35	0.31	0.23	0.17	0.17	0.12	0.09	0.07	0.07	0.07	0.07	0.07
AC Saver Day Of Residential	1.77	1.62	1.52	1.42	1.33	1.25	1.17	1.17	1.17	1.17	1.17	1.17
Aggregator DR	0.96	5.84	5.95	6.04	6.16	6.28	6.40	6.40	6.40	6.40	6.40	6.40
CBP DA (1pm-9pm)	0.04	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 1pm-9pm)*		2.27	2.31	2.36	2.41	2.45	2.50	2.50	2.50	2.50	2.50	2.50
CBP DA (11am-7pm)	0.13	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
CBP DO with new TI (1pm-9pm)	0.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CBP DO with new TI (Elect 1pm-9pm)*		3.50	3.57	3.61	3.68	3.75	3.83	3.83	3.83	3.83	3.83	3.83
CBP DO with new TI (11am-7pm)	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

* CBP DA (Elect 1pm-9pm) and CBP DO with new TI (Elect 1pm-9pm) products will start in 2022, therefore they are intentionally left in blank.

**The Supply Side Total MWs excludes the MWs for BIP.

The load modifying programs are divided into two groups: price responsive programs and non-event based. The load impacts from price responsive programs are forecast to comprise 5% of SDG&E's DR load modifying portfolio where the greater percentage of load impacts are projected to come from Critical Peak Pricing. The load impacts from non-event based are forecast to embrace 95% of SDG&E's DR load modifying portfolio most of this percentage is related to EVTOU5 & EVTOU2 to EVTOU5.

**Table 6-4 Continued: Portfolio Aggregate PY21 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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Modifying Total MWs	10.16	16.02	17.36	19.23	21.28	22.87	24.51	26.15	27.80	29.51	31.38	33.39
Price Responsive	2.05	4.93	3.63	2.99	2.61	2.36	2.18	2.01	1.86	1.73	1.61	1.51
Critical Peak Pricing Large and Medium (Excluding TD)	-0.51	2.31	2.09	1.88	1.69	1.53	1.38	1.24	1.12	1.01	0.92	0.83
Default Small Agricultural TOU and CPP Rates (Excluding TD)	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Default Small Commercial TOU and CPP Rates (Excluding TD)	0.17	0.17	0.12	0.08	0.06	0.04	0.03	0.02	0.02	0.01	0.01	0.01
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	0.36	0.37	0.39	0.41	0.44	0.47	0.50	0.50	0.49	0.48	0.46	0.45
Technology deployment (TD) customers on PSH (Residential CPP)	0.06	0.18	0.19	0.09	0.05	0.02	0.01	0.01	0.00	0.00	0.00	0.00
Voluntary Residential CPP and TOU excluding TD customers on grandfathered PSH*	-0.60											
Voluntary Residential CPP and TOU excluding TD customers on PSH plus TOU	2.54	1.87	0.83	0.52	0.36	0.29	0.25	0.24	0.23	0.22	0.22	0.22
Non-event based	8.11	11.08	13.73	16.23	18.67	20.51	22.33	24.14	25.94	27.78	29.76	31.88
EVTU2 (Including NEM plus Non-NEM)	2.95	3.61	4.47	5.28	6.08	6.68	7.27	7.85	8.44	9.04	9.69	10.38
EVTU5 (Including NEM plus Non-NEM)	5.16	7.48	9.26	10.95	12.59	13.84	15.06	16.28	17.50	18.74	20.08	21.51
Supply Side plus Load Modifying plus Non-event Total MWs	10.16	16.02	17.36	19.23	21.28	22.87	24.51	26.15	27.80	29.51	31.38	33.39

*Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under Grandfathered TOU period definitions until July 31, 2022. Therefore, the impacts of "Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH" are intentionally left in blank.

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

Table 6-5 summarizes the portfolio number of customers forecasted by program for 2021 through 2032 under 1-in-2 SDG&E weather conditions.

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. In August 2032, the number of customers from load modifying programs are forecast to comprise 66% of SDGE's DR portfolio and 34% from supply side programs.

In August 2032, the customers from emergency programs are forecast to comprise 0.002% of SDGE's DR supply side portfolio. The price responsive programs represent 99.4% of SDGE's DR supply side portfolio and most of this percentage is derived from AC Saver Day Ahead Residential. The aggregator DR represents 0.06%, the majority of this percentage is attribute of CBP DO with new TI (Including products Elect 1 p.m.-9 p.m.).

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 14% of SDGE's DR load modifying portfolio where the greater percentage of the number of customers are projected to come from Voluntary Residential CPP excluding TD plus TOU.

