

Summer Saver 2017 Load Impact Program Evaluation

Prepared for:   
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# Executive Summary

San Diego Gas and Electric Company’s (SDG&E) Summer Saver program is a demand response resource based on central air conditioner (CAC) load control that is implemented through an agreement between SDG&E and Comverge, Inc. The previously funded program cycle ended in 2016; in January 2017, SDG&E filed its request to the CPUC for funding to cover the program years 2018 to 2022[[1]](#footnote-1). The 2017 program year was funded through CPUC-authorized bridge funding. This report provides ex post load impact estimates for the 2017 Summer Saver program and ex ante load impact forecasts for 2018–2028.

The Summer Saver program is available to residential and commercial customers with average monthly peak demand up to a maximum of 100 kW over a 12-month period. There are two enrollment options each for both residential and commercial customers. Residential customers can choose between 50% or 100% cycling and commercial customers can choose between 30% and 50% cycling. The incentive paid for each option varies and is based on the number of CAC tons under control at each site. The Summer Saver season runs from May 1 through October 31. A Summer Saver event may be triggered by temperature or system load conditions and customers are not automatically notified when an event occurs; however, customers can sign up to receive event notification.

At the end of 2017, there were 20,483 customers enrolled in the program with a total cooling capacity of 109,017 tons. This represents a 20% decrease in enrolled customers and a 16% decrease in tons relative to 2016. This drop in enrolled customers is significantly higher than in previous years because of changes to the program after the 2016 program year. SDG&E dropped the bottom three deciles (by electricity usage) of residential Summer Saver customers from the program. At the end of 2016, there were 25,469 customers enrolled in the program with a total cooling capacity of 130,338 tons. For the 2017 program year, residential customers represented approximately 76% of Summer Saver participants and accounted for about 61% of the program’s total cooling tons. Among residential participants, 37% selected the highest cycling option (100% cycling); among commercial participants, 79% selected the 50% cycling option over the 30% option.

A total of 19 events were called in 2017 with event hours spanning 3 to 9 PM. Two of the events were evaluation, measurement, and verification (EM&V) “cool weather” test events and one event was called on a Saturday. Event hours varied but the most common event periods were 4 to 8 PM and 5 to 9 PM. The event period from 4 to 8 PM is be used for Average Event Day load impacts. Ex post load impacts are estimated using two approaches—a randomized control trial (RCT) design for a sample of residential customers and a statistically-matched control group for the commercial customers. Table 1‑1 shows the overall 2017 Summer Saver ex post load impacts and the event window temperatures. The average aggregate demand reduction for residential customers totaled 5.7 MW, and the largest load reduction was 9.8 MW on the September 2 event. The aggregate load reduction for commercial customers on the Average Event Day was roughly 0.93 MW, or 0.21 kW per premise. The largest load reduction for commercial customers totaled 1.65 MW and occurred on the August 3 event. In aggregate, the average reduction for the entire Summer Saver program on the Average Event Day totaled 6.7 MW.

Table ‑: 2017 Summer Saver Load Average Ex Post Impacts

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Date | Impact | | | | Average Event Temperature  (°F) |
| **per Ton (kW)** | **per CAC Unit (kW)** | **per Premise (kW)** | **Aggregate (MW)** |
| 8/1/2017 | 0.05 | 0.19 | 0.28 | 6.5 | 81 |
| 8/2/2017 | 0.03 | 0.14 | 0.21 | 4.0 | 84 |
| 8/3/2017 | 0.06 | 0.24 | 0.38 | 7.0 | 82 |
| 8/7/2017 | 0.02 | 0.07 | 0.08 | 2.3 | 76 |
| 8/8/2017 | 0.04 | 0.14 | 0.22 | 4.2 | 78 |
| 8/28/2017 | 0.05 | 0.20 | 0.30 | 6.1 | 82 |
| 8/29/2017 | 0.04 | 0.18 | 0.21 | 5.9 | 85 |
| 8/31/2017 | 0.07 | 0.27 | 0.38 | 8.2 | 86 |
| 9/1/2017 | 0.07 | 0.28 | 0.37 | 8.8 | 91 |
| 9/2/2017 | 0.08 | 0.34 | 0.45 | 10.7 | 92 |
| 9/5/2017 | 0.03 | 0.10 | 0.14 | 3.3 | 80 |
| 9/11/2017 | 0.03 | 0.11 | 0.15 | 3.4 | 79 |
| 9/12/2017 | 0.01 | 0.06 | 0.07 | 1.9 | 75 |
| 9/25/2017 | 0.00 | 0.01 | 0.00 | 0.3 | 75 |
| 9/26/2017 | 0.01 | 0.03 | 0.06 | 0.9 | 75 |
| 9/28/2017 | 0.01 | 0.03 | 0.04 | 0.9 | 77 |
| 10/24/2017 | 0.06 | 0.26 | 0.39 | 7.8 | 100 |
| **Average\*** | **0.05** | **0.22** | **0.31** | **6.7** | **85** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | | |

Ex ante load impacts are intended to represent weather conditions under normal (1-in-2 year) and extreme (1-in-10 year) conditions, defined for two scenarios: one representing weather conditions expected when the SDG&E system peaks and another representing weather conditions when the CAISO system peaks.

In 2018, on a typical event day under 1-in-2 year SDG&E-specific peaking conditions, aggregate load impacts are projected to equal 5.1 MW for residential customers and 1.8 MW for nonresidential customers, for a total program load reduction equal to 6.9 MW. Summer Saver load impacts increase with temperature. Given the events that occurred at lower temperatures that informed the ex ante temperature relationships, the largest impacts are observed on the September monthly system peak days when the temperature is the hottest. In 2018, under 1-in-10 year SDG&E-specific peaking conditions, estimated impacts on the typical event day are forecasted to equal 7.5 MW and 2.6 MW for residential and nonresidential customers, respectively, or 10.1 MW in total. This is about 46% greater than on a typical event day under 1-in-2 year weather conditions. On the September SDG&E monthly system peak day for a 1-in-10 weather year, estimated impacts equal 9.6 MW and 3.3 MW respectively, for a total load reduction of 12.9 MW for the entire program.

# Introduction and Program Summary

San Diego Gas and Electric Company’s (SDG&E) Summer Saver program is a demand response resource based on central air conditioner (CAC) load control that is implemented through an agreement between SDG&E and Comverge, Inc. The previously funded program cycle ended in 2016; in January 2017, SDG&E filed its request to the CPUC for funding to cover the program years 2018 to 2022[[2]](#footnote-2). The 2017 program year was funded through CPUC-authorized bridge funding. This report provides 2017 ex post load impact estimates and ex ante load impact estimates for an 11-year forecast horizon (2018–2028) as required by the California Public Utilities Commission (CPUC) Load Impact Protocols[[3]](#footnote-3), even though the program may not continue in its current form in upcoming years.

The Summer Saver program is classified as a day-of demand response program and is available to both residential and commercial customers, where eligible commercial customers are subject to a demand limit; only those commercial customers with average monthly peak demand up to a maximum of 100 kW over a 12-month period may participate. Summer Saver events may only be called during the months of May through October. Under the current program, load control events may not run for more than 4.5 hours. Participants’ air conditioners cannot be cycled for more than 4.5 hours in any event day and events cannot be triggered for more than 80 hours per year. Load control events can occur on weekends but not on holidays and cannot be called more than three days in any calendar week. These program rules apply to both residential and commercial customers alike.

In 2017, several changes occurred to the program design. First, the annual maximum of event hours was increased from 60 hours to 80 hours. A second change was how Summer Saver events are triggered. Previously, an event was triggered by system conditions, specifically when day-ahead forecasted system load reaches 4,000 MW. Under the new program design, event triggers vary by month. During the months of July, August, or September, a Summer Saver event can be triggered by any of the following criteria:

* Generator heat rates reaching or exceeding 19,000 Btu[[4]](#footnote-4) /kWh;
* Imminent statewide or local emergencies, extreme conditions, and/or local distribution needs; or
* Upon the award of a bid into the California Independent System Operator (CAISO) wholesale market;

Summer Saver events may be called between noon and 9 PM, and each event may last 1 to 4.5 hours in duration. In previous years, a Summer Saver event could have been called between noon and 8 PM, and each event could last 2 to 4 hours.

There are two enrollment options for both residential and commercial participants. Residential customers can choose to have their CAC units cycled 50% or 100% of the time during an event. The incentive paid for each option varies; the 50% cycling option pays $10.35 per ton per year of CAC capacity and the 100% cycling option pays $27 per ton per year. A residential customer with a four ton CAC unit would be paid the following in the form of an annual credit on their SDG&E bill:

* $41.40 for 50% cycling; or
* $108 for 100% cycling.

Commercial customers have the option of choosing 30% or 50% cycling. The incentive payment for 30% cycling is $4.50 per ton per year and $7.50 per ton per year for the 50% cycling option. A commercial customer with five tons of air conditioning would be paid the following in the form of an annual credit on their SDG&E bill:

* $22.50 for 30% cycling; or
* $37.50 for 50% cycling.

Enrollment in the Summer Saver program as of October 2017 is summarized in Table 2‑1. Total enrollment—as measured by number of customers, number of devices, and air conditioning capacity (measured in tons)—has decreased due to the program change to drop the bottom three deciles of residential users and as well as general attrition. As of October 2017, there were 20,483 customers enrolled in the program, which in aggregate represents 109,017 tons of CAC capacity. This represents about a 3.5% decrease in enrolled customers and in enrolled tons relative to 2016. For the 2017 program year, residential customers represented approximately 76% of Summer Saver participants and accounted for about 61% of the program’s total cooling tons. About 63% of residential customers selected the 50% cycling option and approximately 21% of commercial customers chose the 30% cycling option, which represent the lower of the two cycling strategies offered to those customer segments. After holding steady around 50% for many years, the percentage of residential customers taking the 100% cycling option has steadily declined—from 46% in 2014 to 43% in 2015 to 39% in 2016 to 37% in 2017. The reverse trend has been observed among commercial customers selecting the 50% option, from 60% in 2010 to 79% in 2017. In the future, the Summer Saver enrollment is projected to substantially decrease in the early years of the next program cycle, due to changes to program enrollment rules if residential NEM customers are dropped from the program.

Table ‑: Summer Saver Enrollment – October 2017

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Customer Type** | **Cycling Option** | **Enrolled  Customers** | **Enrolled Control  Devices** | **Enrolled  Tons** |
| Commercial | 30% | 1,011 | 2,950 | 11,485 |
| 50% | 3,813 | 8,195 | 31,342 |
| Total | 4,824 | 11,145 | 42,827 |
| Residential | 50% | 9,820 | 11,421 | 39,917 |
| 100% | 5,839 | 7,211 | 26,273 |
| Total | 15,659 | 18,632 | 66,190 |
| **Grand Total** | | **20,483** | **29,777** | **109,017** |

Report Structure

The remainder of this report is organized as follows. Section 3 summarizes the data and methods that were used to develop ex post and ex ante load impact estimates and the validation tests that were applied to assess their accuracy. Section 4 contains the ex post load impact estimates. Section 5 presents the ex ante estimates. Section 5 also provides details concerning the differences between the 2017 and the 2016 ex ante load impacts—in addition to differences between ex post and ex ante load impacts.

# Data and Methodology

This section describes the datasets and analysis methods used to estimate load impacts for each event in 2017 and for ex ante weather and event conditions. Ex post results were calculated using control and treatment groups. In the case of the residential segment within a randomized control trial framework, whereby with random assignment to treatment and control status and reasonably large sample sizes (1,600 residential participants), any differences in the average hourly electric loads of the treatment and control group may be interpreted as being caused by Summer Saver load control and unbiased. In the case of the commercial segment, most of the commercial program participants were statistically matched to a control group of nonparticipants. The methodology used to estimate ex ante load impacts differs this year relative to previous evaluation years. A separate model is run for the residential and nonresidential segments. For residential customers, the ex post load impact estimates from 2015 through 2017 were used to estimate models relating temperature to load reductions that were then used in conjunction with ex ante weather data to estimate ex ante load impacts. Only certain events were used to estimate the relationship between temperature and load reductions. Similarly, for nonresidential customers the average load impacts from 2015 through 2017 were used to estimate models relating temperature to load reductions that were then used in conjunction with ex ante weather data to estimate ex ante load impacts. A more detailed discussion is provided in Section 3.3.

Data

A total of 19 Summer Saver events were called in 2017. Table 3‑1 shows the date, day of week, and the start and end time for each event. It also identifies if an event was an EM&V cool weather test event. All residential and commercial participants were called for each non-EM&V event, except for the control group customers that were held back for measurement and evaluation purposes. Another exception was the event called on August 1 where all residential and commercial customers were called – no customers were held back to serve as a control group on that day. For the two EM&V events, only half of the residential research sample was dispatched (about 1,600 residential customers). The event hours varied from 3 to 9 PM across the events in 2017. There was one weekend event on the Saturday before Labor Day.

