Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

2020 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Commercial Technology Deployment Program

ACKNOWLEDGEMENTS

ABSTRACT

This study quantifies the demand impacts of three related interventions – time of use pricing with a critical peak pricing component, the shift in a time of use pricing window, and commercial thermostats. The study focuses on three primary research questions: What were the 2020 demand reductions due to dispatch operations? Are customers delivering non-dispatchable demand reductions due to the interventions? What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

SDG&E transitioned the full population of approximately 120,000 small business and agricultural customers from rates that did not vary by time of day to time varying rates in 2016. As part of the transition, in 2017 and part of 2018, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices. After the transition was complete the program was transitioned to a rebate model and split by customers on dispatchable rates (Peak Shift at Work (PSW) and Critical Peak Pricing – Default (CPP-D) for medium commercial and Industrial customers) versus those that aren't (AC Saver Day Ahead (ACSDA)). Dispatchable demand reductions were analyzed separately from non-dispatchable energy savings and demand reductions. In 2020, twenty events were called for the AC Saver Day Ahead program and nine were called for CPP. The AC Saver Day Ahead program produced an average load reduction of 0.44 MW on average weekday events, CPP-TD program delivered 1.54 MW of load reduction on average weekday events, and the Small CPP program delivered 5.23 MW of load reduction. ACSDA devices were typically dispatched between 6 and 8 pm and all CPP events occur from 2 to 6 pm.

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1 EXECUTIVE SUMMARY

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). If these customers did not want critical peak pricing, they had the option to elect a time-of-use rate (TOU) without a critical peak component. Approximately 95% of customer sites remained on TOU-CPP rate and 5% elected the TOU only option. In tandem, SDG&E also transitioned small agricultural customers from rates that did not vary by time of day onto default time of use rates. A CPP-TOU rate was offered to customers 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. 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. This commercial thermostat program has now transitioned to a rebate model and has been separated into two program types: one for sites on dispatchable (CPP) rates and ones that are not.

The study analyzes two primary research questions:

- What were the 2020 demand reductions due to dispatch operations?
- What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

Table 1-1 summarizes the estimated ex-post load impact estimates for each of the interventions and distinguishes between dispatchable and non-dispatchable resources.

Table 1-1: Summary of 2020 Average Event Ex Post Load Impact Estimates

Technology Intervention	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction
Small TOU-CPP (2-6 pm events)	108,138	302.37	5.23	1.7%
Tech Deployment: CPP rates (2-6 pm events)	1,204	23.00	1.54	6.7%
Tech Deployment: ACSDA (6-8 pm events)	941	15.17	0.44	2.9%

Table 2 summarizes the small CPP and commercial thermostat dispatchable ex ante reductions under August monthly peaking conditions for a 1-in-2 weather year[1]. The results are shown under both CAISO and SDG&E peaking conditions and reflect the reduction capability from 4-9 pm, which aligns with

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[1] Though no CPP events were called in PY 2019, ex ante estimates for dispatchable rates were developed using impacts from previous years, updated to reflect PY 2019 enrollment forecasts and device connectivity

resource adequacy requirements. For small CPP, the dispatchable reductions decrease due to projected decreases in enrollment due to CCA transition. The Community Choice Aggregator transition is expected to reduce the Small CPP population by over 50%. An initial drop is expected to begin in April 2021, with the majority of sites transitioning during May 2021. Customers that shift from CPP rates to a CCA can no longer be on SDG&E CPP rates, so these sites with smart thermostats that were on CPP rates will be migrated to the non-residential ACSDA program. Over time, customers are expected to sort themselves between TOU-CPP and TOU rates. Despite new installations projected for commercial thermostats, ex ante impacts for commercial thermostats are also expected to decrease given that thermostat connection rates decline over time faster than new thermostats are projected to be added.

Small CPP and commercial thermostat customers on CPP rates are dispatched during the 2 to 6pm event window. There were nine CPP events in PY2020. Commercial thermostat customers on ACSDA were called during a variety of event windows and later in the day, typically from 6 to 8 pm. Across the twenty ACSDA events dispatched in PY 2020, ten were called on days with maximum temperatures above 88 degrees and several were called on days much cooler than that. Due to the late event window of ACSDA, hourly temperature during eight events dipped below 75 degrees when there is far less cooling load available to be curtailed. As a result, ex post impacts per thermostat have historically been much lower for ACSDA than for commercial thermostats on dispatchable rates. However, ex ante impacts per thermostat and per site, as shown in Table 1-2, are higher for ACSDA than for CPP-TD. This is primarily because CPP-TD, as a program for dispatchable rates with a fixed window, is assumed to deliver impacts only during the 2pm to 6pm critical peak window, which only has two hours of overlap with the 4pm to 9pm resource adequacy window. In contrast, the ACSDA program can be dispatched any time between 1pm and 9pm. As such, the ACSDA ex ante impacts assume reductions are delivered for the full duration of the 4pm to 9pm resource adequacy window.

Table 1-2: Summary of Ex ante Dispatchable Demand Reductions

Year	Small CPP			Tech Deployment: CPP rates			Tech Deployment: ACSDA		
	Sites	MW (CAISO)	MW (SDG&E)	Sites	MW (CAISO)	MW (SDG&E)	Sites	MW (CAISO)	MW (SDG&E)
2020	108,995	0.26	0.24	746	0.28	0.26	344	0.81	0.77
2021	51,635	0.14	0.12	371	0.16	0.15	717	2.15	2.17
2022	51,640	0.15	0.13	416	0.19	0.19	673	2.62	2.68
2023	51,645	0.15	0.13	461	0.21	0.20	635	2.33	2.38
2024	51,648	0.15	0.13	505	0.21	0.21	601	2.08	2.12
2025	51,651	0.15	0.13	548	0.22	0.22	571	1.85	1.90
2026	51,653	0.15	0.13	591	0.23	0.23	543	1.66	1.70
2027	51,653	0.15	0.13	591	0.22	0.22	543	1.62	1.65
2028	51,653	0.15	0.13	591	0.22	0.21	543	1.58	1.61
2029	51,653	0.15	0.13	591	0.21	0.21	543	1.54	1.57
2030	51,653	0.15	0.13	591	0.20	0.20	543	1.50	1.53
2031	51,653	0.15	0.13	591	0.19	0.19	543	1.46	1.50

2 INTRODUCTION

Most small business (SMB) customers across the U.S. have the same price throughout the day and do not have an incentive to consider the timing of their energy consumption and the degree to which consumption during peak hours drives energy and infrastructure costs. Between November 2015 and April 2016, SDG&E transitioned over 120,000 small business customers onto time of use rates with a critical peak component (CPP-TOU). While customers were defaulted onto TOU-CPP rates, they could elect to opt-out to a time-of-use (TOU) rate and 5% of them did. As of PY 2020, about 108,000 sites remain on the CPP-TOU rate, implying an annualized three-year opt-out rate of about 3.5%, which is relatively stable relative to the initial 5% opt-out 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.

The transition to time varying rates encourages customers to consider when they consume power in addition to how much they consume. Customers can save by modifying when they use energy and by reducing energy use. The rates also better align the prices customers face and with the cost of supplying power. Prior to the transition, SDG&E implemented an outreach and education campaign designed to increase awareness and improve understanding of the new rate.

2.1 RATE AND TECHNOLOGIES EVALUATED

Two related but distinct interventions were assessed as part of the evaluation:

- CPP-TOU – Critical peak prices are designed to incentivize customers to reduce or shift electricity use from peak hours on a handful of days that drive the need for building additional power infrastructure. Customers receive rate reductions during summer non-event days to offset the higher prices during critical peak events (less than 1% of hours). At SDG&E, the CPP rates are layered on top of TOU rates. Historically, the event window was 11am to 6pm but beginning in 2018 the window was narrowed to 2 to 6pm. The CPP window is projected to shift again in 2022, but the decision has not been finalized, so the forecast does not adjust for this potential shift.

- Smart thermostats – Through 2017, customers undergoing the transition to time varying rates were eligible for free ecobee thermostats to help automated price response during critical peak periods. The thermostats also can help reduce electricity consumption when a business is unoccupied. After the 2017 event season the program was shifted to a rebate design and expanded to allow additional thermostat models.[2] There are four Technology Deployment programs of which some variants have been in operation since 2014[3]. Prior to 2017, customers were not required to be on a CPP rate, customers on TOU only rates are in the AC Saver Day Ahead (ACSDA) programs—one for non-residential customers and one for quasi-residential customers. Historically, all thermostats were dispatched from 2 to 6pm on CPP event days. Beginning in 2018, ACSDA events were called separately and did not necessarily overlap with CPP event days. ACSDA thermostats can be dispatched at any time between 12 pm to 9 pm (on-peak hours) for a maximum of 4 consecutive hours and most events in 2018 were called from 6-8pm. For Technology Deployment customers on CPP rates (CPPTD) thermostats are still dispatched from 2-6pm on CPP event days. The two rate-based programs are Peak Shift at Work (PSW, for small commercial customers) and CPP-D (for medium and large commercial customers). Both CPP and ACSDA devices are curtailed by raising the thermostat temperature set point 4 degrees during the event window.

Both the CPP-TOU and TOU rates provide customers an incentive to reduce or shift electricity use away from peak hours. The CPP-TOU rates include higher prices during critical peak events, an event adder, which is applicable to usage during critical peak events which can be called between the hours of 2 pm and 6 pm during the summer.

2.2 STUDY RESEARCH QUESTIONS

Table 2-1 summarizes the key research questions for each intervention. Both CPP-TOU and commercial thermostats are dispatchable resources that also can lead to daily changes in energy use. Because dispatchable resources are used for operations, the impacts associated with event dispatch are estimated and reported separately from daily, non-dispatchable changes in energy use.

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[2] SDG&E had a limited number of free thermostats available in 2018 that were provided on first serve basis, the remainder of the 2018 thermostats were purchased by the customer and rebates were issued.
[3] Expanded from the former Small Customer Technology Deployment (SCTD) program

Table 2-1: Key Research Questions

	Research Question	CPP-TOU	SCTD
1	What were the demand reductions due to program operations and interventions in 2020 – for each event day and hour?	✓	✓
2	How do load impacts differ for customers who have enabling technology and/or are dually enrolled in other programs?	✓	✓
3	How does weather influence the magnitude of demand response?	✓	✓
4	How do load impacts vary for different customer sizes, locations, and customer segments?	✓	✓
5	What is the ex ante load reduction capability for 1-in-2 and 1-in-10 weather conditions? And how well does it align with ex post results and prior ex ante forecasts?	✓	✓
6	What concrete steps or experimental tests can be undertaken to improve program performance?	✓	✓

2.3 OVERVIEW OF METHODS

The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did the introduction of time varying rates or smart learning thermostats cause a change in critical peak period demand? Or can the differences be explained by other factors? To estimate energy savings, it is necessary to estimate what energy consumption would have been in the absence of the intervention—the counterfactual or reference load.

The change in energy use patterns was estimated using a panel regression with multiple control groups, each matched to a participant. Key modeling design components are as follows:

- **Multiple matched controls:** For each participant, five control sites were identified based on how closely their loads matched the participant on event-like proxy days (e.g. using Euclidian distance matching). A total of five matched control sites were selected for each participant site, ranked by their closeness of fit across all proxy days.

- **Panel regression model with event and non-event day and participants and matched controls:** The data was structured as a time series for each participant. The control loads, weather, and day characteristics were used to predict participant loads. The model coefficients for each control site essentially weight the various control sites based on their predictive power creating a more accurate prediction out of multiple controls. This

approach was used as the primary method for event impacts for critical peak events delivered by AC Saver Day Ahead thermostat participants.

- **Event specific models:** Given the wide range of temperature conditions during events, five proxy days were selected for each event based on the how closely the proxy day conditions, measured by system load, matched the event days (e.g. using Euclidean distance matching). A separate model was estimated for each event including only loads for the event day and the proxy days selected for that event. The number of proxy days included was validated using the model validation process described below.

- **Pre and post event adjustment:** The impact regression also included pre and post event loads to adjust the model for differences. A two hour pre- and post-adjustment period with a two hour pre- and post-buffer was used. Inclusion of these parameters was validated using the model validation process described below.

- **Model validation:** The choice of the number of proxy days (ranging from two to five), of the number of matched control sites (ranging from one to five), and of the inclusion of pre and post event adjustment parameters was validated using a placebo effect approach: a subset of proxy days was used to predict load on the remaining proxy days for each event. In the absence of events, the difference between predicted and actual error should be zero and any deviation is a direct reflection of modeling error. In each case the approach with the least error and best fit was selected.

Figure 2-1 summarizes the out of sample testing process used to select the number of proxy days, controls, and adjustments to be used for modeling. Essentially, the out of sample process is an iterative approach whereby data is systematically left out of the matching model then used to assess model performance—a well performing model should produce matches for loads on days which were not used for the model. The final model is identified based on least bias (% Bias) and best fit (Relative RMSE) metrics. As an example, Figure 2-2 summarizes the model selection analysis for the non-residential TD programs[4]. Each row shows a different adjustment model and each cluster of bars shows results for a selected number of proxy days. Each individual bar in a cluster shows results for a selected number of control sites per participant site. Note that across the 60 models tested, the one with the best precision (lowest RMSE) is the one with a pre and post adjustment, using five proxy days and five control sites. This is the model that was selected for estimating counterfactual loads during events. Using multiple proxy days, matched controls and, adjustments systematically increased model precision though there are diminishing returns to including additional proxy days and matched controls. The model elements tested exhibit a directional improvement trend for additional proxy days and controls. However, this

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[4] Analogous results for Small CPP are summarized in Appendix B

trend diminishes with each the marginal improvement. This trend is likely why the same model was selection as in the prior evaluation.

Figure 2-1: Out of Sample Process for Model Selection

1. Identify testing and training days	2. Define multiple models	3. Run each model using training data (leave out testing days)
• Remove events • Divide proxy days for each event into even and odd by Euclidian distance rank • Leave out every other day for testing	• Number of proxy days ranging from two to five • Number of matches included from one to five • Inclusion of pre- or post-event adjustment parameters	

4. Estimate out-of-sample bias and precision	5. Select the best performing model	6. Estimate loads during actual events using selected number of matched sites and proxy days
• Control for event sampling bias • Bootstrap 20 random draws of 17 events to include in the calculations	• Narrow to models with the least bias • Calculate average precision (RMSE) across draws • Pick the model with the best precision	• Five control sites per participant site • Five proxy days per event

Figure 2-2: TD Program Model Selection Results
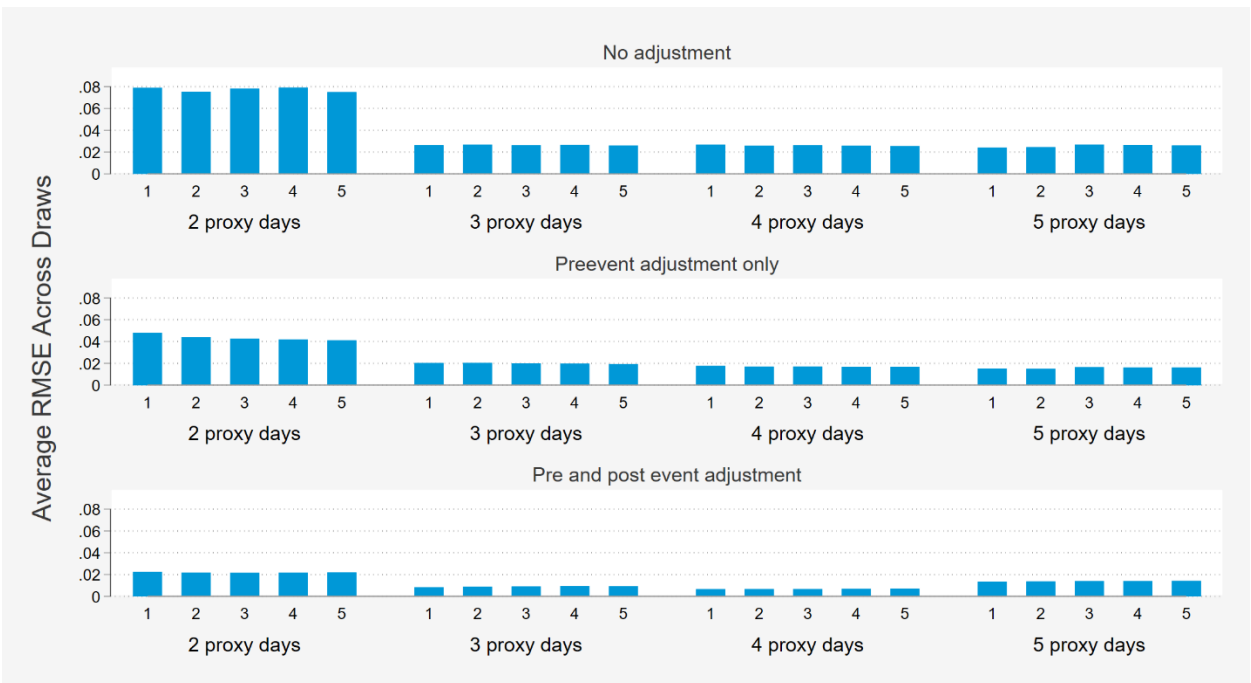
Table 2-2 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom up approach to estimate impacts and to ensure that aggregate impacts across segments equaled the sum of the parts. Because impacts for each segment were added

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together, the segmentation was structured to be mutually exclusive and completely exhaustive. In other words, every customer was assigned to exactly one segment. By design, the segmentation differentiated customers who were expected to deliver demand reductions– such as customers who sign up for event notification or technology to automate response – from customers who were expected to deliver little or no demand reductions. Additional segments were analyzed, after the fact, as part of exploratory analysis, but the core results presented are based on the segmentation detailed below. Importantly, the segmentation categories for Small CPP were simplified in PY 2020 relative to previous years. This introduces a source of difference with the previous methodology but yields more robust results given that simpler segmentation results in many more sites (sample points) per segment. Segments with very few sites were effectively eliminated.

<div align="center">Table 2-2: Evaluation Methods</div>

	CPP-TOU	TD Programs
Data sources / samples	▪ Hottest 20 weekdays and weekends over the past three summers with events (2018-2020), plus any additional event days for: ✓ 108k Small Commercial ✓ 10k CPP-TOU opt outs (to be used for match control group) ✓ 143Ag participants ✓ 3.5k Ag participants (to be used for match control group)	▪ Hottest 20 weekdays and weekends over the past three summers (2018-2020 for TD Programs), plus any additional event days, for event day impacts
Segmentation	▪ Rate ✓ Small Commercial vs Ag ▪ Enrollment in event notification (Y/N) ▪ Climate zone (Coastal vs Inland)	▪ Rate ✓ CPP-TD: PSW (Small) vs CPP-D (Med & Large) ✓ ACSDA: Small vs Med vs Large vs Quasi-residential ▪ Climate zone (Coastal vs Inland)
Estimation method: Ex-post	Fixed effects diff-in-diff regression using matched control from opt-outs for each segment	CPP-TD: Matched control groups analyzed using fixed effects diff-in-diff regression for each segment ACSDA: Panel regression with multiple matched control group for each customer.
Estimation method: Ex-ante	▪ Weather normalized customer regressions by segment for reference loads	▪ Weather normalized customer regressions by segment for reference loads ▪ Regression of historical event percent impacts versus weather for percent reductions ▪ Used 2018-2020 impacts

3 CRITICAL PEAK PRICING EVENT DAY IMPACTS

SDG&E defaulted over 120,000 small customer sites[5] onto CPP-TOU rates between November 2015 and April 2016. Roughly 5% of these customers opted-out and were placed on TOU rates. Figure 3-1 shows this cumulative enrollment in CPP, net of the opt-outs.