Table 6-5 Portfolio Aggregate PY21 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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Supply Side Total number of customers*	25,950	28,915	33,393	38,201	43,511	49,276	55,456	57,720	57,720	57,720	57,720	57,720
Emergency												
BIP												
Price Responsive	25,769	28,602	33,073	37,878	43,181	48,939	55,113	57,377	57,377	57,377	57,377	57,377
AC Saver Day Ahead Commercial (including Quasi-Residential)	676	650	612	576	542	511	481	471	471	471	471	471
AC Saver Day Ahead Residential	15,041	18,829	24,329	29,990	36,019	42,397	49,109	51,383	51,383	51,383	51,383	51,383
AC Saver Day Of Commercial	2,235	1,963	1,450	1,072	792	585	432	432	432	432	432	432
AC Saver Day Of Residential	7,817	7,160	6,683	6,240	5,828	5,446	5,091	5,091	5,091	5,091	5,091	5,091
Aggregator DR	181	313	319	324	330	337	343	343	343	343	343	343
CBP DA (Including products 1pm-9pm)	18	0	0	0	0	0	0	0	0	0	0	0
CBP DA (Including products Elect 1pm-9pm)*		94	96	98	100	102	104	104	104	104	104	104
CBP DA (Including products 11am-7pm)	30	11	11	11	12	12	12	12	12	12	12	12
CBP DO with new TI (Including products 1pm-9pm)	122	0	0	0	0	0	0	0	0	0	0	0
CBP DO with new TI (Including products Elect 1pm-9pm)*		199	203	205	209	213	218	218	218	218	218	218

* CBP DA (Elect 1pm-9pm) and CBP DO with new TI (Elect 1pm-9pm) products will start in 2022, therefore they are intentionally left in blank.

**The Supply Side Total number of customers excludes the number of customers for BIP.

**Table 6-5 Continued: Portfolio Aggregate PY21 number of customers forecasted for the August System Peak Day
Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Modifying	115,449	110,563	96,385	88,906	89,056	89,421	91,060	93,640	96,892	100,801	105,485	110,875
Price Responsive	92,047	77,514	55,433	40,492	33,376	28,240	24,470	21,658	19,542	17,939	16,720	15,786
Critical Peak Pricing Lrg & Med (Excluding TD)***	4,712	4,130	3,612	3,159	2,763	2,417	2,115	1,851	1,620	1,418	1,242	1,088
Default Small Agricultural TOU and CPP Rates (Excluding TD)	166	164	113	73	55	41	31	23	17	13	10	7
Default Small Com TOU and CPP Rates (Excluding TD)***	52,081	51,393	35,221	22,681	16,886	12,522	9,232	6,784	4,961	3,593	2,566	1,795
TD Commercial on PSW (Sm Com CPP) + CPP (Lrg & Med)	383	415	463	514	569	630	695	717	717	717	717	717
TD customers on PSH (Residential CPP) plus TOU	713	713	713	350	172	85	42	20	10	5	2	1
Voluntary Residential CPP and TOU excluding TD customers on grandfathered PSH*	366											
Voluntary Residential CPP and TOU excluding TD customers on PSH***	33,626	20,699	15,311	13,715	12,931	12,545	12,355	12,262	12,217	12,194	12,183	12,178
Non-event based	23,402	33,050	40,952	48,415	55,680	61,181	66,591	71,982	77,350	82,861	88,765	95,089
EVTU2 (Including NEM plus Non-NEM)	7,918	9,612	11,911	14,081	16,194	17,794	19,368	20,935	22,497	24,100	25,817	27,656
EVTU5 (Including NEM plus Non-NEM)	15,484	23,437	29,041	34,333	39,486	43,387	47,223	51,046	54,853	58,762	62,948	67,433
Supply Side plus Load Modifying Total number of customers	141,400	139,479	129,778	127,109	132,568	138,697	146,517	151,361	154,613	158,522	163,206	168,596

*Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under Grandfathered TOU period definitions until July 31, 2022. Therefore, the number of customers of "Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH" are intentionally left in blank.

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

7. Recommendations

The 2021 DR program evaluations contain the evaluators' recommendations for each program. The recommendations pertain to steps that can be taken to improve the measurement and evaluation of DR resources and to improve program performance. This section summarizes the recommendations for each program.

7.1 Supply Side Demand Response

7.1.1 Emergency Programs

7.1.1.1 *Base interruptible program (BIP)*

The following recommendation was made by Christensen:¹⁵

BIP continues to perform well, with its customers providing substantial load impacts with short notice. SDG&E called one weekday event with strong response from its customer.

