San Diego Gas and Electrics 2020 Demand Response Executive Summary

May 26th, 2021

SDGE
A Sempra Energy utility℠

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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 2020 in accordance with (D.) 08-4-050. In Decision (D.) 08-04-050 the California Public Utility Commission (Commission) required the Investor Owned Utilities (IOUs) - San Diego Gas & Electric Company (SDG&E), Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) to perform annual studies of their DR activities in accordance with the load impact protocols[1] and to file the load impact reports by April 1st each year. The original load impact protocols require the preparation of a voluminous number of tables that resulted in the load impact reports being too large to be filed in hard copy. On April 6th, 2009 the Investor Owned Utilities (IOUs) filed a petition to modify D.08-41-050. The petition asked for two things: 1) the removal of the requirement to file the load impact reports in their entirety and 2) to provide the reports to the energy division of the Commission. On April 8th, 2010, D.10-04-006 granted the utilities requests and added an Executive Summary requirement. The executive summaries were to include an overview of the evaluation findings, recommendations for changes to the demand response resource. Additionally, the executive summaries were to include brief descriptions of the methodology, the enrollment forecast, and the inputs and assumptions used for calculating both the ex-post and ex-ante load impact estimates. The IOUs should also report the regression model specifications for each demand response program.

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

Six CPUC decisions over the past three years 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

[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.

- 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

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 pm to 6:00 pm to 4:00 pm to 9:00 pm (HE17-HE21) for each month of the year beginning in 2019. Additionally, combined storage and demand response projects 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 700,000 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 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.

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

During 2020 the Covid-19 pandemic affected nearly everyone in California and the country. In addition to the tragic number of deaths, the effects of Covid-19 were far reaching even into everyday energy usage. SDG&E observed changes to its customer loads as some commercial customer loads were significantly impacted and had lower energy usage than previous years. On the other hand, much of the residential loads increased substantially as people were told to stay home by California's governor Newsom. Starting in mid-March 2020, SDG&E observed about a 5-8% reduction in its commercial and industrial reference loads, and an opposite 10-12% increase to its residential reference loads. More information about the assumptions used in forecasting the load impacts are included in the Section 4: Methodology.

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 2020 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.

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[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.

1. 2020 Statewide Load Impact Evaluation of California's Capacity Bidding Programs, Ex-post and Ex-ante Impacts, Applied Energy Group, April 1st, 2021
2. 2020 Statewide Load Impact Evaluation of California's Critical Peak Pricing Programs, Ex-post and Ex-ante Impacts, Applied Energy Group, April 1st, 2021
3. 2020 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report, Christensen Associates, April 1st, 2021
4. 2020 Load Impact Evaluation of San Diego Gas and Electric's AC Saver Day Of Program, Nexant Inc, April 1st, 2021
5. 2020 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2021
6. 2020 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, 2021
7. 2020 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, 2021
8. 2020 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates, Christensen Associates, April 1st, 2021
9. 2020 Load Impact Evaluation of San Diego Gas and Electric's Residential Default Time-Of-Use Rates[4]

This report contains a summary of the load impact evaluations of SDG&E's Demand Response activities and organized by the following:

Supply Side Resources

Emergency Programs:

Base Interruptible Program (BIP)

[4] SDG&E's Residential Default TOU study will be available on May 27th, 2021. SDG&E submitted both verbal and formal requests stating that this study was delayed by approximately 8 weeks. SDG&E will update and post this Executive Summary along with the Final Residential Default Time-Of-Use study.

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

Default Residential TOU – will be added May 27th, 2021.

Table 2-1 presents the Program Year (PY) 2020 ex-post estimates for the average event day Load Impact in MWs across all SDG&E events, and the load impacts in MWs for SDG&E's Peak Day (September 5th, 2020). 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 2020 SDG&E experienced more extreme weather conditions than it did in 2018 or 2019. In fact, on the week of August 14th-21st SDG&E experienced extreme weather conditions at between a 1 in 5 and 1 in 10 peak condition whereas the state of California was experiencing a 1 in 30 weather condition. CAISO asked the California IOUs to issue rolling blackouts throughout their service territories for both August 14th and 15th. SDG&E called upon some of its largest customers to voluntarily reduce their usage for several hours over the two-day period. SDG&E experienced even warmer conditions over the 2020 Labor Day weekend. September 5th through the 7th were estimated to be a 1 in 30-year peak condition. SDG&E called many of its DR events including CPP events for those 3 days. SDG&E's system peaked at 4,608 MWs at 5:34 P.M. DST on September 5th.

Table 2-1: Program Year (PY) 2020 Ex-post estimates

Program Type and Name	# of Customers on Average Event Day	Event Window Average Event Day HE [a]	Average Event Day Load Impact (MW)
Supply Side Demand Response			
BIP	4	HE19-HE20	0.42
AC Saver Day Ahead Residential	15,137	HE19-HE20	4.55
AC Saver Day Ahead Commercial (including Quasi-Residential)	941	HE19-HE20	0.44
AC Saver Day Of Commercial	3,124	HE19-HE20	0.15
AC Saver Day Of Residential	6,975	HE19-HE20	0.94
CBP DA (Including products 11am-7pm)	4	HE19	0.02
CBP DA (Including products 1pm-9pm)	19	HE19	0.39
CBP DO (Including products 11am-7pm)	67	HE19	0.15
CBP DO (Including products 1pm-9pm)	91	HE19	2.03
Load Modifying			
CPPD Large (Excluding TD)	1,431	HE15-HE18	5.33
CPPD Medium (Excluding TD)	12,244	HE15-HE18	0.20[d]
Default Small Commercial TOU and CPP Rates (Excluding TD)	107,996	HE15-HE18	5.16
Small Agricultural	143	HE15-HE18	0.07
D-TOU Rate 1 (Non-NEM) [bc]	740,215	HE17-HE21	30.29 [c]
D-TOU Rate 1 (NEM) [bc]	63,732	HE17-HE21	8.51 [c]
D-TOU Rate 2 (Non-NEM) [bc]	24,951	HE17-HE21	1.74 [c]
D-TOU Rate 2 (NEM) [bc]	2,428	HE17-HE21	0.87 [c]
EVTOU2 (Including NEM plus Non-NEM) [b]	7,719	HE17-HE21	1.67
EVTOU5 (Including NEM plus Non-NEM [b]	10,867	HE17-HE21	3.56
Technology Deployment (TD) on Small Commercial CPP plus CPP (Large and Medium)	1,204	HE15-HE18	1.54
Voluntary Residential grandfathered CPP on Technology Deployment (TD) [e]			
Voluntary Residential CPP customers on Technology Deployment (TD)	390	HE15-HE18	0.08
Voluntary Residential CPP excluding Technology Deployment (TD) customers	14,995	HE15-HE18	2.43
Voluntary Residential grandfathered CPP excluding Technology Deployment (TD) customers	250	HE15-HE18	0.04[d]
Total	**1,014,927**		**65.4**

a HE means hour ending

b The load impacts for EVTOU2 (Including NEM plus Non-NEM), EVTOU5 (Including NEM plus Non-NEM), D-TOU Rate 1 and, D-TOU Rate 2 are non-event based, energy reported is the average consumption over the RA window for the August average weekday.

c The results for D-TOU (Rate 1 and 2) are not statistically significant from 0.
d The average ex-post estimates are statistically significant for some of event hours but not at the aggregate level.
e In 2020, there were no customers under Voluntary Residential grandfathered CPP on Technology Deployment (TD). Therefore, the impacts are intentionally left in blank.

All ex-ante load impact summaries are averaged over the current Resource Adequacy (RA) hours of 4pm to 9pm 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, 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 those reasons that the ex-post load impact estimates don't align with the forecasts required in this submittal.

Located in Appendix A are the model specifications for each of the studies, ex-post and ex-ante. The ex-ante tables located in Appendix B[5] 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 programs, Dynamic and TOU rates. The MW load impacts are for SDGE 1 in 2 weather conditions for September 2021. In 2019, SDG&E's Load Impact submittal expanded to include ex-ante estimates for Residential Default TOU and Electric Vehicle TOU rates. SDG&E's AC Saver Day Ahead Program is expected contributing about 7.5 MWs in 2021. SDG&E's AC Saver Day Of program continues to decline in enrollment as it is not being marketed.

[5] File names are: AppendixB.TablesforExecutiveSummary_formatted_Mar312021.pdf and AppendixB.TablesforExecutiveSummary_formatted_Mar312021.xls

Table 2-2: Program Year (PY) 2020 Portfolio Ex-ante estimates* based on 1 in 2 SDG&E weather scenarios for the year of 2021

Program Type and Name	Forecasted Customers in September 2021	Ex-ante estimates for the month of September 2021 (MW) over the RA hours
Supply Side Demand Response		
BIP	5	0.91
AC Saver Day Ahead Commercial (including Quasi-Residential)	717	1.80
AC Saver Day Ahead Residential	19,716	5.67
AC Saver Day Of Commercial	3,065	0.32
AC Saver Day Of Residential	8,320	2.03
CBP DA (Including products 11am-7pm)	3	0.01
CBP DA (Including products 1pm-9pm)	15	0.21
CBP DO with new TI (Including products 11am-7pm)	63	0.05
CBP DO with new TI (Including products 1pm-9pm)	101	1.43
Load Modifying Demand Response		
CPPD Large (Excluding TD)	731	1.23
CPPD Medium (Excluding TD)	7,562	-2.12
Default Small Agricultural TOU and CPP Rates (Excluding TD)	68	-0.01
Default Small Commercial TOU and CPP Rates (Excluding TD)	51,635	0.20
D-TOU Rate 1 [bc]	839,311	21.70 [b]
D-TOU Rate 2 [bc]	27,086	.73 [b]
EVTOU2 (Including NEM plus Non-NEM) [c]	6,691	2.01[d]
EVTOU5 (Including NEM plus Non-NEM) [c]	14,767	7.24[d]
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	371	0.12
Voluntary Residential CPP customers on Technology Deployment (TD)	946	0.06
Voluntary Residential grandfathered CPP customers on Technology Deployment (TD)*		
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH	477	-0.12
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH	25,745	2.74
Total	**1,007,395**	**46.21**

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

[b] The results for D-TOU (Rate 1 and 2) are not statistically significant from 0.