Figure 3-1: Small Non-Residential Critical Peak Pricing Enrollment
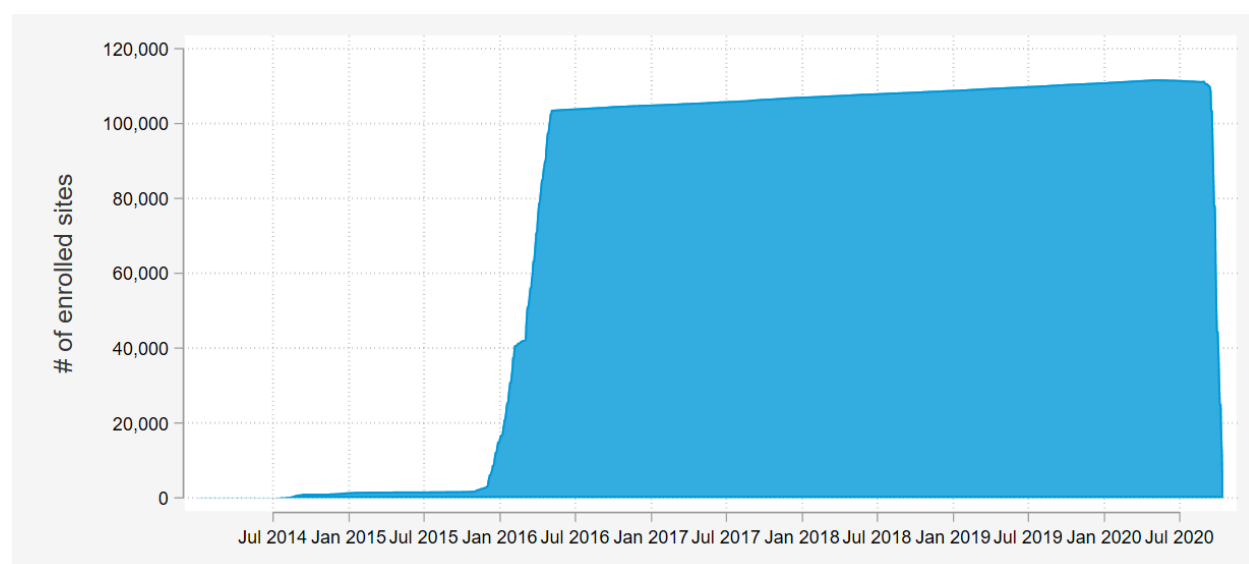
The first event season for CPP was in 2016, but only one CPP event was called that year. It was called on SDG&E's peak day, Monday, September 27th. The PY 2016 evaluation for small customers found that the ex post load impacts for this lone CPP event were not statistically significant. The event was atypical. SDG&E had a low notification rate at the time – less than 25% of customers had elected to provide contact information to SDG&E –notifications were sent the Friday prior to the Monday event, and the event occurred near the end of the summer season.

In PY 2018, six CPP events were called in July and August while in PY 2019, there were no CPP events. In PY2020, there were nine CPP events in August through October.

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[5] Here and throughout this report a site is defined as a premise and service point combination. Note that this figure is slightly higher than the number of sites used for the PY 2020 ex post impact analysis which only included sites still on CPP-TOU rates in PY 2020.

3.1 PARTICIPANT AND EVENT CHARACTERISTICS

Small CPP (Commercial and Agricultural) event impacts were assessed by site (premise and service point combination). Sites were grouped together into segments to assess potential differences in impacts for various groups. The segmentation, summarized in Table 3-1, was developed based on rate class, program, and technology characteristics which may influence impacts. Analysis was performed at the segment level so these granular impacts could therefore be summed, yielding aggregate impacts in addition to the segment specific impacts. Customers on CPP rates and in the TD program are covered in Section 4. Dually enrolled customers, those in the Small CPP program and either Summer Saver or CBP[6], were omitted from the analysis.

The segmentation criteria were defined as follows:

- **Rate class:** what type of rate was the site on throughout the study period?

- **Notification:** did the customer associated with the site receive any event notifications for any site?

- **Climate zone:** in which SDG&E climate zone was the site located?

Table 3-1: Small Critical Peak Pricing Population Segments

Rate class	Climate zone	Notification	Total Sites	Sites in analysis
Small Commercial	Coastal	No	36,318	36,297
		Yes	28,705	28,694
	Inland	No	25,148	25,125
		Yes	17,825	17,820
Small Agricultural	All	All	143	143
Total sites			108,138	108,079

Table 3-1 summarizes the total number of sites in each segment and the final number of sites used for analysis once data cleaning was completed[7]. For most segments, the vast majority of sites were included in the analysis. Due to the small population of the Small Agricultural program, the program

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[6] Just under 4,000 small sites on CPP rates were also enrolled in Summer Saver. Fewer than a dozen small sites on CPP rates were enrolled in CBP
[7] The cleaning algorithm ensured that complete data was available for the study period. Sites for which high quality matches could not be found were also excluded.

was not further segmented. Aggregate ex post analysis results were scaled up to match the total number of sites before data cleaning.

Because other programs also modify loads, those event days cannot be used for counterfactual estimation for dually enrolled CPP participants. Days which were not CPP events but which were events for other DR programs were excluded for dual participants, leaving fewer days for counterfactual estimation.

Table 3-2 shows the nine PY 2020 CPP event days, including the maximum daily temperature weighted by participating sites. These events occurred on various days of week in August through October. The SDG&E system peak occurred on September 5th, 2020 at 5:34 pm.

Table 3-2: Small Critical Peak Pricing Events in 2020

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
8/17/2020	Monday	2:00 PM	6:00 PM	87.7	3,830
8/18/2020	Tuesday	2:00 PM	6:00 PM	91.9	4,028
8/19/2020	Wednesday	2:00 PM	6:00 PM	86.7	3,911
8/20/2020	Thursday	2:00 PM	6:00 PM	88.8	3,861
9/5/2020	Saturday	2:00 PM	6:00 PM	97.7	4,608
9/6/2020	Sunday	2:00 PM	6:00 PM	103.1	4,351
9/7/2020	Monday	2:00 PM	6:00 PM	80.8	3,318
9/30/2020	Wednesday	2:00 PM	6:00 PM	95.8	4,573
10/1/2020	Thursday	2:00 PM	6:00 PM	97.7	4,308

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Small CPP analysis. The analysis was done by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report (rate versus technology based, event and non-event), the characteristic definitions used to build segments were consistent across analyses.

Table 3-3: Small Critical Peak Pricing Evaluation Data Sources

Source	Comments
Hourly interval data	■ Summer 2020 (June 1 through October 31) ■ All analysis done by site (premise id-service point id pair)
Outage information	■ PSPS and CAISO emergency outage data details which customers and what timeframes were impacted by outages ■ Outage days which affected participants or control sites were excluded from the analysis
Customer characteristics	■ Treatment: All small non-residential (Commercial and Agricultural) CPP rates (108,079 sites) ■ Control: TOU only rates (10k commercial sites, 3.5k Ag sites) ■ Industry, zip codes, climate zone, NEM status used in matching model selection ■ NEM status, climate zone, and DR program enrollment used for segmentation
SDG&E hourly system loads	■ Summer 2020 (June 1 through October 31) ■ Used to identify non-event high system load days
Ex post weather data by weather station	■ Used to derive cooling degree days for impact evaluation panel model
Event notification	■ List of notifications sent to each account for each event day ■ Rolled up by customer to identify customers who had received notifications at any site (used in segmentation)

The primary analysis method was a panel regression with a multiple matched control groups. 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. These customers were not enrolled in CPP or other DR programs which might influence energy use. The panel regression model was then used to assess impacts and standard errors for each event and each study segment.

To identify which model best predicted customer loads absent demand reductions, an out of sample approach was still used to select the model specification. The model selection relied on testing how well each model estimated loads for event-like non-event days out-of-sample. Because there was, in fact, no event, it was possible to assess how close model estimates were to the correct answer and the most accurate model. A total of 80 models were tested to select the number of proxy days, number of

matched controls, and structure of same day adjustments to use. The regression model structure and out of sample testing are detailed in Appendix B. Reference loads were developed using pre-2020 and 2020 data to show the differences caused by COVID. These differences are defined more fully in Section 3.4.

3.3   EX POST LOAD IMPACTS

Load reductions are a function of the reference load. When there is lower load, demand response programs have less opportunity for reduction. During summer 2020 and spanning all 2020 events, COVID considerations influenced commercial operations and energy consumption. During the average event for the Small CPP program, the average customer load was 21% lower in 2020 than in 2018 (the last year where events were called). Because reduction potential is a function of underlying energy usage, the decrease in reference loads suggests that the effect of COVID on participant energy usage reduced the potential for reductions during 2020. The meaningful load decrease was observed for a similar population of about 110,000 participants in both years. However, there are limitations to the differences that can be identified by comparing ex post loads across years given multiple changing variables such as weather and participant population. Further, the effect of COVID on loads may be different by granular study segment. Controlling for external factors such as population variability and weather and looking at load across all days (not just event days) helps isolate the effect of COVID on loads. The ex ante reference load analysis controls for temperature differences and population differences by comparing the same customers before and during 2020. This process is further described in Section 3.4.2.

Table 3-4 summarizes the portfolio load reductions for all Small Non-Residential sites on CPP rates (and not dually enrolled in other DR programs) for the nine events and 2 pm to 6 pm reductions for the average weekday and weekend events. The average weekday event aggregate load reduction was 5.23 MW across all 108,138 sites and the average reduction per site was 0.05 kW. Reductions were significant at the 95% level for all events and for the two average events. The greatest reduction was for the event on September 30th with an aggregate reduction of 6.43 MW and a per site reduction of 0.06 kW. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 3-4: Small CPP Program Specific Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions Aggregate (MW)		Average Site (kw)		Significant (90% CI)	Significant (95% CI)
8/17/2020	Avg. 2 to 6 pm	85.5	108,653	5.05		0.05		Yes	Yes
8/18/2020	Avg. 2 to 6 pm	83.8	108,665	4.20		0.04		Yes	Yes
8/19/2020	Avg. 2 to 6 pm	84.9	108,654	4.61		0.04		Yes	Yes
8/20/2020	Avg. 2 to 6 pm	82.7	108,642	4.85		0.04		Yes	Yes
9/30/2020	Avg. 2 to 6 pm	93.2	107,099	6.43		0.06		Yes	Yes
10/1/2020	Avg. 2 to 6 pm	91.5	107,116	6.22		0.06		Yes	Yes
Avg Weekday Event	Avg. 2 to 6 pm	87.0	108,138	5.23		0.05		Yes	Yes
9/5/2020	Avg. 2 to 6 pm	94.6	108,058	0.26		0.00		Yes	Yes
9/6/2020	Avg. 2 to 6 pm	97.5	108,056	0.12		0.00		Yes	Yes
9/7/2020	Avg. 2 to 6 pm	78.0	108,057	0.12		0.00		Yes	Yes
Avg Weekend Event	Avg. 2 to 6 pm	90.0	108,057	0.17		0.00		Yes	Yes

Reductions were also segmented by rate class, climate zone, and customers who signed up for event notifications[8]. Table 3-5 details the reference loads and load reductions overall and by each of these study segments[9] for the average 2 pm to 6 pm CPP event window. Both aggregate reductions and average reductions per site are shown. Small Commercial portfolio impacts for the average event were 5.16 MW in aggregate or 1.7% of whole building load, while program specific impacts were 5.23 MW— 1.7% of whole building load. Note that dually enrolled customers are omitted from this analysis.

Segmentation of load impacts shows minor differences in three of the commercial segments. Inland customers regardless of notification and coastal customers receiving notifications produced reductions of 2.1% to 2.9% of whole building load. The coastal customers not receiving notification produced reductions which were small in magnitude and not statistically significant, though directionally slightly negative, implying an increase in load.

As a whole, program specific impacts for the 107,996 Small Commercial sites were 5.16 MW. Program reductions for the 143 Agricultural sites were directionally positive but not statistically significant. Sites dually enrolled in other DR programs are excluded from program reductions

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[8] Sites were classified as receiving notifications if any site under the parent customer received notifications. There were multiple indirect channels where sites that did not directly sign up for notification could become aware of them. SDG&E publicized the events via mass media channels – radio and TV – and customers at many smaller sites that did not sign up for notification also had medium and large facilities that were signed for event notification.
[9] Results for more granular segments including NEM status and dual enrollment in other DR programs are included in the appendix.

Table 3-5: Small CPP Program Average Event Reductions by Segment

Subcategory	Temp	Sites	Aggregate (MW)				Average Site (kw)			t-stat
			Ref Load	Reduction	% Reduction	Std Error	Ref Load	Reduction	Std Error	
Comm: Coastal & no notification	85.0	36,318	93.94	-0.04	0.0%	0.01	2.59	0.00	0.00	-6.30
Comm: Coastal & received notification	85.1	28,705	90.23	1.87	2.1%	0.11	3.14	0.07	0.00	16.36
Comm: Inland & no notification	89.8	25,148	62.37	1.71	2.7%	0.18	2.48	0.07	0.01	9.43
Comm: Inland & received notification	89.8	17,825	55.14	1.62	2.9%	0.31	3.09	0.09	0.02	5.16
Agricultural portfolio	90.3	143	0.70	0.07	9.7%	0.13	4.87	0.47	0.93	0.51
Commercial portfolio	86.9	107,996	301.68	5.16	1.7%	0.37	2.79	0.05	0.00	13.92
All study segments	87.0	108,138	302.35	5.23	1.7%	0.38	2.80	0.05	0.00	13.88

The load shape for the average event day is summarized in greater detail in Figure 3-2. Note that the figure, extracted from the Ex Post Load Impact Table, is for the small CPP portfolio population. The figure shows the aggregate hourly loads (actual and counterfactual) for these sites. The tables accompanying each figure show aggregate impacts for the 2 pm to 6 pm event window. Load was reduced by 1.7% during the average event window, larger than past years (0.7% in 2018), but in line with reductions for CPP rates with no enabling technology. Program reductions begin appearing around noon, which suggests lingering behaviors from the historical event window.

Figure 3-2: Small CPP Program Specific Impacts

Table 1: Menu options

Type of results	Aggregate
Category	Program specific impacts
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

CPP Event start	2:00 PM
CPP Event end	6:00 PM
Total enrolled accounts	108,138
Avg load reduction 2PM-6PM	5.23
% Load reduction 2PM-6PM	1.7%
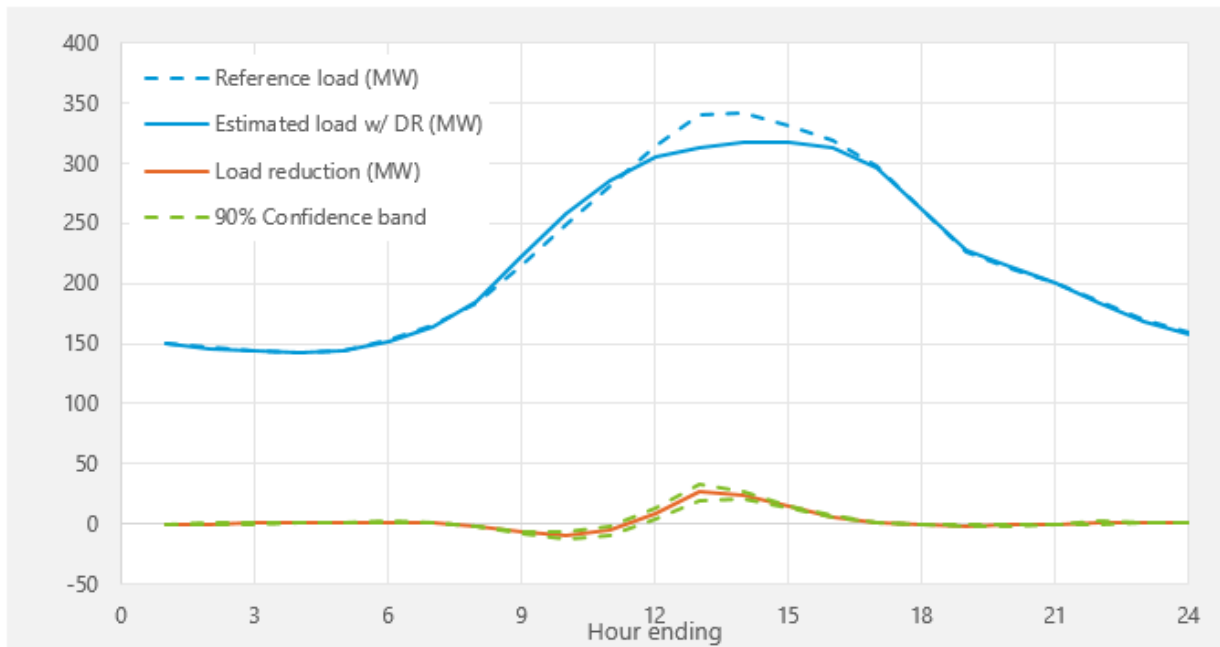
3.4 EX ANTE LOAD IMPACTS

A key objective of the 2020 evaluation is to quantify the relationship between demand reductions, temperature and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The

historical load patterns and performance during actual events are used to estimate the reductions for a standardized set of weather conditions.

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

1. Estimate the relationship between customer loads (absent DR) and weather

2. 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

3.4.1   RELATIONSHIP OF CUSTOMER LOADS AND PERCENT REDUCTIONS TO WEATHER

Figure 3-3 summarizes the relationship between weather and CPP participant loads in 2018 through 2020. Only days when CPP resources were not dispatched are included. The panel to the left shows average hourly loads for current participants for different temperature bins, defined by the daily maximum temperature. Typically, this curve trends upward, but due to COVID and the unusually hot season in PY2020, there appears to be a dip as temperatures exceed 90 degrees F. The panel to the right shows the relationship between daily maximum temperatures and hourly loads. The hottest temperature day in the right panel is not the highest load curve. A larger sample size covering more years (with and without COVID) would likely restore the expected shape of this curve. Generally, energy demand and discretionary load increases with hotter weather.

Figure 3-4 shows the relationship between aggregate small commercial CPP loads and SDG&E daily peak loads. Daily peaks that occurred before 5pm are shown in blue and those that occurred later are shown in grey. Daily peaks that occur later in the day (after 5pm) are smaller in magnitude and occur on days where maximum daily temperatures are about 5 to 10 degrees cooler than days with earlier peaks. Not surprisingly, small commercial customers use more power when it is extremely hot and contribute to peak demand, which drives the need for additional generation, transmission, and distribution infrastructure. Based on our analysis, we estimated that loads from small commercial CPP participants account for approximately 10% of SDG&E's peak load absent demand response. Customers in the Coastal climate zone comprise about 60% of these loads. Because small commercial loads are a major driver of SDG&E peaks, if managed, they can reduce the need to build additional infrastructure to accommodate additional peak load. Because more discretionary load is in use during peaking conditions, reductions from CPP participants can be larger precisely when resources are needed most.