7.1.2 Aggregator Programs

7.1.2.1 *Capacity Bidding Program (CBP)*

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs:¹⁶

- a) **Aggregator In-Depth Interviews.** AEG recommends performing in-depth interviews (IDI) for all active PY2022 aggregators. These IDIs will provide valuable insight into aggregator performances and challenges that can:
 - **Inform the ex-post analysis,** allowing the evaluator to appropriately set up the regression analyses. In other words, specify indicators that can isolate special cases such as notification issues, delivery issues, etc. Such specifications will allow for more accurate event-level estimates.
 - **Inform the ex-ante analysis,** receiving feedback on aggregator outlook on CBP participation/nominations will allow evaluators to develop more informed forecast assumptions.

¹⁵ 2021 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1, 2022) – page 56

¹⁶ 2021 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2022) – page 77-78

7.1.3 Price Responsive Programs

7.1.3.1 AC Saver Day Ahead commercial and residential programs

DSA made the following recommendation for commercial and residential¹⁷:

- **If possible, avoid bidding sites that lack connected thermostats into the CAISO markets.** Sites with loads that cannot be controlled or dispatched do not deliver any detectable demand reduction. They simply dilute the demand reductions and make them harder to detect. SDG&E should continue efforts to remove thermostats disconnected for prolonged periods from the dispatch portal.
- **Continue to monitor loads and assumptions about the effect of COVID-19 on loads.** Analyze load data and public health data to evaluate the appropriateness of the “new normal” assumption going forward.

DSA made the following recommendation for commercial only¹⁸:

- **Anticipate** lower load reductions for CPP-TD with the new 4 to 8 p.m. CPP event window. Commercial loads decline substantially after 5 p.m. as does load reduction potential.
- **Develop and deploy a robust outreach and education plan to inform participants regarding the new CPP window due to start in PY 2022.** The event window is planned to change from 2 p.m. to 6 p.m. to 4 p.m. to 8 p.m. for PY 2022. Outreach may not be critical for the technology enabled CPP TD programs, but participants should be informed and doing so will help ensure any behavioral response that is layered on the technology response will not be lost.

DSA made the following recommendation for residential only:

Review dispatch strategy to optimize load reductions. While there are a few methods of demand response dispatch, the 4-degree setback is an algorithm with diminishing returns. PY 2020 was the first year with several events lasting 3 to 5 hours, demonstrating that impacts may be high in the first hour or two of an event drop notably in the third and fourth hour of an event. Dispatch strategies can be designed to maintain more consistent impacts across multiple event hours and potentially produce higher average impacts across event hours by producing greater impacts in later event hours, e.g., in hour 3 or 4. For example, setbacks can be stepped such that the setback is 2-degrees in hour 1, 3-degrees in hour 2, and 4-degrees in hour 3. Setback strategies can also be used to minimize customer

¹⁷ 2021 Load Impact Evaluation for San Diego Gas and Electric’s Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program (Mar 2022) – page 60

¹⁸ 2021 Load Impact Evaluation for San Diego Gas and Electric’s Residential Technology Deployment Program (Mar 2022) – page 38

discomfort while maximizing average impact. As an example, a stepped dispatch may be less noticeable and less uncomfortable for residential occupants, which is all the more important as residential weekday occupancy has increased in the face of COVID-19. Another area for consideration is a more gradual pre-cooling strategy. BYOT thermostats exhibit a clear, substantial pre-cooling notch in the hour before events. Stepped pre-cooling, similar to stepped event hour setbacks, can be used to dampen the pre-cooling notch while improving participant comfort.

7.1.3.2 AC Saver Day Of commercial and residential programs

Resource Innovations made the following recommendations:¹⁹

- Change the methodology for estimating the residential ex-post reference loads from a RCT design to a statistical matching framework for upcoming program years. While the RCT design is more statistically robust than the matched control group approach, this change in methodology would provide multiple benefits. First, it would eliminate the risk of future paging issues like those experienced in 2020, as well as prevent sampling error due to changes in customer load between the two control groups from one season to the next (as seen between 2020 and 2021). Further, this would allow the entire enrolled residential population to provide load impacts without the need to hold back approximately 800 customers per cycling segment, which represents about 10% of the residential 50% cycling group and about 30% of the residential 100% cycling group.
- To ensure that the program's direct load control devices are dispatching during events and producing load reductions, a field study should be conducted that examines the fleet of devices for functionality, prioritizing those that have been installed for the longest period of time. This is particularly important if new residential customers continue to be re-added to the program using legacy AC Saver switches. Alternatively, a data-based analysis could be designed that uses clustering or similar techniques to identify specific devices that do not exhibit evidence of cycling during program events.
- Consider calling events for commercial participants that include hours before 6 p.m. in order to achieve larger commercial impacts.