Table ‑: Summary of 2017 Summer Saver Events

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Date | Day of Week | Start Time | End Time | EM&V Test Event |
| 7/11/2017 | Tuesday | 3:00 PM | 7:00 PM | X |
| 8/1/2017 | Tuesday | 4:00 PM | 8:00 PM |  |
| 8/2/2017 | Wednesday | 4:00 PM | 8:00 PM |  |
| 8/3/2017 | Thursday | 4:00 PM | 8:00 PM |  |
| 8/7/2017 | Monday | 7:00 PM | 8:00 PM |  |
| 8/8/2017 | Tuesday | 6:00 PM | 8:00 PM |  |
| 8/17/2017 | Thursday | 4:00 PM | 8:00 PM | X |
| 8/28/2017 | Monday | 4:00 PM | 8:00 PM |  |
| 8/29/2017 | Tuesday | 5:30 PM | 9:00 PM |  |
| 8/31/2017 | Thursday | 4:00 PM | 8:00 PM |  |
| 9/1/2017 | Friday | 4:00 PM | 8:00 PM |  |
| 9/2/2017 | Saturday | 5:00 PM | 9:00 PM |  |
| 9/5/2017 | Tuesday | 5:00 PM | 8:00 PM |  |
| 9/11/2017 | Monday | 5:00 PM | 9:00 PM |  |
| 9/12/2017 | Tuesday | 5:00 PM | 9:00 PM |  |
| 9/25/2017 | Monday | 5:00 PM | 9:00 PM |  |
| 9/26/2017 | Tuesday | 5:00 PM | 9:00 PM |  |
| 9/28/2017 | Thursday | 5:00 PM | 9:00 PM |  |
| 10/24/2017 | Tuesday | 3:00 PM | 5:00 PM |  |

Table 3‑2 shows the distribution of CAC tonnage by cycling option and climate zone for the residential participant population as of October 2017 and for the residential sample used for the ex post analysis. The differences between the fraction of residential customer tonnage in the residential sample and population cells are small, as are the differences across climate zones and cycling options. Sample weights ae applied during the analysis so that load impacts for each cycling strategy (and overall) reflect the program’s enrollment across climate zones.

Table ‑: Distribution of CAC Tonnage by Program Option and Climate Zone  
2017 Residential Population

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Cycling Option** | **Group** | **Climate Zone 1** | **Climate Zone 2** | **Climate Zone 3** | **Climate Zone 4** | **Total** |
| 50% | Population | 23% | 1% | 0% | 57% | 73% |
| Sample | 8% | 0% | 0% | 68% | 49% |
| 100% | Population | 6% | 0% | 0% | 23% | 27% |
| Sample | 17% | 0% | 0% | 63% | 51% |
| **Total** | **Population** | 29% | 1% | 0% | 82% | 100% |
| **Sample** | 24% | 0% | 0% | 131% | 100% |

Methodology

The primary task in developing ex post load impacts is to estimate reference load for each event. The reference load is a measure of what participant demand would have been in the absence of the CAC cycling during an event. The primary task in estimating ex ante load impacts—which is often of more practical concern—is to make the best use of historical data on loads and load impacts to predict future program performance. The data and models used to estimate ex post impacts are typically the key inputs to the ex ante analysis.

Two distinct approaches were used for estimating the reference loads: a randomized controlled trial (RCT) design and a statistical matching design. Residential customer impacts were estimated using an RCT. The commercial customer impacts were estimated with a matching study. Under the randomized controlled trial, random samples of residential Summer Saver customers were selected for each cycling strategy. During each event, half of the sample did not have their CAC units cycled so that these customers could be used to provide a reference load for those who did have their units cycled. Under the matching design, a matched control was selected for nearly all of the commercial Summer Saver program participants.

Ex Post Methodology

#### RCT Framework

An RCT is an experimental research approach in which customers are randomly assigned to treatment and control conditions so that the only difference between the two groups, other than random chance, is the existence of the treatment condition. In this context, half of the roughly 3,200 customers in the residential sample had their CAC unit cycled while the remaining customers served as the control group. The group that received the event signal alternated from event to event. This design has significant advantages in providing fast, reliable impact estimates if sample sizes are large enough.

#### Statistical Matching Framework

Consistent with the methodology used in the 2015 and 2016 Summer Saver evaluations, a matched control group was selected for the commercial program population—whereby one nonparticipant was selected as a match for each participant on each event. The entire SDG&E small and medium business (SMB) customer population was made available for the statistical matching analysis. Each matched customer was chosen because they most closely resembled their matched participant in terms a dissimilarity statistic described in Equation 3‑1. The dissimilarity statistic measures how similar each candidate for a match is to any given participant customer based on how well (or not) their energy usage characteristics match those of the participant on both the event day and other hot non-event days in 2017, called proxy days. Details surrounding the selection of 2017 proxy days are presented, including a list of the 2017 proxy days, are provided in Appendix A. The characteristics used in the dissimilarity statistic are:

* Average demand during the hours 3 to 7 PM on the average proxy day;
* Average demand from midnight to 10 AM on the event day; and
* Average demand from 10 AM to 3 PM on the event day[[5]](#footnote-5).

Equation ‑: Dissimilarity Statistic for Commercial Matching

|  |  |
| --- | --- |
| Variable | Definition |
|  | Average demand across the 2017 proxy days during the hours 3 to 7 PM |
|  | Average demand on the event day from midnight to 10 AM |
|  | Average demand on the event day from 10 AM to 3 PM |
| 1 | Commercial Summer Saver participant to be matched |
|  | Indexes the pool of control customers |

This dissimilarity statistic used was chosen as the optimal metric for matching among four alternately specified metrics and following an out-of-sample testing exercise with many propensity score matching models that suggested an alternative approach may perform better. The best metric was chosen based on pre-treatment balance measures.

Matches were chosen such that only customers in the same industry and climate zone would be matched to one another. Likewise NEM customers were only matched to other NEM customers, and customers taking the Critical Peak Pricing (CPP) electric rate or the time-of-use (TOU) electric rate were only matched to customers with the same electric rate. This approach minimizes the differences between participants and matched nonparticipants while allowing for good subgroup estimates.

The matching process simply proceeds, one Summer Saver participant at a time, by selecting the non-participant with the same industry, NEM, and pricing status and with the smallest dissimilarity statistic. A single non participant may be selected more than once as a matched control customer.

#### Load Impact Estimation

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

Within each of these program segments, load impacts were estimated for each hour of each event day for both RCT and matching customers using two approaches.

First, we simply calculated the difference between the average demand for those customers who were cycled (the treatment group) and those who were not (the control group). We refer to this simple difference in average hourly load as the “unadjusted” load impact.

However, since randomization and matching both can leave some residual differences between the treatment and control groups that is not due to the CAC cycling, we also estimate what we refer to as the “adjusted” load impact that takes into account the small differences between the treatment and control group usage and thereby improves the accuracy and precision of the estimate. This adjusted estimate of load impacts is determined by a lagged dependent variable (LDV) regression model

The regression, described in Equation 3‑2, essentially uses variation among the group that was not cycled to figure out the relationship between demand before the event and on proxy days to the demand during the event window and afterward. The regression can then make a prediction for all of the cycled customers based on that simple model. This is very similar to how a ratio adjustment works. A ratio adjustment multiplies event window demand for the control group by the difference the cycled and control demand prior to the event. An LDV model with one variable does the same thing, but it allows the adjustment to account for differences between the cycled and control group on proxy days as well.[[6]](#footnote-6)

Equation ‑: LDV Model for Estimating Impacts

|  |  |
| --- | --- |
| Variable | Definition |
|  | Average demand in the event hour being studied |
|  | An indicator for whether customer i was cycled |
|  | Average demand in the hour being studied on the average proxy day |
|  | Average demand in the event window on the average proxy day |
|  | Average demand after the event window on the average proxy day |
|  | Average demand from midnight to 7 AM on the event day |
|  | Average demand from 7 AM to 10 AM on the event day |
|  | Average demand from 10 AM to four hours before the event on the event day |
|  | Average demand during the four hours before the event |
|  | Indexes customers |
|  | Estimated impact |
|  | Estimated regression coefficients |
|  | Error term |

For estimating treatment effects, as we are doing in this setting, the adjustments from the LDV only change the estimate of the treatment effect if the group that was cycled is different from the group that was not cycled on proxy days or in the hours leading up to the event. These differences should be relatively small for most of the important treatment effect estimates since the matching and RCT performed well. When that is true, the treatment effect estimates with and without the adjustment will look similar, but the confidence intervals will be much smaller for the adjusted version because the LDV model uses the data more efficiently.

Hourly impact estimates for the residential Summer Saver population were calculated by taking a weighted average of the impact estimates for each cycling option, with weights determined by the number of tons enrolled on each cycling option, and climate zone within cycling option. Impacts for the average event day were calculated from treatment and control group load shapes averaged across 8/2/2017, 8/3/2017, 8/28/2017, 8/31/2017, and 9/1/2017. These five events were all called from 4 to 8 PM.

Ex Post Validation Analysis

Table 3‑3 compares the sample size, average CAC tonnage, and cycling option for the randomly selected test groups of residential participants. The two groups are very similar along the dimensions of CAC tonnage and cycling option – the sample sizes for both groups are about 1,600 customers, average tonnage per household is about 4.3 tons, and the share of 50% (versus 100%) cycling participants is the same.

Table ‑: 2017 Residential A and B Group Comparison  
Sample Size, Tonnage, and Cycling Options

|  |  |  |  |
| --- | --- | --- | --- |
| **Group** | **Sample Size** | **Average CAC Tonnage per Household** | **% of Customers on 50% Cycling** |
| A | 1,590 | 4.2 | 50% |
| B | 1,589 | 4.3 | 50% |
| **Total/Average** | **3,179** | **4.3** | **50%** |

Even though random assignment and statistical matching should produce research groups with similar characteristics, it is still important to compare the two groups based on electricity consumption when Summer Saver events are not in effect since, in the absence of very large samples, differences in energy consumption between them can still occur—due to chance in an RCT and due to a heterogeneous control pool with statistical matching. In 2017, the absolute hourly differences between the residential A and B groups for both cycling strategies combined during event hours on hot, nonevent days are 5% or less. For the commercial participants, matched nonparticipants were selected from the SDG&E SMB population. The absolute hourly differences between the commercial control and treatment (i.e., Summer Saver participants) on hot, nonevent days are less than 4% during event hours.

Figure 3‑1 and Figure 3‑2 illustrate these differences on seven hot nonevent days in 2017. As the figures show, the two groups are quite similar with respect to load shape and reflect the magnitude of hourly differences summarized above. Figure 3‑3 and Figure 3‑4 show the comparison of groups A and B, as well as treatment and matched control, further segmented by cycling option. At the cycling level, residential A and B groups show more substantial hourly differences for both the cycling options compared to the differences between nonevent loads when both cycles are combined. The differences are slightly larger for 50% cycling than for 100%. The commercial participant and matched control groups for the 50% and 30% cycling options also show small differences in consumption. These differences are comparable to those observed in 2016 and reflect the larger sample size that the matching approach affords.

Figure ‑: Residential A and B Group Comparison  
Average Load on the Seven Hottest 2017 Nonevent Days



Figure ‑: Commercial Matched Control and Treatment Group Comparison  
Average Load on the Seven Hottest 2017 Nonevent Days



Figure ‑: Residential A and B Group Comparison  
Average Load on the Seven Hottest 2017 Nonevent Days by Cycling Option



Figure ‑: Commercial Matched Control and Treatment Group Comparison  
Average Load on the Five Hottest 2017 Nonevent Days by Cycling Option



Ex Ante Impact Estimation Methodology

Ex ante load impacts were developed using relatively recent ex post load impacts. While reliably estimated load impacts are available going back ten years, the older load impact estimates are not likely to be as relevant as the most recent ones, due to the fact that the program’s fleet has been aging over the past ten years without any significant program efforts to refresh older equipment in field. Ex post load impacts from 2015, 2016, and 2017 were used as the foundational data for developing the ex ante model that estimates Summer Saver load impacts’ weather response.

In 2017, the majority of events were called markedly later in the day than in previous years. In estimating ex ante load impacts, we fit a single model that estimates the weather responsiveness of average ex post load impacts. Since events were called so late in the day in 2017, the average load impacts used for 2017 events are defined as the average load impact across the window 6 to 8 PM. Summer Saver events called in 2015 and 2016 occurred earlier in the day, and here the average load impacts use in ex ante estimation are defined as the average load impact across the window 3 to 5 PM. The benefit of these selections of the hours included in the averages are that none of the hours included in them are first-hour load impacts (which are usually much lower than impacts later in events) and that they result in the greatest amount of data points available for estimating the model. We refer in the remainder of this section to this set of average load impacts, the 3 to 5 PM average ex post impacts from 2015-2016 and the 6 to 8 PM average ex post impacts from 2017 as the core 2015-2017 ex post impacts.