Figure 3-3: Weather Sensitivity of Small Commercial CPP Loads
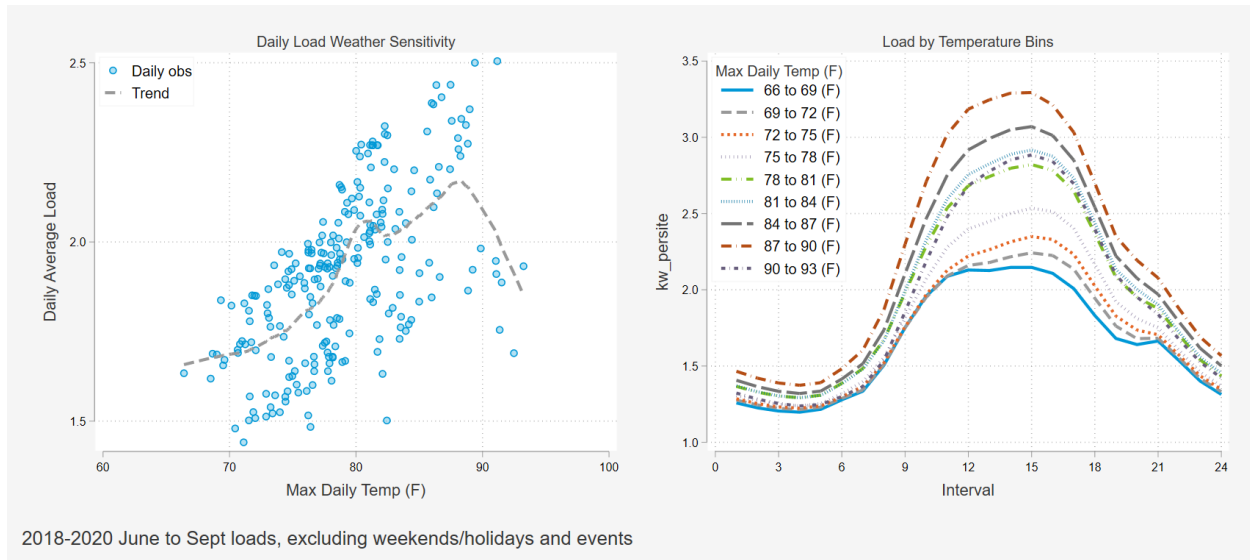
Figure 3-4: Small Commercial CPP Load versus System Daily Peaks
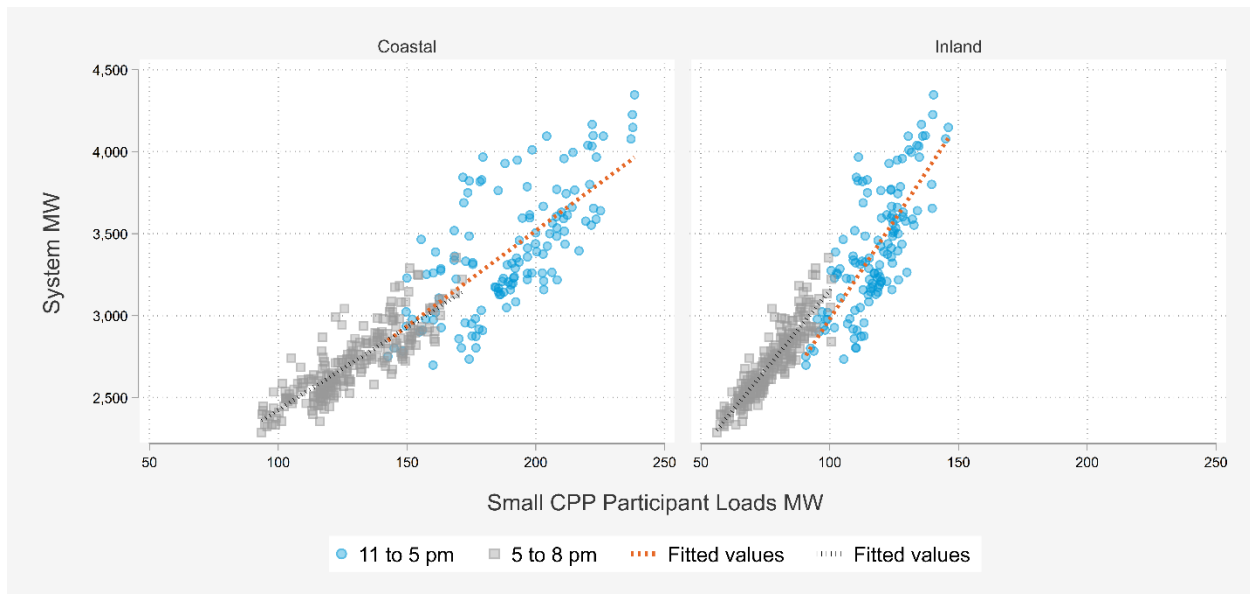
Figure 3-5 shows hourly event percent reductions for these events as a function of hourly temperatures. The left panel shows weekdays and the right shows the weekend and holiday event hours from PY 2020. Note that while most reductions are positive in magnitude, a handful are negative or near zero (and not statistically significant). Weekdays show a positive trend as warmer temperatures result in larger percent reductions. The hour of day is also noted in the figure, showing that hour 15, the first event hour, is larger than subsequent hours, regardless of temperature. The weekend and holiday events are mostly insignificant, and there are too few observations from which to deduce any trends.

Figure 3-5: 2020 Small Commercial CPP Hourly Reductions and Temperatures
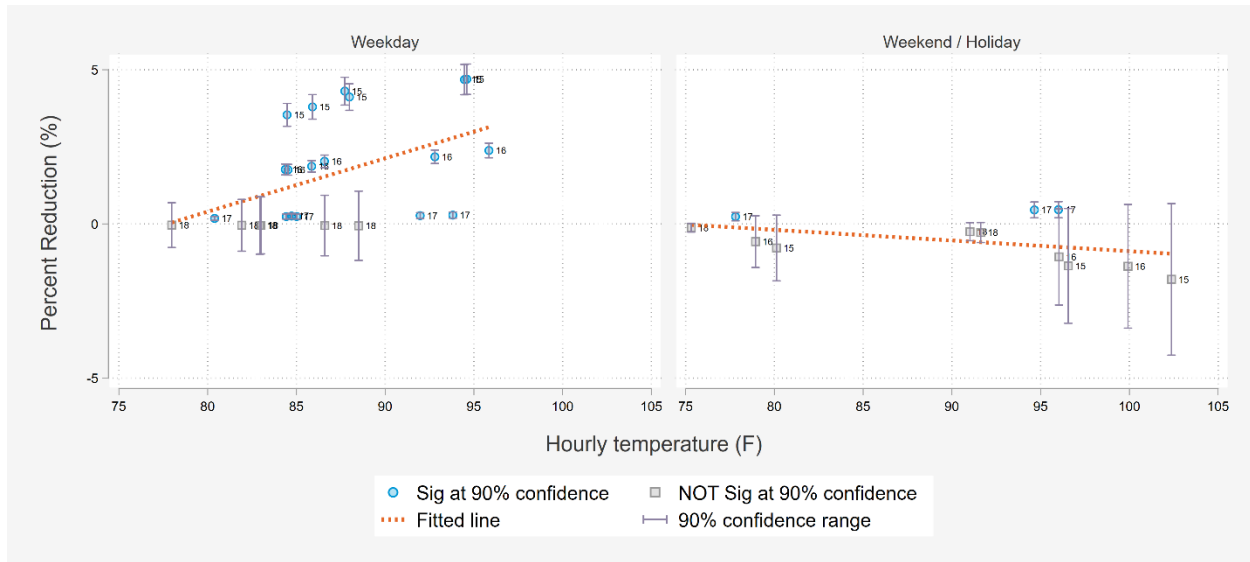
3.4.2 COVID-19 LOAD ADJUSTMENTS

Beginning in March 2020, shutdowns began across the United States as a response to the COVID pandemic. As commercial businesses closed, many workers either lost their jobs or began working from home. The shutdown impacted sectors at different levels of intensity and during different time periods, but all 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.

Figure 3-6 shows percent difference between these two sets of reference loads (pre-COVID-19 and post-COVID-19) for Small CPP participants. The figure shows the comparison for the SDG&E August peak day 1-in-2 weather condition but comparisons were modeled for all ex ante weather conditions and day types. The blue line shows the percent difference for whole building loads between pre-COVID-19 and post-COVID-19 reference load. The negative effect indicates that across all hours post-COVID-19 reference loads were lower than pre-COVID-19 reference loads. Small commercial loads were about 12% lower during event hours (2pm to 6pm). Small agricultural loads were also lower post-COVID-19 but the magnitude was much noisier because it was constructed using only 143 sites, compared to about 108,000 small commercial sites.

Figure 3-6: COVID Effect on Loads, August Peak Day, 1-in-2 Weather
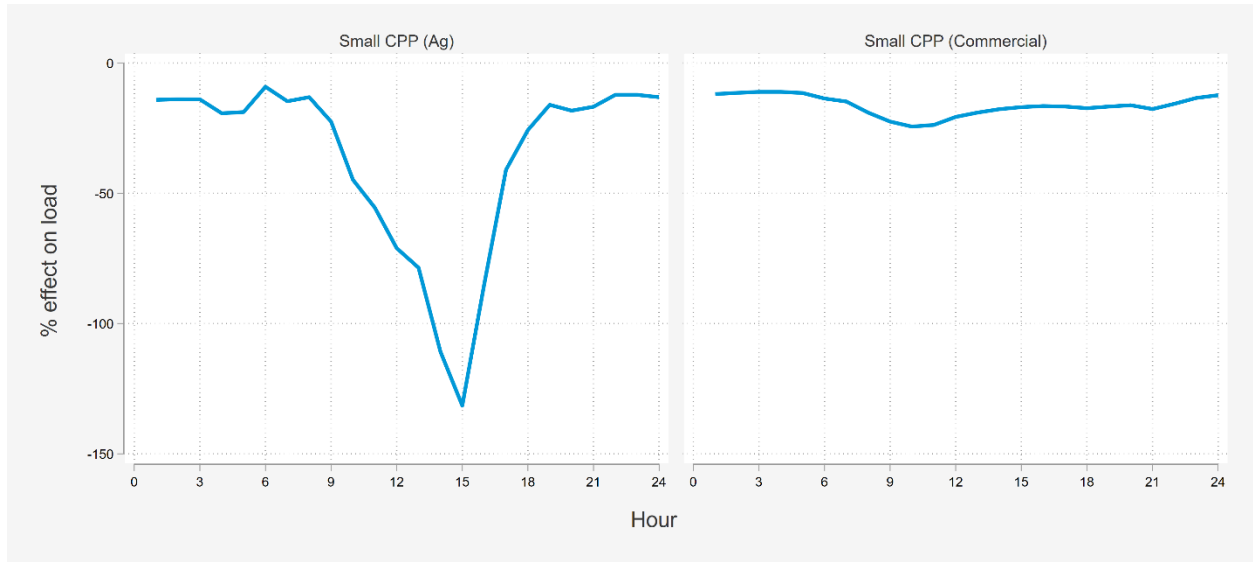
Predicting ex-ante impacts requires further assumptions regarding COVID's potential lingering effects. SDG&E's load forecast for the next two years includes assumptions about the retention over time of the effect of COVID-19 on loads. Figure 3-7 summarizes the monthly assumption for the portion of COVID-19 load effects that will be retained. The same assumptions were used for all non-residential programs including Small CPP and TD programs. These retention percentages are applied to the COVID-19 load effect (percent different between pre and post COVID-19 reference loads) to incorporate assumptions about COVID-19 into the ex ante reference loads. Notably, the full effect of COVID-19 is assumed to have been in place during most of 2020, to steadily drop during 2021, and to have completely disappeared by 2022, with reference loads reverting back to pre-2020 levels.

Figure 3-7: COVID Effect Retention by Month and Year
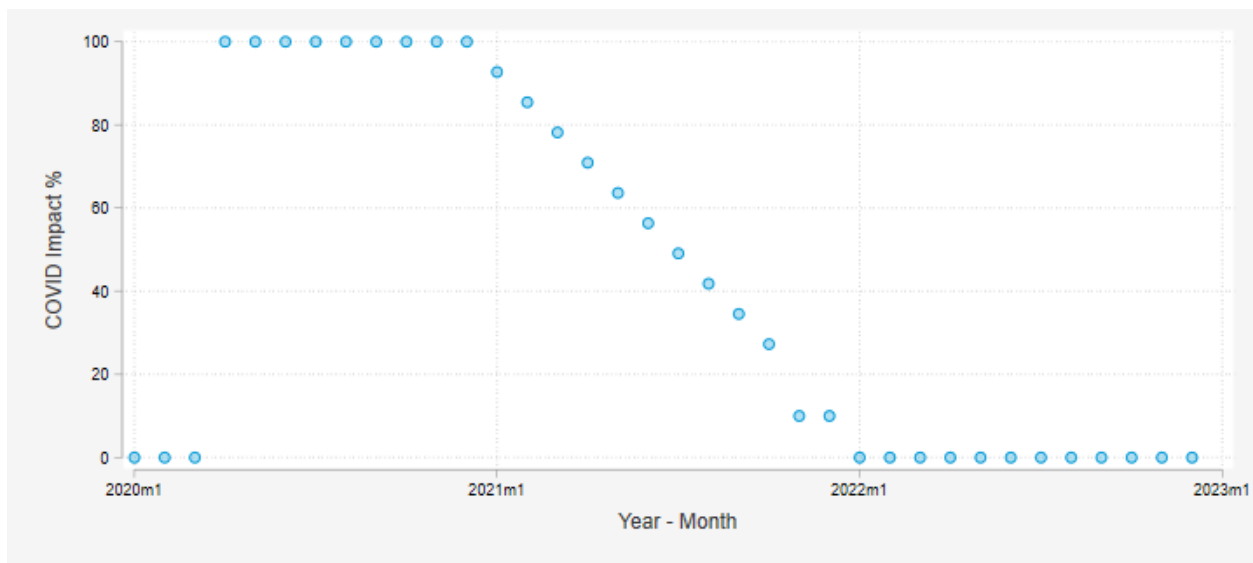
3.4.3 EX ANTE LOAD IMPACTS

Table 3-6 summarizes the ex ante demand reduction capability by forecast year and planning condition. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm on August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions. They align with the planning conditions used for resource adequacy attribution. To avoid double counting, the table only includes resources that are not dually enrolled in other DR programs, known as portfolio impacts.

Table 3-6: Small CPP Portfolio Impacts for August Monthly Peak Day (4-9 pm)[10]

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2020	108,995	0.26	0.25	0.24	0.32
2021	51,635	0.14	0.13	0.12	0.16
2022	51,640	0.15	0.14	0.13	0.17
2023	51,645	0.15	0.14	0.13	0.17
2024	51,648	0.15	0.14	0.13	0.17
2025	51,651	0.15	0.14	0.13	0.17
2026	51,653	0.15	0.14	0.13	0.17
2027	51,653	0.15	0.14	0.13	0.17
2028	51,653	0.15	0.14	0.13	0.17
2029	51,653	0.15	0.14	0.13	0.17
2030	51,653	0.15	0.14	0.13	0.17
2031	51,653	0.15	0.14	0.13	0.17

The enrollment forecast was developed by SDG&E and shows a declining number of customers enrolled in small non-residential CPP. The steep drop in sites in 2021 is due to the expected defaulting of non-residential sites to a Community Choice Aggregation energy supplier in April and May 2021. The expectation is that roughly half of Small CPP participants will be served by the CCA starting in 2021. This transition will result in disenrollment from SDG&E's CPP rates, which precludes participation in SDG&E's CPP events. Note that participants served by CCAs will remain on SDG&E's distribution TOU rates. For ex ante impacts, reduction in enrollment forecasts are assumed to have a proportional effect on the magnitude of demand reduction resources. This assumption is conservative. In past

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[10] Small commercial impacts only. Excludes 143 Agricultural sites for which aggregate loads and impacts are negligible. Results for Agricultural sites are available in the accompanying Ex ante table generator.

implementations, less price responsive customers opted out of default CPP rates, leading to lower enrollment rates, but a limited effect on reduction capability.

3.4.4 COMPARISON OF EX POST AND EX ANTE LOAD IMPACTS

Table 3-7 compares the demand reductions from 2020 events to the reduction expected for the 1-in-2 weather conditions used for planning. Results are shown for both the 4 to 9 pm resource adequacy window. In PY 2020, small CPP customers delivered 5.23 MW during the dispatch period of 2 to 6 pm. The 4 to 9 pm ex post reductions are much lower, -0.46 MW, because CPP events can only be called from 2 to 6 pm. When similar hours are compared, ex ante resource estimates are somewhat higher than the ex post impacts. With such small impacts (on the order of 1%) such variability is to be expected.

Table 3-7: Small CPP Comparison of PY 2019 Ex Post and PY 2020 Ex Ante Load Impacts

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex Post Avg. Weekday	Event Period (2pm to 6pm)	108,138	302.35	5.23	1.7%	90.4
	Resource Adequacy Period (4 to 9pm)	108,138	239.44	-0.46	-0.2%	90.4
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	108,995	231.63	0.24	0.1%	88.6
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	108,995	238.05	0.26	0.1%	88.6

*Table shows portfolio impacts. To avoid double counting, it excluded commercial thermostats and customers dually enrolled in other DR programs. Also excludes 143 Agricultural sites for which aggregate loads and impacts are negligible.

4 COMMERCIAL THERMOSTAT EVENT DAY IMPACTS

Customers undergoing the transition to time varying rates were eligible for free Ecobee thermostats to help automated price response during critical peak periods. The thermostats can also help reduce electricity consumption when a business is unoccupied. The program was known as the Small Commercial Technology Deployment (SCTD) and has been in operation since 2014. However, prior to 2017, customers were not required to be on a CPP rate and, as a result, SCTD also included participants who are enrolled in TOU only rates with no dispatchable component. Thermostats are dispatched from 2-6 pm and Technology Deployment events historically coincided with CPP events, of which there were one in 2016 and three in 2017. In PY2020, nine CPP events were called, but they did not all fall on ACSDA event days.

In 2018, the program changed from a free thermostat to a rebate model and was broadened to include additional thermostat models. Figure 4-1 summarizes four the specific program designations for the PY 2019 evaluation. There are two programs (and accompanying rates) for customers on CPP-TOU rates: Peak Shift at Work (PSW) for Small non-residential customers and CPP-D for Medium and Large non-residential customers. Devices enrolled in these programs are dispatched during CPP events, of which there were none in PY 2019. For customers who are not on dispatchable rates, there are also two programs AC Saver Day Ahead (ACSDA) for non-residential customers and ACSDA for quasi-residential customers (who are on residential rates). ACSDA events are typically called from 6 to 8 pm. ACSDA thermostats can be dispatched at any time between 12 pm to 9 pm (on-peak hours) for a maximum of 4 consecutive hours and most events in 2019 were called from 6-8pm. For all four programs, devices are curtailed by raising the thermostat temperature set point 4 degrees during the event window.