¹⁹ AC Saver Day Of 2021 Load Impact Program Evaluation by Nexant (Mar 2022) -page 49 and 50

- In order to facilitate a less tenuous connection between ex-post and ex-ante, SDG&E should call three to four events that are four hours in duration each season, between the hours of 4 p.m. to 9 p.m. The results from these events will help the load impact evaluator produce robust the ex-ante impacts for the Resource Adequacy window.

7.2 Load Modifying DR

7.2.1 Price responsive Programs

7.2.1.1 Critical Peak Pricing (CPP)

Christensen made the following recommendation:

In 2021, SDG&E didn't call any events. Calling events will improve the understanding of customer response to the program.²⁰

7.2.1.2 Default Small Commercial CPP

DSA made the following recommendation:²¹

- **Develop and deploy a robust outreach and education plan to inform participants regarding the new CPP window due to start in PY 2022.** The event window is planned to change from 2 to 6 p.m. to 4 to 8 p.m. for PY 2022. However, small CPP participants appear to still be responding to the original 11 a.m. to 6 p.m. window. For the behavioral Small CPP program it will be critical to help participants understand that load reductions are needed after 4 p.m. Multiple communication modes should be used to deliver this messaging.
- **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, about 1%, providing ample room to improve reductions. However, 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.

²⁰ 2021 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates by Christensen (April 1st, 2022) – page 116

²¹ 2021 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program (April 1, 2022) – page 48

- **Notification rates for small CPP can be improved.** Customers elect whether or not to sign up for notifications and by which channels they receive notification. Because notification is closely linked to response, additional efforts to improve notification rates are recommended. The share of sites enrolled to receive notifications has dropped somewhat since PY 2018 when CPP events were last called. In PY 2018 roughly 60% of sites received event notifications while that number dropped to 43% in PY 2020. Sites receiving event notifications tend to produce greater impacts so an increase in notification rates has the potential to meaningfully increase load reductions.
- **Continue to monitor loads and assumptions about the effect of COVID-19 on loads.** Analyze load data and public health data to evaluate the appropriateness of the “new normal” assumption going forward.

7.2.1.3 Voluntary Residential CPP and TOU

In 2021, SDG&E didn’t call any events. Calling events will improve the understanding of customer response to the program.

The treatment group among CPP customers will begin rapidly decreasing in enrollment as customers migrate to Community Choice Aggregator programs. As a result, finding valid incremental treatment customers will become more difficult in future years. The reduction of incremental customers limits the experimental leverage of estimating TOU load impacts for future program years.²²

7.2.2 Nonevent Based Programs

7.2.2.1 Electric Vehicle Time of Use

Electric vehicles have the potential to transform the electric grid fundamentally. They are a new, incremental, flexible, and critical load. As the residential electric vehicle market saturation 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 2.4M vehicles in SDG&E territory, and the grid implications of transportation electrification are large. It has become increasingly important to provide customers incentives and tools to manage charging to lower bills and reduce use during peak hours.

²² 2021 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates by Christensen (Mar 2022) – page 73

Key recommendations from the evaluation are:

- Evaluate 1st year impacts for all sites that reached a full year of experience with electric vehicle time-of-use rates. Currently, the evaluation includes all incremental sites that enrolled on the rate over the study period. As a result, the number of sites evaluated for October is small and grows during the study period. The approach creates two challenges. The sample size for early months is inherently small, and we have very little data on behavior with TOU rates for the most recent enrollments. Shifting from analyzing sites that enrolled over the study period to analyzing sites that reached a full year of experience under TOU rates addresses these challenges. It ensures a large enough number of sites are analyzed each month and ensures we fully factor in the behavior of each new enrollment.
- Remove from the analysis sites whose enrollment on electric vehicle TOU rates coincides with the introduction of the electric vehicle into the home. Electric vehicles fundamentally change whole home load patterns and consumptions levels. Without sufficient data on charging patterns without the EVTOU5 and EVTOU2 rates, it is impossible to estimate the TOU effect on load patterns. The same applies to the installation of solar or battery storage. They fundamentally change whole home loads, and sites with installations over the study period (or the pre-intervention year) should be removed from the analysis.
- Assess whether SDG&E can incorporate California Department of Motor Vehicle (DMV) registration data to identify control sites – sites with electric vehicles that are not enrolled on EVTOU5 or EVTOU2. The DMV makes vehicle registration data available for public use but with limitations on how it is used and requirements regarding public notices and data security. While algorithms to identify electric vehicles using AMI data are helpful, vehicle registration data is a better source of information.
- Track historical first-year savings to avoid extrapolating from the new cohort of participants to the full population. Currently, the evaluation extrapolates the impacts from the new cohort of participants to the full population. This is done because it is often not feasible to reliably estimate the TOU price response for sites that have been enrolled on the TOU rates for multiple years. The pre-TOU data is too distant in time for a reliable analysis. An alternative is to track first-year savings by enrollment cohort, enabling SDG&E to estimate the aggregate impacts better.
- 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.