Another important quality of the core 2015-2017 ex post load impacts used in estimating ex ante load impacts is that all ex post impacts in the estimation dataset reflect important changes to the program; the drop of the bottom 30% of electricity users that occurred in 2017 and the upcoming drop of NEM customers in 2018.[[7]](#footnote-7)

The methodology for estimating ex ante impacts in 2017 is the same for residential and commercial participants. The core 2015-2017 average ex post impact was modeled as a function of the average temperature for the first 17 hours of each event day—midnight to 5 PM (mean17). This 17-hour average is used to capture the impact of heat buildup leading up to and including the event hours. Per ton load impacts have historically been used in the Summer Saver load impact evaluation so that the load impacts would be scalable to ex ante scenarios where the tonnage and number of devices per premise may be different.

The regressions only include one explanatory variable; more complicated models were not found to perform better in prior Summer Saver evaluations, owing mostly to the relatively limited dataset of ex post load impacts that is available for ex ante estimation. Equation 3‑3 presents the model that was used to predict average ex post impacts as a function of weather. This model is estimated separately by customer class (residential and commercial) and cycling strategy. The estimated parameters from the models are used to predict load impacts under 1-in-2 and 1-in-10-year ex ante weather conditions.

Equation ‑: Ex Ante Model for Predicting Ex Post Load Impacts’ Weather Response

|  |  |
| --- | --- |
| Variable | Definition |
| *Impactd* | Core 2015-2017 average ex post impacts |
|  | Estimated constant |
|  | Estimated parameter coefficient |
|  | Average temperature over the 17 hours prior to the start of the event for each event day |
|  | The error term for each day *d* |

Figure 3‑5 and Figure 3‑6 show residential core ex post impacts from 2015, 2016, and 2017 (by cycling strategy) graphed against mean17; the average ex post load impacts (kW per ton) are represented by blue dots. The figures also show three lines, where the blue line represents the ex ante estimate of the weather responsiveness of the ex post load impacts, as estimated by the model in Equation 3-3. The blue line in both figures shows a strong weather response – the hotter it is, the higher the average Summer Saver load impacts. There are also two grey lines which represent the two ex ante models developed in the prior evaluation. In 2016, two ex ante models were developed, where one used ex post impacts from May through August events, and the second used ex post impacts from September and October events.

The 2016 load impacts did not have the benefit of the ex post load impacts that occurred at the lower temperatures between 65 and 75 °F (mean17). These impacts at lower temperature serve as a lower bound for load impacts at cool temperatures. Summer Saver load impacts will eventually become zero at even cooler temperatures but that only expected to occur during winter months when the program is not available for dispatch. With load impacts at these temperatures, a clear weather response signature is now seen for both cycling strategies; the greater weather response (i.e., steepness of the slope of the regression line) is greater as estimated year as compared to last.

Figure ‑: Average 2015–2017 Ex Post Load Impacts and 2018 Ex Ante Predictions  
for Residential 50% Cycling Participants[[8]](#footnote-8)



Figure ‑: Average 2015–2017 Ex Post Load Impacts and 2018 Ex Ante Predictions  
for Residential 100% Cycling Participants[[9]](#footnote-9)



Figure 3‑7 and Figure 3‑8 show the commercial ex post impacts from 2015, 2016, and 2017 (by cycling strategy) as a function of mean17 for commercial participants. Here again the blue dots represent the core ex post load impacts and the blue line represents the relationship of ex post load impacts to mean17. Again the grey lines are the ex ante relationships estimated by the prior load impact evaluation, where one line is for September and October events and the other is for events called May through August. As also seen for residential participants, with some empirical data now available for commercial load impacts at cooler temperature, a clear weather response is now visible.

Figure ‑: Average 2015–2017 Ex Post Load Impacts and 2018 Ex Ante Predictions  
for Nonresidential 30% Cycling Participants

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Figure ‑: Average 2015–2017 Ex Post Load Impacts and 2018 Ex Ante Predictions  
for Nonresidential 30% Cycling Participants

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After the ex ante impacts have been estimated for what would be expected for average ex post load impacts, the next step is to predict impacts for the individual hours covered by the CPUC resource adequacy window, 1 to 6 PM, which is 5 hours in duration.

To estimate hourly ex ante load impacts, we use the 2015, 2016, and 2017 load impacts[[10]](#footnote-10) to estimate the ratio of first hour, second hour, third hour, and fourth hour load impacts to the average load impacts. These ratios, calculated separately for residential and commercial segments, when applied to the predicted ex ante average load impact, provide a consistent hourly shape to ex ante load impacts. Since there are no 5-hour Summer Saver events, the middle hour (3 to 4 PM)’s ratio is a linear interpolation of the 2 to 3 PM and 4 to 5 PM’s ratios.

This method constrains the relative size of event impacts across different hours to be the same for all ex ante estimates. Event impacts vary with weather, but with this approach the ratio of the impact at 4 PM to the impact at 5 PM, for example, is always the same.

A separate ex ante model could be used for each event hour. Such a strategy would have the virtue of independently identifying the effect of weather on event impacts at different times of day. However, when there are only a moderate number of events and, for some hours, many fewer events than for other hours, that strategy risks fitting spurious trends to individual hours or trends across hours that conflict with one another. Given the highly auto correlated nature of the data, the differential impact of weather on different event hours is likely to be difficult to measure compared with the primary effect of temperature on average event impacts.

Table 3-4 illustrates how this approach to estimating the hourly shape of average load impacts plays out in ex ante load impacts for the RA window. For the case of residential 100% cycling, the load impacts for the 1-in-10 scenario are higher than those for 1-in-2, reflecting the model’s prediction for higher average load impacts under hotter weather conditions, but the relationship between the hourly load impacts and the average load impacts are constant across the 1-in-2 and 1-in-10 load impacts.

Table ‑: Hourly Load Impacts Compared to Average Impacts for Residential 100% Cycling

|  |  |  |  |
| --- | --- | --- | --- |
| **Hour of Event** | **Ratio: Hourly Impact / Core Impact** | **Hourly Impact for Typical SDG&E Event Day, 1-in-2 Weather (kW/ton)** | **Hourly Impact for Typical SDG&E Event Day, 1-in-10 Weather (kW/Ton)** |
| 1-2 PM | 0.93 | 0.09 | 0.13 |
| 2-3 PM | 1.30 | 0.12 | 0.18 |
| 3-4 PM | 1.20 | 0.11 | 0.17 |
| 4-5 PM | 1.11 | 0.10 | 0.16 |
| 5-6 PM | 0.89 | 0.08 | 0.13 |

In all prior Summer Saver load impact evaluations, at least some minimal load impacts for each hour of the RA window was available for estimating ratios relative to an average. However, in 2017, very few events were called that covered many RA window hours, so the ratios were calculated with an orientation to “first event hour”, “second event hour”, and so forth, rather than 1 PM, 2 PM, etc. The first hour load impacts are then applied as a percentage of control group load at 1 to 2 PM, the second hour load impacts are applied as a percentage of control group load at 2 to 3 PM, and so forth.

As discussed above, average ex ante load impacts were estimated directly based on ex post impacts. However, the CPUC Load Impact Protocols require that reference loads also be estimated to accompany ex ante load impacts even though they may not always be necessary for load impact estimation, as is true here. To meet this requirement, reference loads were estimated in a manner similar to the approach used for ex ante load impacts; models for estimating reference loads are estimated separately by customer type and cycling strategy. The following steps are taken to estimate reference loads:

* Average control group usage during the 6 to 8 PM time period for 2015, 2016, and 2017 event days are modeled as a function of mean17;
* The parameters from this regression were used to predict average control group usage for the period 6 to 8 PM under ex ante weather conditions;
* A ratio of average control group load for each hour of the 2015, 2016, and 2017 event days to the average 6 to 8 PM control group load on those days is calculated; and
* Control group load profiles (i.e., reference load) are derived by applying the hourly ratios to the predicted average 6 to 8 PM loads under all the ex ante weather conditions.

Finally, estimates of the ex ante snapback effect were developed in a similar manner. Snapback refers to the increase in load following termination of a load control event as a result of the increased temperature that occurs in buildings when air conditioning is cycled. As with load impacts and reference loads, snapback for residential customers was calculated by cycling strategy. The calculation consisted of the following steps:

1. Average the snapback values across the six hours after each ex post event;

2. Develop a ratio between snapback in each hour and snapback in the first hour;

3. Multiply the snapback value in the first hour by the ratios previously used to scale the ex post reference load to ex ante weather conditions; and

4. Multiply the adjusted snapback values for each set of ex ante weather conditions by the snapback ratios to get snapback values for the six hours after each ex ante event.

Commercial snapback is assumed to be zero as there is little prior evidence of CAC snapback after Summer Saver events for commercial participants.

# Ex Post Load Impact Estimates

This section contains the ex post load impact estimates for program year 2017. Residential load impacts are presented first, followed by commercial load impacts.

Residential Ex Post Load Impact Estimates

A total of 19 Summer Saver events were called in 2017 including two EM&V cold weather test events. Table 4‑1 presents ex post load impacts for the residential program segment for program years 2017 and 2016, for comparison. The 2017 ex post load impacts do not include load impacts estimates for the two EM&V cold weather events, since the whole program was not dispatched on those days.

Aggregate residential load impacts ranged from a low of 0.46 MW on September 26, 2017 to a high of 9.8 MW on September 2, 2017. The temperatures on September were also the lowest across all the 2017 events. A temperature metric that captures overnight heat buildup – the average temperature from midnight to 5PM, denoted “mean17” – was only 69 **°**F on September 26th, indicating that cooling loads that day would likely be minimal. On the other hand, mean17 on September 2 (which should be noted was also the Saturday of Labor Day weekend in 2017) was 84 **°**F. It should be noted that there were three events that were called under similarly low temperature conditions, September 5, 26, and 28. All three of those events yielded de minimus load impacts. The two days with the highest load impacts were associated with the Labor Day weekend, Friday, September 1 and Saturday, September 2, both dispatched under similar temperature conditions. All 2017 Summer Saver residential impacts are statistically significant at the 90% confidence level.

“Average Event Day” load impacts are calculated in a way such that the events included in the average are the same with respect to duration of event and time of day. It would be misleading to calculate an average event load impacts where the time of day varied – load impacts for the direct load control of residential CAC units are highly sensitive to the hour in which the event is dispatched. Here, average event day load impacts are calculated using 8/2/2017, 8/3/2017, 8/28/2017, 8/31/2017, and 9/1/2017.[[11]](#footnote-11) All five of these events were dispatched from 4 to 8 PM. Note that load impacts for these event days reflect a wide of temperature conditions. The five 2017 Summer Saver events included in the Average Event Day estimate yield an aggregate load reduction of 5.7 MW.

The Average Event Day load impact, per premise, in 2016 and 2017 were both approximately 0.42 kW. They were calculated using similar event windows (3-7 PM in 2016 and 4-8 PM in 2017) and were dispatched under similar weather conditions. The key driver of the difference between ex post load impacts in 2016 and 2017 is the number of residential customers enrolled in the program. Approximately one-third of the participants in the program were removed from participation on the basis of low electricity usage; the intent of this action was to remove customers from the program who do not use their CAC unit. As we will show below, there is evidence that the reference load for the average customer has indeed increased since this enrollment drop has occurred, but the hoped-for boost in average load impacts did not seem to have materialized. Nexant recommends an analysis of the customers who were selected for de-activation to assess whether it could be optimized for better identifying non-CAC users (rather than lower usage customers).

Table ‑: Summer Saver 2017 and 2016 Residential Ex Post Load Impact Estimates

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Year** | **Date** | **Impact** | | | **Mean17 (°F)** |
| **Per CAC Unit (kW)** | **Per Premise (kW)** | **Aggregate (MW)** |
| 2016 | 6/20/2016 | 0.27 | 0.32 | 6.20 | 82 |
| 7/22/2016 | 0.56 | 0.67 | 12.87 | 80 |
| 8/15/2016 | 0.45 | 0.54 | 10.39 | 80 |
| 9/26/2016 | 0.34 | 0.40 | 7.69 | 80 |
| 9/27/2016 | 0.18 | 0.21 | 4.06 | 84 |
| **Average\*** | **0.36** | **0.42** | **8.13** | **81** |
| 2017 | 8/1/2017 | 0.31 | 0.37 | 5.72 | 76 |
| 8/2/2017 | 0.19 | 0.23 | 3.12 | 78 |
| 8/3/2017 | 0.32 | 0.39 | 5.33 | 80 |
| 8/7/2017 | 0.14 | 0.17 | 2.34 | 74 |
| 8/8/2017 | 0.20 | 0.24 | 3.34 | 75 |
| 8/28/2017 | 0.31 | 0.36 | 5.04 | 76 |
| 8/29/2017 | 0.36 | 0.42 | 5.87 | 78 |
| 8/31/2017 | 0.43 | 0.51 | 7.02 | 82 |
| 9/1/2017 | 0.50 | 0.59 | 8.18 | 84 |
| 9/2/2017 | 0.59 | 0.71 | 9.78 | 84 |
| 9/5/2017 | 0.19 | 0.22 | 3.11 | 74 |
| 9/11/2017 | 0.19 | 0.22 | 3.09 | 78 |
| 9/12/2017 | 0.11 | 0.13 | 1.85 | 75 |
| 9/25/2017 | 0.03 | 0.03 | 0.48 | 70 |
| 9/26/2017 | 0.03 | 0.03 | 0.46 | 69 |
| 9/28/2017 | 0.05 | 0.06 | 0.88 | 70 |
| 10/24/2017 | 0.38 | 0.45 | 6.29 | 82 |
| **Average\*\*** | **0.35** | **0.42** | **5.74** | **80** |
| \* Reflects the average 2016 Summer Saver event (all events 3-7 PM) | | | |  |  |
| \*\* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |  |

Table 4‑2 shows the average per premise reference loads, load impacts, and percent impact for residential customers by cycling option. On the average event day, the reference load for the 50% cycling strategy group was nearly 25% higher than the reference load for the 100% cycling strategy. This suggests that customers who use their CAC units more are less likely to select the 100% cycling option. So, even though the cycling percentage between these groups differs by a factor of two, load impacts for the 100% group are only about 35% higher than that of the 50% cycling segment since the reference loads for the 50% cycling customers are commensurately higher. On the average event day, reference load for customers in the 50% cycling group is 2.4 kW per premise and 1.77 kW per premise for customer in the 100% cycling group. Per premise load impacts on the average event day are 0.35 kW for the 50% cycling group and 0.53 kW for the 100% cycling group. Load impacts are at their highest on September 2, with 100% cycling participants delivering 0.97 kW in per premise load impacts and 50% cycling delivering 0.54 kW.