Figure 4-1: Summary of TD Program Taxonomy

PY 2014-2017	PY 2018-2020
SCTD (2-6pm dispatch)	CPP-TD: tstats on dispatchable rates (PSW & CPP-D 2-6pm dispatch)
	ACSDA: tstats _not_ on dispatchable rates (Non & Quasi-res, typically 6-8pm dispatch)
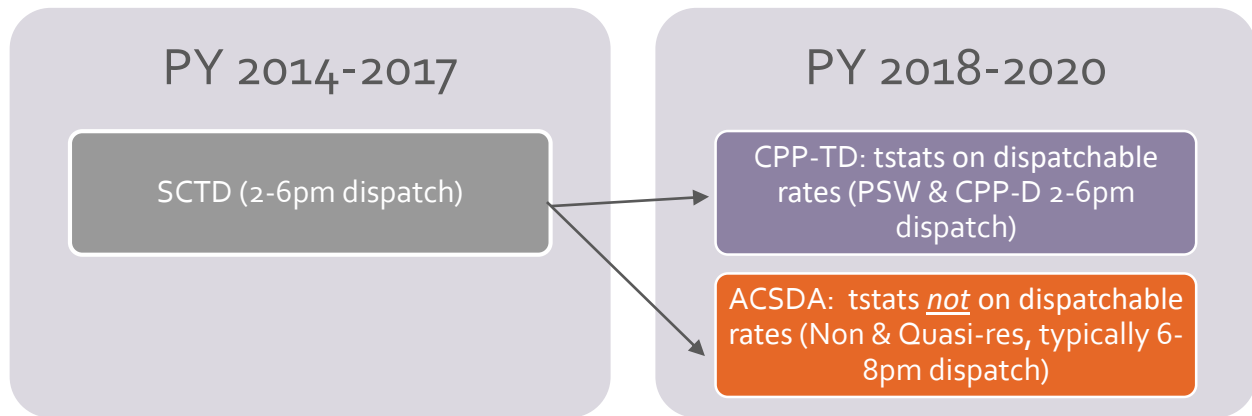
Table 4-1 shows the customer site counts and aggregate percent reduction for the previous three program years for each of the Commercial TD programs.

Table 4-1: Historical Program Overview

| Program | Count of Sites (Aggregate Percent Reductions) | | |
	2018	2019	2020
PSW	1,184 (7.5%)	No Events	773 (7.0%)
CPP-D	592 (5.9%)	No Events	431 (6.6%)
ACSDA Non-Residential	385 (4.2%)	355 (2.9%)	397 (3.0%)
ACSDA Quasi-Res	1,174 (2.2%)	1,097 (1.0%)	544 (1.5%)

There are over 18,000 devices installed at over 3,000 non-residential sites. Roughly 11,000 devices are installed at sites on dispatchable rates (small commercial on PSW and medium and large on CPP-D) and the remaining 7,000 are installed at non-residential and quasi-residential sites on non-dispatchable rates enrolled in AC Saver Day Ahead (ACSDA). As noted above, no events were called for sites on dispatchable rates (CPP-TD). Reductions for ACSDA sites, while statistically significant on average and consistently positive across events, were somewhat smaller than in PY 2018 (3% versus about 4%). These relatively low impact magnitudes remain can mostly be explained by the late ACSDA dispatch window (6 to 8pm for most events) and cooler weather (over half of ACSDA event were called on days with max temperatures below 86F).

Device connectivity is a key driver of realized load impacts because only connected thermostats can receive dispatch signals and deliver load reductions. As such connectivity has been closely monitored since PY 2018. In PY 2018 and PY 2019 roughly half of devices were not connected. However, much of this was due to the auto-enrollment of new accounts moving into a site with a previously enrolled thermostat. In practice the device is often no longer connected and simply ends up diluting results. In PY 2020 SDG&E discontinued the practice of auto-enrollment and removed inactive thermostats from

the dispatch portal. This has enabled separation of site attrition, primarily driven by move-outs, from thermostat connectivity. There is still a steady decline in connectivity over time and it is an important consideration for forecasting future impacts but it is smaller in magnitude after controlling for site attrition. Impacts continue to be derived at a per connected thermostat basis so they can be applied to enrollment forecasts reflecting numbers of connected devices in addition to enrolled sites. Future efforts to reconnect disconnected devices, particularly among programs or customer segments delivering greater reductions, could substantially increase future load reduction potential for the Technology Deployment programs.

4.1 TECHNOLOGY AND EVENT CHARACTERISTICS

The thermostats used as the enabling device receive a signal from SDG&E to curtail usage during events. For all PY2020 events, thermostats were controlled by raising the setpoint temperature by 4 degrees. This approach is intended to reduce energy usage by air conditioning units. However, to receive the curtailment signals, the devices must be connected to the internet and registered in the SDG&E dispatch portal. This is initially set up during the device installation process, but connectivity can be affected by internet reliability. Once connected, the device can receive and execute curtailment signals, and it can also communicate event notifications to users before the beginning of an event. Participating, connected devices were sent event notifications 24 hours prior to an event.

The PY2019 evaluation highlighted the issue of disconnected devices and the dampening effect this had on average "per-site" and "per-device" impacts. The failure rate described in the past incorporated two threads of failure-site attrition and thermostat failure. Site attrition occurs when a site, or customer, un-enrolls from a program or moves outside of the service territory. Thermostat failure occurs when a customer changes a setting that disconnects their thermostat from the internet. This could be caused by a change in the internet router, a new password, a new internet service provider or any other simple disconnection where the customer fails to reconnect their device.

For PY2020, site attrition and thermostat disconnections were disaggregated. In part, this helped distinguish between de-enrollments, presumably largely due to move-outs, and device disconnections which may possibly be remedied through participant outreach. This was important for modeling enrollment going forward since historically customers moving into an enrolled site were automatically enrolled in the program, but in practice the device was no longer connected or receiving dispatch signals. Functionally, this artificially lowered the observed thermostat survival rate because it was conflated with site move-outs. Just prior to the PY 2020 event season the practice of automatic enrollment at move-in was discontinued and roughly 2,000 sites were unenrolled that had previously been enrolled due to this practice.

Table 4-2 and Figure 4-2 show the failure rates and survival trends based on years since enrollment and years since installation, respectively. Note that thermostat survival only includes thermostats for enrolled sites. Essentially, the site survival trend reflects the rate at which sites remain enrolled over

time while the thermostat survival trend shows the rate over time at which thermostats at enrolled sites remain connected. Note that site attrition, which is a function of site move ins and move outs as well as intentional unenrollment varies more than thermostat disconnection rates which are a function of technology.

Table 4-2: Failure Rates by Cause

Program	Site Attrition			Tstat Disconnection		
	Expected	Lower bound	Upper bound	Expected	Lower bound	Upper bound
CPPTD	1.3%	1.0%	1.6%	3.5%	3.2%	3.9%
ACSDA	12.5%	11.1%	14.1%	1.8%	1.6%	2.1%

Figure 4-2: Survival Rates Over Time
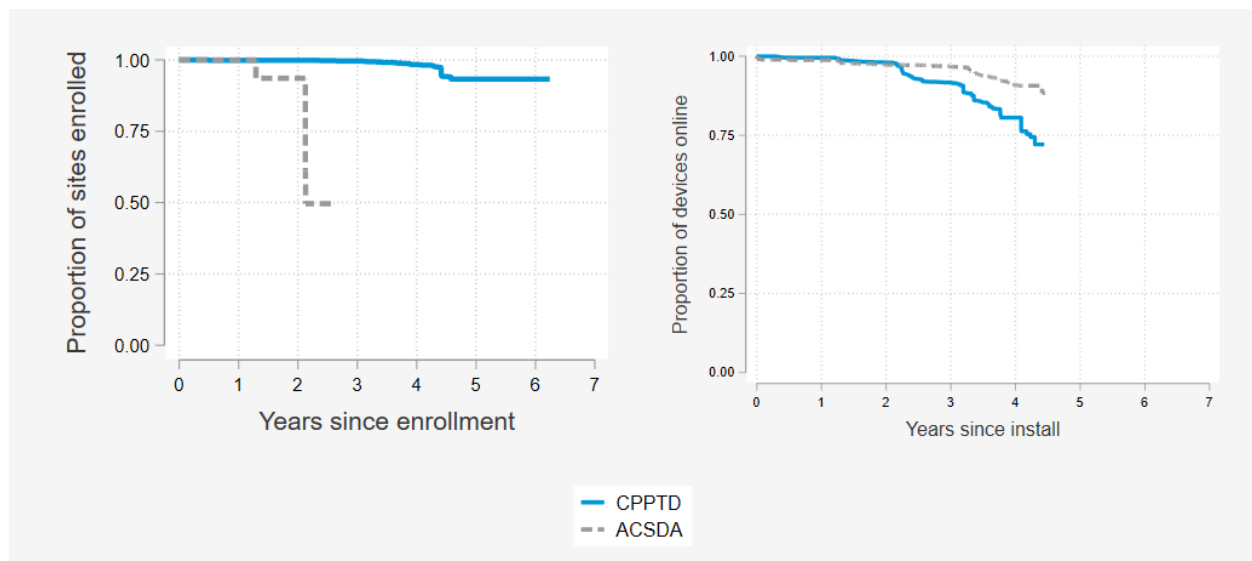
Table 4-3 shows program counts for enrolled sites, installed thermostats, and connected thermostats during the average PY 2020 weekday event. Commercial thermostat event impacts were assessed by site (premise and service point combination). After initial analysis confirmed that no perceptible, meaningful, or significant impacts were observed for sites with zero connected thermostats in 2020, the analysis was narrowed to focus on sites with at least one thermostat connected at any time during the event season. In PY 2020 SDG&E discontinued the practice of auto-enrollment. Thermostats which were inactive for more than two years and sites that had been auto-enrolled were removed from the dispatch portal: about 5,000 inactive thermostats and 1,100 inactive sites. This resulted in about one

third fewer total enrolled sites than in previous years but about the same number connected devices. Some sites with no registered thermostat are still enrolled but cannot receive dispatch signals. These sites were excluded from the ex ante enrollment forecast under the assumption that they will be removed from the enrollment list before PY 2021.

Sites were grouped together into segments to assess potential differences in impacts for various groups. The segmentation, summarized in Table 4-3, was developed based on rate size and on rate characteristics which may influence impacts. The analysis was performed at the segment level so these granular impacts could therefore be summed, yielding aggregate impacts in addition to the segment specific impacts.

The segmentation criteria were defined as follows:

- **Rate:** was the site on a rate with a CPP component during the study period?
- **Rate size**: what size (demand level for rate[11]) was the site classified as throughout the study period?
- **Climate zone:** in which SDG&E climate zone was the site located?

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[11] Small sites are on AS rates (such as ATOU and ASTODPSW) and have maximum demand below 20 kW—classification was assigned by rate. Medium and large sites are on AL rates or PA CP2 rates (such as ALTOU or PATODCP2). Medium sites were distinguished from Large sites by applying a maximum demand cutoff of 200 kW.

Table 4-3: Commercial Thermostat Programs and Populations

Program Rate	Size	Climate zone	Total sites	Total Connected sites	Connected sites in event analysis	Total installed devices	Total connected devices
CPPTD (PSW)	Small	Coastal	429	264	263	1,308	815
		Inland	344	200	199	921	478
CPPTD (CPP-D)	Large	Coastal	39	32	32	704	593
		Inland	24	20	20	554	501
	Medium	Coastal	215	136	135	2,539	1,543
		Inland	153	102	101	1,361	747
ACSDA (non-res)	Large	Coastal	23	19	19	441	382
		Inland	40	36	36	1,765	1,696
	Medium	Coastal	80	54	54	783	414
		Inland	88	64	63	963	617
	Small	Coastal	64	44	44	227	155
		Inland	102	71	71	383	249
ACSDA (quasi-res)	Quasi-res	Coastal	273	6	6	339	12
		Inland	271	18	18	328	19
TOTAL			**2,144**	**1,066**	**1,061**	**12,614**	**8,219**

Table 4-3 also summarizes the total number of sites in each segment and the final number of sites used for the ex post event analysis once data cleaning was completed[12]. As one might expect, smaller sites are more numerous but larger sites have more devices per site. Of particular note is the quasi-residential group, which includes only 24 connected devices among 544 sites. This represents about half the sites which were enrolled in PY2019, before inactive sites and thermostats were removed from the dispatch portal. About 500 of the remaining 544 do not have a registered thermostat and will likely be unenrolled before PY 2021. Analysis from PY 2017 demonstrated that loads for quasi-residential sites are highly correlated given that hundreds of sites are typically managed by a single customer and impacts were analyzed using a methodology tailored to this type of data. However, given the small number of connected devices and sites remaining in PY 2020, quasi-residential sites were analyzed using the same multiple matched control group methodology as all other sites.

Table 4-4 shows the nine PY 2020 CPP event days, including the maximum daily temperature weighted by participating commercial thermostat sites. These events occurred on various days of week in August

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[12] The cleaning algorithm ensured that complete data was available for the study period. Loads and impacts were scaled to address the five sites not in the analysis.

and September, with one late season event in October. The SDG&E system peak occurred on September 5th at 5:34 pm, 2020 and this coincided with a CPP event.

Table 4-5 shows the twenty PY 2020 ACSDA event days. Though there are some overlaps with CPP event days there are key notable differences. ACSDA events have been called more frequently than CPP events, are called during later dispatch windows (6 to 8pm for most events compared to 2 to 6pm for CPP events) and are called during cooler weather. The ACSDA season included three weekend events and one holiday event on Labor Day. The SDG&E system peak occurred on September 5th at 5:34 pm, 2020 and this coincided with an ACSDA event.

Table 4-4: Commercial Thermostat CPPTD Events in 2020

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
8/17/2020	Monday	2:00 PM	6:00 PM	87.7	3,830
8/18/2020	Tuesday	2:00 PM	6:00 PM	91.9	4,028
8/19/2020	Wednesday	2:00 PM	6:00 PM	86.7	3,911
8/20/2020	Thursday	2:00 PM	6:00 PM	88.8	3,861
9/5/2020	Saturday	2:00 PM	6:00 PM	97.7	4,608
9/6/2020	Sunday	2:00 PM	6:00 PM	103.1	4,351
9/7/2020	Monday	2:00 PM	6:00 PM	80.8	3,318
9/30/2020	Wednesday	2:00 PM	6:00 PM	95.8	4,573
10/1/2020	Thursday	2:00 PM	6:00 PM	97.5	4,308

Table 4-5: Commercial Thermostat ACSDA Events in 2020

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
6/10/2020	Wednesday	6:00 PM	8:00 PM	93.1	3,275
6/22/2020	Monday	7:00 PM	9:00 PM	76.7	2,599
7/9/2020	Thursday	6:00 PM	8:00 PM	80.2	2,830
7/10/2020	Friday	6:00 PM	8:00 PM	86.8	3,260
7/11/2020	Saturday	6:00 PM	8:00 PM	90.1	3,339
7/13/2020	Monday	6:00 PM	8:00 PM	84.5	3,286
7/14/2020	Tuesday	6:00 PM	8:00 PM	80.0	2,912
7/29/2020	Wednesday	6:00 PM	8:00 PM	79.5	2,830
7/30/2020	Thursday	6:00 PM	9:00 PM	82.4	3,229
7/31/2020	Friday	5:00 PM	8:00 PM	87.7	3,465
8/3/2020	Monday	6:00 PM	8:00 PM	81.3	3,023

Event day	Day of week	Event start	Event end	Max daily temp (F)	SDG&E system load (MW)
8/14/2020	Friday	5:00 PM	9:00 PM	93.7	3,843
8/17/2020	Monday	5:00 PM	8:00 PM	90.9	3,830
8/18/2020	Tuesday	4:00 PM	8:00 PM	95.7	4,028
8/19/2020	Wednesday	6:00 PM	8:00 PM	89.9	3,911
8/21/2020	Friday	6:00 PM	8:00 PM	91.8	3,967
8/27/2020	Thursday	6:00 PM	8:00 PM	88.8	3,828
9/5/2020	Saturday	5:00 PM	8:00 PM	100.6	4,608
9/6/2020	Sunday	5:00 PM	8:00 PM	104.9	4,351
9/7/2020	Monday	5:00 PM	8:00 PM	83.4	3,318

4.2 DATA SOURCES AND ANALYSIS METHOD

Table 4-6 summarizes the five data sources used to conduct the commercial thermostat event impact analysis. The analysis was done by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report (rate versus technology based, event and non-event), the characteristic definitions used to build segments were consistent across analyses.

Table 4-6: Commercial Thermostat Event Impact Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2020 ▪ All analysis done by site (premise id-service point id pair)
Outage information	▪ PSPS and SDG&E emergency outage data details which customers and what timeframes were impacted by outages ▪ Outage days which affected participants or control sites were excluded from the analysis
Customer characteristics	▪ Treatment: All non-residential (Commercial and Agricultural) commercial thermostat participants, including quasi-residential sites ▪ Control: All non-residential sites not on CPP or other DR programs ▪ Industry, zip codes, climate zones used in matching model selection
Thermostat installation data	▪ Installation and last connected dates

Source	Comments
SDG&E hourly system loads	▪ Summer 2020 ▪ Used to identify non-event high system load days
Ex post weather data by weather station	▪ Used to derive cooling degree hours for impact evaluation panel model

The primary analysis method was a panel regression with a multiple matched control groups. The distance matching approach used selected five matched control sites for each of the non-residential ACSDA sites among a matched control candidate pool of roughly 11,000 TOU sites. These customers were not enrolled in CPP or other DR programs which might influence energy use. The panel regression model was then used to assess impacts and standard errors for each event and each study segment.

To identify which model best predicted customer loads absent demand reductions, an out of sample approach was still used to select the model specification. The model selection relied on testing how well each model estimated loads for event-like non-event days out-of-sample. Because there was, in fact, no event, it was possible to assess how close model estimates were to the correct answer and the most accurate model. A total of 60 models were tested to select the number of proxy days, number of matched controls, and structure of same day adjustments to use. The regression model structure is detailed in Appendix A. The model selection process and results are covered more in depth in section 2.3.

4.3 EX POST LOAD IMPACTS

4.3.1 PEAK SHIFT AT WORK: SMALL NON-RESIDENTIAL CPP WITH TECHNOLOGY

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. During summer 2020 and spanning all 2020 events, COVID considerations influenced commercial operations and energy consumption. During the average event for the non-residential CPP-TD programs (PSW and CPP-D with thermostats), the average whole building load was 10% lower per thermostat and average cooling load per thermostat was 10% lower in 2020 than in 2018 (the last year where events were called), despite the average 2020 event being called during similar temperature conditions. Because reduction potential for a thermostat program such as CPP-TD is a function of cooling load, the decrease in reference loads suggests that the effect of COVID on participant energy usage reduced the potential for reductions during 2020. However, there are limitations to the differences that can be identified by comparing ex post loads across years given multiple changing variables such as weather and participant population. Most notably, the population of customers and thermostats changed meaningfully during these two seasons due to the removal of disconnected sites and thermostats. Further, the effect of COVID on loads may be different by program, customer size, and more granular study segment. But given the population size, population variability and weather variability, it is necessary to control for

these external factors to isolate the effect of COVID on loads. This is the approach taken for quantifying and incorporating the effect of COVID on ex ante reference loads. This process is further described in Section 4.4.2.

Table 4-7 summarizes the load reductions for all PSW sites for the nine events and 2 pm to 6 pm reductions for the average weekday and weekend events. In aggregate, the weekday events delivered 0.27 MW of load reduction across all 773 enrolled sites and the average weekday reduction per site was 0.59 kW. Though 2,229 devices were installed at enrolled sites, only 1,292 devices on average were connected during the PY 2020 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 0.21 kW. Reductions were strongly significant on average (t value=33.52) and for each event (t value≥3.91). Reductions were higher and more significant during the weekday events than the weekend events. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-7: PSW Program Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction			t-stat	Significant (90% CI)
						Aggregate (MW)	Average Site (kw)	Average Connected Tstat (kw)		
8/17/2020	2 to 6 pm	85.8	773	2,219	1,307	0.27	0.58	0.20	14.62	Yes
8/18/2020	2 to 6 pm	83.9	773	2,219	1,307	0.30	0.64	0.23	16.01	Yes
8/19/2020	2 to 6 pm	85.1	773	2,219	1,306	0.30	0.65	0.23	17.98	Yes
8/20/2020	2 to 6 pm	82.7	773	2,219	1,304	0.25	0.54	0.19	15.18	Yes
9/30/2020	2 to 6 pm	93.5	774	2,261	1,267	0.29	0.62	0.23	13.23	Yes
10/1/2020	2 to 6 pm	91.9	771	2,239	1,263	0.23	0.49	0.19	12.37	Yes
Avg Weekday Event	2 to 6 pm	87.1	773	2,229	1,292	0.27	0.59	0.21	33.52	Yes
9/5/2020	2 to 6 pm	95.0	774	2,259	1,272	0.12	0.25	0.09	6.43	Yes
9/6/2020	2 to 6 pm	97.9	774	2,259	1,272	0.14	0.31	0.11	5.47	Yes
9/7/2020	2 to 6 pm	78.2	774	2,259	1,272	0.08	0.17	0.06	3.91	Yes
Avg Weekend Event	2 to 6 pm	90.4	774	2,259	1,272	0.11	0.24	0.09	10.92	Yes

Reductions were also analyzed within climate zone segment. Table 4-8 details the reference loads and load reductions overall and by segment for the average 2 pm to 6 pm event window. In addition to aggregate reductions, average reductions per connected thermostat are also shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 7.0% of whole building was curtailed during the average event, while 25% of cooling load was curtailed per connected device.