[c] Shaded values are non-event base.

[d] EVTOU non-event estimates correspond to September Peak Day

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 (i.e., 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 that exist 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 at least 100 kW and 15% of their Monthly Average Peak Demand, calculated by the customer's energy usage during the hours from 1pm – 6pm. 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 (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 a 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.[6]

[6] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_BIP.pdf

3.1.2 Aggregator Programs

3.1.2.1 Capacity Bidding Program (CBP)

CBP is a statewide price-responsive program launched in 2007. The Capacity Bidding Program (CBP) is a supply side program that provides incentives to aggregators to sign up commercial customers who commit to shed load when triggered. The program is open to bundled, Direct Access (DA) customers and Community Choice Aggregation ("CCA") customers. The Utility may call an 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). SDG&E has four 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 11am – 7pm and 1pm – 9pm. The aggregator selects a product to nominate their customer(s) into. CBP is a seasonal DR program that runs yearly from May 1 to October 31. CBP has its own tariff, Schedule CBP.[7] 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.[8]

[7] http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_misc.html

[8] 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) 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	1pam 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	1pam to 9pm	2 hours	4 hours	24	1	6

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.[9] 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

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

50%; and (2) a 100% cycling option where the AC is turned off for the entire duration of the event. Commercial customers may choose between a 30% cycling and a 50% cycling option. Customers enrolled on the Day-Of option are not permitted to override individual events. Customers receive an annual capacity payment based on the size of their air-conditioner and the cycling option that they choose.

Customers with 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. New customers 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. All CPP tariffs are designed for bundled service customers. In addition to 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.[10]

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 3pm and can be triggered up to 18 CPP days a year and the CPP period is from 2pm to 6pm.

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. SDG&E's small commercial and industrial customers do not have demand charges, therefore there are there are demand components. Between November 2015 and April 2016, SDG&E defaulted over 120,000 small business customers from rates that did not vary by time of day onto time varying pricing with a critical peak pricing 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 5% of them did. As of PY 2020, about 108,138 sites remain on the CPP-TOU rate. 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.

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

[10] 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.

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 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

For 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.

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 offers different time of use rates for its customers that have electric vehicles. This study focuses on whole premise electric vehicle rates. Currently SDG&E offers EV-TOU2, EV-TOU5 and VGI rates to its residential customers that own electric vehicles.

The TOU periods for both EVTOU2 and EVTOU5 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 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. SDG&E's VGI rate is SDG&E's most progressive dynamic electric rate. The VGI rate includes a number of VGI Program Facilities which provide electric vehicle charging under the VGI rate.[11] The dynamic rate consists of three components: an hourly base rate, an hourly commodity base rate, and an hourly distribution base rate. The commodity base rate includes an adjustment based on the California Independent System Operator (CAISO) day-ahead hourly price, an adder to reflect the

[11] VGI Program Facilities are installed, operated, and maintained by SDG&E, pursuant to D.16-01-045, and are located at workplaces and multi-unit dwellings.

system's top 150 system peak hours, and an adjustment to reflect day-of CAISO surplus energy hours. The hourly distribution base rate includes an adder to reflect the top 200 annual hours of peak demand for the individual circuit feeding the VGI charging station. The rates are applicable to either the individual vehicle customer charging through the VGI Program Facility or the Site Host providing the charging.[12]

3.3.1.2 Default Residential Time of Use (D-TOU)

SDG&E's D-TOU rate options started out as a pilot in 2018. The pilot was implemented in response to California Public Utilities Commission (CPUC) Decision 15-07-001. A key objective of the pilot is to develop insights that will help guide SDG&E's approach to implementation of default TOU pricing for the majority of its residential customers and the CPUC's policy decisions regarding default pricing. Prior to 2018 SDG&E had fewer than 5% of its residential customers on TOU rates.

Findings from the first summer of the pilot—June through October 2018—are documented in the "Default Time-Of-Use Pricing Pilot Interim Evaluation" dated April 1, 2019 (hereafter referred to as the Interim Report). The Interim Report contains detailed background information on the pilot, describes the pilot design and the load impact evaluation methodology, discusses SDG&E's pilot implementation and treatments, and presents load impacts for the first summer period. It also presents structural bill impacts and summarizes pre-enrollment opt-out rates. Findings from the first winter and the full first year of the pilot are documented in the "Default Time-Of-Use Pricing Pilot Final Evaluation" dated November 1, 2019 (hereafter referred to as the Final Report).

4. Methodology

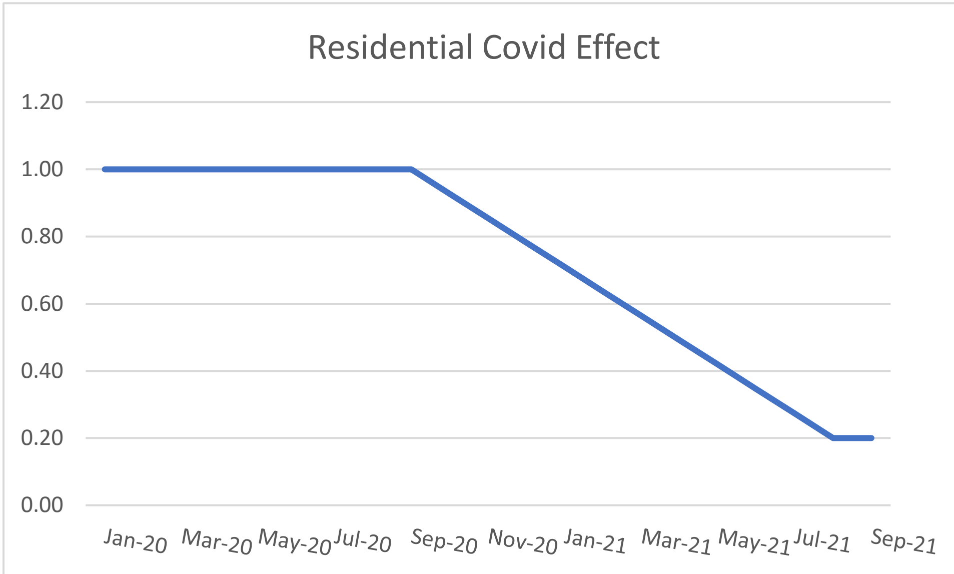
A summary of ex-post and ex-ante methods are provided in Table 4-1. Each DR activity uses its unique method to analyze results. Ex-post methods are used to calculate reductions for actual demand response events. Many factors go into each result such as weather conditions,

[12] The Site Host is an applicable site that allows SDG&E to install, operate, and maintain VGI Program Facilities on its property. Site Hosts agree to participate in and follow the requirements of the VGI program. The Site Host determines if the VGI Program Facilities on its property will be billed to the driver or the Site Host.

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.

SDG&E recognizes that the Covid-19 pandemic has had significant opposite effects on both residential and non-residential reference loads during 2020. The reference loads were significantly higher for residential and lower for non-residential during the last 9 months of 2020. SDG&E provided "factors" to be applied on the ex-ante estimates to simulate how Covid-19 is expected to affect 2021 loads. There is a slight difference between residential and non-residential in the Covid-19 effect during the last two months as non-residential was estimated to have a 10% residual effect in August and September 2021 versus the 20% residual effect for SDG&E's residential class as shown in Figure 4-1. All consultants received both sets of factors.

Figure 4-1: Residential Covid-19 Factors



Also starting in 2021, SDG&E will have a significant portion of their load departing to Communication Choice Aggregators (CCA). Those departing load assumptions were provided to SDG&E's consultants and are identified in the summary of Analysis Methodologies by program below. This load departure affects SDG&E's CPP programs the most ranging from 40% to 55% depending on the customers class starting with the commercial and industrial loads departing prior to the summer of 2021. SDG&E's CPP residential program will see a significant reduction starting in the 2nd quarter of 2022.

Table 4-1: Summary of Analysis Methodologies by Program

Supply Side Demand Response Programs			
Program	**Method**	**Evaluation**	**Key Assumptions**
AC Saver Day Ahead Commercial	Ex-Post: Panel Regression with a multiple matched control group for each customer. Ex-Ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads.	• Professional workforce transitioned to remote work and service business were required to curtail operations, average commercial participant whole building and cooling loads decreased by 30% or more during typical event hours as a result of COVID-19. • 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.
AC Saver Day Ahead Residential	Ex-Post: Panel Regression with a multiple matched control group Ex-Ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads.	• Average residential whole building and cooling loads increased by 30% or more during typical event hours as a result of COVID-19.

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

Program	Method	Evaluation	Key Assumptions
AC Saver Day Of Commercial	Ex-Post: Statistical matching design Ex-Ante: Adapted ex-ante methodology that takes into account the effect COVID-19 has on reference loads and load impacts.	Under the matching design, a matched control selected for all the commercial AC Saver Day Of program participants. This approach was chosen for the commercial segment due to the smaller size of the program population and the larger relative effect of holding back a control group from program from program dispatch. In addition, the ex-ante analysis's basis were converted to percentage load reductions, the evaluation also included an additional change from prior years; the development of a "base case" reference load, which reflects economic conditions absent the COVID-19 pandemic, a COVID-19 factor which represents an hourly scalar multiplier that can be applied to base case reference load to obtain "COVID-19-impacted reference load", and the application of a "timing" scalar that can be used to roll off the COVID-19 factor over time during the 11-year period of our ex-ante forecast window.	• Commercial snapback is assumed to be zero. • Enrollment is projected to decrease over the next few program years. • Accounts for the effects of COVID-19 pandemic that are expected to still be in effect in 2021 and beyond. • The assumption was that COVID-19 effects on program load impacts can be isolated to changes in reference load implies that we may convert absolute load impacts (kW) to load reductions as a percentage of reference load (%) and use both 2019 and 2020 ex-post percent load reductions to model the weather responsiveness of AC Saver Day Of load impacts.
AC Saver Day Of Residential	Ex-Post: Randomized Controlled Trial (RCT) Ex-Ante: The ex-ante estimates only assume changes to reference load due to COVID-19, and not changes in load impacts independent of reference load.	Random samples of residential AC Saver Day Of customers were selected from each cycling strategy. In addition, the ex-ante analysis's basis were converted to percentage load reductions, the evaluation also included an additional change from prior years; the development of a "base case" reference load, which reflects economic conditions absent the COVID-19 pandemic, a COVID-19 factor which represents an hourly scalar multiplier that can be applied to base case reference load to obtain "COVID-19-impacted reference load", and the application of a "timing" scalar that can be used to roll off the COVID-19 factor over time during the 11-year period of our ex-ante forecast window.	• Enrollment is projected to decrease over the next few program years. • Snapback for residential customer was calculated based on cycling strategy. • Accounts for the effects of COVID-19 pandemic that are expected to still be in effect in 2021 and beyond.