7.2.2.2 VGI Pilot Program

The Power-Your-Drive charging app has a key feature – the ability to restrict charging when prices exceed a threshold – that is rarely used. We recommend changing the default settings. To enable this feature, customers have to change the default settings and define a price threshold to automate the response. We recommend an A/B test to assess how changing the default settings affects charging behavior. In specific, we recommend testing a default that avoids charging when prices are high (above \$0.50/kWh), provides users a push notice that prices are high, and allows drivers to “charge anyway” via the push of a button.²³

²³ 2021 Load Impact Evaluations for San Diego Gas and Electric’s Electric Vehicles Time-of-Use (TOU) Rates by Demand Side Analytics (Apr 2022)

Appendix A: Regression Specifications

A.1 Supply Side Demand Response

A.1.1 Emergency Programs

A.1.1.1 Base interruptible program (BIP)

The paragraphs below describe the ex-post and ex-ante methodologies²⁴:

a) Ex-post

The following is a general form of the model that was separately estimated for each enrolled BIP customer.

Table A.1-1 below describes the terms included in this equation for the observed demand in a given hour h and date d :

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

²⁴ 2021 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1st, 2022)

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

Variable Name	Variable Description
Q_t	the demand in hour t for a BIP customer
The various b 's	the estimated parameters
$h_{i,t}$	an indicator variable for hour i , equal to one when t corresponds to hour i of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day DR of other demand response programs in which the customer is enrolled (e.g. DR = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10 (may be excluded via model screening)
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
$MON_t, FRI_t,$	indicator variables for Monday and Friday (Sunday hourly indicator variable is included in models that include weekend dates)
$MONTH_{j,t}$	a series of indicator variables for each month (model screening may include separate hourly profiles by month)
$SUMMER_t$	an indicator variable for the summer pricing season ²⁵
e_t	the error term

B) Ex-ante

Because BIP events may be called in any month of the year, separate regression models were estimated to allow for simulated winter reference loads. The winter model is shown below. This model is estimated separately from the summer *ex-ante* model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table A.1-2 describes the terms included in the equation.

²⁵ The summer pricing season is May through October for SDG&E.

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

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

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

A.1.2 Aggregator Programs

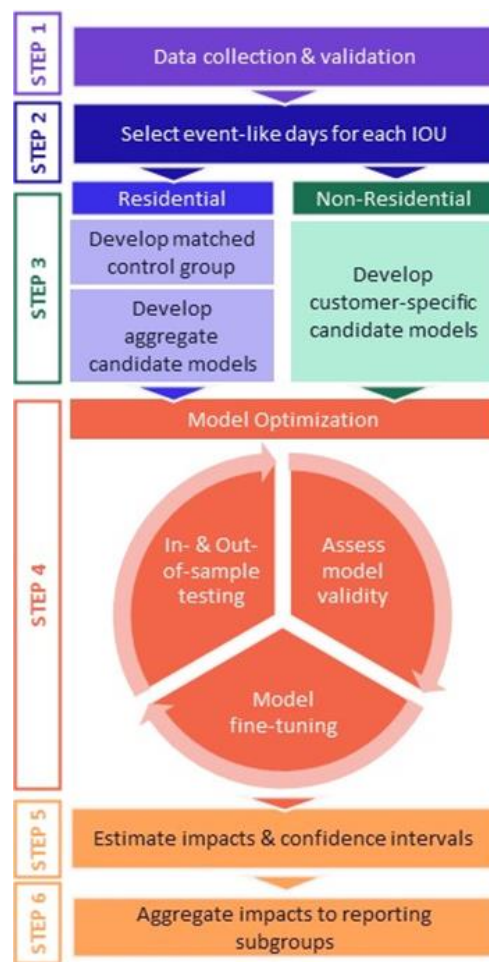
A.1.2.1 Capacity Bidding Program (CBP)

The paragraphs below describe the ex-post and ex-ante methodologies²⁶:

a) Ex-post

Figure A.2-1 illustrates a high-level overview of the approach AEG used to develop *ex-post* impacts. The subsections that follow describe the process in more detail.