In aggregate, about 59% of connected devices were in the Coastal zone and these devices delivered about 55% of the 3.88 MW of reductions for the PSW program. Devices in the Inland zone, where event temperatures were also higher, delivered more per connected device largely because there was more AC load available for curtailment. In hotter environments, AC units must run more often to maintain a comfortable set point, meaning more runtime and load can be avoided by raising the set point than in the face of cooler outdoor temperatures where the AC is already running less often.

Table 4-8: PSW Program Average Event Reductions by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			t-stat
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	
Small	Coastal	2 to 6 pm	85.3	429	1,308	815	2.14	0.16	7.4%	0.65	0.20	30%	25.50
	Inland	2 to 6 pm	89.6	344	921	478	1.75	0.11	6.5%	1.10	0.24	22%	21.43
All	All	2 to 6 pm	87.1	773	2,229	1,292	3.88	0.27	7.0%	0.85	0.21	25%	33.52

The average event day load shape is summarized in greater detail in Figure 4-3. Note that the figure, extracted from the Ex Post Load Impact Table, is for the CPPTD (PSW) participant population. The left panel shows the aggregate hourly MW loads (actual and counterfactual) for these sites. The right panel shows kW impacts per connected thermostat as a function of cooling load. The tables accompanying each figure show impacts for the 2 pm to 6 pm event window. Load impacts were evident for the average event window with a 7.0% aggregate reduction and a 24.9% cooling load reduction per connected thermostat.

Figure 4-3: CPPTD Peak Shift at Work: Summary for Average Event

Aggregate (MW)

Table 1: Menu options

Program	CPPTD (PSW)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	2:00 PM
Event end	6:00 PM
Total sites	773
Total installed thermostats	2,229
Total connected thermostats	1,292
Percent of thermostats connected	58%
Avg load reduction 2PM-6PM	0.27
% Load reduction 2PM-6PM	7.0%

Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	CPPTD (PSW)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	2:00 PM
Event end	6:00 PM
Total sites	773
Total installed thermostats	2,229
Total connected thermostats	1,292
Percent of thermostats connected	58%
Avg load reduction 2PM-6PM	0.21
% Load reduction 2PM-6PM	24.9%
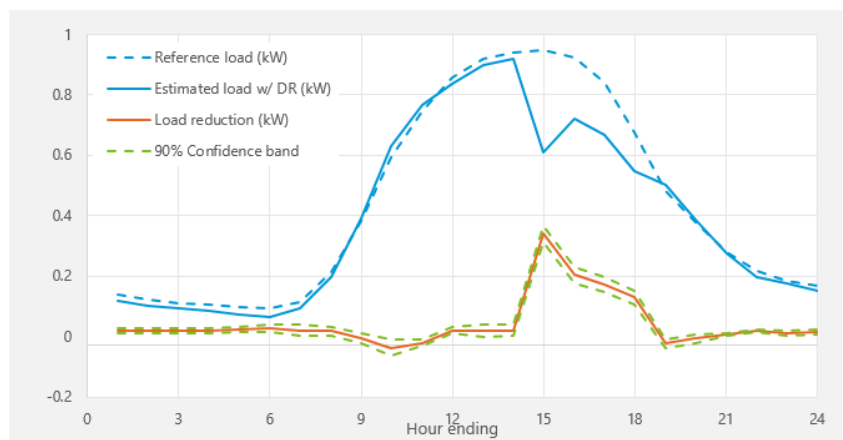
4.3.2 CPP-D: MEDIUM & LARGE NON-RESIDENTIAL CPP WITH TECHNOLOGY

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. During summer 2020 and spanning all 2020 events, COVID considerations influenced commercial operations and energy consumption. During the average event for the non-residential CPP-TD programs (PSW and CPP-D with thermostats), the average whole building load was 10% lower per thermostat and average cooling load per thermostat was 10% lower in 2020 than in 2018 (the last year where events were called), despite the average 2020 event being called during similar temperature conditions. Because reduction potential for a thermostat program such as CPP-TD is a function of cooling load, the decrease in reference loads suggests that the effect of COVID on participant energy usage reduced the potential for reductions during 2020. However, there are limitations to the differences that can be identified by comparing ex post loads across years given multiple changing variables such as weather and participant population. Most notably, the population of customers and thermostats changed meaningfully during these two seasons due to the removal of disconnected sites and thermostats. Further, the effect of COVID on loads may be different by program, customer size, and more granular study segment. But given the population size, population variability and weather variability, it is necessary to control for these external factors to isolate the effect of COVID on loads. This is the approach taken for quantifying and incorporating the effect of COVID on ex ante reference loads. This process is further described in Section 4.4.2.

Table 4-9 summarizes the load reductions for the Medium and Large Non-Residential sites on the CPP-D rate with thermostats for the nine events and 2 pm to 6 pm reductions for the average weekday and weekend events. The average weekday event aggregate load reduction was 1.27 MW across the 431 sites. The average reduction per site was 4.37 kW. Though 5,157 devices were installed at enrolled sites, only 3,384 devices on average were connected during the PY 2020 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 0.37 kW. Reductions were strongly significant on average (t value=38.58) and for most events (t value≥2.98). Reductions were much higher and more significant for the weekday events. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-9: CPP-D With Thermostat Ex Post Load Impacts

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction Aggregate (MW)		Reduction Average Site (kw)		Reduction Average Connected Tstat (kw)		t-stat	Significant (90% CI)
8/17/2020	2 to 6 pm	85.6	450	5,351	3,525	1.65		5.54		0.47		20.16	Yes
8/18/2020	2 to 6 pm	84.0	450	5,351	3,525	1.32		4.43		0.37		17.94	Yes
8/19/2020	2 to 6 pm	85.1	450	5,351	3,525	1.40		4.70		0.40		20.34	Yes
8/20/2020	2 to 6 pm	83.0	450	5,351	3,525	1.19		3.99		0.34		15.91	Yes
9/30/2020	2 to 6 pm	93.0	396	4,859	3,179	1.06		3.84		0.33		12.30	Yes
10/1/2020	2 to 6 pm	91.3	388	4,681	3,025	0.99		3.69		0.33		12.85	Yes
Avg Weekday Event	2 to 6 pm	87.0	431	5,157	3,384	1.27		4.37		0.37		38.58	Yes
9/5/2020	2 to 6 pm	94.4	396	4,859	3,198	0.75		2.72		0.23		7.76	Yes
9/6/2020	2 to 6 pm	97.7	396	4,859	3,197	0.28		1.03		0.09		2.98	Yes
9/7/2020	2 to 6 pm	78.0	396	4,859	3,197	0.68		2.47		0.21		5.62	Yes
Avg Weekend Event	2 to 6 pm	90.0	396	4,859	3,197	0.57		2.08		0.18		10.49	Yes

Reductions were also analyzed within climate zone segment. Table 4-10 details the reference loads and load reductions overall and by segment for the average weekday 2 pm to 6 pm event window. In addition to aggregate reductions, average reductions per connected thermostat are also shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 6.6% of whole building was curtailed during the average event, while 24% of cooling load was curtailed per connected device.

In aggregate, about 15% of connected devices were installed at large customer sites and these devices delivered about 47% of the 1.27 MW of reductions for the CPP-D program. Medium customers in the coastal zone make up the majority of the sites and connected devices in the CPP-D program. However, medium customers save the same average connected percent reduction despite the climate zone— 24%. This percent reduction varies more for large customers based on climate zone, with Coastal customers reducing 13% of average connected cooling load and Inland customers saving 40%. This difference is attributed to the large difference in reference load for the large Coastal customers.

Table 4-10: CPP-D with Thermostat Program Average Event Ex Post Load Impacts by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	t-stat
Large	Coastal	2 to 6 pm	84.9	39	704	593	6.24	0.20	3.2%	2.62	0.34	13%	12.45
	Inland	2 to 6 pm	91.6	24	554	501	2.68	0.24	8.8%	1.16	0.47	40%	16.84
Medium	Coastal	2 to 6 pm	84.5	215	2,539	1,543	6.39	0.49	7.7%	1.34	0.32	24%	26.60
	Inland	2 to 6 pm	90.2	153	1,361	747	3.83	0.31	8.0%	1.71	0.41	24%	24.66
All	All	2 to 6 pm	87.0	431	5,157	3,384	19.12	1.27	6.6%	1.57	0.37	24%	38.58

The average event day load shape is summarized in greater detail in Figure 4-4. Note that the figure, extracted from the Ex Post Load Impact Table, is for the CPP-D participant population. The left panel shows the aggregate hourly loads (actual and counterfactual) for these sites. The right panel shows impacts per connected thermostat as a function of cooling load. The tables accompanying each figure show impacts for the 2 pm to 6 pm event window. Load impacts were evident for the average weekday event window with a 6.6% aggregate reduction and a 23.8% cooling load reduction per connected thermostat.

Figure 4-4: CPP-D Summary for Average Event

Aggregate (MW)

Table 1: Menu options

Program	CPPTD (CPP-D)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	2:00 PM
Event end	6:00 PM
Total sites	431
Total installed thermostats	5,157
Total connected thermostats	3,384
Percent of thermostats connected	66%
Avg load reduction 2PM-6PM	1.27
% Load reduction 2PM-6PM	6.6%

Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	CPPTD (CPP-D)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	2:00 PM
Event end	6:00 PM
Total sites	431
Total installed thermostats	5,157
Total connected thermostats	3,384
Percent of thermostats connected	66%
Avg load reduction 2PM-6PM	0.37
% Load reduction 2PM-6PM	23.8%
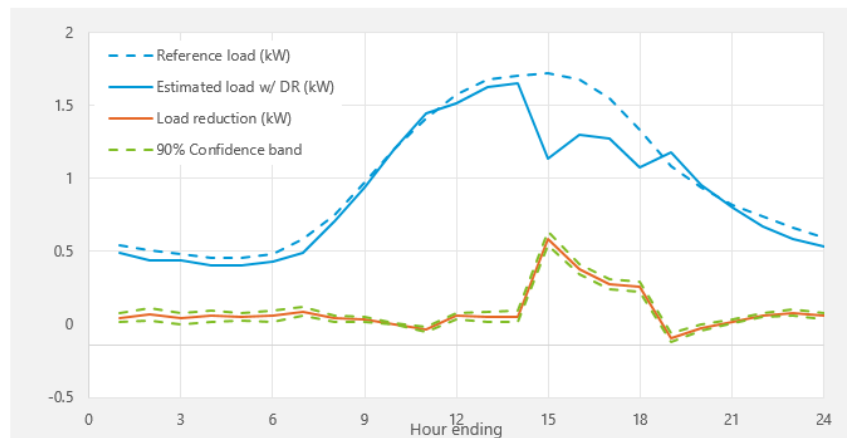
4.3.3   AC SAVER DAY AHEAD: NON-RESIDENTIAL WITH TECHNOLOGY

The AC Saver program called 20 events during PY 2020. The ACSDA events were typically called from 6 to 8 pm, though ten events were called during slightly different windows or on a weekend or holiday. The standard events are used to create the Average Event impacts. Load reductions were significant for most individual events. The average weekday event window was significant with an average aggregate reduction of 0.42 MW and the average weekend event window was significant with an average aggregate reduction of 0.48 MW.

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. During summer 2020 and spanning all 2020 events, COVID considerations influenced commercial operations and energy consumption. During the average event for the non-residential ACSDA programs (non-residential and quasi-residential), the average whole building load was 10% lower per thermostat and average cooling load per thermostat was 2% lower in 2020 than in 2019, despite the average 2020 event being warmer by about 1-degree F. Because reduction potential for a thermostat program such as ACSDA is a function of cooling load, the decrease in reference loads suggests that the effect of COVID on participant energy usage reduced the potential for reductions during 2020. However, there are limitations to the differences that can be identified by comparing ex post loads across years given multiple changing variables such as weather and participant population. Most notably, the population of customers and thermostats changed meaningfully during these two seasons due to the removal of disconnected sites and thermostats. Further, the effect of COVID on loads may be different by program, customer size, and more granular study segment. But given the population size, population variability and weather variability, it is necessary to control for these external factors to isolate the effect of COVID on loads. This is the approach taken for quantifying and incorporating the effect of COVID on ex ante reference loads. This process is further described in Section 4.4.2.

Table 4-11 and Table 4-12 summarize the load reductions for all Non-Residential ACSDA sites for the 20 events, 6 pm to 8 pm reductions for the average weekday event and 5 pm to 8 pm reductions for the average weekend event. The full event hours for the seven non-standard event days are provided at the bottom of Table 4-11. None of these are included in the calculations for the average event. The average aggregate load reduction for the average weekday event was 0.42 MW across all 397 enrolled sites and the average reduction per site was 1.47 kW. Though 4,561 devices were installed at enrolled sites, only 3,512 devices on average were connected during the PY 2020 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 0.12 kW.

Of the 20 events in PY 2020, 17 events produced reductions significant at the 90% level. Aggregate reductions for significant events range from 0.28 MW (August 19 and July 30) to 0.98 MW (August 21). These dates, respectively, also exhibited the highest and lowest average site reductions and average

connected thermostat reductions of the significant events. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-11: ACSDA Non-Residential Program Weekday Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction Aggregate (MW)	Reduction Average Site (kw)	Reduction Average Connected Tstat (kw)	t-stat	Significant (90% CI)
6/10/2020	6 to 8 pm	79.5	389	4,425	3,420	0.31	1.08	0.09	2.86	Yes
7/9/2020	6 to 8 pm	72.1	395	4,519	3,488	0.30	1.05	0.09	3.04	Yes
7/10/2020	6 to 8 pm	77.5	395	4,519	3,488	0.48	1.67	0.14	2.95	Yes
7/13/2020	6 to 8 pm	73.4	395	4,519	3,488	0.74	2.58	0.21	6.55	Yes
7/14/2020	6 to 8 pm	70.7	395	4,519	3,488	0.40	1.38	0.11	3.33	Yes
7/29/2020	6 to 8 pm	70.8	395	4,519	3,488	-0.05	-0.18	-0.02	0.00	No
8/3/2020	6 to 8 pm	72.5	401	4,553	3,507	0.31	1.08	0.09	3.62	Yes
8/19/2020	6 to 8 pm	78.2	401	4,680	3,585	0.28	0.97	0.08	2.27	Yes
8/21/2020	6 to 8 pm	81.0	401	4,680	3,583	0.98	3.35	0.27	7.22	Yes
8/27/2020	6 to 8 pm	77.2	401	4,680	3,583	0.48	1.66	0.13	5.25	Yes
Avg Weekday Event	**6 to 8 pm**	**75.3**	**397**	**4,561**	**3,512**	**0.42**	**1.47**	**0.12**	**10.00**	**Yes**
6/22/2020	7 to 9 pm	66.4	389	4,425	3,420	0.30	1.06	0.09	5.18	Yes
7/30/2020	6 to 9 pm	73.9	395	4,519	3,488	0.28	0.98	0.08	4.71	Yes
7/31/2020	5 to 8 pm	78.5	395	4,519	3,488	0.39	1.37	0.11	1.62	No
8/14/2020	5 to 9 pm	83.1	401	4,680	3,599	0.97	3.32	0.27	7.69	Yes
8/17/2020	5 to 8 pm	80.6	401	4,680	3,599	0.33	1.14	0.09	3.49	Yes
8/18/2020	4 to 8 pm	82.3	401	4,680	3,585	0.72	2.46	0.20	8.74	Yes

Table 4-12: ACSDA Non-Residential Program Weekend Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction Aggregate (MW)	Reduction Average Site (kw)	Reduction Average Connected Tstat (kw)	t-stat	Significant (90% CI)
7/11/2020	6 to 8 pm	80.6	395	4,519	3,488	0.81	2.82	0.23	6.21	Yes
9/5/2020	5 to 8 pm	89.0	439	5,022	3,557	0.21	0.71	0.06	0.74	No
9/6/2020	5 to 8 pm	87.2	439	5,022	3,557	0.59	1.95	0.17	4.16	Yes
9/7/2020	5 to 8 pm	73.9	439	5,022	3,556	0.65	2.13	0.18	5.66	Yes
Avg Weekend Event	**5 to 8 pm**	**83.4**	**439**	**5,022**	**3,557**	**0.48**	**1.59**	**0.14**	**5.31**	**Yes**

Reductions were also analyzed within climate zone for Small, Medium, and Large customers in the ACSDA program. Table 4-13 details the reference loads and load reductions overall and by size-climate zone segment for the average weekday and weekend events. In addition to aggregate reductions,

average reductions per connected thermostat are also shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 3.0% of whole building load was curtailed during the average event, while 19% of cooling load was curtailed per connected device.

In aggregate, about 27% of connected devices were in the coastal zone and these devices delivered 0.16 MW of the 0.42 MW—about one third—of reductions for the ACSDA Non-Residential program. Large customers exhibited the largest reference loads in aggregate and per connected thermostat for their respective climate zones. Significant load reductions were found customers in all sizes except for small coastal customers.

Table 4-13: ACSDA Non-Residential Program Average Weekday Event Reductions by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	t-stat
Large	Coastal	6 to 8 pm	72.8	23	441	382	2.78	0.08	2.8%	1.67	0.20	12%	5.08
	Inland	6 to 8 pm	76.2	40	1,765	1,696	7.58	0.15	2.0%	0.67	0.09	14%	4.90
Medium	Coastal	6 to 8 pm	73.6	80	783	414	1.53	0.08	5.4%	1.17	0.20	17%	9.66
	Inland	6 to 8 pm	76.8	88	963	617	1.67	0.08	5.0%	0.37	0.13	36%	10.35
Small	Coastal	6 to 8 pm	73.3	64	227	155	0.21	0.00	0.2%	0.23	0.00	1%	0.23
	Inland	6 to 8 pm	76.7	102	383	249	0.50	0.03	5.3%	0.62	0.11	17%	6.23
All	All	6 to 8 pm	75.3	397	4,561	3,512	14.27	0.42	3.0%	0.63	0.12	19%	10.00

The average event day load shape is summarized in greater detail in Figure 4-5. Note that the figure, extracted from the Ex Post Load Impact Table, is for the ACSDA non-residential participant population for the average event day. The average event day reflects weekday events that ranged from 6 to 8 pm The left panel shows the aggregate hourly MW loads (actual and counterfactual) for these sites. The right panel shows impacts per connected thermostat as a function of cooling load. Note that the cooling loads (kW per connected device, in the right panel) were estimated by isolating weather sensitive load from whole building load then divided by devices per site to yield cooling load per site. As expected, cooling load are more concentrated during the day when cooling loads tend to be a higher. The tables accompanying each figure show aggregate impacts for the 6 pm to 8 pm event window. Load reductions are statistically significant and similar on a percentage basis (3.0%) as in PY 2019 (2.9%). Though aggregate load reductions are 3.0%, reductions are 19% of cooling load per connected thermostat. This 19% reduction translates to 0.12 kW per connected thermostat, which is slightly lower than the connected thermostat reduction of PY 2019 (0.18 kW).