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

Program	Method	Evaluation	Key Assumptions
Base Interruptible Program	Ex-Post: Regression analysis of customer-level hourly load data Ex-ante: 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.	BIP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models.	• Average program FSL achievement rate is assumed. • Enrollment increases by one each year until 2025, then remains constant thereafter. • BIP customers, on average, exhibited a reduction in load as a response to the COVID-19 pandemic which began in March 2020. As a result, the ex-ante reference loads and load impacts were adjusted to account for how COVID will affect customer usage over the forecast period.
Capacity Bidding Commercial CBP	Ex-Post: Customer-specific hourly regression models as the primary evaluation method. Ex-ante: Based on 4 primary steps: 1) prediction of weather-adjusted impacts for each customer; 2) generation of per-customer average impacts by subgroup; 3) creation of annual load impact forecasts over the next 11 years; and 4) an assessment of uncertainty and the development of confidence intervals.	Customer-specific regressions allow for granularity in the results and can readily be used to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects.	• Enrollment to increase 2% annually from 2021-2022 based on improvements made to the program. • Day Of enrollment to increase by 1% based on the TI program. • 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	Ex-Post: Within subjects approach. Ex-Ante: Weather-Adjusted, per-customer Impacts	The within subjects design leverages the participant's own load on event-like days to estimate the reference load. Ex-ante load impact forecasts were developed by combining enrollment forecasts and per-customer load impacts generated from the analysis of current ex-post load impact estimates.	• Methods were based on the total non-participant to participant ratio. A non-participant to participant ratio of at least 3 to 1 is required to obtain a good match. Forty percent of Large & Medium CPP was removed starting with 2021 program year due to CCA migration. • The ex-ante load impacts were estimated and incorporated the current and future impacts of COVID-19 in the ex-ante forecast.
Default Residential Time-Of-Use: Rate 1*	Ex-Post: Comparison group with difference regression focused on pre-treatment and post-treatment effects. Ex-Ante: Weather-Adjusted, per-customer impacts that incorporates results from previous D-TOU evaluations.	In the matched control group methodology, customers in both treatment and control groups experience the same conditions except for exposure to the TOU rate. This means when energy usage is compared across groups, the difference can be attributed to the treatment effect, i.e., the TOU load impact. Ex-ante load impact forecasts were developed by incorporating impacts from previous evaluations performed with control groups, the normalized reference loads from the current evaluation were combined with these population-weighted percentage impacts to generate predictions for ex ante weather conditions using a regression model.	• Weather-normalized is used to remove the impacts of varying weather characteristics in each year. • Estimates are dependent on very consistent energy usage behaviors that closely match the measurable conditions. • Ex ante estimations were calculated with combined normalized reference loads from the current evaluation with both the pilot customers and the first group of mass default customers (from previous studies) population-weighted percentage impacts to generate predictions for ex ante impacts using a regression model.
Default Residential Time-Of-Use: Rate 2*	Ex-Post: Matched control group with difference regression focused on pre-treatment and post-treatment effects. Ex-Ante: Weather-Adjusted, per-customer impacts that incorporates results from previous D-TOU evaluations.	In the matched control group methodology, customers in both treatment and control groups experience the same conditions except for exposure to the TOU rate. This means when energy usage is compared across groups, the difference can be attributed to the treatment effect, i.e., the TOU load impact. Ex-ante load impact forecasts were developed by incorporating impacts from previous evaluations performed with control groups, the normalized reference loads from the current	• Weather-normalized is used to remove the impacts of varying weather characteristics in each year. • Estimates are dependent on very consistent energy usage behaviors that closely match the measurable conditions. Ex ante estimations were calculated with combined normalized reference loads from the current evaluation with both the pilot customers and the first group of mass

		evaluation were combined with these population-weighted percentage impacts to generate predictions for ex ante weather conditions using a regression model.	default customers (from previous studies) population-weighted percentage impacts to generate predictions for ex ante impacts using a regression model.
Default Small Commercial CPP	Ex-post: Fixed effects diff-in-diff regression using matched control from opt-outs for each segment. Matched control groups analyzed using fixed effects diff-in-diff regression for each segment. Ex-ante: Ex-ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment.	The distance matching approach used selected 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.	• As the professional workforce transitioned to remote work and service business were required to curtail operations, average commercial participant whole building and cooling loads decreased by about 12% during typical event hours. Fifty percent of the customers were removed starting with 2021 program year due to CCA migration. • PY2020 Small CPP events are assumed to have occurred under COVID conditions. As such, 2020 loads were used to develop post-COVID-19 reference loads. To model what loads would have been in the absence of COVID-19, historical loads from 2018 and 2019 were used to develop pre-COVID-19 reference loads.

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

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Electric Vehicle Time-Of-Use: EVTOU2, EVTOU5 & VGI	Ex-Post: Difference-in-difference analysis method Ex-ante: Based on analyses of per-customer load impact findings from ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments. Estimating ex-ante reference loads and load impacts were required an adjustment to account for how COVID will affect customer usage over the forecast period.	Difference-in-difference analysis involve selecting quasi-experimental matched control groups and then comparing the usage of treatment and control group customers on relevant days or time periods, where the comparisons are then adjusted by usage differences on pre-treatment or non-event days. In PY2020, the COVID-19 pandemic influenced customer reference loads and load impacts. It was estimated the effect COVID had on the average	• To calculate TOU load impacts for EVTOU2 and EVTOU5 customers, seasonal percentage peak load impacts from the ex-post analysis are applied to weather-sensitive reference loads that are developed. • To calculate the VGI Pilot, separate analyses are conducted for workplace and "home" charging to evaluate different charging behaviors.

		customer's hourly reference loads. Separate hourly COVID effects are estimated by rate (EVTOU2 and EVTOU5) and NEM status. Second, we adjust the magnitude of the COVID effect over time based on utility-provided assumptions regarding the expected evolution of the COVID effect during the forecast period.	

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

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Voluntary Residential CPP & TOU	Ex-Post: Difference-in-Difference analysis method. Ex-Ante: 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. In PY2020, the COVID-19 pandemic influenced customer reference loads and load impacts.	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. The DR-TOU load impacts for NEM customers are not based on percentages relative to the reference load. The ex-ante load impact, consequently, would not differ as a result of COVID-19 adjustments to reference loads. The assumption is made that differences between the PY20 and PY19 ex-post level load impacts for NEM customers is a result of COVID-19. The magnitude of the COVID effect on NEM ex-ante load impacts decreases over time based on the assumed timeline provided by SDG&E.	• Fifty five percent of the customers were removed starting in 2022 program year due to CCA migration.

*The Default Residential Time-Of-Use: Rate 1 and Rate 2 ex-post and ex-ante methodology will be updated on March 27th, 2021.

5. Ex-Post Load Impact Estimates

Ex-post load impact results are calculated for each demand response event that was initiated during the previous event year. Table 5-1 below shows the average load reduction for each demand response activity. When looking at these results it's important to keep in mind that each DR activity is unique, and dispatches can be based on multiple factors. DR activities vary in the number of participants, the number of events called and not all of SDG&E's DR is weather sensitive. Though some load impacts might be smaller than others, each DR activity faces challenges, like AC Saver Day Ahead. 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 2020 SDG&E Average DR LI Ex-post estimates by Program

Supply Side Demand Response							
Program	Reference Load (MW)	Observed Event Load (MW)	Load Impact per Customer (kW)	% Load Impact	Aggregate Impact (MW)	Accounts Called	Number of Events
AC Saver Day Ahead Commercial	15.17	14.74	0.46	2.90%	0.44	941	20
AC Saver Day Ahead Residential	21.86	17.32	0.30	20.8%	4.55	15,137	20
AC Saver Day Of Commercial	15.41	15.38	0.05	1.0%	0.15	3,124	20
AC Saver Day Of Residential	10.07	9.13	0.134	9.3%	0.94	6,975	20
Base Interruptible Program	0.6	0.2	106.08	68%	0.42	4	5
Capacity Bidding Program	21	18.4	14.33	12%	2.57	181	81*

* SDG&E triggered 16 CBP-DA 11am-7pm events, 25 CBP-DA 1pm-9pm events, 18 CBP-DO 11am-7pm events, and 22 CBP-DO 1pm-9pm events.

Table 5-1 continued: Summary of 2020 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)	Accounts Called	Number of Events
Critical Peak Pricing excluding TD	624.5	619.0	0.4	0.88%	5.53	13,675	9
CPP customers on Technology Deployment (TD)	19.12	17.85	2.95	6.6%	1.27	431	
Default Small Commercial CPP	301.68	296.52	0.05	1.7%	5.16	107,996	9
Small Agricultural	0.70	0.63	0.47	9.7%	0.07	143	
PSW customers on Technology Deployment (TD)	3.88	3.61	0.35	7.0%	0.2	773	
Voluntary Residential grandfathered CPP customers on Technology Deployment (TD)*							9
Voluntary Residential CPP customers on Technology Deployment (TD)	0.67	0.59	0.21	12%	0.08	390	
Voluntary Residential CPP excluding Technology Deployment (TD) customers	18.32	15.86	0.16	13%	2.43	14,995	
Voluntary Residential grandfathered CPP excluding Technology Deployment (TD) customers	0.30	0.26	0.15	13%	0.04	250	
Electric Vehicle Time-Of-Use: EVTOU2**	15.44	13.77	0.22	10.8%	1.67	7,719	TOU
Electric Vehicle Time-Of-Use: EVTOU5**	21.02	17.46	0.33	16.9%	3.56	10,867	TOU
Default Residential Time-Of-Use: Rate 1*** (Non-NEM)	775.48	745.18	0.04	3.9%	30.29	740,215	TOU
Default Residential Time-Of-Use: Rate 1*** (NEM)	114.01	105.50	0.13	7.5%	8.51	63,732	TOU
Default Residential Time-Of-Use: Rate 2*** (Non-NEM)	30.88	29.14	0.07	5.6%	1.74	24,951	TOU
Default Residential Time-Of-Use: Rate 2*** (NEM)	5.04	4.17	0.36	17.2%	0.87	2,428	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
*** The results for D-TOU (Rate 1 and 2) are not statistically significant from 0 and ex-post estimates are based on August Average Weekday.