Table ‑: Summer Saver 2017 Residential Average (per Premise) Reference Load, Impacts, and Percent Impacts by Cycling Option

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Event Date | Average Reference Load per Premise (kW) | | Average Load Impact per Premise (kW) | | Average Percent Impact | |
| **50%** | **100%** | **50%** | **100%** | **50%** | **100%** |
| 8/1/2017 | 2.00 | 1.50 | 0.34 | 0.41 | 17% | 27% |
| 8/2/2017 | 1.84 | 1.45 | 0.18 | 0.29 | 10% | 20% |
| 8/3/2017 | 2.25 | 1.64 | 0.30 | 0.53 | 13% | 33% |
| 8/7/2017 | 1.81 | 1.46 | 0.17 | 0.18 | 9% | 12% |
| 8/8/2017 | 1.89 | 1.44 | 0.22 | 0.28 | 11% | 19% |
| 8/28/2017 | 2.22 | 1.59 | 0.32 | 0.44 | 14% | 28% |
| 8/29/2017 | 2.66 | 2.09 | 0.36 | 0.52 | 14% | 25% |
| 8/31/2017 | 2.61 | 1.96 | 0.43 | 0.64 | 16% | 33% |
| 9/1/2017 | 2.87 | 2.19 | 0.50 | 0.73 | 17% | 33% |
| 9/2/2017 | 3.29 | 2.66 | 0.54 | 0.97 | 16% | 37% |
| 9/5/2017 | 1.78 | 1.39 | 0.20 | 0.26 | 11% | 19% |
| 9/11/2017 | 2.02 | 1.64 | 0.15 | 0.35 | 7% | 21% |
| 9/12/2017 | 1.63 | 1.28 | 0.13 | 0.13 | 8% | 10% |
| 9/25/2017 | 1.08 | 0.96 | 0.03 | 0.05 | 3% | 6% |
| 9/26/2017 | 1.08 | 0.92 | 0.05 | 0.01 | 4% | 1% |
| 9/28/2017 | 1.25 | 1.05 | 0.05 | 0.09 | 4% | 9% |
| 10/24/2017 | 2.26 | 1.52 | 0.44 | 0.50 | 19% | 32% |
| **Average\*** | **2.36** | **1.77** | **0.35** | **0.53** | **15%** | **30%** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | | | |

Aggregate ex post load impacts for residential portion of Summer Saver are presented in Table 4‑3 for each event day and are segmented by cycling option. Each cycling option contributes roughly half of the total residential load impacts. On the average event day, the 50% cycling participants deliver about 3 MW load reduction while the 100% cycling participants contribute a bit less, 2.7 MW. On September 2, these proportions are closer – 50% cycling provides 4.8 MW and 100% cycling provides 4.9 MW of load impacts.

Table ‑: Summer Saver 2017 Residential Average (per Premise) and Aggregate Load Impacts by Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Event Date | Average Load Impact per Premise (kW) | | Aggregate Load Impact (MW) | |
| **50%** | **100%** | **50%** | **100%** |
| 8/1/2017 | 0.34 | 0.41 | 3.30 | 2.37 |
| 8/2/2017 | 0.18 | 0.29 | 1.58 | 1.47 |
| 8/3/2017 | 0.30 | 0.53 | 2.67 | 2.68 |
| 8/7/2017 | 0.17 | 0.18 | 1.49 | 0.88 |
| 8/8/2017 | 0.22 | 0.28 | 1.94 | 1.39 |
| 8/28/2017 | 0.32 | 0.44 | 2.80 | 2.19 |
| 8/29/2017 | 0.36 | 0.52 | 3.20 | 2.60 |
| 8/31/2017 | 0.43 | 0.64 | 3.76 | 3.23 |
| 9/1/2017 | 0.50 | 0.73 | 4.44 | 3.67 |
| 9/2/2017 | 0.54 | 0.97 | 4.77 | 4.87 |
| 9/5/2017 | 0.20 | 0.26 | 1.72 | 1.29 |
| 9/11/2017 | 0.15 | 0.35 | 1.32 | 1.76 |
| 9/12/2017 | 0.13 | 0.13 | 1.17 | 0.65 |
| 9/25/2017 | 0.03 | 0.05 | 0.24 | 0.25 |
| 9/26/2017 | 0.05 | 0.01 | 0.42 | 0.06 |
| 9/28/2017 | 0.05 | 0.09 | 0.45 | 0.43 |
| 10/24/2017 | 0.44 | 0.50 | 3.87 | 2.49 |
| **Average\*** | **0.35** | **0.53** | **3.06** | **2.65** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

A growing and important customer segment at SDG&E is the population of residential customers with net energy metering (NEM) billing arrangements. These customers have solar photo-voltaic (PV) generating units installed at their home, which typically generate a substantial portion of the home’s electricity needs when the sun is shining. Summer Saver load impacts for customers with NEM status are even more sensitive to the time of day that events are dispatched. If Summer Saver events are called early in the day when PV units are producing electricity, the load impacts that SDG&E realizes are zero. But if a Summer Saver event is called after the sun goes down, NEM customers can contribute to the program’s load impacts. Table 4‑4 shows the estimated event impacts for residential NEM and non-NEM customers for each of the events and Average Event Day. On a per premise basis, the NEM customers have higher load impacts than non-NEM customers for most of the events as well as the average event. The highest NEM customer per premise load impact was 0.98 kW on September 2 which was a Saturday. The highest non-NEM customer load impact was 0.62 kW also on September 2. The aggregate load impact for the Average Event Day for NEM customers was 1.31 MW while it was 4.42 MW for Non-NEM customers, based on Average Event Day per premise load impacts of 0.50 kW and 0.39 kW, respectively.

Table ‑: Summer Saver 2017 Residential Average (per Premise) and Aggregate Load Impacts by NEM Status

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Event Date | Average Load Impact per Premise (kW) | | Aggregate Load Impact (MW) | |
| **NEM** | **Non-NEM** | **NEM** | **Non-NEM** |
| 8/1/2017 | 0.35 | 0.37 | 1.02 | 4.57 |
| 8/2/2017 | 0.27 | 0.22 | 0.70 | 2.42 |
| 8/3/2017 | 0.45 | 0.36 | 1.20 | 4.01 |
| 8/7/2017 | 0.27 | 0.15 | 0.71 | 1.64 |
| 8/8/2017 | 0.33 | 0.22 | 0.87 | 2.42 |
| 8/28/2017 | 0.44 | 0.34 | 1.17 | 3.82 |
| 8/29/2017 | 0.44 | 0.42 | 1.15 | 4.73 |
| 8/31/2017 | 0.69 | 0.46 | 1.81 | 5.10 |
| 9/1/2017 | 0.59 | 0.60 | 1.54 | 6.72 |
| 9/2/2017 | 0.98 | 0.62 | 2.57 | 6.95 |
| 9/5/2017 | 0.27 | 0.22 | 0.69 | 2.44 |
| 9/11/2017 | 0.12 | 0.25 | 0.31 | 2.76 |
| 9/12/2017 | 0.18 | 0.13 | 0.48 | 1.43 |
| 9/25/2017 | 0.01 | 0.03 | 0.02 | 0.39 |
| 9/26/2017 | 0.07 | 0.03 | 0.18 | 0.29 |
| 9/28/2017 | 0.10 | 0.05 | 0.26 | 0.54 |
| 10/24/2017 | 0.63 | 0.42 | 1.66 | 4.69 |
| **Average\*** | **0.50** | **0.39** | **1.31** | **4.42** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

Table 4‑5 shows estimated event impacts for residential customers segmented by usage quintiles, and

Table 4‑6 shows the same, but segmented by usage deciles. Each customer was placed into 1 of 5 quintiles (or one of 10 deciles, in the case of

Table 4‑6 based on their average usage during peak hours from 11 AM to 6 PM on a proxy event days in 2017.[[12]](#footnote-12) Impact estimates were calculated separately for each quintile and decile using the average event hour of the 2017 Average Event Day to determine reference loads and load impacts. Load impacts by quantile largely increase with electricity usage, however the lower quantiles’ load impacts are often perturbed by the presence of negative net load in the case of customers with NEM status, also contributing to relatively large standard errors. In the case of the largest quintiles, per premise load impacts top out at 0.53 kW for 50% cycling and 1.02 kW for 100% cycling; for the largest decile, 50% cycling load impacts peak at 0.62 kW and 100% cycling load impacts peak at 1.13 kW.

Table ‑: Summer Saver 2017 Residential Average (per Premise) Load Impacts by Usage Quintile and Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Quintile** | **Residential Customers** | | | |
| **50% Cycling** | | **100% Cycling** | |
| **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** | **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** |
| 1 | 0.24 | 0.05 | 0.40 | 0.06 |
| 2 | 0.23 | 0.04 | 0.24 | 0.04 |
| 3 | 0.28 | 0.05 | 0.36 | 0.04 |
| 4 | 0.45 | 0.05 | 0.62 | 0.05 |
| 5 | 0.53 | 0.06 | 1.02 | 0.07 |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

Table ‑: Summer Saver 2017 Residential Average (per Premise) Load Impacts by Usage Decile and Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Decile | Residential Customers | | | |
| **50% Cycling** | | **100% Cycling** | |
| **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** | **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** |
| 1 | 0.31 | 0.09 | 0.51 | 0.10 |
| 2 | 0.16 | 0.06 | 0.27 | 0.06 |
| 3 | 0.18 | 0.06 | 0.20 | 0.04 |
| 4 | 0.29 | 0.06 | 0.27 | 0.06 |
| 5 | 0.24 | 0.06 | 0.34 | 0.06 |
| 6 | 0.31 | 0.07 | 0.37 | 0.06 |
| 7 | 0.48 | 0.07 | 0.56 | 0.07 |
| 8 | 0.42 | 0.07 | 0.69 | 0.07 |
| 9 | 0.45 | 0.08 | 0.92 | 0.09 |
| 10 | 0.62 | 0.10 | 1.13 | 0.11 |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

Commercial Ex Post Load Impact Estimates

Table 4‑7 presents ex post load impact estimates for commercial customers for each 2017 event day (excluding the two EM&V cool weather event days) and the Average Event Day. Here again, the Average Event Day load impacts are calculated using 8/2/2017, 8/3/2017, 8/28/2017, 8/31/2017, and 9/1/2017, and excluding 8/1/2017. All five of these events were dispatched from 4 to 8 PM. The 2016 ex post load impacts are shown for comparison. The commercial segment of the program is smaller than the residential segment; commercial customers represent about 24% of total Summer Saver participants and approximately 39% of enrolled CAC tonnage. Not only are the numbers of enrolled customers and cooling tons smaller, but the per premise load impacts for commercial customers are smaller than those of residential customers. This is due in part to the fact that enrolled commercial CAC units are, on average, cycled less than the residential CAC units – either 30% or 50% (as opposed to 50% or 100% in the case of the residential segment). Commercial load impacts are also lower than residential load impacts due to the timing of Summer Saver events, which in 2017 are timed when pre premise load is ramping down towards the commercial daily minimum usage that occurs in the evening and overnight hours, as opposed to during the residential daily maximum usage that occurs at the same time.

Commercial aggregate impacts vary from a low of -0.16 MW (not statistically significant) on September 25 to a high of 1.65 MW on August 3. Commercial load impact peaks occurs on a different day than the residential segment, the highest commercial load impact of 0.37 kW per premise occurs on August 3 (a Thursday) while the highest residential load impact occurred on September 2, the Saturday of Labor Day weekend.