Figure 4-5: ACSDA Non-Residential Summary for Average Event

Aggregate (MW)

Table 1: Menu options

Program	ACSDA (non-res)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	6:00 PM
Event end	8:00 PM
Total sites	397
Total installed thermostats	4,561
Total connected thermostats	3,512
Percent of thermostats connected	77%
Avg load reduction 6PM-8PM	0.42
% Load reduction 6PM-8PM	3.0%

Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	ACSDA (non-res)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

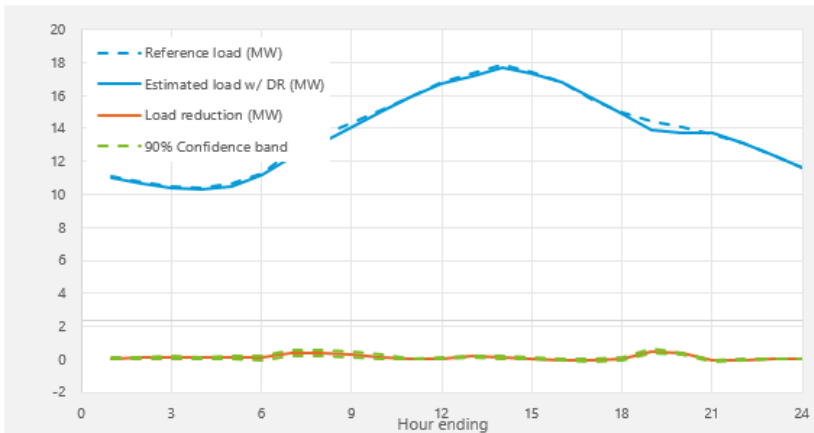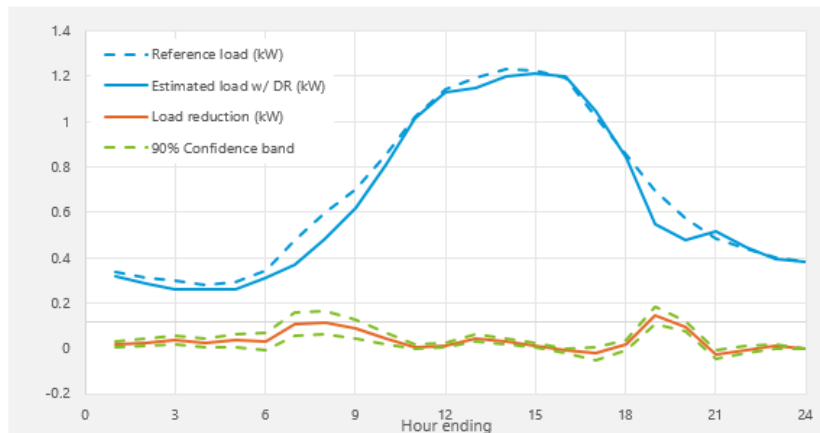| Event start	6:00 PM
Event end	8:00 PM
Total sites	397
Total installed thermostats	4,561
Total connected thermostats	3,512
Percent of thermostats connected	77%
Avg load reduction 6PM-8PM	0.12
% Load reduction 6PM-8PM	19.0%

4.3.4 AC Saver Day Ahead: Quasi-Residential with Technology

Twenty events were called for the AC Saver Day Ahead program during PY 2020. Like with enrolled non-residential sites, reductions were found to be statistically significant for quasi-residential enrolled sites. However, the number of connected sites and the loads per site are so small that average weekday aggregate load reductions were just 0.01 MW. Only 31 thermostats were connected during PY 2020, making it difficult to detect any reductions. Greater impacts may be achieved by calling events earlier in the day or on hotter days and by reconnecting disconnected devices. Any observations regarding loads and impacts should be considered in the context of the small sample size enrolled in this program.

In addition, clusters of dozens or even hundreds of quasi-res sites are often managed by a single customer, reflecting the fact that quasi-residential customers are often property management companies. Based on observation, loads tend to be relatively correlated across sites managed by the same customer which further presents a challenge for detecting load reductions. However, most of the disconnected devices were managed by a single customer and were disconnected on or around the same date in 2017.

Load reductions are a function of the reference load. When there is lower load, specifically lower cooling load, demand response programs have less opportunity for reduction. During summer 2020 and spanning all 2020 events, COVID considerations influenced commercial operations and energy consumption. During the average event for the non-residential ACSDA programs (non-residential and quasi-residential), the average whole building load was 10% lower per thermostat and average cooling load per thermostat was 2% lower in 2020 than in 2019, despite the average 2020 event being warmer by about 1-degree F. Because reduction potential for a thermostat program such as ACSDA is a function of cooling load, the decrease in reference loads suggests that the effect of COVID on participant energy usage reduced the potential for reductions during 2020. However, there are limitations to the differences that can be identified by comparing ex post loads across years given multiple changing variables such as weather and participant population. Most notably, the population of customers and thermostats changed meaningfully during these two seasons due to the removal of disconnected sites and thermostats. Further, the effect of COVID on loads may be different by program, customer size, and more granular study segment. But given the population size, population variability and weather variability, it is necessary to control for these external factors to isolate the effect of COVID on loads. This is the approach taken for quantifying and incorporating the effect of COVID on ex ante reference loads. This process is further described in Section 4.4.2.

Table 4-14 and Table 4-15 summarize the load reductions for all ACSDA Quasi-Residential sites for each of the 20 events and for the average events for weekdays and weekends, respectively. As described in the non-residential ACSDA section, four events occurred on weekends (or holidays) and six events occurred during a different window than the average event window. The non-standard event windows are presented below the average weekday event in Table 4-14, and the weekend events are presented

chronologically in Table 4-15. Only weekday events called during the standard 6 pm to 8 pm window are included in the average weekday event results. And the average weekend event includes September 5th through September 7th. The fourth weekend event occurred during a different window and is not considered for the "average weekend event" calculation. The average weekday aggregate load reduction was 0.01 MW across all 544 enrolled sites and the average reduction per site was 0.57 kW and this was significant at the 90% confidence level (t-value = 10.62). Of 667 devices installed at enrolled sites, only 31 devices on average were connected during the PY 2020 event season. Because only connected devices can be dispatched, all reductions are delivered by these connected devices. The average reduction per connected device was 0.44 kW.

Most events were statistically significant at the 90% significance level. Reductions were very small in magnitude on average, due to the limited number of connected devices. In the tables, the orange bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Table 4-14: ACSDA Quasi-Residential Program Weekday Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction Aggregate (MW)	Reduction Average Site (kw)	Reduction Average Connected Tstat (kw)	t-stat	Significant (90% CI)
6/10/2020	6 to 8 pm	77.3	544	667	31	0.01	0.38	0.30	3.09	Yes
7/9/2020	6 to 8 pm	72.9	544	667	31	0.01	0.51	0.40	2.35	Yes
7/10/2020	6 to 8 pm	80.5	544	667	31	0.02	0.87	0.67	4.47	Yes
7/13/2020	6 to 8 pm	75.4	544	667	31	0.01	0.45	0.35	1.23	No
7/14/2020	6 to 8 pm	71.1	544	667	31	0.02	0.65	0.50	3.24	Yes
7/29/2020	6 to 8 pm	74.9	544	667	31	0.01	0.59	0.46	5.49	Yes
8/3/2020	6 to 8 pm	75.8	544	667	31	0.02	0.66	0.51	4.24	Yes
8/19/2020	6 to 8 pm	80.5	544	667	31	0.01	0.61	0.48	4.12	Yes
8/21/2020	6 to 8 pm	83.1	544	667	31	0.01	0.30	0.23	1.55	No
8/27/2020	6 to 8 pm	79.5	544	667	31	0.02	0.65	0.50	4.16	Yes
Avg Weekday Event	**6 to 8 pm**	**77.1**	**544**	**667**	**31**	**0.01**	**0.57**	**0.44**	**10.62**	**Yes**
6/22/2020	7 to 9 pm	66.1	544	667	31	0.00	0.19	0.15	3.77	Yes
7/30/2020	6 to 9 pm	77.4	544	667	31	0.02	0.94	0.73	7.29	Yes
7/31/2020	5 to 8 pm	84.9	544	667	31	0.03	1.07	0.83	7.45	Yes
8/14/2020	5 to 9 pm	83.0	544	667	31	0.03	1.06	0.82	8.26	Yes
8/17/2020	5 to 8 pm	83.6	544	667	31	0.01	0.51	0.39	4.50	Yes
8/18/2020	4 to 8 pm	85.2	544	667	31	0.01	0.56	0.43	6.44	Yes

Table 4-15: ACSDA Quasi-Residential Program Weekend Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Reduction Aggregate (MW)	Reduction Average Site (kw)	Reduction Average Connected Tstat (kw)	t-stat	Significant (90% CI)
7/11/2020	6 to 8 pm	81.4	544	667	31	0.01	0.50	0.38	1.54	Yes
9/5/2020	5 to 8 pm	90.1	544	667	28	0.01	0.27	0.23	1.94	Yes
9/6/2020	5 to 8 pm	89.8	544	667	28	0.00	0.15	0.13	0.20	No
9/7/2020	5 to 8 pm	74.6	544	667	28	0.02	0.70	0.60	3.10	Yes
Avg Weekend Event	**5 to 8 pm**	**84.8**	**544**	**667**	**28**	**0.01**	**0.37**	**0.32**	**3.40**	**Yes**

Quasi-Residential reductions were also analyzed by climate zone segment. Table 4-16 details the reference loads and load reductions overall and by segment for the average 6 pm to 8 pm weekday event window. In addition to aggregate reductions, average reductions per connected thermostat are shown. Note that the reference load for aggregate impacts includes the whole building load across all enrolled sites as recorded at the meter; the reference load for the average connected thermostat is the cooling load per connected thermostat, estimated by isolating the weather sensitive portion of whole building load. In aggregate, 1.5% of whole building was curtailed during the average event, while 26%

of cooling load was curtailed per connected device. While devices are split approximately evenly between the two zones, enrolled sites and reductions vary greatly. The coastal region has 12 connected thermostats, but exhibits 3.8% aggregate reduction and roughly 60% reduction in cooling load for the average connected device. There are fewer enrolled sites in the inland climate zone, but slightly more connected thermostats in this region with 19 connected devices. Estimated savings were negative, but insignificant for the Inland climate zone. Due to the small sample size, load reduction results for ACSDA quasi-residential sites should be viewed with caution.

Table 4-16: ACSDA Quasi-Residential Program Average Event Reductions by Segment

Size	Climate zone	Event Window	Avg Event Temp (F)	Sites Enrolled	Installed Devices	Connect-ed Devices	Aggregate (MW)			Average connected tstat (kW)			
							Ref load (whole bldg)	Reduc-tion	% Reduc-tion	Ref load (cooling)	Reduc-tion	% Reduc-tion	t-stat
Quasi-res	Coastal	6 to 8 pm	73.9	273	339	12	0.37	0.01	3.8%	1.95	1.17	60%	14.65
	Inland	6 to 8 pm	78.2	271	328	19	0.54	0.00	-0.1%	1.55	-0.02	-1%	-0.53
All	All	6 to 8 pm	77.1	544	667	31	0.91	0.01	1.5%	1.66	0.44	26%	10.62

The average event day load shape is summarized in greater detail in Figure 4-6. Note that the figure, extracted from the Ex Post Load Impact Table, is for the ACSDA quasi-residential participant population for the average event day. The average event day reflects weekday events where event hours matched the 6 to 8 pm window. The left panel shows the aggregate hourly loads (actual and counterfactual) for these sites. The right panel shows impacts per thermostat as a function of cooling load. The tables accompanying each figure show impacts for the 6 pm to 8 pm event window. Aggregate load reductions, though statistically significant, are smaller on a percentage basis than for the Non-Residential Program. However, the average connected thermostat cooling load reduction, as a percent, is larger for the Quasi-Residential (26.5%) than the Non-Residential program (19%). Though aggregate load reductions are 1.5%, reductions are 26.5% of cooling load per connected thermostat.

As noted above, there are just a 31 quasi-residential sites enrolled in ACSDA so any observations regarding loads and impacts should be considered in the context of the small sample size enrolled in this program. Though impacts are largely significant, the population is small and quasi-residential participants tend to exhibit idiosyncratic loads, so it is not possible to draw robust inferences about what impacts would be for a much larger quasi-residential participant population.

Figure 4-6: ACSDA Quasi-Residential Summary for Average Event

Aggregate (MW)

Table 1: Menu options

Program	ACSDA (quasi-res)
Type of result	Aggregate
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	6:00 PM
Event end	8:00 PM
Total sites	544
Total installed thermostats	667
Total connected thermostats	31
Percent of thermostats connected	5%
Avg load reduction 6PM-8PM	0.01
% Load reduction 6PM-8PM	1.5%

Average per Connected Thermostat – Cooling Load (kW)

Table 1: Menu options

Program	ACSDA (quasi-res)
Type of result	Average Connected Thermostat (Cooling load)
Type of site	All
Category	All
Subcategory	All study segments
Event date	Avg. Weekday Event 2020

Table 2: Event day information

Event start	6:00 PM
Event end	8:00 PM
Total sites	544
Total installed thermostats	667
Total connected thermostats	31
Percent of thermostats connected	5%
Avg load reduction 6PM-8PM	0.44
% Load reduction 6PM-8PM	26.5%
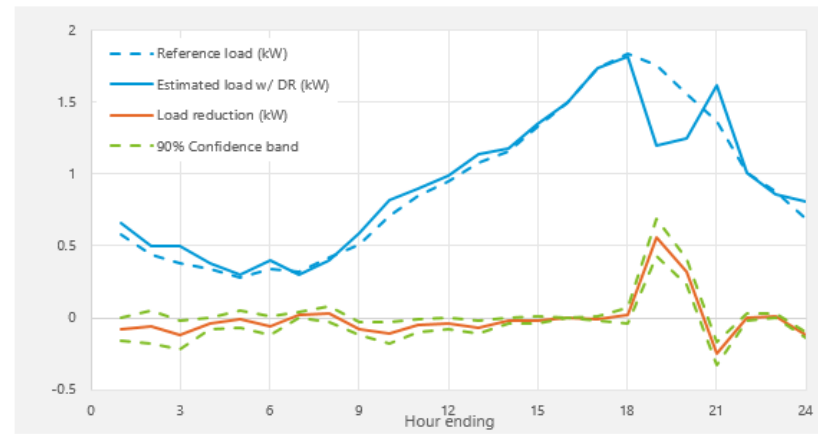
4.4 EX ANTE LOAD IMPACTS

A key objective of the 2020 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used the reductions for a standardized set of weather conditions.

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

1. Estimate the relationship between 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

4.4.1 RELATIONSHIP OF CUSTOMER LOADS AND PERCENT REDUCTIONS TO WEATHER

Figure 4-7 summarizes the relationship between weather for commercial customers with commercial thermostats on CPP rates. Figure 4-8 does the same for ACSDA customers (excluding quasi-residential). Only days when the smart thermostat resources were not dispatched are included. Overall, energy demand and discretionary load increases with hotter weather.

These figures also provide an estimate for typical cooling loads for commercial thermostat sites by assessing how whole building loads per thermostat vary with temperature (left panel). The baseload is estimated by the load on cooling neutral days (max daily temperatures around 65 degrees, e.g. blue line in left panel). Net cooling loads (right panel) are total loads for each weather bin minus the baseload. Note that hotter temperature bands were available for plotting for ACSDA devices which skew less heavily toward the Coastal zone than do devices on dispatchable rates.

Due to small sample size for the CPPTD program, the peak temperature band (red) is not actually the highest load in the visual (gray). However, on days with the highest usage (the 87-90 max daily temperature band) average whole building load per thermostat for CPPTD devices is about 4.1 kW during the typical 2-6 pm CPP event window, but cooling loads are only 37% of this, or about 1.5 kW per thermostat. On days with 90-93 max daily temperature (Figure 4-8 green curve) average cooling load per thermostat for non-residential ACSDA devices is about 4.25 kW during the 1 pm to 6 pm period that

counts towards resource adequacy requirements, and cooling load is about 1.5 kW during this time frame. ACSDA events are typically called later in the day but can be called anytime from 12pm to 9pm.

Because impacts are directly driven by connected thermostats controlling cooling loads, ex ante impacts were estimated as a function of cooling loads on a per thermostat basis.

Figure 4-7: Weather Sensitivity of CPPTD Program Participant Loads

2018-2020 June to Sept loads, excluding weekends/holidays and events
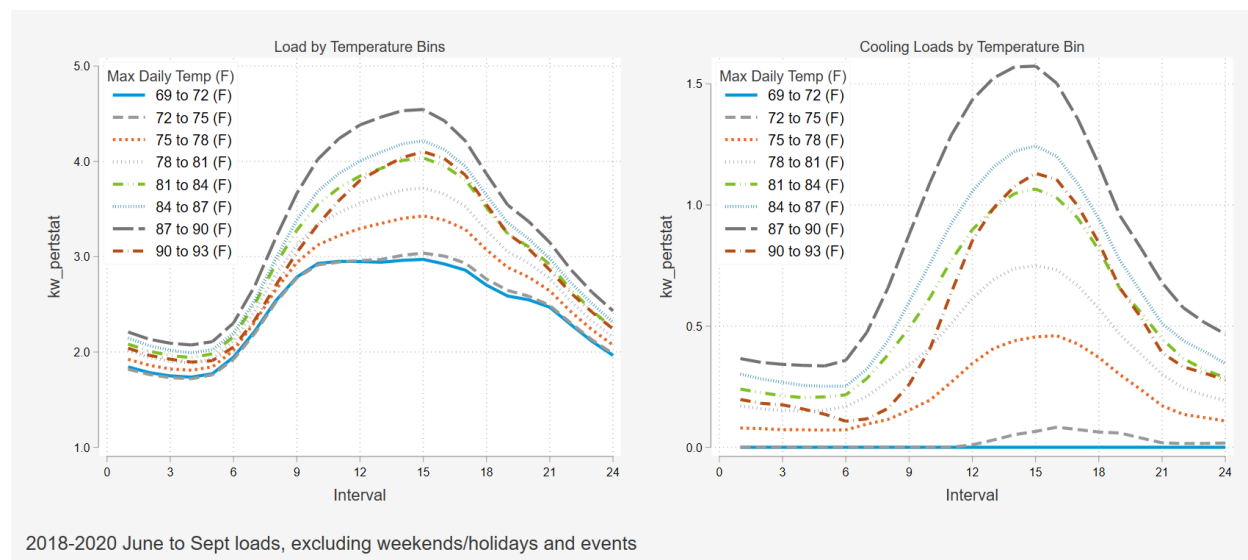
Figure 4-8: Weather Sensitivity of ACSDA Non-residential Program Participant Loads

2018-2020 June to Sept loads, excluding weekends/holidays and events
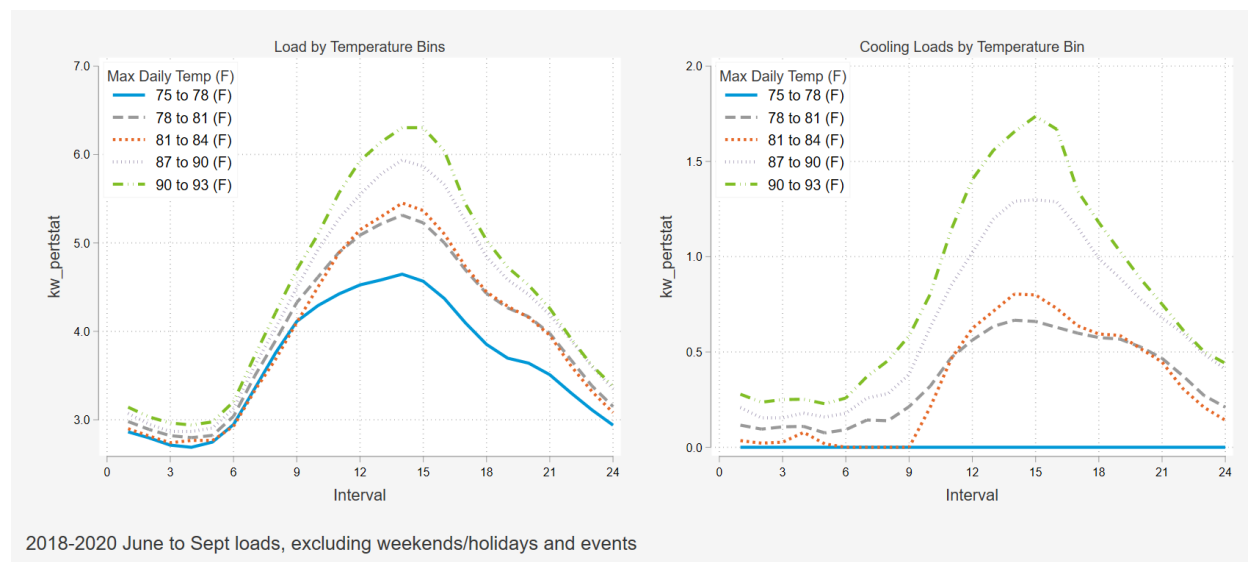
Figure 4-9 shows the relationship between aggregate loads for Technology Deployment sites and SDG&E daily peak loads during PY2020. Daily peaks that occurred before 5pm (typically at 4 or 5pm)

are shown in blue and those that occurred later are shown in grey. The patterns are similar for Technology Deployment sites on CPP rates and those on ACSDA.