6. 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.[13] 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).

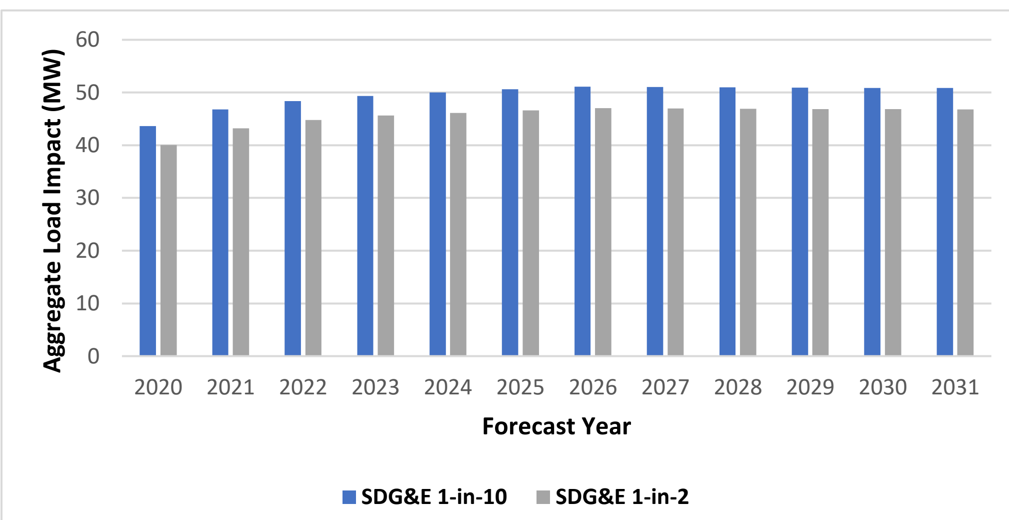
The load impact estimates for each program align with the peak period now used for resource adequacy planning, which is 4 to 9 PM, year-round.

6.1 Projected Change in PY20 Portfolio Load Impacts from 2020–2031

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 9% from 2021 to 2031 (from 47 MW in 2021 to 51 MW in 2031) under 1-in-10 weather conditions. On the other hand, SDG&E's portfolio is projected to increase by 8% from 2021 to 2031 (from 43 MW in 2021 to 47 MW in 2031) under 1-in-2 weather conditions. Previously stated the results from the D-TOU report showed non-statistically significant results from Ex ante estimates.

Figure 6-1: Projected Change in PY19 Portfolio Load Impacts from August 2020–2031



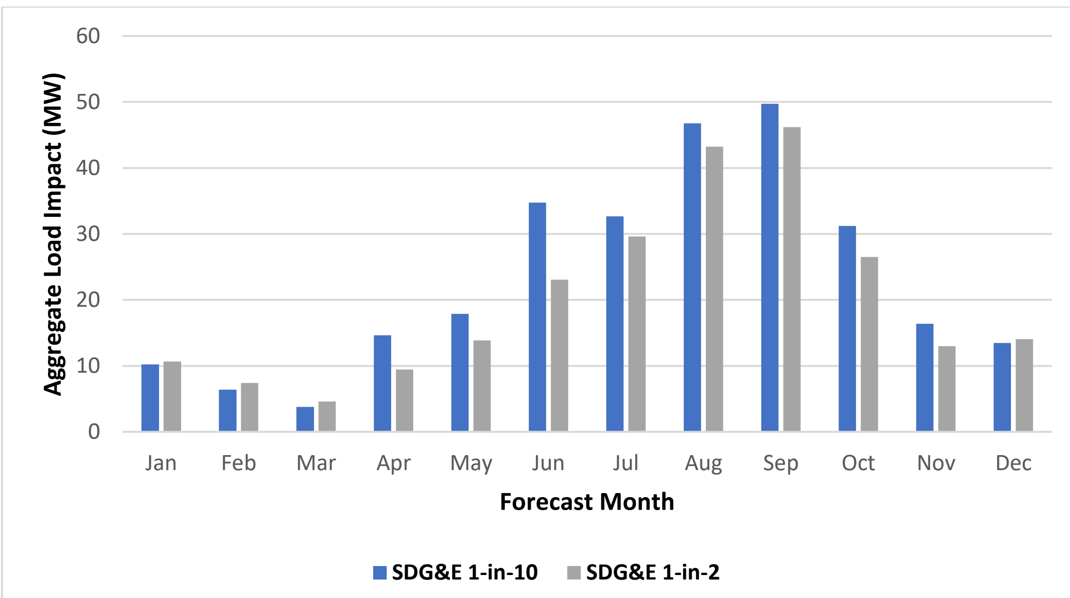
[13] DR Load Impact Protocols and Regulatory Guidance (Protocols 17-23) by CPUC (Apr 2008) - page 93-110

6.2 Portfolio Aggregate Load Impacts by Month for the year of 2021

Figure 6-2 shows the 2021 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 2021, SDGE's DR portfolio projects 50 MW of load reduction during the September monthly system peak day under SDGE's 1-in-10 weather conditions. The months of June, July, and August load impacts are little bit smaller than the month of September delivering 35, 33, and 47 MW respectively under SDGE's 1-in-10 conditions.

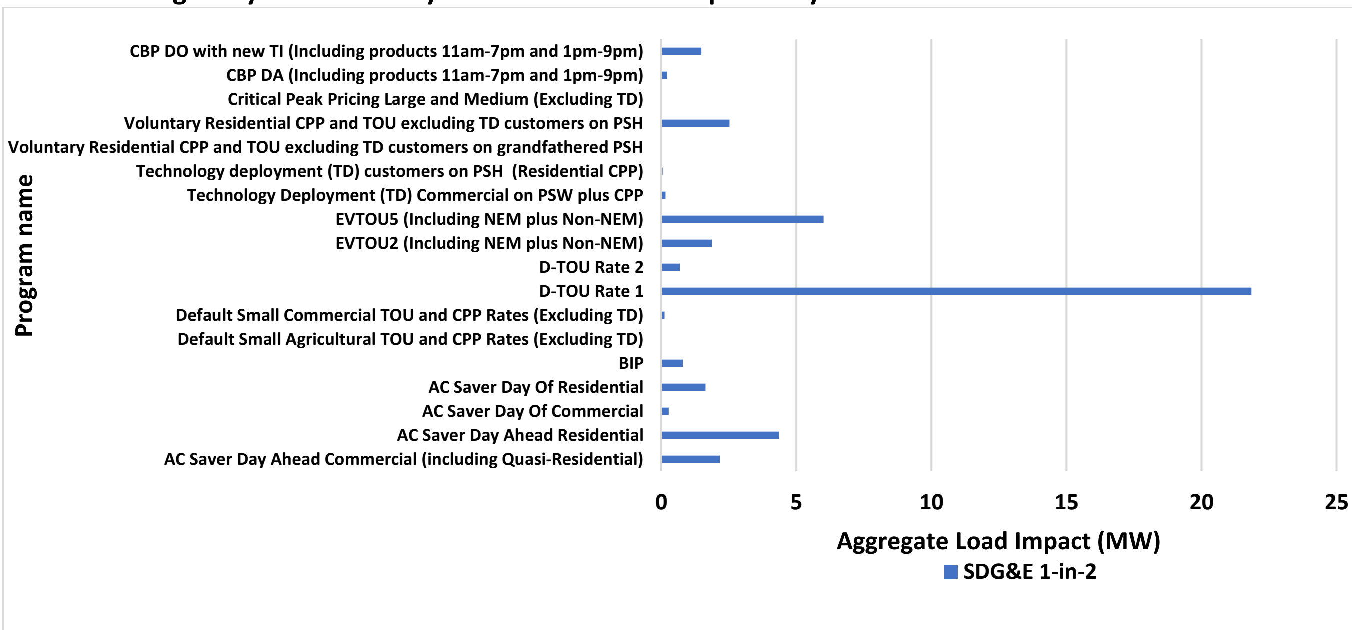
Figure 6-2: PY20 Portfolio Aggregate Ex-ante Load Impact Estimates (MW) for the year of 2021 by 1-in-2 and 1-in-10 SDG&E-specific System Conditions and Monthly System Peak Day



6.3 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 26% of SDGE's DR portfolio, 69% from non-event programs and 4% from aggregator and 2% 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 Voluntary Residential CPP and TOU excluding TD customers on grandfathered PSH and Critical Peak Pricing Large and Medium (Excluding TD).

Figure 6-3: Distribution of PY20 Portfolio Aggregate Load Impacts by Program Type 2021 August System Peak Day under 1-in-2 SDG&E-specific System Conditions



6.4 Portfolio Load Impacts by Program from 2020-2031

Table 6-4 summarizes the portfolio load impacts by program for 2020 through 2031 under 1-in-2 SDG&E weather conditions.

In August 2031, the load impacts from load modifying programs are forecast to comprise 76% of SDGE's DR portfolio and 24% 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 13% of SDG&E's DR supply side portfolio. The price responsive programs represent 71% of SDGE's DR supply side portfolio and most of this percentage is derivate from AC Saver Day Ahead Residential. The aggregator DR represents 16%, the majority of this percentage is attribute of CBP DO with new TI (Including products 11am-7pm and 1pm-9pm).