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



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

²⁶ 2021 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2022)

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.²⁷ An hourly model like the equation below can be equivalently estimated as one model with hourly dummy variables or as 24 separate hourly models.

$$kwh_{it} = \beta_0 + \beta_1\alpha_t + \beta_2\delta_t + \beta_3CDH_t + \beta_4EVNT + \beta_5(\alpha_t * EVNT) + \varepsilon_{it}$$

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.2-1 presents the different explanatory variables used to create candidate models for the CBP.

²⁷ Any unexplained variation will end up in the error term.

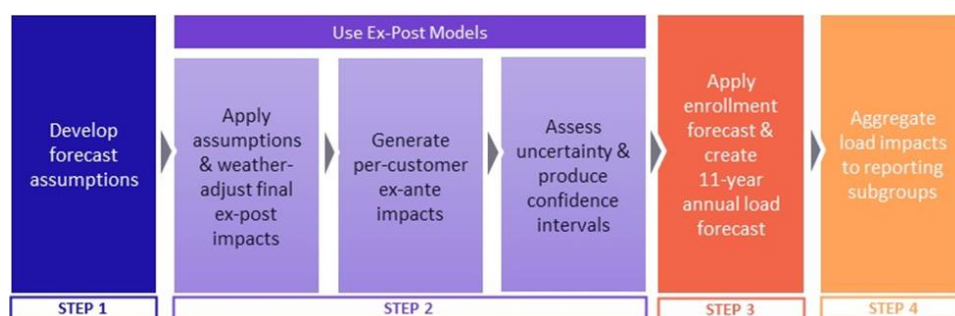
Table A-3: Explanatory Variables Included in Candidate Regression Models

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.2-2 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

The use of a panel model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. The equation for the model is presented below. A separate model was estimated for each intervention and hour of the day for each of the analysis segments identified as part of the evaluation plan. Pre and post event terms (single hour with two-hour buffer) were added to the Technology Deployment models to implement the same calibration for these load control programs²⁸:

$$kW_{i,t} = a + \sum_{n=1}^5 b_n \cdot Control_{i,t,n} + \sum_{n=1}^{max} c_n \cdot Event_n + d \cdot CDH_{i,t} + \delta_t + \varepsilon_{i,t}$$

Table A-4: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$kW_{i,t}$	Is the usage for each individual customer and time period
a	Is the model intercept
b	Loads for the five most closely matched control sites based on Euclidean distance matching. They did not experience the treatment and are weighted based on their predictive power.
$Control_{i,t,n}$	The hourly used for five control sites, with each match
c	Controls for differences between event and non-event days

Table A-5 continued: Explanatory Variables included in Regression Models

Variable Name	Variable Description
Event	Is a binary variable indicating if day is an event. Separate variables are used for each event, so impacts are estimated for each event. It has a value of zero on event-like proxy days. The five closest non-event days were included as proxy days for each event. Separate proxy days were selected for each event using Euclidean distance matching.
d	Is the parameter for weather sensitivity of loads
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.

²⁸ 2021 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program by DSA (Mar 2022)

a) Ex-ante

A key objective of the 2021 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 methodologies²⁹:

b) Ex-post

Two distinct approaches were used for estimating the ex-post reference loads: a randomized controlled trial (RCT) design and a statistical matching design. Residential customer impacts were estimated using an RCT. The commercial customer impacts were estimated with a matching study.

A matched control group was selected for the commercial program population whereby one nonparticipant was selected as a match for each participant on each event. The entire SDG&E small and medium business (SMB) customer population was made available for the statistical matching analysis. Each matched customer was chosen because they most closely resembled their matched participant in terms of the dissimilarity statistic described in the equation below:

²⁹ AC Saver Day Of 2020 Load Impact Program Evaluation by Nexant (Mar 2021)

Dissimilarity Statistic for Commercial Matching

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

Table A-6: Explanatory Variables included in Regression Models

Variable Name	Variable Description
<i>PeakProxy</i>	Average demand across the 2021 proxy days during the event window hours
<i>EventMorn</i>	Average demand on the event day from midnight to 10 a.m.
<i>EventMidday</i>	Average demand on the event day from 10 a.m. to the start of the event
<i>j j</i>	Commercial AC Saver Day Of participant to be matched
<i>i</i>	Index of the pool of control customers

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

Within each of these program segments, load impacts were estimated for each hour of each event day for both RCT and matched customers. The regression below essentially uses variation among the group that was not cycled to establish the relationship between the demand before the event and on proxy days and the demand during the event window and afterward.