Daily peaks that occur later in the day (after 5pm) are smaller in magnitude and occur on days where maximum daily temperatures are about 5 to 10 degrees cooler than days with earlier peaks. Not surprisingly, smart thermostat participants use more power when it is extremely hot and contribute to peak demand, which drives the need for additional generation, transmission, and distribution infrastructure. Because cooling loads are a major driver of SDG&E peaks, if managed, they can reduce the need to build additional infrastructure to accommodate additional peak load. Because more discretionary load is in use during peaking conditions, reductions from commercial thermostats can be larger precisely when resources are needed most.

Figure 4-9: Commercial Thermostat Customer Loads During System Daily Peaks
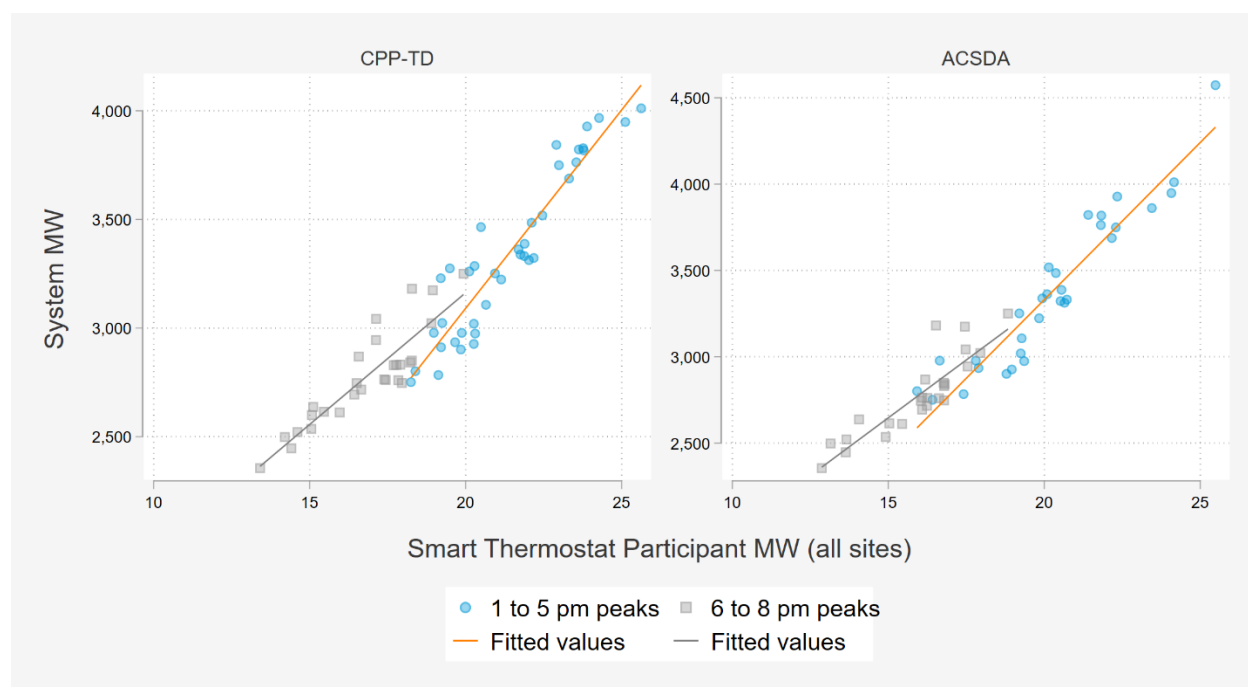
Because the commercial thermostats are dispatched automatically for events, the main driver of differences in ex ante impacts are differences in loads. While no CPPTD events were called in 2019, 2018 and 2020 events were included in the ex ante model estimation. The percent change in energy use was estimated for each of the ex post segments defined in Table 4-3 and applied to 1-in-2 and 1-in-10 weather year customer loads.

Figure 4-10 and Figure 4-11 show hourly event percent reductions for historical weekday events as a function of hourly temperatures for sites on each Technology Deployment program. Reductions are

largely positive in magnitude, a handful are near zero (and not statistically significant) and few are negative, indicating an increase in load, but insignificant. All programs show the positive relationship between temperature and load reductions.

Figure 4-10: 2018-2020 CPPTD Hourly Reductions and Temperatures
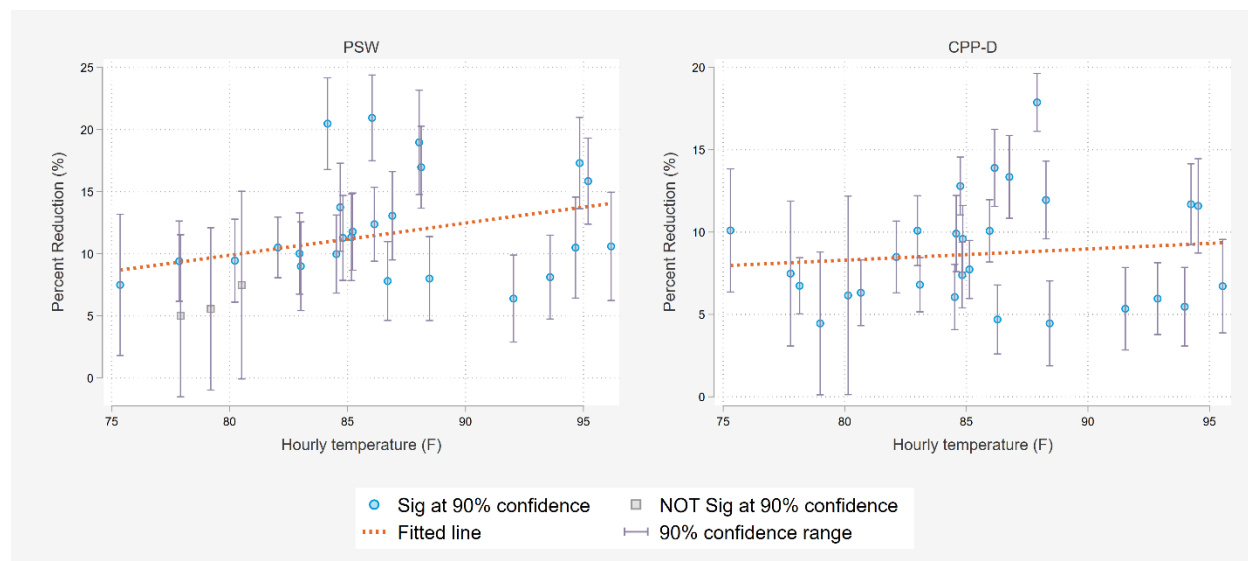
Figure 4-11: 2018-2020 ACSDA Hourly Reductions and Temperatures
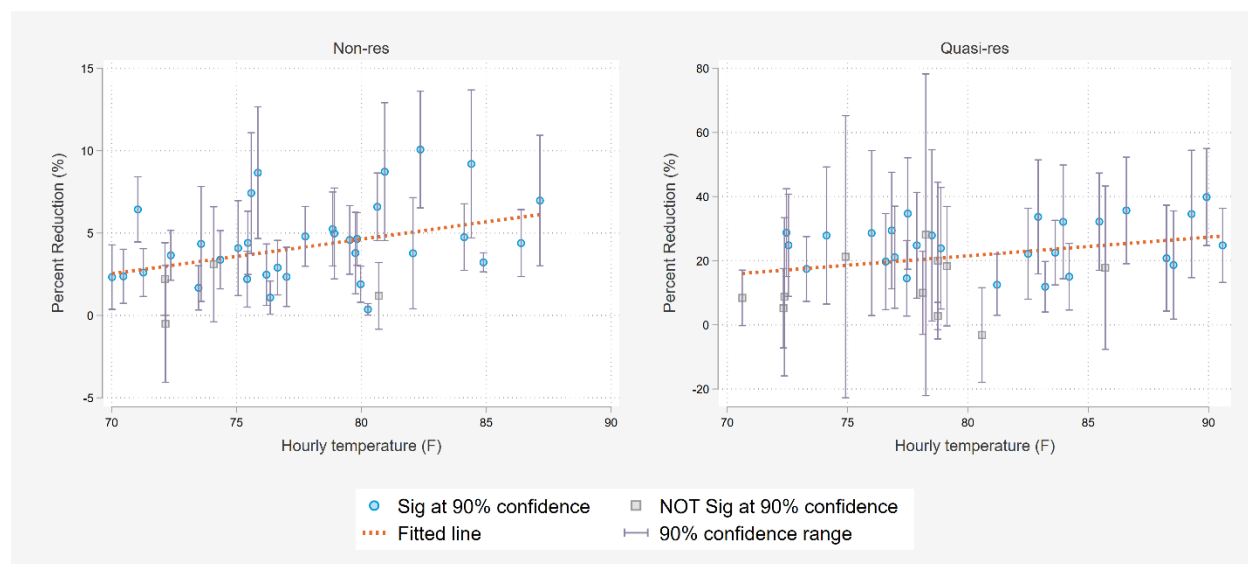
4.4.2   COVID-19 ADJUSTMENTS

 Beginning in March 2020, shutdowns began across the United States as a response to the COVID pandemic. As commercial businesses closed, many workers either lost their jobs or began working from home. The shutdown impacted sectors at different levels of intensity and during different time periods,

but all PY2020 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.

Figure 4-12 shows percent difference between these two sets of reference loads (pre-COVID-19 and post-COVID-19) for Small CPP participants. The figure shows the comparison for the August peak day 1-in-2 weather condition but comparisons were modeled for all ex ante weather conditions and day types. The blue line shows the percent difference for whole building loads between pre-COVID-19 and post-COVID-19 reference load. The negative effect indicates that across all hours post-COVID-19 reference loads were lower than pre-COVID-19 reference loads. The gray line shows the percent difference for cooling loads. Again, cooling loads were higher during all hours post-COVID-19. CPP-TD whole building loads were about 20% lower and cooling loads were about 30% to 40% lower during event hours (2pm to 6pm). ACSDA whole building loads were about 20 to 30% lower and cooling loads were about 60% lower during event hours (6pm to 8pm). These percent differences are essentially the load effect of COVID-19: with the full effect load would look like 2020, if the effect were to disappear loads would look more like pre-2020.

Figure 4-12: COVID Effect on Loads, August Peak Day, 1-in-2 Weather
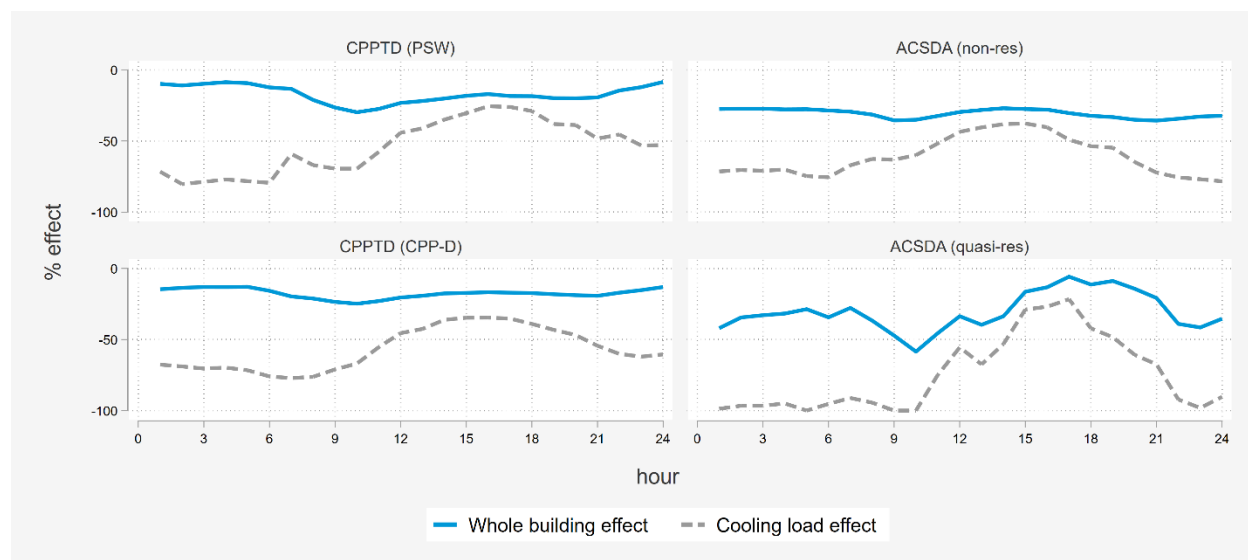
Predicting ex-ante impacts requires further assumptions regarding COVID's potential lingering effects. SDG&E's load forecast for the next two years includes assumptions about the retention over time of the effect of COVID-19 on loads. Figure 4-13 summarizes the monthly assumption for the portion of COVID-19 load effects that will be retained. The same assumptions were used for all non-residential programs including Small CPP and TD programs. These retention percentages are applied to the COVID-19 load effect (percent different between pre and post COVID-19 reference loads) to

incorporate assumptions about COVID-19 into the ex ante reference loads. Notably, the full effect of COVID-19 is assumed to have been in place during most of 2020, to steadily drop during 2021, and to have completely disappeared by 2022, with reference loads reverting back to pre-2020 levels.

Figure 4-13: COVID Effect Retention by Month and Year
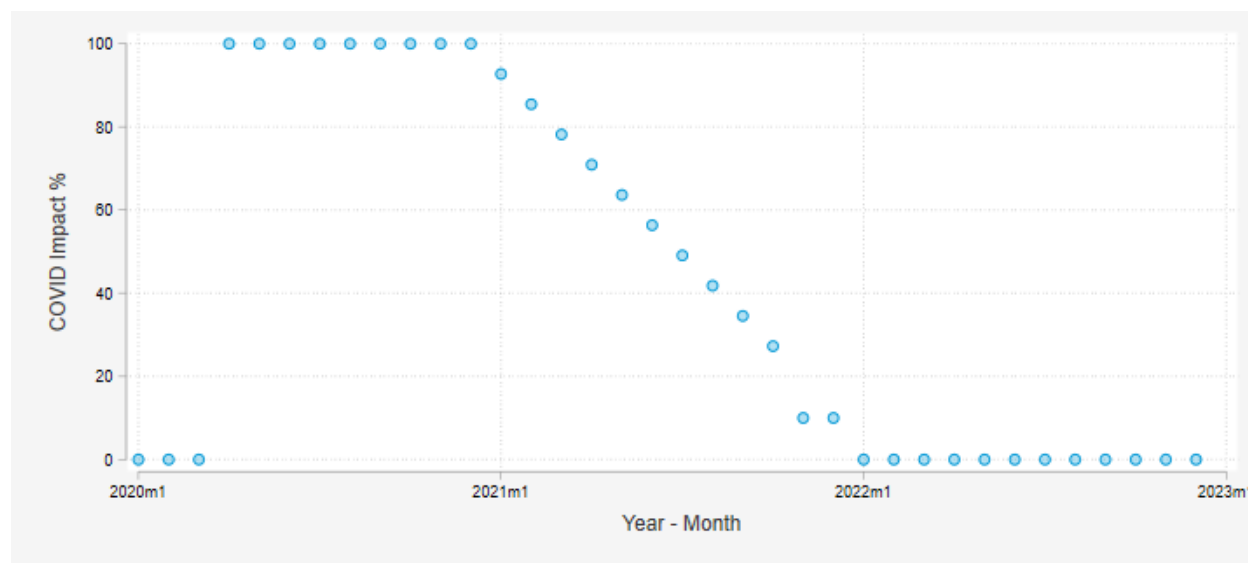
4.4.3   EX ANTE LOAD IMPACTS

Table 4-17 summarizes the ex ante demand reduction capability by forecast year for 1-in-2 SDG&E weather planning conditions across all four Technology Deployment programs. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August 1-in-2 peaking conditions in alignment with the planning conditions used for resource adequacy attribution. They incorporate an enrollment forecast for sites and devices developed using the following inputs and assumptions:

- Site attrition and device connectivity rates described in section 4.1. These are used to produce forecast for enrolled sites, total thermostats, and connected thermostats over time.

- Modest new enrollments for CPP-TD programs and no new enrollments were for ACSDA programs. Site counts are held constant after 2026. This aligns with plans to keep CPP-TD programs open to BYOT participation and plans to discontinue new enrollments in ACSDA.

- 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.

Table 4-17 summarizes expected August peak day 1-in-2 reductions for the four TD programs. Ultimately, forecasted ex ante load reductions reflect load reductions are delivered by connected devices among enrolled sites. Reductions are a function of the number of enrolled sites (which decrease over time), the connectivity rate over time for installed devices (which decreases over time), and the estimated load reduction per connected device (which stays constant over time on a percentage basis). The estimated load reductions are also influenced by reference loads. Due to the COVID-19 pandemic beginning in 2020, average reference loads were lower for non-residential customers, which in turn reduced load reductions. However, this effect is assumed to largely wane in 2021 and completely expire by 2022 as reflected in the load impact increases expected in 2021 and 2022. After this load adjustment impacts are assumed to slowly decrease over time as participants un-enroll (or move out) and thermostats become disconnected.