Table 6-4: Portfolio Aggregate PY20 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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Supply Side Total MWs	9.59	10.95	11.57	11.85	12.13	12.40	12.61	12.34	12.08	11.82	11.58	11.35
Emergency	0.63	0.80	1.05	1.15	1.25	1.35	1.45	1.45	1.45	1.45	1.45	1.45
BIP	0.63	0.80	1.05	1.15	1.25	1.35	1.45	1.45	1.45	1.45	1.45	1.45
Price Responsive	7.31	8.45	8.78	8.93	9.07	9.20	9.31	9.04	8.78	8.53	8.29	8.05
AC Saver Day Ahead Commercial (including Quasi-Residential)	0.77	2.17	2.68	2.38	2.12	1.90	1.70	1.65	1.61	1.57	1.53	1.50
AC Saver Day Ahead Residential	4.38	4.37	4.35	4.79	5.18	5.53	5.84	5.61	5.39	5.18	4.98	4.78
AC Saver Day Of Commercial	0.28	0.28	0.29	0.28	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
AC Saver Day Of Residential	1.89	1.63	1.46	1.47	1.49	1.51	1.51	1.51	1.51	1.51	1.51	1.51
Aggregator DR	1.65	1.70	1.74	1.77	1.81	1.84	1.84	1.84	1.84	1.84	1.84	1.84
CBP DA (Including products 11am-7pm and 1pm-9pm)	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24
CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)	1.44	1.48	1.51	1.54	1.57	1.61	1.61	1.61	1.61	1.61	1.61	1.61

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 7% of SDG&E's DR load modifying portfolio where the greater percentage of load impacts are projected to come from Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH. The load impacts from non-event based are forecast to embrace 93% of SDG&E's DR load modifying portfolio most of this percentage is related to D-TOU Rate 1.

Table 6-4 Continued: Portfolio Aggregate PY20 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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Modifying Total MWs	**30.45**	**32.26**	**33.24**	**33.79**	**34.02**	**34.23**	**34.45**	**34.65**	**34.85**	**35.05**	**35.25**	**35.46**
Price Responsive	**1.29**	**1.84**	**1.95**	**2.01**	**2.09**	**2.16**	**2.24**	**2.29**	**2.35**	**2.40**	**2.47**	**2.53**
Critical Peak Pricing Large and Medium (Excluding TD)***	-0.84	-0.87	-0.57	-0.55	-0.51	-0.48	-0.46	-0.44	-0.41	-0.39	-0.37	-0.35
Default Small Agricultural TOU and CPP Rates (Excluding TD)	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Default Small Commercial TOU and CPP Rates (Excluding TD)***	0.24	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	0.26	0.15	0.19	0.20	0.21	0.22	0.23	0.22	0.21	0.21	0.20	0.19
Technology deployment (TD) customers on PSH (Residential CPP)	0.02	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH*	-0.31	-0.14										
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH***	1.93	2.53	2.16	2.19	2.22	2.26	2.30	2.34	2.38	2.43	2.47	2.52

Table 6-4 Continued: Portfolio Aggregate PY20 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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Non-event based	**29.16**	**30.42**	**31.29**	**31.79**	**31.93**	**32.07**	**32.21**	**32.36**	**32.50**	**32.64**	**32.79**	**32.93**
D-TOU Rate 1**	21.22	21.85	21.93	22.01	22.09	22.17	22.25	22.33	22.41	22.49	22.57	22.65
D-TOU Rate 2**	0.71	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
EVTOU2 (Including NEM plus Non-NEM)	2.96	1.88	0.92	0.82	0.89	0.95	1.01	1.07	1.14	1.20	1.26	1.32
EVTOU5 (Including NEM plus Non-NEM)	4.27	6.01	7.76	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27
Supply Side plus Load Modifying Total MWs	**40.04**	**43.21**	**44.81**	**45.65**	**46.15**	**46.63**	**47.06**	**46.98**	**46.92**	**46.87**	**46.83**	**46.81**

*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.
** The results for D-TOU (Rate 1 and 2) are not statistically significant from 0.
*** 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 2020 through 2031 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 2031, the customers from emergency programs are forecast to comprise 0.02% of SDGE's DR supply side portfolio. The price responsive programs represent 99.5% of SDGE's DR supply side portfolio and most of this percentage is derivate from AC Saver Day Ahead Residential. The aggregator DR represents 0.44%, the majority of this percentage is attribute of CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)

In August 2031, the number of customers from load modifying programs are forecast to comprise 96% of SDGE's DR portfolio and 4% from supply side programs.

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 8% of SDGE's DR load modifying portfolio where the greater percentage of the number of customers are projected to come from Default Small Commercial TOU and CPP Rates (Excluding TD) customers. The customers from non-event based are forecast to embrace 92% of SDGE's DR load modifying portfolio the majority of this percentage is related to D-TOU Rate 1.

Table 6-5 Portfolio Aggregate PY20 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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Supply Side Total MWs	28,684	32,004	34,862	37,515	39,976	42,261	44,345	44,345	44,345	44,345	44,345	44,345
Emergency	4	5	6	7	8	9	9	9	9	9	9	9
BIP	4	5	6	7	8	9	9	9	9	9	9	9
Price Responsive	28,503	31,817	34,670	37,318	39,775	42,055	44,139	44,139	44,139	44,139	44,139	44,139
AC Saver Day Ahead Commercial (including Quasi-Residential)	344	717	673	635	601	571	543	543	543	543	543	543
AC Saver Day Ahead Residential	16,600	19,716	22,598	25,264	27,731	30,012	32,123	32,123	32,123	32,123	32,123	32,123
AC Saver Day Of Commercial	3,297	3,065	2,987	2,912	2,838	2,766	2,766	2,766	2,766	2,766	2,766	2,766
AC Saver Day Of Residential	8,262	8,320	8,412	8,507	8,605	8,706	8,706	8,706	8,706	8,706	8,706	8,706
Aggregator DR	177	182	186	190	193	197	197	197	197	197	197	197
CBP DA (Including products 11am-7pm and 1pm-9pm)	18	18	19	19	19	20	20	20	20	20	20	20
CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)	159	164	167	170	174	177	177	177	177	177	177	177

Table 6-5 Continued: Portfolio Aggregate PY20 number of customers forecasted for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Modifying	1,010,296	974,899	968,211	972,909	976,745	980,714	984,729	988,749	992,813	996,926	1,001,045	1,005,214
Price Responsive	**148,871**	**87,534**	**74,965**	**75,217**	**75,319**	**75,543**	**75,803**	**76,056**	**76,342**	**76,666**	**76,984**	**77,341**
Critical Peak Pricing Lrg & Med (Excluding TD)***	13,566	8,293	4,933	4,767	4,434	4,205	3,992	3,796	3,611	3,440	3,239	3,050
Default Small Agricultural TOU and CPP Rates (Excluding TD)	143	68	68	68	68	68	68	68	68	68	68	68
Default Small Com TOU and CPP Rates (Excluding TD)***	108,995	51,635	51,640	51,645	51,648	51,651	51,653	51,653	51,653	51,653	51,653	51,653
TD Commercial on PSW (Sm Com CPP) + CPP (Lrg & Med)	746	371	416	461	505	548	591	591	591	591	591	591
TD customers on PSH (Residential CPP)	392	946	865	865	865	865	865	865	865	865	865	865
Voluntary Residential CPP and TOU excluding TD customers on grandfathered PSH	472	477										
Voluntary Residential CPP and TOU excluding TD customers on PSH***	24,557	25,745	17,043	17,412	17,800	18,207	18,634	19,083	19,555	20,050	20,569	21,115
Non-event based	**861,425**	**887,364**	**893,246**	**897,692**	**901,426**	**905,171**	**908,926**	**912,693**	**916,471**	**920,261**	**924,061**	**927,873**
D-TOU Rate 1	814,818	839,059	842,085	845,121	848,169	851,227	854,297	857,377	860,469	863,572	866,686	869,811
D-TOU Rate 2	28,021	27,085	27,090	27,095	27,100	27,105	27,110	27,115	27,119	27,124	27,129	27,134
EVTOU2 (Including NEM plus Non-NEM)	7,719	6,752	6,022	6,233	6,915	7,596	8,278	8,959	9,641	10,322	11,004	11,685
EVTOU5 (Including NEM plus Non-NEM)	10,867	14,468	18,049	19,242	19,242	19,242	19,242	19,242	19,242	19,242	19,242	19,242
Supply Side plus Load Modifying Total number of customers	1,038,980	1,006,903	1,003,073	1,010,424	1,016,721	1,022,975	1,029,074	1,033,094	1,037,158	1,041,271	1,045,390	1,049,558

*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 2020 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:[14]

SDG&E called five events but may want to consider calling earlier events to ensure that its customers are capable of consistently meeting their obligation during hours in which their loads are above their FSL. BIP is an emergency program and may be triggered based on Utility discretionary events for test purposes, when the California Independent System Operator (CAISO) has called for Interruptible Load under CAISO Operating Procedure 4420 or when extreme temperature conditions are impacting system demand. However, this decision is likely offset by the need to call events during the RA window.

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: [15]

a) Reevaluate the definition of the average event day. The current definition, consistent across all IOUs, includes all events called calculating the average, regardless of participant count and event timing. Results for the most prevalent event hour are presented. In PY2020, a number of events were called in "outlier" hours. Although only a handful, these outlier events, by definition, are included in the average but are not represented in the reported event hour. As more outlier events are dispatched, it is likely that certain exclusions may be considered and applied as appropriate.

[14] 2020 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1, 2021) – page 59

[15] 2020 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2021) – page 77-78

b) Clearly differentiate between nominated customers and dispatched customers. The terminology should be updated to more clearly differentiate between customers nominated on a monthly or seasonal basis and those actually called, or dispatched, for individual events. This includes the differentiation between nominated load and delivered load.

7.1.3 Price Responsive Programs

7.1.3.1 AC Saver Day Ahead commercial and residential programs

DSA made the following recommendation[16]:

- **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.
- **Test different ways to nudge customers with disconnected thermostats to reconnect them.** Only connected thermostats deliver reductions and roughly half of installed thermostats are now disconnected. Without an intervention, a larger share of those devices will become disconnected as more time elapses. In specific, we recommend randomized control trial four different groups:
    - Control (n = 100)
    - Postcard or letter reminder (n = 100)
    - Postcard or letter reminder + follow up phone call (n = 100)
    - Postcard or letter reminder + incentive (n =100)
    - Postcard or letter reminder + follow up phone call + incentive (n=100)

  This will allow SDG&E to quantify how well different methods work at getting customers to reconnect and assess their cost-effectiveness.