LDV Model for Estimating Impacts

$$Demand_i = a + t * Cycled_i + b * Proxy_i + c * ProxyWindow_i + d * ProxyEve_i + e * EventMorn1_i + f * EventMorn2_i + g * EventMorn3_i + h * PreEvent_i + u_i$$

Table A-7: Explanatory Variables included in Regression Models

Variable Name	Variable Description
<i>Demand</i>	Average demand in the event hour being studied
<i>Cycled</i>	An indicator for whether customer <i>i</i> was cycled
<i>Proxy</i>	Average demand in the hour being studied on the average proxy day
<i>ProxyWindow</i>	Average demand in the event window on the average proxy day
<i>ProxyEve</i>	Average demand after the event window on the average proxy day
<i>EventMorn1</i>	Average demand from midnight to 7 a.m. on the event day
<i>EventMorn2</i>	Average demand from 7 a.m. to 10 a.m. on the event day
<i>EventMorn3</i>	Average demand from 10 a.m. to four hours before the event on the event day
<i>PreEvent</i>	Average demand during the four hours before the event
<i>i</i>	Customer index
<i>t</i>	Estimated impact
<i>a – h</i>	Estimated regression coefficients
<i>u</i>	Error term

b) Ex-ante

Table A-8 presents the model that is used to estimate reference load and load impacts as a function of weather. This model is estimated separately by customer class (residential and commercial) and cycling strategy. The estimated parameters from the models are used to predict reference loads under 1-in-2 and 1-in-10-year ex-ante weather conditions for all months of the year that the program may be dispatched.

Table A-8: Ex-ante Model for Reference Loads and Load Impacts

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

Variable Name	Variable Description
<i>impact_d</i>	Core 2018,2019 and 2021 ex-post impacts
<i>b₀</i>	Estimated constant
<i>b₁</i>	Estimated parameter coefficient
<i>mean17_d</i>	Average temperature over the first 17 hours of the day for each event day
<i>ε_d</i>	The error term for each day d

A.2 Load Modifying DR

A.2.1 Price responsive Programs

A.2.1.1 Critical Peak Pricing (CPP)

The paragraphs below describe the ex-post and ex-ante methodologies:³⁰

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. The weather during the summer of 2021 was significantly milder than the summer of 2020. Because of the milder weather, SDG&E did not have the need to call its load modifying DR, and therefore there are no ex-post results for any of SDG&E's CPP rates

b) Ex-ante

Per-customer load impacts are derived from the ex-ante load impacts provided in the previous PY2020 analysis since no events were called in 2021.

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.

Load impacts are provided for the years 2022 through 2032^[1], for a number 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.

Per-customer load impacts are derived from an analysis of the current and previous ex-post load impact evaluations. SDG&E is shifting CPP event hours to 4 p.m. - 9 p.m. in June 2022. To account for this change, ex-post percentage load impacts are mapped by hour-type onto the ex-ante event window. Uncertainty-adjusted load impacts were generated using the standard errors from the ex-post typical event day load impacts. Scenario-specific percent load impacts were developed from 10th, 30th, 50th, 70th, and 90th percentile load changes estimated for the relevant program year.

³⁰ 2021 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Ante Load Impacts by Christensen (Mar 2022)

A.2.1.2 Default Small Commercial CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies³¹:

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. The weather during the summer of 2021 was significantly milder than the summer of 2020. Because of the milder weather, SDG&E did not have the need to call its load modifying DR, and therefore there are no ex-post results for any of SDG&E's CPP rates.

b) Ex-ante

A key objective of the 2021 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. At a fundamental level, the process of estimating ex-ante impacts included 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.2.1.3 Voluntary Residential CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies for and TOU rates³²:

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. The weather during the summer of 2021 was significantly milder than the summer of 2020.

³¹ 2021 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program by DSA (Mar 2022)

³² 2021 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates by Christensen (April 2022)

Because of the milder weather, SDG&E did not have the need to call its load modifying DR, and therefore there are no ex-post results for any of SDG&E's CPP rates.

b) Ex-ante

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on analyses of per-customer load impact findings from ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments. Since no CPP events took place in 2021, the ex-ante analysis for CPP events applies CPP event load impacts from PY2020 to simulated reference loads using PY2021 customer load data.