Table 4-17: Non-residential Smart Thermostat Portfolio Impacts for 1-in-2 SDG&E Weather Conditions, August Monthly Peak Day

Year	CPP-TD		Total	ACSDA		Total
	PSW	CPP-D		Non-Res	Quasi-Res	
2020	0.06	0.20	0.26	0.76	0.01	0.77
2021	0.04	0.12	0.15	2.16	0.01	2.17
2022	0.05	0.14	0.19	2.67	0.01	2.68
2023	0.05	0.15	0.20	2.37	0.01	2.38
2024	0.06	0.15	0.21	2.11	0.01	2.12
2025	0.06	0.16	0.22	1.89	0.01	1.90
2026	0.07	0.16	0.23	1.69	0.01	1.70
2027	0.07	0.15	0.22	1.65	0.01	1.65
2028	0.06	0.15	0.21	1.61	0.01	1.61
2029	0.06	0.14	0.21	1.57	0.01	1.57
2030	0.06	0.14	0.20	1.53	0.01	1.53
2031	0.06	0.13	0.19	1.49	0.01	1.50

Table 4-18 and Table 4-19 summarize the ex ante demand reduction capability by forecast year for different planning conditions, respectively, for sites on dispatchable rates (CPP-TD) and those that are not (ACSDA). The tables reflect dispatchable demand reductions available from 4 pm to 9 pm on August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions. They align with the planning conditions used for resource adequacy attribution. The enrollment forecast for the number of enrolled sites was developed by SDG&E was also applied to the counts of installed thermostats and shows an initial increase followed by a decrease in sites, installed devices, and connected devices over time for the ACSDA programs. For the CPP-TD programs, all three categories show a decrease in forecasted enrollment. The number of thermostats connected reflects the decline in connectivity

observed historically and overlays this decline on the total population of installed thermostats. An important consideration for the ex ante predictions includes the assumptions for how COVID will influence the reference loads over time. Reference loads were lower in PY 2020 due to the pandemic, and SDG&E provided predictions based on how this COVID factor will influence the reference loads in forthcoming years. Impacts are a function of connected thermostats as well as the reference load. These confounding impacts cause the irregular trend in the ACSDA impacts over time. CPPTD shows a clear decrease in impacts each year, suggesting that the change in enrollment is predicted to overshadow the changing reference loads shown in the first few years.

Table 4-18: CPP-TD Portfolio Ex Ante Impacts for August Monthly Peak Day

Year	Sites	Tstats installed	Tstats connected	Average Reference Load	CAISO		SDG&E	
					1-in-2	1-in-10	1-in-2	1-in-10
2020	746	4,602	4,602	5	0.28	0.27	0.26	0.27
2021	371	2,150	2,083	6	0.16	0.15	0.15	0.15
2022	416	2,357	2,218	7	0.19	0.19	0.19	0.18
2023	461	2,560	2,347	7	0.21	0.20	0.20	0.19
2024	505	2,761	2,469	7	0.21	0.21	0.21	0.20
2025	548	2,960	2,586	7	0.22	0.22	0.22	0.21
2026	591	3,155	2,697	7	0.23	0.22	0.23	0.22
2027	591	3,155	2,603	7	0.22	0.22	0.22	0.21
2028	591	3,155	2,512	7	0.22	0.21	0.21	0.20
2029	591	3,155	2,423	7	0.21	0.20	0.21	0.19
2030	591	3,155	2,338	7	0.20	0.19	0.20	0.19
2031	591	3,155	2,256	7	0.19	0.19	0.19	0.18

Table 4-19: ACSDA Portfolio Ex Ante Impacts for August Monthly Peak Day

Year	Sites	Tstats installed	Tstats connected	Average Reference Load	CAISO		SDG&E	
					1-in-2	1-in-10	1-in-2	1-in-10
2020	344	3,938	3,938	6.72	0.81	0.77	0.77	0.84
2021	717	6,071	5,917	7.42	2.15	2.12	2.17	2.08
2022	673	5,605	5,319	8.23	2.62	2.61	2.68	2.49
2023	635	5,194	4,794	8.17	2.33	2.31	2.38	2.21
2024	601	4,831	4,333	8.11	2.08	2.06	2.12	1.97
2025	571	4,509	3,926	8.05	1.85	1.84	1.90	1.75
2026	543	4,224	3,567	7.99	1.66	1.64	1.70	1.57
2027	543	4,224	3,469	7.99	1.62	1.60	1.65	1.53
2028	543	4,224	3,374	7.99	1.58	1.56	1.61	1.49
2029	543	4,224	3,281	7.99	1.54	1.52	1.57	1.45

Year	Sites	Tstats installed	Tstats connected	Average Reference Load	CAISO		SDG&E	
					1-in-2	1-in-10	1-in-2	1-in-10
2030	543	4,224	3,192	7.99	1.50	1.49	1.53	1.42
2031	543	4,224	3,105	7.99	1.46	1.45	1.50	1.38

4.4.4 COMPARISON OF EX POST AND EX ANTE LOAD IMPACTS

Table 4-20 compares the observed demand reductions from PY 2020 events to the PY 2020 reductions expected for the 1-in-2 weather conditions used for planning. Results are shown for the 4 to 9 pm resource adequacy window. In 2020, CPPTD customers delivered 1.54 MW during the dispatch period of 2 pm to 6 pm and 0.37 MW during the 4 to 9 pm resource adequacy window, which extends three hours beyond the CPP dispatch window. Ex post reductions during the resource adequacy window are much lower because they include three hours with no reductions, from 6 to 9 pm. Ex ante impacts for the resource adequacy window are lower than the corresponding ex post impacts. This is in part because ex ante temperatures for 1-in-2 weather conditions shown here are two degrees lower than for the events called in 2020 (ex post). Ex post results also reflect a changing mix of connected devices over the course of the summer and the unique hourly temperature profiles of each event, whereas ex ante impacts assume a fixed number of connected devices and weather for a single peak day.

Table 4-20: CPPTD Comparison of Ex Post and Ex Ante Load Impacts for 2020

Result Type	Day Type and Period	Sites	Tstats connected	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex Post Avg. Weekday	Event Period (2pm to 6pm)	1,204	4,676	23.00	1.54	6.7%	90.7
	Resource Adequacy Period (4 to 9pm)	1,204	4,676	19.30	0.37	1.9%	90.7
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	746	4,602	14.36	0.26	1.8%	88.4
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	746	4,602	14.75	0.28	1.9%	88.3

*Table shows portfolio impacts. To avoid double counting, it excludes commercial thermostats and customers dually enrolled in other DR programs.
**For comparability to ex ante, only includes events with average event temperature above 70F
***Ex ante site counts are lower due to exclusion of sites with no associated thermostat

Table 4-21 makes a similar comparison for ACSDA programs. An important difference is that ex post impacts are shown on average only across events with average temperature surpassing 70 F. Excluding the cooler events makes for a more meaningful comparison with ex ante results. In 2020, ACSDA customers delivered 0.44 MW during the typical dispatch period of 6 pm to 8 pm. However, because thermostat resources were largely only dispatched for two hours during the five-hour window, ex post reductions during the 4 to 9 pm resource adequacy window were lower (0.15 MW). In contrast, ex ante reference loads and impacts are greater for the 4 to 9 pm window, mostly because they assume five hours of dispatch. In addition, temperatures were over seven degrees higher for 1-in-2 planning conditions than for the PY 2020 events. Further, it is important to note that percent reductions for ACSDA were relatively low and there is a greater degree of uncertainty with small percentage impacts. As with the CPPTD programs, ex post results also reflect a changing mix of connected devices over the course of the summer and the unique hourly temperature profiles of each event, whereas ex ante impacts assume a fixed number of connected devices and weather for a single peak day.

Table 4-21: ACSDA Comparison of Ex Post and Ex Ante Load Impacts for 2020

Result Type	Day Type and Period	Sites	Tstats connected	Load without DR (MW)	Load Reduction (MW)	% Reduction	Daily Max Temp (F)
Ex Post Avg. Weekday**	Event Period (6pm to 8pm)	941	3,543	15.17	0.44	2.9%	85.6
	Resource Adequacy Period (4 to 9pm)	941	3,543	15.46	0.15	1.0%	85.6
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9pm)	344	3,938	16.60	0.77	4.6%	93.3
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9pm)	344	3,938	16.97	0.81	4.8%	92.6

*Table shows portfolio impacts. To avoid double counting, it excludes commercial thermostats and customers dually enrolled in other DR programs.
**For comparability to ex ante, only includes events with average event temperature above 70F
***Ex ante site counts are lower due to exclusion of sites with no associated thermostat

5 CONCLUSIONS AND RECOMMENDATIONS

The two different interventions – CPP-TOU and commercial thermostats – each delivered statistically significant demand reduction, but there is room for improvement. The recommendations below may not be currently funded, and costs need to be considered alongside other research and program priorities. For clarity, we present the recommendations for technology deployment programs and critical peak pricing separately.

5.1 TECHNOLOGY DEPLOYMENT RECOMMENDATIONS

- **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. SDG&E is currently conducting research with a sample of residential ACSDA participants identified as having recently disconnected thermostats. Specifically, the research includes a recommend randomized control trial with three different groups:

    - Control (n = ~135)

    - Postcard or letter reminder + follow up phone call (n = ~135)

    - Postcard or letter reminder + incentive (n = ~135)

    This will allow SDG&E to quantify how well different methods work at getting customers to reconnect and assess their cost-effectiveness. Though there was not a large enough population to conduct this research with non-residential participants, results from the residential may be qualitatively informative for possible outreach strategies for non-residential participants.

- **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 30% or more 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 analyses 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.

5.2 SMALL COMMERCIAL CRITICAL PEAK PRICING RECOMMENDATIONS

- **Assess if additional communications encouraging response improve reductions using randomized controlled trials.** The magnitude of demand reductions during events is small on a percentage basis, about 1%, providing ample room to improve reductions. However, most reductions were delivered by sites receiving event notifications. Additional communications require resources and their effectiveness at improving price response is unknown. Because of the potential, however, we recommend testing the effectiveness of more education regarding event response. It is critical, however, for the test to be implemented using randomized control trials, so it is possible to assess if the communications had any impact on price response.

- **Notification rates for small CPP can be improved.** Customers elect whether or not to sign up for notifications and by which channels they receive notification. Because notification is closely linked to response, additional efforts to improve notification rates are recommended. The share of sites enrolled to receive notifications has dropped somewhat since PY 2018 when CPP events were last called. In PY 2018 roughly 60% of sites received event notifications while that number dropped to 43% in PY 2020. Sites receiving event notifications tend to produce greater impacts so an increase in notification rates has the potential to meaningfully increase load reductions.

- **Continue to monitor loads and assumptions about the effect of COVID-19 on loads.** 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 analyses 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.

APPENDIX

A. PANEL REGRESSION MODELS WITH MULTIPLE CONTROLS: TD PROGRAMS

Panel regressions with multiple control groups were used as the primary method for estimating load impacts for PY 2020 impacts for TD programs. The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads with a panel model, one should observe:

- Very similar energy use patterns for participant and counterfactual loads when the intervention is not in place.

- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.

- The timing of the change should coincide with the introduction of intervention.

The use of a panel model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. The equation for the model is presented below in Equation A 0-1 and Table A 0-1. 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.

Equation A 0-1: Ex Post Regression Model for TD Programs

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

Where:

Table A 0-1: Ex Post Regression Elements for TD Programs

$kW_{i,t}$	Is the usage for each individual customer and time period
a	Is the model intercept
b	Loads for the five most closely matched control sites based on Euclidean distance matching. They did not experience the treatment and are weighted based on their predictive power.
c	Controls for differences between event and non-event days
d	Is the parameter for weather sensitivity of loads
Event	Is a binary variable indicating if day is an event. Separate variables are used for each event so impacts are estimated for each event. It has a value of zero on event-like proxy days. The five closest non-event days

	were included as proxy days for each event. Separate proxy days were selected for each event using Euclidean distance matching.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

B. PANEL REGRESSION MODELS WITH MULTIPLE CONTROLS: SMALL CPP

Panel regressions with multiple control groups were used as the primary method for estimating load impacts for PY 2020 impacts for Small CPP. The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads with a panel model, one should observe:

- Very similar energy use patterns for participant and counterfactual loads when the intervention is not in place.

- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.

- The timing of the change should coincide with the introduction of intervention.

The use of a panel model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. The equation for the model is presented below in Equation B 0-2 and $kW_{i,t} = \text{a} + \sum_{n=1}^{5} \text{b}_n \cdot Control_{i,t,n} + \text{c} \cdot kW_{i,t-5} + \text{d} \cdot CDH_{i,t} + \delta_t + \varepsilon_{i,t}$

Where:
Table B 0-2. A separate model was estimated for each intervention, each hour of the day, and each of the analysis segments identified as part of the evaluation plan.

Equation B 0-2: Ex Post Regression Model for Small CPP

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

Where:

Table B 0-2: Ex Post Regression Elements for Small CPP

$kW_{i,t}$	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.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

As with the TD Program analysis, out of sample testing was used for model selection. Figure B 0-1 summarizes the model variants tested and resulting RMSE. Also as modeled for the TD Program analysis, variants included the number of event proxy days (2 through 5), the number of control sites (1 through 5), and the same day adjustments. The adjustment variants tested included no adjustment, a two hour prevent adjustment, a 5-hour lag adjustment, and a 5 and 6-hour lag adjustment. All adjustments performed similarly, on the order of 0.05 to 0.06 RMSE, and produced markedly lower RMSE than applying no adjustment. The lag 5-hour lag approach was ultimately selected over the pre-event adjustment given the observed response in hours leading up to event start.

Figure B 0-1: Small CPP Model Selection Results
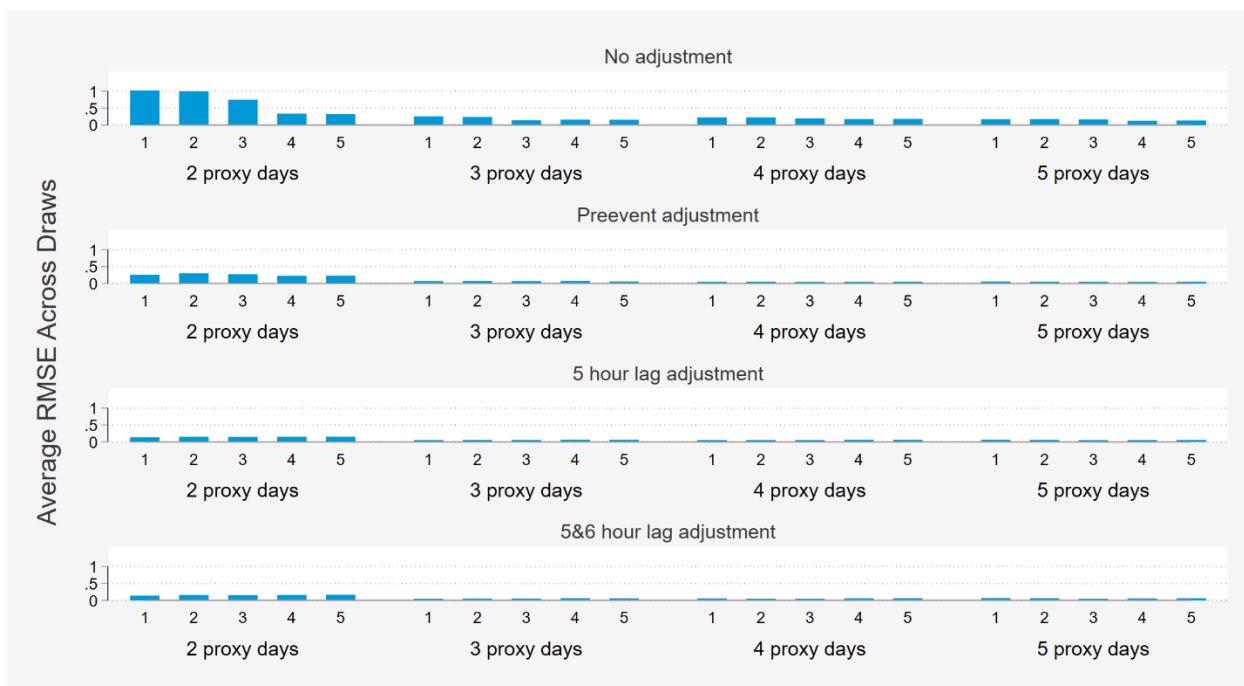
The key load impact coefficient for this regression model is the interaction of event impacts with weather sensitivity, e.g. the expected load impact (kW) for each cooling degree hour. This approach is described in the California Load Impact Protocols[13] and has the advantage of producing ex post results which directly reflect the weather impact relationship that is a key input to ex ante load impacts.

This relationship was modeled for each hour and day type (weekdays and weekends). The example regression summary in Figure B 0-2 below shows the results for hour ending 15 for weekday events. The highlighted term represents the event day weather sensitivity term: for each cooling degree hour average load is expected to drop by 0.00659 kW.

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[13] http://www.calmac.org/events/FinalDecision_AttachementA.pdf, pages 70-72

Figure B 0-2: Ex Post Regression Example for Small CPP

```
Linear regression, absorbing indicators        Number of obs    =  1,619,729
Absorbed variable: site_id                      No. of categories =    109,051
                                                F(   8,1510670)  =     694.66
                                                Prob > F         =     0.0000
                                                R-squared        =     0.9811
                                                Adj R-squared    =     0.9797
                                                Root MSE         =     2.4618
```

		Robust				
kwh	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
eventday_cpp#c.cdh65						
1	-.0065894	.0003153	-20.90	0.000	-.0072074	-.0059715
kwh						
L5.	1.509874	.0301685	50.05	0.000	1.450745	1.569003
_kwh_match_1	.0756694	.0390454	1.94	0.053	-.0008582	.1521971
_kwh_match_2	.1397278	.0398529	3.51	0.000	.0616176	.217838
_kwh_match_3	.0063335	.0125676	0.50	0.614	-.0182986	.0309656
_kwh_match_4	.0240203	.0209156	1.15	0.251	-.0169736	.0650142
_kwh_match_5	-.004661	.0101335	-0.46	0.646	-.0245223	.0152003
cdh65	.0306782	.0008337	36.80	0.000	.0290442	.0323122
daytype						
Weekday	0	(omitted)				
daytype#c.cdh65						
Weekday	0	(omitted)				
_cons	-1.912648	.1893787	-10.10	0.000	-2.283823	-1.541472

Table B 0-3 below shows how this weather sensitivity regression coefficient is converted to kW and percent impacts. Essentially, though the relationship between load and weather is the same across events, the load impact varies across events as a function of weather (CDH) on each event. To derive load impacts the weather sensitivity coefficient (kW per CDH) for weekday events during hour ending 15 is multiplied by the CDH in that hour for a given event.

Table B 0-3: Ex Post Impact Calculation Example for Small CPP

(A) Event Date	(B) Sites	(C) Avg Ref Load (kW)	(D) Avg kW Impact per CDH	(E) CDH	(F=D*E) Avg Impact (kW)	(G=B*F) Total Impact (MW)	(H=F/C) % Impact (%)
17-Aug-20	108,595	2.89	-0.00659	22.7	-0.150	-16.3	-5.2%
18-Aug-20	108,606	2.98	-0.00659	19.5	-0.128	-13.9	-4.3%
19-Aug-20	108,595	2.99	-0.00659	20.9	-0.138	-15.0	-4.6%
20-Aug-20	108,583	3.04	-0.00659	23.0	-0.151	-16.4	-5.0%
30-Sep-20	107,039	3.34	-0.00659	29.5	-0.195	-20.8	-5.8%
1-Oct-20	107,057	3.39	-0.00659	29.9	-0.197	-21.1	-5.8%
Avg Weekday Event	*108,079*	*3.10*	*-0.00659*	*24.2*	*-0.160*	*-17.3*	*-5.2%*