The 2017 impacts are very similar to those observed in 2016; the Average Event Day load impact in 2016 (where events where called from 3-7PM) was 0.28 kW per premise and the Average Event Day in load impact was 0.21 in 2017 (where events were called from 4-8 PM). The very small and/or negative load impacts in 2017 are not statistically significant.

Table ‑: Summer Saver 2016 and 2017 Commercial Ex Post Load Impact Estimates

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Year | Date | Impact | | | Mean17 (°F) |
| **Per CAC Unit (kW)** | **Per Premise (kW)** | **Aggregate (MW)** |
| 2016 | 6/20/2016 | 0.16 | 0.39 | 1.72 | 80 |
| 7/22/2016 | 0.16 | 0.37 | 1.66 | 79 |
| 8/15/2016 | 0.13 | 0.31 | 1.38 | 79 |
| 9/26/2016 | 0.10 | 0.24 | 1.08 | 81 |
| 9/27/2016 | 0.04 | 0.10 | 0.45 | 84 |
| **Average\*** | **0.12** | **0.28** | **1.26** | **81** |
| 2017 | 8/1/2017 | 0.08 | 0.19 | 0.83 | 80 |
| 8/2/2017 | 0.09 | 0.20 | 0.90 | 83 |
| 8/3/2017 | 0.16 | 0.37 | 1.65 | 81 |
| 8/7/2017 | -0.01 | -0.01 | -0.06 | 75 |
| 8/8/2017 | 0.08 | 0.20 | 0.89 | 77 |
| 8/28/2017 | 0.10 | 0.24 | 1.06 | 81 |
| 8/29/2017 | 0.00 | 0.00 | -0.01 | 83 |
| 8/31/2017 | 0.11 | 0.26 | 1.15 | 85 |
| 9/1/2017 | 0.06 | 0.15 | 0.66 | 90 |
| 9/2/2017 | 0.09 | 0.20 | 0.90 | 91 |
| 9/5/2017 | 0.02 | 0.05 | 0.22 | 79 |
| 9/11/2017 | 0.03 | 0.08 | 0.35 | 78 |
| 9/12/2017 | 0.01 | 0.02 | 0.07 | 75 |
| 9/25/2017 | -0.01 | -0.03 | -0.16 | 75 |
| 9/26/2017 | 0.04 | 0.09 | 0.42 | 75 |
| 9/28/2017 | 0.01 | 0.01 | 0.05 | 76 |
| 10/24/2017 | 0.14 | 0.33 | 1.49 | 99 |
| **Average\*\*** | **0.09** | **0.21** | **0.93** | **84** |
| \* Reflects the average 2016 Summer Saver event (all events 3-7 PM)  \*\* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | | |

A comparison of average impacts per CAC unit in Table 4‑1 and Table 4‑7 reveals that the Average Event Day impact per CAC unit for commercial customers is only 0.09 kW while it is 0.35 kW for residential customers. Much of the difference is due to the lower average cycling strategy used for commercial customers, but per CAC unit load impacts can be compared across residential and commercial participants on the same cycling strategy to determine if other factors may be at play.

Table 4‑8 shows the comparison of average load impact per CAC for 50% cycling residential and 50% commercial customers, respectively. Considering only 50% cycling for the commercial segment only raises the Average Event Day load impact per CAC to 0.10 kW, nearly a third as much as the residential per CAC load impact on the Average Event Day of 0.30 kW.

Table ‑: Comparison of 2017 Residential and Commercial   
Summer Saver 50% Cycling Load Impacts

|  |  |  |
| --- | --- | --- |
| Event Date | Average Load Impact per CAC Unit (kW) | |
| **Residential 50%** | **Commercial 50%** |
| 8/1/2017 | 0.30 | 0.09 |
| 8/2/2017 | 0.15 | 0.10 |
| 8/3/2017 | 0.26 | 0.18 |
| 8/7/2017 | 0.15 | -0.01 |
| 8/8/2017 | 0.19 | 0.10 |
| 8/28/2017 | 0.27 | 0.13 |
| 8/29/2017 | 0.31 | -0.02 |
| 8/31/2017 | 0.37 | 0.13 |
| 9/1/2017 | 0.43 | 0.08 |
| 9/2/2017 | 0.46 | 0.09 |
| 9/5/2017 | 0.17 | 0.03 |
| 9/11/2017 | 0.13 | 0.07 |
| 9/12/2017 | 0.11 | 0.00 |
| 9/25/2017 | 0.02 | 0.02 |
| 9/26/2017 | 0.04 | 0.04 |
| 9/28/2017 | 0.04 | 0.00 |
| 10/24/2017 | 0.38 | 0.16 |
| **Average\*** | **0.30** | **0.10** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | |

Figure 4‑1 shows the reference and observed loads for residential and commercial 50% cycling customers on the 2017 Average Event Day. Load impacts during the 2017 Average Event Day are optimized due to the timing of the event, 4-8 PM, for residential customers. But the event timing for commercial customers is less than optimal, occurring when occupancy and business processes are winding down. Another differentiating factor (which would need to be validated by a field study) may be that due to the advanced age of the Summer Saver program, fewer commercial load control devices are still installed and functional. Many businesses have contracts with HVAC contractors for regular maintenance, and HVAC contractors may be inclined to remove or disconnect equipment such as load control devices that they may not recognize as legitimate equipment.

Figure ‑: Reference and Observed Loads for the Average Event Day –   
2017 Residential and Commercial 50% Cycling



Table 4‑9 presents aggregate load impacts for commercial participants on each event day segmented by cycling strategy. On a per premise basis, load impacts for the 50% cycling option range from -0.04 kW to 0.40 kW. Per premise load impacts for the 30% cycling option range from -0.25 kW to 0.28 kW. On the average event day, load impacts for 50% cycling were approximately 70% larger than those produced by the 30% cycling strategy. It should be noted, however, that at the cycling strategy reporting level, only the Average Event Day impacts are statistically significant at the 90% level of confidence.

Table ‑: Summer Saver 2017 Commercial Average (per Premise) and Aggregate Load Impacts by Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Event Date | Average Impact per Premise (kW) | | Aggregate Impact (MW) | |
| **30%** | **50%** | **30%** | **50%** |
| 8/1/2017 | 0.19 | 0.19 | 0.18 | 0.68 |
| 8/2/2017 | 0.19 | 0.22 | 0.19 | 0.77 |
| 8/3/2017 | 0.28 | 0.40 | 0.27 | 1.39 |
| 8/7/2017 | 0.02 | -0.02 | 0.02 | -0.07 |
| 8/8/2017 | 0.14 | 0.21 | 0.14 | 0.75 |
| 8/28/2017 | 0.06 | 0.29 | 0.05 | 1.02 |
| 8/29/2017 | 0.12 | -0.04 | 0.11 | -0.13 |
| 8/31/2017 | 0.20 | 0.28 | 0.20 | 0.97 |
| 9/1/2017 | 0.02 | 0.18 | 0.02 | 0.65 |
| 9/2/2017 | 0.21 | 0.21 | 0.20 | 0.73 |
| 9/5/2017 | 0.04 | 0.06 | 0.04 | 0.19 |
| 9/11/2017 | -0.12 | 0.16 | -0.11 | 0.56 |
| 9/12/2017 | 0.08 | 0.00 | 0.08 | -0.01 |
| 9/25/2017 | -0.25 | 0.04 | -0.24 | 0.13 |
| 9/26/2017 | 0.05 | 0.09 | 0.05 | 0.31 |
| 9/28/2017 | 0.14 | -0.01 | 0.14 | -0.03 |
| 10/24/2017 | 0.24 | 0.35 | 0.23 | 1.24 |
| **Average\*** | **0.15** | **0.23** | **0.15** | **0.79** |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

Table 4‑10 and Table 4‑11 show the estimated event impacts for commercial customers segmented by usage quintiles and deciles, respectively, using the same methodology as was used to segment residential customers. The tables show both the average impact as well as the standard error of the estimates for each quintile by cycle. The estimates at the quintile and decile level have very large standard errors and the customer count in each group is very small; the average per premise load impacts do not follow the same trends that the residential segments do. A robust set of estimates segmented by customer size would require a larger number of customers to analyze in the case of commercial Summer Saver participants.

Table ‑: Summer Saver 2017 Commercial Average (per Premise) Load Impacts by Usage Quintile and Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Quintile | Commercial Customers | | | |
| **30% Cycling** | | **50% Cycling** | |
| **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** | **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** |
| 1 | 0.04 | 0.09 | 0.07 | 0.04 |
| 2 | 0.13 | 0.07 | 0.02 | 0.03 |
| 3 | 0.24 | 0.10 | 0.23 | 0.04 |
| 4 | 0.38 | 0.12 | 0.16 | 0.06 |
| 5 | 0.04 | 0.30 | 0.74 | 0.16 |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

Table ‑: Summer Saver 2017 Commercial Average (per Premise) Load Impacts by Usage Decile and Cycling Option

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Decile | Commercial Customers | | | |
| **30% Cycling** | | **50% Cycling** | |
| **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** | **Average\* Per Premise Load Impact (kW)** | **Load Impact Standard Error (kW)** |
| 1 | 0.08 | 0.11 | 0.05 | 0.07 |
| 2 | 0.08 | 0.11 | 0.05 | 0.04 |
| 3 | 0.24 | 0.09 | -0.02 | 0.04 |
| 4 | 0.00 | 0.11 | 0.06 | 0.04 |
| 5 | 0.25 | 0.14 | 0.26 | 0.06 |
| 6 | 0.20 | 0.13 | 0.21 | 0.06 |
| 7 | 0.54 | 0.18 | 0.17 | 0.08 |
| 8 | 0.26 | 0.15 | 0.17 | 0.09 |
| 9 | 0.11 | 0.27 | 0.40 | 0.14 |
| 10 | 0.02 | 0.53 | 1.14 | 0.30 |
| \* Reflects the average 4-8 PM weekday 2017 Summer Saver event | | | | |

# Ex Ante Load Impact Estimates

This section presents ex ante load impact estimates for SDG&E’s Summer Saver program. Residential ex ante estimates are provided first, followed by estimates for nonresidential customers. These estimates are compared to the ex ante estimates produced in 2016. The last subsection provides a detailed discussion of the differences between ex post and ex ante estimates.

## Ex Ante Estimates

The models described in Section 3 were used to estimate load impacts based on ex ante event weather conditions and enrollment projections for the years 2018–2028. As was the case in the prior Summer Saver evaluation, program enrollment is expected to change substantially in the upcoming year of the forecast horizon. Therefore, the tables in this section will show annual load impact estimates for the 2018–2028 forecast horizon, under the assumptions of how the program will change in future years. The most significant changes will occur on the residential side, with NEM customers no longer permitted to enroll in Summer Saver starting in 2018.

The Protocols require that ex ante load impacts to be estimated assuming weather conditions associated with both normal and extreme utility operating conditions. Normal conditions are defined as those that would be expected to occur once every 2 years (1-in-2 conditions) and extreme conditions are those that would be expected to occur once every 10 years (1-in-10 conditions). From 2008 to 2014, the California IOUs based their ex ante weather conditions on system operating conditions specific to each individual utility for estimating demand response load impacts. However, ex ante weather conditions could alternatively reflect 1-in-2 and 1-in-10 year operating conditions for the CAISO rather than the operating conditions for each IOU. While the Protocols remain silent on this issue, a letter from the CPUC Energy Division to the IOUs dated October 21, 2014 directed the utilities to provide impact estimates under two sets of operating conditions starting with the April 1, 2015 filings: one reflecting operating conditions for each IOU and one reflecting operating conditions for the CAISO system.

In order to meet this new requirement, California’s IOUs contracted with Nexant in 2014 to develop ex ante weather conditions based on the peaking conditions for each utility and for the CAISO system. Nexant subsequently updated these weather conditions for SDG&E in 2017.[[13]](#footnote-13) The new ex ante weather dataset utilizes a shorter historical window of weather conditions that better reflect relatively recent warming trends.

Ex ante weather conditions for CAISO peaking conditions and SDG&E peaking conditions may differ, and the extent to which that can happen largely depends on the correlation between individual utility and CAISO peak loads. Based on CAISO and SDG&E system peak loads for the top 25 CAISO system load days each year from 2006 to 2013, the correlation coefficient for SDG&E is 0.56, indicating that there are many days on which the CAISO system loads are high while SDG&E loads are more modest. This correlation for SDG&E tends to be weakest when CAISO loads have been below 46,000 MW. CAISO loads often reach 43,000 MW when loads in the Los Angeles area are extreme but San Diego loads are moderate—or vice-versa. However, whenever CAISO loads have exceeded 45,000 MW, loads typically have been high across all three IOUs.

Table 5‑1 and Table 5‑2 show the Summer Saver residential and commercial enrollment-weighted average temperature from midnight to 5 PM (mean17) for the typical event day and the monthly system peak day under the four sets of weather conditions for which load impacts are estimated. The differences in mean17 values based on SDG&E peak conditions and CAISO peak conditions, and also based on normal and extreme weather, can be significant. For example, the residential Summer Saver-enrollment weighted temperature on a 1-in-10 SDG&E September peak day is 85 ºF, while on a CAISO 1-in-10 peak September day it is 82 ºF. There are also large differences across months. As seen below, even small differences in the value of mean17 can have large impacts on aggregate load impacts.