[16] 2020 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program (Mar 2021) – page 60

7.1.3.2 AC Saver Day Of commercial and residential programs

Nexant made the following recommendations: [17]

- In order 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. 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.
- In order 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 PM in order to achieve larger commercial impacts.
- 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 PM to 9 PM. The results from these events will help the load impact evaluator produce robust the ex-ante impacts for the Resource Adequacy window.

[17] AC Saver Day Of 2020 Load Impact Program Evaluation by Nexant (Mar 2021) -page 52 and 53

7.2 Load Modifying DR

7.2.1 Price responsive Programs

7.2.1.1 Critical Peak Pricing (CPP)

AEG has developed three recommendations for future research and evaluation related to the non-residential CPP programs:[18]

- **Investigate the experiences of small and medium participants**. While PY2020 saw improvements in the pacts among small and medium customers, we do not fully understand why the impacts improved. Through future or ongoing process evaluations, ensure that special care is taken to better understand the experiences of small and medium customers on the CPP rates. Participant surveys and focus groups can be used to understand aspects of participation including, effects of extreme weather, effects of COVID, awareness of events, ability to respond to events, and actions taken during events. Conducting research while maintaining statistically significant samples by key industry groups and size may provide invaluable insights for both program staff and future impact evaluations.
- **Investigate the effect of notifications on customer impacts**. Again, through the use of participant surveys and/or focus groups, conduct research to better understand participant choices regarding notification, their awareness of notifications, and how they respond to notifications on event days. It would also be of interest to know how those that elected not to receive notifications learn about events.
- **Consider opportunities to improve robustness of within-subjects designs**. For most of the subgroups, we elected not to develop a matched control group for this evaluation because of the small ratios of participants to non-participants and the opt-out nature of the CPP/PDP rates which would likely lead to poor matches and introduce self-selection bias. Unfortunately, the within-subjects design may also have led to the introduction of bias, particularly among those groups with very small impacts due to a lack truly comparable event like days. Since all utilities expect their participant population to grow (and the non-participant pools to continue to shrink)

[18] 2020 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Nate Load Impacts by AEG (Mar 2021) – page 87

we recommend considering the following opportunities to mitigate this bias in the future. We propose two options for consideration:

- **Intentionally call test events on cooler days and, unless absolutely necessary, try not to call events on all the hottest days of the season**. This will provide the models with better information as to how participants would behave during events on a wider range of temperatures and improve their performance.
- **Consider developing a randomized EM&V group that could be used as a control during events.** These customers might not be called to respond on all event days, or, might be called to respond on alternate days. This would significantly improve the ability of the evaluation to detect the true impact of the CPP program.

7.2.1.2 Default Small Commercial CPP

Since no CPP events were called in PY 2019, the following recommendations from PY 2018 could not be reviewed. However, they will likely still merit exploration in subsequent program years:[19]

- 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. Additional communications require resources and their effectiveness at improving price response is unknown. Because of the potential, however, we recommend testing the effectiveness of more education regarding event response. It is critical, however, for the test to be implemented using randomized control trials, so it is possible to assess if the communications had any impact on price response.
- Notification rates for small CPP can be improved further. 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. From 2016 to 2017, the notification rate

[19] 2020 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 2021) -page 61

improved from under 25% to 44%. Because many customers have multiple sites (and don't always sign up all sites), customers for roughly 60% sites received notification. Despite the improvement, there is further room to improve notifications. Notification rate remained largely unchanged in PY 2018.

- Continue to monitor loads and assumptions about the effect of COVID-19 on loads. As the professional workforce transitioned to remote work and service business were required to curtail operations, average commercial participant whole building and cooling loads decreased by about 12% during typical event hours. Given that reference load assumptions are a key driver of ex-ante load impacts it is key to monitor this going forward. For example, though current assumptions and analysis indicate that loads may revert to pre-COVID-19 levels within the next year or two it is possible that a "new-normal" may occur with lower daytime loads and occupancy for commercial buildings.

7.2.1.3 Voluntary Residential CPP and TOU

According to Christensen, the rising level of residential customers being defaulted onto a TOU rate limits the experimental leverage of estimating TOU load impacts for future program years. Specifically, customers enrolled on a standard tiered rate have served as potential control group customers that provide counterfactual usage. Without a suitable control group, TOU estimates may be more susceptible to between year usage changes that are caused by unobserved (to the researcher) factors[20].

7.2.2 Nonevent Based Programs

7.2.2.1 Electric Vehicle Time of Use

The ability to reliably estimate TOU load impacts for EV customers depends on knowing when the customer acquired and began charging the EV. In the absence of this information, the analysis runs the risk of confounding TOU price response with load changes due to EV adoption. While we believe we have developed a method that effectively identifies customers who have

[20] 2020 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 2020) – page 73

had an EV during our entire analysis period (before and after switching to an EVTOU rate), it would be helpful for SDG&E to consider whether it is feasible to collect additional information on customer EV adoption dates.[21].

7.2.2.2 VGI Pilot Program

If looking to scale up VGI, the timing of the load impacts suggests a higher reliability value for the application of home charging than workplace, as more of the load impact occurs during the RA window. For workplace RTH, charging algorithms could be explored that alternate the charge pattern depending on current prices[22].

7.2.2.3 Residential Default TOU

In the future, Nexant recommends that SDG&E provide ex ante updates only—based on historical ex post analysis, changes in expected customer enrollment, and any changes in the ex ante weather scenarios—and not conduct additional ex post analysis of the D-TOU rate in subsequent program years. Alternatively, the effect of TOU rates on residential customer load could be moved outside of measurement & evaluation and embedded directly into the residential load forecast, and not included in the load impact protocol based evaluations[23].

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[21] 2020 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates by Christensen (Apr 2021) – page 66

[22] 2020 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates by Christensen (Apr 2021) – page 66

[23] 2020 Load Impact Evaluation of SDG&E's Residential Default Time-Of-Use Rates by Nexant, Inc. (Apr 2021) – page 47

Appendix A: Regression Specifications

A.1 Supply Side Demand Response

A.1.1 Emergency Programs

A.1.1.1 Base interruptible program (BIP)

The paragraphs below describe the ex-post and ex-ante methodologies[24]:

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] 2020 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Apr 1st, 2021)

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 are 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
$MONTH_{j,t}$	a series of indicator variables for each month
e_t	the error term

A.1.2 Aggregator Programs

A.1.2.1 Capacity Bidding Program (CBP)

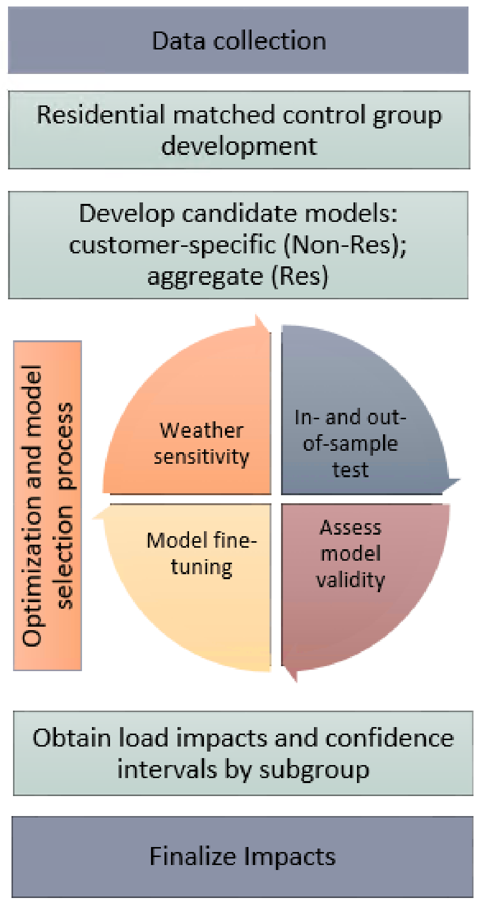
The paragraphs below describe the ex-post and ex-ante methodologies[26]:

a) Ex-post

[26] 2020 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2021)

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.

Simple weather sensitive example:

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

where:

$kwh_{i,d}$ is the customer's consumption in hour i on day d.

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d.

and, all other terms are defined above.

Simple non-weather sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + MornLoad_{i,d} + DayofWeek_{i,d} + P_{i,d} + \varepsilon_{i,d}$$

where:

$kwh_{i,d}$ is the customer's consumption in hour i on day d.

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d.

and, all other terms are defined **Error! Reference source not found.**above.

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

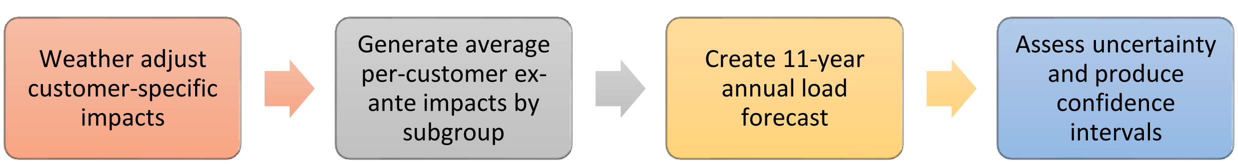
Table A-3: Explanatory Variables Included in Candidate Regression Models

Variable Name	Variable Description
	Baseline Variables
$Weather_{i,d}$	Weather-related variables including average daily temperature, cooling degree hour (CDH) terms with base value of 70, heating degree hour (HDH) with base value of 60, and lagged versions of various weather-related variables
$Month_{i,d}$	A series of indicator variables for each month
$DayOfWeek_{i,d}$	A series of indicator variables for each day of the week
$OtherEvt_{i,d}$	Equals one on event days of other demand response programs in which the customer is enrolled
$AvgLoad_{i,d}$	The average of each day's load in specified window
	Impact Variables
$P_{i,d}$	An indicator variable for aggregator program event days
$P * Month_{i,d}$	An indicator variable for aggregator program event days interacted with the month
$P*EventHour_{i,d}$	An indicator variable for aggregator program event days interacted with an indicator for the hour the event is called
$P*EventWindow_{i,d}$	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 programs[27]:

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

Table A-4: Explanatory Variables included in Regression Models

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

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

Variable Name	Variable Description
d	Is the parameter for weather sensitivity of loads
Event	Is a binary variable indicating if day is an event. Separate variables are used for each event so impacts are estimated for each event. It has a value of zero on event-like proxy days. The five closest non-event days were included as proxy days for each event. Separate proxy days were selected for each event using Euclidean distance matching.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

[27] 2020 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 2021)

a) Ex-ante

A key objective of the 2020 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. Incorporate reference load impacts due to COVID-19, initially and over time
3. Estimate the relationship between cooling load percent reduction, temperature, and hours into an event using historical event data
4. Predict cooling loads and percent reductions for 1-in-2 and 1-in-10 weather year conditions
5. Combine the loads and percent reductions to estimate impacts per connected thermostat
6. Incorporate the enrollment/device forecast and device connectivity forecast

A.1.3.2 AC Saver Day Of commercial and residential programs

The paragraphs below describe the ex-post and ex-ante methodologies[28]:

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

[28] AC Saver Day Of 2020 Load Impact Program Evaluation by Nexant (Mar 2021)

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:

Dissimilarity Statistic for Commercial Matching

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

Table A-6: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$PeakProxy$	Average demand across the 2020 proxy days during the event window hours
$EventMorn$	Average demand on the event day from midnight to 10 AM
$EventMidday$	Average demand on the event day from 10 AM to the start of the event
$j\,j$	Commercial AC Saver Day Of participant to be matched
i	Index of the pool of control customers

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

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
$Demand$	Average demand in the event hour being studied
$Cycled$	An indicator for whether customer *i* was cycled
$Proxy$	Average demand in the hour being studied on the average proxy day
$ProxyWindow$	Average demand in the event window on the average proxy day
$ProxyEve$	Average demand after the event window on the average proxy day
$EventMorn1$	Average demand from midnight to 7 AM on the event day
$EventMorn2$	Average demand from 7 AM to 10 AM on the event day
$EventMorn3$	Average demand from 10 AM to four hours before the event on the event day
$PreEvent$	Average demand during the four hours before the event
i	Customer index
t	Estimated impact
$a-h$	Estimated regression coefficients
u	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

$$ref_d = b_0 + b_1 \cdot mean17_{\mathrm{d}} + \varepsilon_d$$

Variable Name	Variable Description
ref_d	Reference Load: Average reference load during the period 6 to 8 PM during all events called at that time in 2019-2020 Load Impacts: Average ex-post load impacts (% load reduction) for events called 6 to 8 PM in 2019 and 2020
b_0	Estimated constant
b_1	Estimated parameter coefficient
$mean17_d$	Average temperature over the first 17 hours of the day for each event day
ε_d	The error term for each day d

A.2 Load Modifying DR

A.2.1 Price responsive Programs

A.2.1.1 Critical Peak Pricing (CPP)

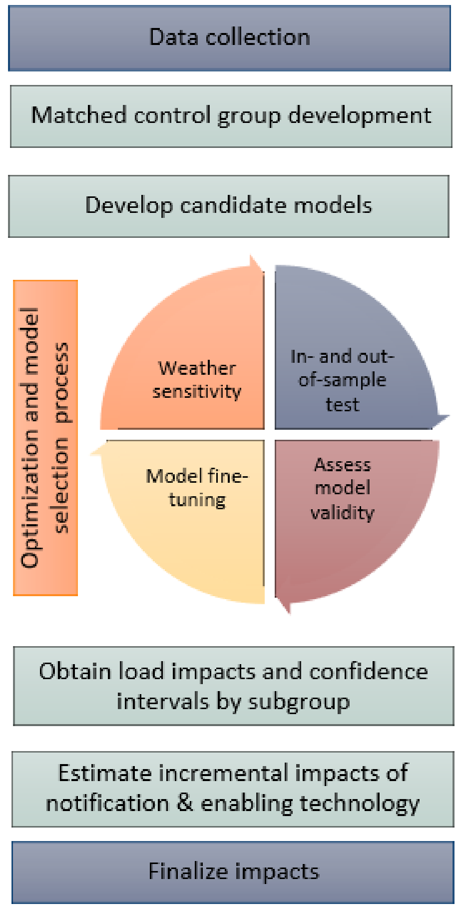
The paragraphs below describe the ex-post and ex-ante methodologies:[29]

a) Ex-post

AEG's approach to the ex-post analysis is summarized below with a few key points to highlight:

- Utilized a within-subjects approach or a matched control group. For subgroups where it was feasible, AEG developed a matched control group. AEG employed a within-subjects design for subgroups where it was not feasible leveraging event-like days in 2019.
- Estimated subgroup level models for each IOU, size, and industry. The purpose of subgrouping is to minimize variation in the models, which is feasible given the number of participants in CPP.
- Estimated customer-specific models for a small subset of extremely large (x-large) customers.

[29] 2020 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Ante Load Impacts by AGE (Mar 2021)


Data collection
Matched control group development
Develop candidate models
Optimization and model selection process
Weather sensitivity
In- and out-of-sample test
Model fine-tuning
Assess model validity
Obtain load impacts and confidence intervals by subgroup
Estimate incremental impacts of notification & enabling technology
Finalize impacts

b) Ex-ante

The figure below provides an overview of the ex-ante analysis approach.

Create Annual Weather-Adjusted Reference Load

- Estimate the weather-adjusted per customer reference loads using the coefficients from the ex-post models and inputs from the weather scenarios.
  - Where winter data is unavailable (SCE only), non-summer impacts are based on June data calibrated to reflect seasonality.

Apply the COVID adjustment to Reference Load

- The effect of COVID-19 conditions is estimated for each size group using a simple regression approach.
- Apply the effect to the reference load using IOU-specific factors to remove the effect of COVID-19 conditions over time.

Calculate the Per Customer Load Impacts

- Estimate the weather-adjusted per customer load impacts using the coefficients from the ex-post models and inputs from the weather scenarios.
- Incorporate the COVID adjustment by calculating the new load impacts as a percent of the new (COVID-adjusted) reference load.

Apply the enrollment forecast

- Assume zero impacts for 1st year defaulted small and medium customers (SCE only).
- Multiply annual per customer impacts by enrollment forecast to arrive at aggregate forecast.

A.2.1.2 Default Small Commercial CPP and TOU

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

a) Ex-post

Panel regressions with multiple control groups were used as the primary method for estimating load impacts for PY 2020 impacts for Small CPP.

[30] 2020 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 2021)

Equation B 0-1: Ex-post Regression Model for Small CPP

$$kW_{i,t} = \mathrm{a} + \sum_{n=1}^{5} \mathrm{b}_n \cdot Control_{i,t,n} + \mathrm{c} \cdot kW_{i,t-5} + \mathrm{d} \cdot CDH_{i,t} + \delta_t + \varepsilon_{i,t}$$

Where:

Table A-9: Ex-post Regression Elements for Small CPP

$\mathrm{kW}_{\mathrm{i,t}}$	Is the usage for each individual customer and time period
$Control_{i,t,n}$	The hourly used for five control sites, with each match
Event	Is a binary variable indicating if day is an event. Separate variables are used for weekday and weekend events so weather sensitivity of loads is estimated separately for weekday vs for weekend events. 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.
a	Is the model intercept
b	Loads for the five most closely matched control sites based on Euclidean distance matching. They did not experience the treatment and are weighted based on their predictive power.
c	5-hour lagged site load
d	Parameters for weather sensitivity of loads on event days vs on non-event days
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.
$\varepsilon_{\mathrm{i,t}}$	Represents the error term for each individual customer and time period.

b) Ex-ante

A key objective of the 2020 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 customer loads (absent DR) and weather
2. Incorporate reference load impacts due to COVID-19, initially and over time
3. Use the models to predict customers loads (absent DR) for 1-in-2 and 1-in-10 weather year conditions
4. Apply the average percent reductions, at an hourly level, from historical events. The average reduction was employed because experience with small business default CPP is limited and there is less of a history of program performance across events.
5. Estimate reductions for 1-in-2 and 1-in-10 weather year conditions
6. Incorporate the enrollment forecast.

A.2.1.3 Voluntary Residential CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies for both voluntary Residential CPP and TOU rates[31]:

a) Ex-post

The equation below illustrates a high-level overview of the approach Christensen used to develop residential CPP *ex-post* impacts.

$$kWh_{c,d} = \beta_0 + \Sigma_{Evts(i)} (\beta_{1,i} \text{ x } CPP_{c,d} \text{ x } Evt_{i,d}) + \beta_2 \text{ x } \mathrm{CPP}_{c,d} + \Sigma_{Evts(i)} (\beta_{3,i} \text{ x } TD_{c,d} \text{ x } Evt_{i,d}) + \Sigma_{Cust} (\beta_{4,Cust} \text{ x } C_c) + \Sigma_{date} (\beta_{5,date} \text{ x } D_{date,d}) + \beta_6 \text{ x } SS\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table A.7-1. Incremental customers are used to estimate the residential CPP load impacts in each regression. Results are then scaled to the program level of enrollments.