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 methodologies³³:

a) Ex-post

EV TOU Ex-Post Evaluation Approach Summary

Methodology Component	Description
1. Population or sample analyzed	The full population of incremental participants, along with a matched control group, was analyzed. The evaluation focused only on incremental sites that enrolled on EVTOU in 2021 and excluded sites who had a change in electric vehicle, solar, or battery status that coincided with the study period. The evaluation includes 25% of the new enrollments because it is common for customer to enroll on TOU rates for electric vehicles when they first get their vehicle.
2. Data included in the analysis	The analysis included up to year of pre and post TOU data. The same data was included for participants and matched control. In all cases, we ensured that both the participant and control had pre and post TOU data for the same day of year.
3. Use of control groups	We relied on control group of customers with electric vehicles but who were not on SDG&E's TOU rates for electric vehicles. The process involves two steps. First, we build electric vehicle propensity using AMI data to identify unique load patterns that indicate the presence of electric vehicles (but avoiding variables about load shape and overall consumption). As part of the analysis, DSA will also identify the date the electric vehicle(s) arrived at the household. Once control candidates with electric vehicles had been identified, we matched customers who enrolled on TOU rates for electric vehicles in 2021 using 2020 (pre-treatment) hourly AMI data. The matching on pre-treatment loads used Euclidian distance matching and matched were selected only from customers with similar electric vehicle propensity scores.
4. Evaluation Method	Panel regression difference-in-differences with fixed customer effects, daily time effects, and weather were used to isolate the load impact. Regressions were run for like days. For example, when we estimated impacts for the top 10 highest system load days, we included only the top 10 highest load days in the year before and after EV TOU enrollment. This ensures the difference in differences adjustment was calibrated to correct day types.
5. Model selection	The approach relies more heavily on selecting a comparable matched control group than the model specification. We conducted a tournament to identify the model that performed best at identifying the control pool with electric vehicles, but not on TOU rates for electric vehicles. For the evaluation, we used a standard difference-in-differences panel regression with customer fixed effects, date-time effects, and weather explanatory variables.
6. Segmentation of impact results	The results were segmented by: <ul style="list-style-type: none">▪ Rate▪ Region in SDG&E territory (based on 3-digit zip code)▪ Solar status▪ Low income

³³ 2021 Load Impact Evaluations for San Diego Gas and Electric's Electric Vehicles Time-of-Use (TOU) Rates by Demand Side Analytics (Apr 2022)

b) Ex-ante

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	<p>The key steps were:</p> <ul style="list-style-type: none">▪ Segment customers by rate type (EV TOU5 and EVTOU2) and solar status▪ Estimate the relationship between reference loads and weather on a per household basis.▪ Use the models to predict reference loads for 1-in-2 and 1-in-10 weather year conditions.▪ Estimate the relationship between EVTOU load impacts and weather▪ Predict the reductions for 1-in-2 and 1-in-10 weather year conditions▪ Combine per customers reference loads and load impacts with an incremental forecast of enrollment on EV TOU rated developed by SDG&E.
3. Accounting for changes in the participant mix	The ex-ante load impacts accounts for changes in the participant mix across the two main rate types – EVTOU2 and EVTOU5 – and due to rooftop solar status.
4. Producing busbar level impacts	Granular results for distribution planning have been required for the last few years. A key consideration in the approach is that there is more data about customer loads than there is data on the percent reductions delivered during events. To develop ex-ante impacts at the busbar level, we use the load impacts by segment and the current mix of customers at the busbar level to estimate the granular impacts.

c) Power Your Drive

Methodology Component	Description
1. Population or sample analyzed	Charging data from all PYD charging sessions from the program's launch in 2017 through December 2021 were provided for evaluation. We analyzed charging sessions from January 2019 through December 2021. Until 2019, the program was still quickly bringing stations online and aggressively enrolling participants.
2. Data included in the analysis	For the PYD evaluation, we utilized: <ul style="list-style-type: none"> ▪ Charging session level kWh consumption data ▪ Driver Enrollment Data ▪ Site and Station characteristics ▪ Charging \$/kWh prices by day, hour, and station ▪ Historical weather patterns from Weather station records
3. Evaluation Method	Panel regression by charging station with multiple fixed effects. Regressions were run in relation to both Price response and Event responses. The Price model related price changes on the program to hourly charging kWh. The Event based model flagged hours with circuit or system Critical Peak Pricing adders as events. The coefficients of these models demonstrate the magnitude of customer response to measured changes in pricing as well as event hours.
4. Model selection	To estimate customer response DSA ran linear regressions with multiple fixed effects and multi-way clustering. The regressions treated station ID, date, day of week and hour as categorical regressors, and captured Station ID and date as fixed effects in each panel.
5. Segmentation of impact results	The results will be segmented by: <ul style="list-style-type: none"> ▪ Site type: Workplace vs. Multi-Unit Dwellings ▪ Rate to Host vs. Rate to Driver

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