Table ‑: Residential Summer Saver Enrollment-weighted Ex Ante Weather Conditions (mean17)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Customer Type | Cycling | Day Type | CAISO System Peak Weather (ºF) | | SDG&E System Peak Weather (ºF) | |
| **1-in-2** | **1-in-10** | **1-in-2** | **1-in-10** |
| Residential | 50% | Typical Event Day | 76 | 80 | 76 | 81 |
| May Peak Day | 68 | 76 | 70 | 77 |
| June Peak Day | 68 | 82 | 68 | 79 |
| July Peak Day | 73 | 77 | 76 | 78 |
| August Peak Day | 81 | 80 | 80 | 82 |
| September Peak Day | 83 | 82 | 82 | 85 |
| October Peak Day | 73 | 78 | 76 | 79 |
| 100% | Typical Event Day | 76 | 80 | 76 | 81 |
| May Peak Day | 67 | 76 | 70 | 77 |
| June Peak Day | 68 | 82 | 68 | 79 |
| July Peak Day | 73 | 77 | 76 | 78 |
| August Peak Day | 81 | 80 | 79 | 82 |
| September Peak Day | 83 | 82 | 82 | 85 |
| October Peak Day | 73 | 78 | 76 | 79 |

Table ‑: Commercial Summer Saver Enrollment-weighted Ex Ante Weather Conditions (mean17)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Customer Type** | **Cycle** | **Day Type** | **CAISO System Peak Weather (ºF)** | | **SDG&E System Peak Weather (ºF)** | |
| **1-in-2** | **1-in-10** | **1-in-2** | **1-in-10** |
| Commercial | 30% | Typical Event Day | 76 | 79 | 76 | 81 |
| May Peak Day | 67 | 76 | 70 | 77 |
| June Peak Day | 68 | 81 | 68 | 78 |
| July Peak Day | 72 | 76 | 75 | 78 |
| August Peak Day | 80 | 79 | 79 | 82 |
| September Peak Day | 82 | 82 | 82 | 85 |
| October Peak Day | 73 | 78 | 75 | 79 |
| 50% | Typical Event Day | 75 | 79 | 76 | 80 |
| May Peak Day | 67 | 76 | 70 | 77 |
| June Peak Day | 67 | 80 | 68 | 78 |
| July Peak Day | 72 | 76 | 75 | 77 |
| August Peak Day | 80 | 79 | 78 | 82 |
| September Peak Day | 82 | 82 | 82 | 84 |
| October Peak Day | 73 | 78 | 75 | 79 |

Summer Saver enrollment is assumed to attrit over the forecast horizon. Table 5‑3 shows the enrollment forecast for each customer segment for the summer months of each year from 2018 to 2023. The residential enrollment forecast importantly reflects the exclusion of NEM customers starting in 2018. The forecast reflects an annual enrollment decrease from 2018-2022 of approximately 0.4% for 50% cycling residential customers and 13% for 100% cycling residential customers. The forecast reflects an annual enrollment decrease from 2018-2022 of approximately 8% for 30% cycling commercial customers and 3% for 50% cycling commercial customers.

Table ‑: 2018–2028 Summer Saver Program Enrollment Forecast

Number of Enrolled Customers

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Customer Type** | **Forecast Year** | **Forecast Month** | | | | | |
| **May** | **June** | **July** | **August** | **September** | **October** |
| Residential | 2018 | 12,154 | 12,154 | 12,154 | 12,154 | 12,154 | 12,154 |
| 2019 | 11,606 | 11,606 | 11,606 | 11,606 | 11,606 | 11,606 |
| 2020 | 11,123 | 11,123 | 11,123 | 11,123 | 11,123 | 11,123 |
| 2021 | 10,698 | 10,698 | 10,698 | 10,698 | 10,698 | 10,698 |
| 2022-2028 | 10,323 | 10,323 | 10,323 | 10,323 | 10,323 | 10,323 |
| Commercial | 2018 | 4,680 | 4,680 | 4,680 | 4,680 | 4,680 | 4,680 |
| 2019 | 4,504 | 4,504 | 4,504 | 4,504 | 4,504 | 4,504 |
| 2020 | 4,336 | 4,336 | 4,336 | 4,336 | 4,336 | 4,336 |
| 2021 | 4,176 | 4,176 | 4,176 | 4,176 | 4,176 | 4,176 |
| 2022-2028 | 4,024 | 4,024 | 4,024 | 4,024 | 4,024 | 4,024 |

While Summer Saver events can be called any time between noon and 9 PM, ex ante load impacts reported here represent the average load impact across the hours from 1 to 6 PM, reflecting the peak period as defined by the CPUC for determining resource adequacy requirements.

Table 5-4 summarizes the average and aggregate load impact estimates per premise under SDG&E-specific peaking conditions and CAISO peaking conditions for 2018. For residential customers, 2018 reflects the most significant changes to enrollment due to the drop of residential NEM customers from the program. The per premise load impacts are highest under both CAISO and SDG&E system September monthly peak conditions for residential and commercial. Similarly, the per premise impacts are lowest for the May monthly peak for all scenarios and customer types.

For a typical event day in a 1-in-2 year under SDG&E-specific weather conditions, the impact per premise is 0.42 kW for residential customers and 0.62 kW under 1-in-10 weather conditions. The hottest weather conditions are expected in the month of September, where under the SDG&E-specific 1-in-2 conditions per premise load impacts peak at 0.67 kW and at 0.79 kW under 1-in-10 conditions. Large differences between 1-in-2 and 1-in-10 load impacts are driven by large differences in mean17, which vary by 5 or 6 degrees across some of the above conditions; a difference of 5 degrees on average over 17 hours represents a very large difference in temperature conditions and air conditioning requirements.

Load impacts for commercial customers follow similar patterns. Under the SDG&E peaking scenarios, typical event day per premise load impacts are 0.39 kW under the 1-in-2 assumption and 0.55 kW under the 1-in-10 assumption. In September, commercial per premise load impacts peak at 0.63 kW under 1-in-2 conditions and 0.71 under 1-in-10 conditions. While the commercial load impacts are very similar to residential impacts, they on the one hand reflect lower cycling strategies and on the other reflect more CAC units enrolled in the program per premise. The net effect is that commercial load impacts are similar, but somewhat lower, than residential. The milder cycling strategies also yield less-sensitive load impacts for commercial participants as compared to residential participants.

The aggregate program load reduction potential for residential customers is 5.1 MW for a typical event day under SDG&E-specific 1-in-2 year weather conditions in 2018 and 1.8 MW for commercial customers. Under SDG&E-specific 1-in-10 year weather conditions, the aggregate impacts for residential and commercial customers are 7.5 MW and 2.5 MW, respectively. The aggregate impacts under CAISO weather conditions are slightly lower for both weather year types.

Table ‑: 2018 Ex Ante Load Impact Estimates by CAISO and SDG&E-specific Weather and Day Type

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Customer Type | Day Type | Per Premise Impact (kW) | | | | Aggregate Impact (MW) | | | |
| **CAISO 1-in-2** | **SDGE 1-in-2** | **CAISO 1-in-10** | **SDGE 1-in-10** | **CAISO 1-in-2** | **SDGE 1-in-2** | **CAISO 1-in-10** | **SDGE 1-in-10** |
| Residential | Typical Event Day | 0.41 | 0.42 | 0.57 | 0.62 | 5.0 | 5.1 | 7.0 | 7.5 |
| May Monthly Peak | 0.06 | 0.16 | 0.41 | 0.46 | 0.7 | 1.9 | 5.0 | 5.7 |
| June Monthly Peak | 0.08 | 0.07 | 0.64 | 0.53 | 0.9 | 0.8 | 7.8 | 6.4 |
| July Monthly Peak | 0.27 | 0.40 | 0.46 | 0.50 | 3.3 | 4.8 | 5.5 | 6.1 |
| August Monthly Peak | 0.60 | 0.55 | 0.56 | 0.66 | 7.3 | 6.7 | 6.8 | 8.0 |
| September Monthly Peak | 0.68 | 0.67 | 0.64 | 0.79 | 8.3 | 8.1 | 7.8 | 9.6 |
| October Monthly Peak | 0.29 | 0.40 | 0.50 | 0.54 | 3.5 | 4.8 | 6.1 | 6.5 |
| Commercial | Typical Event Day | 0.37 | 0.39 | 0.51 | 0.55 | 1.7 | 1.8 | 2.4 | 2.6 |
| May Monthly Peak | 0.05 | 0.16 | 0.38 | 0.44 | 0.2 | 0.7 | 1.8 | 2.1 |
| June Monthly Peak | 0.06 | 0.07 | 0.55 | 0.46 | 0.3 | 0.3 | 2.6 | 2.1 |
| July Monthly Peak | 0.24 | 0.36 | 0.39 | 0.43 | 1.1 | 1.7 | 1.8 | 2.0 |
| August Monthly Peak | 0.53 | 0.49 | 0.50 | 0.60 | 2.5 | 2.3 | 2.4 | 2.8 |
| September Monthly Peak | 0.63 | 0.63 | 0.60 | 0.71 | 2.9 | 3.0 | 2.8 | 3.3 |
| October Monthly Peak | 0.26 | 0.36 | 0.48 | 0.50 | 1.2 | 1.7 | 2.2 | 2.3 |

### Comparison of Ex Ante Load Impacts by Month

September ex ante conditions are much hotter than typical event day conditions and therefore have the highest impacts. In 2018, the residential program is estimated to provide an average impact of 9.6 MW over the 5-hour event window from 1 to 6 PM on a 1-in-10 September monthly system peak day and 8.1 MW on the September monthly system peak day under 1-in-2 year weather conditions for SDG&E-specific peaking conditions. Under CAISO peak conditions, residential aggregate load reduction on a September monthly system peak day is 8.3 MW for 1-in-2 and 7.8 MW for 1-in-10.

There is significant variation in load impacts across months and weather conditions for residential customers and commercial customers. Based on 1-in-2 year weather, the low temperatures in May and June typically experienced in San Diego result in the smallest average and aggregate load impacts. The May and June 1-in-2 year impacts for residential customers are less than 2.0 kW while the September estimate is 8.1 kW. For residential customers, the May 1-in-10-year estimate is on average 3 times greater than the 1-in-2 year estimates as a result of the 1‑in-10 year temperatures being much warmer than the 1-in-2 year temperatures for May. For commercial customers, the May 1-in-10-year estimate is on average 3 times greater than the 1-in-2 year estimates.

Table 5‑5 and Table 5‑6 provide ex ante impact estimates on an hourly basis for residential and commercial customers, respectively. The hours reflect the peak period as defined by the CPUC resource adequacy requirements, 1 to 6 PM. Residential and commercial impacts peak in the hour from 2 to 3 PM. Both customer types’ impacts are lowest in the 5 to 6 PM window.

Table ‑: 2018 Summer Saver Ex Ante Load Impact Estimates by Weather Year, Day Type and Hour Residential Customers – SDG&E Peaking Conditions

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Weather Year | Day Type | Hour of Day | | | | | Average (MW) |
| **1 to 2 PM (MW)** | **2 to 3 PM (MW)** | **3 to 4 PM (MW)** | **4 to 5 PM (MW)** | **5 to 6 PM (MW)** |
| 1-in-2 | Typical Event Day | 5.1 | 6.3 | 5.7 | 5.1 | 3.4 | 5.1 |
| May Monthly Peak | 1.9 | 2.3 | 2.1 | 1.9 | 1.2 | 1.9 |
| June Monthly Peak | 0.9 | 1.0 | 0.9 | 0.8 | 0.5 | 0.8 |
| July Monthly Peak | 4.8 | 5.9 | 5.4 | 4.8 | 3.2 | 4.8 |
| August Monthly Peak | 6.7 | 8.3 | 7.5 | 6.7 | 4.5 | 6.7 |
| September Monthly Peak | 8.0 | 10.0 | 9.0 | 8.1 | 5.4 | 8.1 |
| October Monthly Peak | 4.8 | 5.9 | 5.4 | 4.8 | 3.2 | 4.8 |
| 1-in-10 | Typical Event Day | 7.4 | 9.2 | 8.4 | 7.5 | 5.0 | 7.5 |
| May Monthly Peak | 5.6 | 7.0 | 6.3 | 5.6 | 3.8 | 5.7 |
| June Monthly Peak | 6.3 | 7.9 | 7.1 | 6.4 | 4.3 | 6.4 |
| July Monthly Peak | 6.0 | 7.5 | 6.8 | 6.1 | 4.1 | 6.1 |
| August Monthly Peak | 7.9 | 9.9 | 8.9 | 8.0 | 5.4 | 8.0 |
| September Monthly Peak | 9.4 | 11.8 | 10.7 | 9.5 | 6.4 | 9.6 |
| October Monthly Peak | 6.5 | 8.0 | 7.3 | 6.5 | 4.4 | 6.5 |