[31] 2020 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 2021)

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
$CPP_{c,d}$	Variable indicating whether customer *c* is only a *CPP* customer (*i.e.*, not also dually enrolled in *TD*) on date *d* (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date *d* is the i^{th} event day (1=i^{th} event, 0 if not)
$TD_{c,d}$	Variable indicating whether customer *c* is a dually enrolled *CPP* and *TD* customer on date *d (*1 = yes, 0 if not)
$SS\_Evt_{c,d}$	Variable indicating that date *d* is *a Summer Saver* event day (1=event, 0 if not) for customer *c*
β_0	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event *d* for *CPP* only customers
β_2	Estimated non-event day response for incremental *CPP* customers
$\beta_{3,d}$	Estimated load impact for event *d* for dually enrolled *CPP* and *TD* customers
$\beta_{4,Cust}$ and $\beta_{5,date}$	Customer and date fixed effects
β_6	Estimated average *Summer Saver* load impact
C_c	Variable indicating that the observation is for customer *c*
$D_{date,d}$	Date indicator variable (1 = date *d* equals date *day*)
$\varepsilon_{c,d}$	Error term

The equation below illustrates a high-level overview of the approach Christensen used to develop TOU *ex-post* impacts.

$$kWh_{c,d} = \beta_0 + \beta_1 \text{ x } (TOU_c \text{ x-post}_{c,d}) + \Sigma_{Cust} (\beta_{2,Cust} \text{ x } C_c) + \Sigma_{dates} (\beta_{3,dates} \text{ x } D_{dates}) \\ + \beta_4 \text{ x } Evt_{c,d} + \beta_5 \text{ x } AC\_Evt_{c,d} + \beta_6 \text{ x } TD\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table A.7-2. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

Table A-11: Description of Variables Used in the TOU Analysis Regressions

Variable Name	Variable Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
TOU_c	Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer
$Evt_{c,d}$	Variable indicating whether date ***d*** is an event day for customer *c* [32]
$Post_{c,d}$	Variable indicating that date ***d*** is in the post-enrollment period for customer *c*
$TD\_Evt_{c,d}$	Variable indicating that date ***d*** is a *TD* event day (1= event, 0 if not) for customer *c*
$SS\_Evt_{c,d}$	Variable indicating that date ***d*** is an *AC Saver Day Of* event day (1=event, 0 if not) for customer *c*
β_0	Estimated constant coefficient
β_1	Estimate of TOU load impact
$\beta_{2,\text{Cust}}$ and $\beta_{3,\text{date}}$	Estimated customer and date fixed effects
β_4	Estimate of average event-day load impact
β_5 and β_6	Estimated average *TD* and SS event event-day load impacts
C_c	Variable indicating that the observation is associated with customer *c*
D_{date}	Variable indicating that the observation is for date *d*
$\varepsilon_{c,d}$	Error term

b) Ex-ante

In 2020 SDG&E called nine residential CPP events, six of which were called on a weekday. Since the *ex-ante* analysis relies on weekday load impacts, this means there are six events on which to base the *ex-ante* forecasts. The percentage load impact is used for the average weekday event to simulate the *ex-ante* CPP load impact. 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.

In PY2020, the COVID-19 pandemic influenced customer reference loads and load impacts. The following primary sections provide details regarding a standard *ex-ante* methodology. Additional methods and adjustments used to account for COVID-19 during the forecast period are explained in section 6.4 of the Christensen final report.

[32] For CPP customers, the *Evt* variable indicates that a day is a CPP event day.

A.2.2 Nonevent Based Programs

A.2.2.1 Electric Vehicle Time Of Use

The paragraphs below describe the ex-post and ex-ante methodologies[33]:

a) Ex-post

To obtain TOU load impacts for EV customers, a distinct model is estimated for each required result:

$$kWh_{c,d} = \beta_0 + \beta_1 \text{ x } (EVTOU_c \text{ x-post}_{c,d}) + \Sigma_{Cust} (\beta_{2,Cust} \text{ x } C_c) + \Sigma_{date} (\beta_{3,date} \text{ x } D_{date}) + \beta_4 \text{ x } TOU_{c,d} + \beta_5 \text{ x } AC\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table A.8-1. Incremental customers are used to estimate the EVTOU load impacts in each regression. Results are then scaled to the program level of enrollments.

Table A-12: Description of Variables Used in the EVTOU Analysis Regressions

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
$EVTOU_c$	Variable indicating whether customer *c* is an EVTOU (1) or Control (0) customer
$Post_{c,d}$	Variable indicating that date *d* is in the post-enrollment period for customer *c*
$TOU_{c,d}$	Variable indicating whether customer *c* is on a, non-EVTOU, TOU rate on date *d*[34]
$AC\_Evt_{c,d}$	Variable indicating that date *d* is an *AC Saver Day Of* event day (1=event, 0 if not) for customer *c*
β_0	Estimated constant coefficient
β_1	Estimate of the EVTOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
β_4	Estimate of average TOU load impact (non EVTOU)

b) Ex-ante

To calculate TOU load impacts for EVTOU2 and EVTOU5 customers, seasonal percentage peak load impacts from the *ex-post* analysis are applied to weather-sensitive reference loads. NEM customer reference loads and load impacts are estimated separately from non-NEM customers. Ex-post seasonal level TOU load impacts are applied to reference loads and scaled

[33] 2020 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates by Christensen (Apr 2021)

[34] For customers that switched between a standard rate and TOU rate before transitioning to an EVTOU rate.

to the count of enrolled customers. The proportion of NEM customers is assumed to remain constant throughout the forecast period. Non-NEM and NEM results are customer weighted to produce program TOU outcomes.

A.2.2.2 Default TOU

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

a) Ex-post

The general steps for Nexant's comparison of participants' energy usage prior to being defaulted onto the D-TOU rate was: generating statistical estimates of usage as a function of weather, applying the resulting regression coefficients to 2020 weather conditions, and calculating the difference between weather-normalized pre-treatment and post-treatment usage values. The difference represents the change in consumption under 2020 weather conditions.

First, Nexant fit a degree-hour regression model separately for each premise and time period. A typical regression specification of this nature is as follows:

$$kW_{i,t} = \boldsymbol{\alpha}_i + \beta_{Cool} \times CDH_{i,t} + \beta_{Heat} \times HDH_{i,t} + \varepsilon_{i.t}$$

Table A-13: Description of Ex-post Variables Used in the D-TOU Analysis Regressions

Variable Name	Variable Description
$kW_{i,t}$	Per customer load impact for each week, for the hour h
α_i	Estimated constant
β_{Cool}	Estimated cooling parameter coefficient
β_{Heat}	Estimated heating parameter coefficient
$CDH_{i,t}$	Average cooling degree hours for each week, for the hour h
$HDH_{i,t}$	Average heating degree hours for each week, for the hour h
$\varepsilon_{i.t}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

In the above equation, the variable $kW_{i,t}$ equals electricity usage during the time period of interest, which might be each hour of the day, peak or off-peak periods, daily usage or some

[35] 2020 Load Impact Evaluation of SDG&E's Residential Default Time-Of-Use Rates by Nexant, Inc. (Apr 2021) – page 10-15.

other period. The index i refers to customers and the index t refers to the time period of interest. The estimating database would contain electricity usage data during both the pretreatment and post-treatment periods for all participants. The terms $CDH_{i,t}$ and $HDH_{i,t}$ refer to the calculated cooling degree-hours or heating degree-hours at given base temperatures during the time period. Cooling or heating degree-hours are calculated as the difference between the mean temperature of the hour and a base temperature, usually 65°F. Cooling degree-hours are used if the actual temperature is above the base temperature, while heating degree-hours are used if the actual temperature is below the base temperature. Nexant tested a variety of base temperatures, whether to use a fixed or variable degree-hour approach, and alternative temperature measurements to determine which specification performs best. Lastly, the β_{Cool} and β_{Heat} terms represent the estimated coefficients from the temperature terms.

After the optimal model was selected, the coefficients were applied to 2020 weather conditions. Lastly, load impacts for each segment were estimated by taking the difference between the weather-normalized pre-treatment and post-treatment usage values.

b) Ex-ante

Ex ante impact estimates were calculated by incorporating ex post percentage load impacts from the most recent evaluations of SDG&E D-TOU customers. Nexant conducted evaluations in PY2019 for both the pilot customers and the first group of mass default customers. Both of these evaluations benefited from making use of a control group methodology, allowing for impact estimates that feature a much higher level of confidence than the current ex post evaluation. The normalized reference loads from the current evaluation were combined with these population-weighted percentage impacts to generate predictions for ex ante weather conditions using a regression model. The ex ante model specification takes as its dependent variable the average hourly impact and reference load for each month from November 2019 through October 2020. The independent variables for each hour were the average temperature from midnight to hour ending 17 (mean17) and a binary indicator for the calendar month. There is a positive relationship between temperature and load impacts; as temperatures rise, so do load impacts. The model specification is presented in the equation below:

Hourly Ex-ante Load Impact Model Specification

$$Impact_h = a + b \cdot mean17_h + \sum_{i=1}^{12} c_i \cdot month_{hi} + \boldsymbol{\varepsilon}$$

Table A-14: Description of Ex-ante Variables Used in the D-TOU Analysis Regressions

Variable Name	Variable Description
$Impact_h$	Per customer ex-post load impact for each week, for the hour h
a	Estimated constant
b	Estimated parameter coefficient
c	Estimated parameter coefficient
$mean17_h$	Average temperature from midnight to hour ending 17
$month_{hi}$	A binary indicator for each month *i* of the year, January through December, for the hour *h* of interest
$\boldsymbol{\varepsilon}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

c) COVID-19

First, Nexant fit a weather-based regression model separately for each premise and time period, similar to the ex post load impacts methodology. To represent the change in usage associated with COVID-19, an additional variable was added to capture months during the pandemic. A typical regression specification of this nature is as follows:

$$kW_{i,t} = \boldsymbol{\alpha}_i + \beta_{Cool} \times CDH_{i,t} + \beta_{Heat} \times HDH_{i,t} + \beta_{COVID} \times COVID_{i,t} + \varepsilon_{i.t}$$

Table A-15: Description of COVID-19 Variables Used in the D-TOU Analysis Regressions

Variable Name	Variable Description
$kW_{i,t}$	Per customer load impact for each week, for the hour h
α_i	Estimated constant
β_{Cool}	Estimated cooling parameter coefficient
β_{Heat}	Estimated heating parameter coefficient
β_{COVID}	Estimated COVID-19 impact parameter coefficient
$CDH_{i,t}$	Average cooling degree hours for each week, for the hour h
$HDH_{i,t}$	Average heating degree hours for each week, for the hour h
$COVID_{i,t}$	A binary indicator for each month for which COVID-19 impacts apply
$\varepsilon_{i.t}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

In the above equation, the variable $kW_{i,t}$ equals electricity usage during the time period of interest, which might be each hour of the day, peak or off-peak periods, daily usage or some other period. The index i refers to customers and the index t refers to the time period of interest. The estimating database would contain electricity usage data during both the post-treatment periods for all participants in 2019 and 2020, with flags for each month of the pandemic. The COVID-19 binary flags for impact on residential customer load were provided by SDG&E.

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