Table ‑: 2018 Summer Saver Ex Ante Load Impact Estimates by Weather Year, Day Type and Hour Commercial Customers – SDG&E Peaking Conditions

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Weather Year | Day Type | Hour of Day | | | | | Average (MW) |
| **1 to 2 PM (MW)** | **2 to 3 PM (MW)** | **3 to 4 PM (MW)** | **4 to 5 PM (MW)** | **5 to 6 PM (MW)** |
| 1-in-2 | Typical Event Day | 2.3 | 2.0 | 1.8 | 1.6 | 1.4 | 1.8 |
| May Monthly Peak | 0.9 | 0.8 | 0.7 | 0.6 | 0.6 | 0.7 |
| June Monthly Peak | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 |
| July Monthly Peak | 2.2 | 1.8 | 1.7 | 1.5 | 1.3 | 1.7 |
| August Monthly Peak | 2.9 | 2.5 | 2.2 | 2.0 | 1.7 | 2.3 |
| September Monthly Peak | 3.8 | 3.2 | 2.9 | 2.6 | 2.3 | 3.0 |
| October Monthly Peak | 2.1 | 1.8 | 1.6 | 1.5 | 1.3 | 1.7 |
| 1-in-10 | Typical Event Day | 3.3 | 2.8 | 2.5 | 2.3 | 2.0 | 2.6 |
| May Monthly Peak | 2.6 | 2.2 | 2.0 | 1.8 | 1.6 | 2.1 |
| June Monthly Peak | 2.7 | 2.3 | 2.1 | 1.9 | 1.6 | 2.1 |
| July Monthly Peak | 2.6 | 2.2 | 2.0 | 1.8 | 1.5 | 2.0 |
| August Monthly Peak | 3.6 | 3.1 | 2.8 | 2.5 | 2.2 | 2.8 |
| September Monthly Peak | 4.3 | 3.6 | 3.3 | 3.0 | 2.6 | 3.3 |
| October Monthly Peak | 3.0 | 2.6 | 2.3 | 2.1 | 1.8 | 2.3 |

Table 5‑7 provides program-level ex ante aggregate estimates for each hour. In 2018, the program is expected to provide its highest impact under 1-in-10 year conditions in September. Under those conditions, the average impact over the event window is expected to be 12.5 MW, with an hourly peak of 15.2 MW from 2 to 3 PM.

Table ‑: 2018 Summer Saver Ex Ante Load Impact Estimates by Weather Year, Day Type and Hour –All Customers – SDG&E Peaking Conditions

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Weather Year | Day Type | Hour of Day | | | | | Average (MW) |
| **1 to 2 PM (MW)** | **2 to 3 PM (MW)** | **3 to 4 PM (MW)** | **4 to 5 PM (MW)** | **5 to 6 PM (MW)** |
| 1-in-2 | Typical Event Day | 7.4 | 8.3 | 7.5 | 6.7 | 4.8 | 6.9 |
| May Monthly Peak | 2.8 | 3.1 | 2.8 | 2.5 | 1.8 | 2.6 |
| June Monthly Peak | 1.3 | 1.4 | 1.3 | 1.1 | 0.8 | 1.2 |
| July Monthly Peak | 6.9 | 7.8 | 7.0 | 6.3 | 4.5 | 6.5 |
| August Monthly Peak | 9.6 | 10.8 | 9.7 | 8.7 | 6.2 | 9.0 |
| September Monthly Peak | 11.8 | 13.2 | 11.9 | 10.7 | 7.7 | 11.1 |
| October Monthly Peak | 6.9 | 7.8 | 7.0 | 6.3 | 4.5 | 6.5 |
| 1-in-10 | Typical Event Day | 10.7 | 12.1 | 10.9 | 9.8 | 7.0 | 10.1 |
| May Monthly Peak | 8.2 | 9.2 | 8.3 | 7.5 | 5.3 | 7.7 |
| June Monthly Peak | 9.1 | 10.2 | 9.2 | 8.3 | 5.9 | 8.5 |
| July Monthly Peak | 8.6 | 9.7 | 8.8 | 7.8 | 5.6 | 8.1 |
| August Monthly Peak | 11.5 | 12.9 | 11.7 | 10.5 | 7.5 | 10.8 |
| September Monthly Peak | 13.7 | 15.4 | 14.0 | 12.5 | 9.0 | 12.9 |
| October Monthly Peak | 9.4 | 10.6 | 9.6 | 8.6 | 6.2 | 8.9 |

## Comparison of 2016 Ex Ante Load Impacts to 2017 Ex Ante Load Impacts

The 2016 Summer Saver load impact evaluation estimated that the program’s 2018 capacity load reduction is reached under August SDG&E-specific 1-in-10 weather conditions; residential load impacts peak at 9.6 MW and 1.9 MW in the case of the commercial segment.

This current year’s evaluation yields similar estimates of program capacity for the residential segment, 9.6 MW in the case of the residential segment vs. last year’s estimate of 9.6 MW, but higher estimates of program capacity for the commercial segment – 3.3 MW versus 1.9 MW last year. This year the month of peak program resource delivery has also moved from August to September.

The differences between the 2018 ex ante load impact estimates are a composite net change reflecting differences in two key factors that influence ex ante load impacts:

**Enrollment** – Forecasted enrollment has decreased slightly for the residential segment, from 12,795 enrolled residential customers to 12,154 enrolled residential customers. Forecasted commercial enrollment has increased 46% from 3,204 customers to 4,680 customers.

**Per customer load impacts** – Peak per customer load impacts have increased slightly from 0.75 kW in the prior evaluation to 0.76 kW in the current load impact evaluation, while per customer load impacts have increased by 15% for commercial participants, increasing from 0.59 kW to 0.68 kW this year.

Across the range of ex ante weather conditions, the relationship between load impacts and temperature as estimated by ex ante modeling has also changed since the prior evaluation. The data available in the prior evaluation indicated only mild weather-responsiveness in load impacts. However, this current evaluation has a greater diversity of weather conditions associated with ex post load impacts available for estimation. This more diverse data has revealed a clear and more significant signature of weather-response in Summer Saver load impacts. Accordingly, per premise load impacts at lower load impacts are lower than in the prior evaluation, and per premise load impacts are higher at the highest temperature conditions.

## Relationship between Ex Post and Ex Ante Estimates

Ex post and ex ante load impacts may differ for a variety of reasons, including differences in weather conditions, the timing and length of the event window, and other factors such as differences in actual versus forecasted enrollment. Table 5‑8 presents an overall comparison of 2017 ex post load impacts and the ex ante load impacts as estimated for 2018, to indicate how different ex post and ex ante load impacts can be. Only the months of August through October are shown for comparison, since there were no events taking place in May or June 2017. July is not included because there were no commercial events that took place in July 2017. It is important to note that the 2018 ex ante impacts reflect the drop of the residential solar users but the ex post estimates do not.

Generally speaking, the 2017 August and September ex post average aggregate impacts are lower than the 2018 ex ante impacts due to the high number of events called at very low temperatures. The October the 2017 ex post impact is higher than the 2018 October ex ante impacts due to the high temperature experienced during the event called in October.

Table ‑: Comparison of 2017 Ex Post Load Impacts to 2018 Ex Ante Load Impacts by Month

|  |  |  |
| --- | --- | --- |
| Month | 2017 Ex Post Average Aggregate Impacts\* (MW) | 2018 Ex Ante Impact\*\* SDG&E  1-in-2 (MW) |
|
| August | 6.0 | 9.0 |
| September | 3.8 | 11.1 |
| October | 7.8 | 6.5 |
| \*Average of 2017 events by month  \*\*For RA hours of 1-6 PM | | |

Greater detail in comparing the ex post load impacts to ex ante load impacts is shown in Table 5‑9 and Table 5‑10. These tables step through how aggregate load impacts for the two residential cycling strategies change as a result of differences in the factors underlying ex post and ex ante estimates. Table 5‑11 and Table 5‑12 show the same information for commercial customers.

* **Columns A through E** describe the particular circumstances of each 2017 Summer Saver load control event. Each event is denoted by its date, shown in Column A. Column B shows the time of the event window, and column C shows the average hourly ex post load impact for that event aggregated to the 2017 enrollment population. Column D shows the average hourly ex post load impact as shown in column C, but aggregated to the 2018 projected enrollment population.
* **Column F** presents the load impacts that the ex ante model predicts for the predicted load impacts for the ex ante event window, which is always 1 to 6 PM and for the ex post weather conditions (Column E).
* **Columns G and H** compare Column I with the 2017 ex ante load impact estimates given the SDG&E-specific ex ante weather conditions for 1-in-2 and 1-in-10 year system peaking scenarios.
* **Columns I through J** show the 2018 ex ante load impacts for 1-in-2 and 1-in-10 year conditions for CAISO peaking conditions.

Taken together, Table 5‑9 through Table 5‑12 demonstrate the following information on how 2016 load impacts relate to the projected ex ante impacts that are based on measured load impacts from 2015, 2016, and 2017:

**August and September Temperatures Were Cool –** A comparison of Column E to the SDG&E 1-in-2 temperatures shown in Column G indicates that in August and September, most of the events that were called were called at temperatures less than what is expected during a 1-in-2 SDG&E monthly system peak day. As a result, most of the values in Column F are slightly lower than the MW values in Column G. This holds for both residential and commercial segments.

**The October Event Temperature Was Hot –** The same comparison of Columns E and G shows that the October event was much hotter than would be expected on a 1-in-10 SDG&E system peak day. Accordingly, the load impacts estimated by the ex ante model at the ex post temperatures are much higher than the 1-in-10 estimates.

**Controlling for temperature, Commercial Load Impacts in 2017 Were Lower than 2015 and 2016 –** A comparison of Column D with Column F reveals that, controlling for temperature, the observed load impacts are lower than the modeled load impacts. Since the ex ante model takes into account load impacts from 2015, 2016, and 2017, the fact that the 2017 load impacts are lower than the modeled average, implies that load impacts in 2015 and 2016 were higher than the modeled average.

Table ‑: Differences in 2017 Ex Post and 2018 Ex Ante Load Impacts Due to Key Factors – Residential 50% Cycling

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **2017 Ex Post** | | | | **2017 Ex Ante Model** | | | | |
| **Event Window** | **Ex Post Aggregate Impacts (MW)** | **Ex Post Aggregate Impacts using Enrollment Forecast (MW)** | **Mean17** | **Ex Ante Impact (1 - 6 PM) using Ex Post Weather (MW)** | **Ex Ante Impact SDG&E 1-in-2 (MW)** | **Ex Ante Impact SDG&E 1-in-10 (MW)** | **Ex Ante Impact CAISO 1-in-2 (MW)** | **Ex Ante Impact CAISO 1-in-10 (MW)** |
|
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** |
| 7/11/2017 | 3-7 pm | 3.7 | 3.5 | 76 | 3.1 | 3.0 (76°F) | 3.8 (78°F) | 2.1 (73°F) | 3.5 (77°F) |
| 8/1/2017 | 4-8 pm | 3.3 | 2.7 | 76 | 3.0 | 4.2 (80°F) | 5.0 (82°F) | 4.5 (81°F) | 4.2 (80°F) |
| 8/2/2017 | 4-8 pm | 1.6 | 1.5 | 78 | 3.8 |
| 8/3/2017 | 4-8 pm | 2.7 | 2.3 | 80 | 4.2 |
| 8/7/2017 | 7-8 pm | 1.5 | 1.1 | 74 | 2.6 |
| 8/8/2017 | 6-8 pm | 1.9 | 1.5 | 75 | 2.7 |
| 8/17/2017 | 4-8 pm | 0.7 | 0.8 | 68 | 0.9 |
| 8/28/2017 | 4-8 pm | 2.8 | 2.5 | 76 | 3.2 |
| 8/29/2017 | 5-9 pm | 3.2 | 3.0 | 78 | 3.8 |
| 8/31/2017 | 4-8 pm | 3.8 | 3.1 | 82 | 4.8 |
| 9/1/2017 | 4-8 pm | 4.4 | 4.1 | 84 | 5.6 | 5.0 (82°F) | 5.9 (85°F) | 5.1 (83°F) | 4.8 (82°F) |
| 9/2/2017 | 5-9 pm | 4.8 | 3.7 | 84 | 5.5 |
| 9/5/2017 | 5-8 pm | 1.7 | 1.5 | 74 | 2.5 |
| 9/11/2017 | 5-9 pm | 1.3 | 1.7 | 78 | 3.8 |
| 9/12/2017 | 5-9 pm | 1.2 | 0.9 | 75 | 2.8 |
| 9/25/2017 | 5-9 pm | 0.2 | 0.3 | 70 | 1.2 |
| 9/26/2017 | 5-9 pm | 0.4 | 0.3 | 69 | 0.9 |
| 9/28/2017 | 5-9 pm | 0.5 | 0.4 | 70 | 1.5 |
| 10/24/2017 | 3-5 pm | 3.9 | 3.0 | 83 | 5.0 | 3.0 (76°F) | 4.1 (79°F) | 2.3 (73°F) | 3.8 (78°F) |

Table ‑: Differences in 2017 Ex Post and 2018 Ex Ante Load Impacts Due to Key Factors – Residential 100% Cycling

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **2017 Ex Post** | | | | **2017 Ex Ante Model** | | | | |
| **Event Window** | **Ex Post Aggregate Impacts (MW)** | **Ex Post Aggregate Impacts using Enrollment Forecast (MW)** | **Mean17** | **Ex Ante Impact (1 - 6 PM) using Ex Post Weather (MW)** | **Ex Ante Impact SDG&E 1-in-2 (MW)** | **Ex Ante Impact SDG&E 1-in-10 (MW)** | **Ex Ante Impact CAISO 1-in-2 (MW)** | **Ex Ante Impact CAISO 1-in-10 (MW)** |
|
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** |
| 7/11/2017 | 3-7 pm | 2.3 | 1.8 | 76 | 1.8 | 1.7 (76°F) | 2.2 (78°F) | 1.1 (73°F) | 2.0 (77°F) |
| 8/1/2017 | 4-8 pm | 2.4 | 1.7 | 76 | 1.7 | 2.4 (79°F) | 3.0 (82°F) | 2.7 (81°F) | 2.5 (80°F) |
| 8/2/2017 | 4-8 pm | 1.5 | 1.1 | 78 | 2.3 |
| 8/3/2017 | 4-8 pm | 2.7 | 2.1 | 80 | 2.5 |
| 8/7/2017 | 7-8 pm | 0.9 | 0.6 | 74 | 1.5 |
| 8/8/2017 | 6-8 pm | 1.4 | 1.1 | 74 | 1.5 |
| 8/17/2017 | 4-8 pm | 0.5 | 0.4 | 68 | 0.3 |
| 8/28/2017 | 4-8 pm | 2.2 | 1.6 | 76 | 1.8 |
| 8/29/2017 | 5-9 pm | 2.6 | 2.0 | 78 | 2.2 |
| 8/31/2017 | 4-8 pm | 3.2 | 2.4 | 81 | 2.8 |
| 9/1/2017 | 4-8 pm | 3.7 | 3.1 | 84 | 3.4 | 3.0 (82°F) | 3.6 (85°F) | 3.1 (83°F) | 2.9 (82°F) |
| 9/2/2017 | 5-9 pm | 4.9 | 3.6 | 84 | 3.4 |
| 9/5/2017 | 5-8 pm | 1.3 | 1.0 | 74 | 1.4 |
| 9/11/2017 | 5-9 pm | 1.8 | 1.3 | 78 | 2.2 |
| 9/12/2017 | 5-9 pm | 0.7 | 0.6 | 75 | 1.6 |
| 9/25/2017 | 5-9 pm | 0.2 | 0.1 | 70 | 0.6 |
| 9/26/2017 | 5-9 pm | 0.1 | 0.1 | 69 | 0.4 |
| 9/28/2017 | 5-9 pm | 0.4 | 0.2 | 70 | 0.7 |
| 10/24/2017 | 3-5 pm | 2.5 | 2.1 | 83 | 3.1 | 1.7 (76°F) | 2.4 (80°F) | 1.2 (73°F) | 2.2 (78°F) |

Table ‑: Differences in 2017 Ex Post and 2018 Ex Ante Load Impacts Due to Key Factors – Commercial 30% Cycling

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **2017 Ex Post** | | | | **2017 Ex Ante Model** | | | | |
| **Event Window** | **Ex Post Aggregate Impacts (MW)** | **Ex Post Aggregate Impacts using Enrollment Forecast (MW)** | **Mean17** | **Ex Ante Impact (1 - 6 PM) using Ex Post Weather (MW)** | **Ex Ante Impact SDG&E 1-in-2 (MW)** | **Ex Ante Impact SDG&E 1-in-10 (MW)** | **Ex Ante Impact CAISO 1-in-2 (MW)** | **Ex Ante Impact CAISO 1-in-10 (MW)** |
|
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** |
| 8/1/2017 | 4-8 pm | 0.2 | 0.2 | 75 | 0.3 | 0.4 (79°F) | 0.5 (82°F) | 0.5 (80°F) | 0.5 (79°F) |
| 8/2/2017 | 4-8 pm | 0.2 | 0.2 | 78 | 0.4 |
| 8/3/2017 | 4-8 pm | 0.3 | 0.3 | 79 | 0.5 |
| 8/7/2017 | 7-8 pm | 0.0 | 0.0 | 74 | 0.3 |
| 8/8/2017 | 6-8 pm | 0.1 | 0.1 | 74 | 0.3 |
| 8/28/2017 | 4-8 pm | 0.1 | 0.1 | 75 | 0.3 |
| 8/29/2017 | 5-9 pm | 0.1 | 0.1 | 77 | 0.4 |
| 8/31/2017 | 4-8 pm | 0.2 | 0.2 | 80 | 0.5 |
| 9/1/2017 | 4-8 pm | 0.0 | 0.0 | 83 | 0.6 | 0.6 (82°F) | 0.7 (85°F) | 0.6 (82°F) | 0.5 (82°F) |
| 9/2/2017 | 5-9 pm | 0.2 | 0.2 | 83 | 0.6 |
| 9/5/2017 | 5-8 pm | 0.0 | 0.0 | 74 | 0.3 |
| 9/11/2017 | 5-9 pm | -0.1 | -0.1 | 78 | 0.4 |
| 9/12/2017 | 5-9 pm | 0.1 | 0.1 | 75 | 0.3 |
| 9/25/2017 | 5-9 pm | -0.2 | -0.2 | 70 | 0.1 |
| 9/26/2017 | 5-9 pm | 0.1 | 0.0 | 69 | 0.1 |
| 9/28/2017 | 5-9 pm | 0.1 | 0.1 | 70 | 0.1 |
| 10/24/2017 | 3-5 pm | 0.2 | 0.2 | 82 | 0.6 | 0.3 (75°F) | 0.4 (79°F) | 0.2 (73°F) | 0.4 (78°F) |

Table ‑: Differences in 2017 Ex Post and 2018 Ex Ante Load Impacts Due to Key Factors – Commercial 50% Cycling

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **2017 Ex Post** | | | | **2017 Ex Ante Model** | | | | |
| **Event Window** | **Ex Post Aggregate Impacts (MW)** | **Ex Post Aggregate Impacts using Enrollment Forecast (MW)** | **Mean17** | **Ex Ante Impact (1 - 6 PM) using Ex Post Weather (MW)** | **Ex Ante Impact SDG&E 1-in-2 (MW)** | **Ex Ante Impact SDG&E 1-in-10 (MW)** | **Ex Ante Impact CAISO 1-in-2 (MW)** | **Ex Ante Impact CAISO 1-in-10 (MW)** |
|
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** |
| 8/1/2017 | 4-8 pm | 0.7 | 0.7 | 75 | 1.3 | 1.8 (78°F) | 2.2 (82°F) | 2.0 (80°F) | 1.8 (79°F) |
| 8/2/2017 | 4-8 pm | 0.8 | 0.8 | 78 | 1.7 |
| 8/3/2017 | 4-8 pm | 1.4 | 1.5 | 79 | 1.8 |
| 8/7/2017 | 7-8 pm | -0.1 | -0.1 | 74 | 1.2 |
| 8/8/2017 | 6-8 pm | 0.7 | 0.8 | 74 | 1.2 |
| 8/28/2017 | 4-8 pm | 1.0 | 1.1 | 75 | 1.3 |
| 8/29/2017 | 5-9 pm | -0.1 | -0.1 | 77 | 1.6 |
| 8/31/2017 | 4-8 pm | 1.0 | 1.0 | 79 | 1.9 |
| 9/1/2017 | 4-8 pm | 0.6 | 0.7 | 83 | 2.4 | 2.3 (82°F) | 2.6 (84°F) | 2.3 (82°F) | 2.2 (82°F) |
| 9/2/2017 | 5-9 pm | 0.7 | 0.8 | 83 | 2.4 |
| 9/5/2017 | 5-8 pm | 0.2 | 0.2 | 74 | 1.2 |
| 9/11/2017 | 5-9 pm | 0.6 | 0.6 | 78 | 1.7 |
| 9/12/2017 | 5-9 pm | 0.0 | 0.0 | 75 | 1.3 |
| 9/25/2017 | 5-9 pm | 0.1 | 0.1 | 70 | 0.6 |
| 9/26/2017 | 5-9 pm | 0.3 | 0.3 | 69 | 0.5 |
| 9/28/2017 | 5-9 pm | 0.0 | 0.0 | 70 | 0.7 |
| 10/24/2017 | 3-5 pm | 1.2 | 1.3 | 82 | 2.3 | 1.3 (75°F) | 1.8 (79°F) | 1.0 (73°F) | 1.8 (78°F) |

# Recommendations

SDG&E implemented the evaluation recommendation from the PY 2016 load impact evaluation, which was to dispatch EM&V test events at lower temperatures so as to more readily establish the direct relationship of Summer Saver load impacts with temperature. Two EM&V events were in fact dispatched in 2017, at relatively low temperatures as compared with the relatively hot temperature conditions of historic SDG&E Summer Saver events.

SDG&E additionally changed the dispatch requirements for the program in 2017, resulting in a large number of events called at some of the coolest temperatures observed in the program’s history. This collection of events with ex post load impacts observed at low temperatures provided ample material for revealing a clear weather trend for the program’s load impacts. The events called in 2017 do not necessarily shed light as to where exactly Summer Saver load impacts would become zero, which would mostly be the case for winter months, but this is not currently of great import for the Summer Saver load impact evaluation, as the program is only tariffed to be available in summer months where the central air conditioning load reduction potential, while small for months like May and June, is nonzero.

The 2017 Summer Saver load control events were also different from prior years in another way, which leads to this evaluation’s recommendation for the program. The 2017 events were dispatched largely in the evening hours, where the earliest event hour in 2017 was the hour 3 to 4 PM. Only two events were dispatched that early in the afternoon. The majority were dispatched to begin at 5 PM or later, which represents a significant departure from prior dispatch decisions for this program. With so many events’ duration of 4 to 8 PM and 5 to 9 PM, a significant disconnect between the ex post load impacts and the ex ante load impacts that must be produced to satisfy the CPUC Load Impact Protocols. The Protocols require that ex ante load impacts be reported for the RA window of 1 to 6 PM, which is now at quite a distance from a typical event window of 5 to 9 PM.

The current dispatch protocol of the program indicates that Summer Saver’s current best use to SDG&E is for new purposes: 1) to meet SDG&E system needs 2) more often (i.e., at cooler temperatures), 3) at a different time of day than the CAISO resource adequacy period, and 4) to meet operational needs other than reliability services.

In light of these changes, we recommend that SDG&E dispatch EM&V events during the CAISO resource adequacy window of 1-6 PM so as to collect information, internal to each program year, that can be used to develop an estimate of the relationship between hourly load impacts from 1 – 6 PM and load impacts later in the evening. The assumptions used in this evaluation to translate evening load impacts to afternoon load impacts may prove to be too simple. EM&V events called during the RA window can help establish empirical evidence as to how percentage load impacts differ (or do not) during the RA window from the evening hours.





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1. https://www.sdge.com/sites/default/files/regulatory/Application\_of\_SDGE\_2018-2022\_Demand\_Response\_with\_attachments\_COS.pdf [↑](#footnote-ref-1)
2. <https://www.sdge.com/sites/default/files/regulatory/Application_of_SDGE_2018-2022_Demand_Response_with_attachments_COS.pdf> [↑](#footnote-ref-2)
3. See CPUC Rulemaking 07-01-041 Decision (D.) 08-04-050, “Adopting Protocols for Estimating Demand Response Load Impacts” and Attachment A, “Protocols.” [↑](#footnote-ref-3)
4. British thermal unit, defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. [↑](#footnote-ref-4)
5. All 2017 events began at 3 PM or later. [↑](#footnote-ref-5)
6. Such an LDV model would be specified as [↑](#footnote-ref-6)
7. The 2016 Summer Saver load impact evaluation included secondary and tertiary estimates of 2015 and 2016 ex post load impacts with the bottom 30% of electricity users and NEM customers removed from the dataset so that ex ante estimates could reflect the anticipated program changes in 2017 and 2018. Availability of ex post load impacts with no NEM customers included in the estimates is another reason why load impacts from 2015, 2016, and 2017 were selected for ex ante estimation. [↑](#footnote-ref-7)
8. Ex post load impacts reflect the 2017 and anticipated 2018 program changes to drop the bottom 30% electricity users as well as NEM customers. [↑](#footnote-ref-8)
9. Ibid. [↑](#footnote-ref-9)
10. Utilizing only those events that are four hours in duration, which is the majority of all Summer Saver events. [↑](#footnote-ref-10)
11. Note that 8/1/2017 was another day that had a 4-8 PM event but is not included in this average. Load impacts for this day had to be estimated using an alternate (day-matching) methodology since both research groups A and B were dispatched (there was no control group held back on that day). [↑](#footnote-ref-11)
12. See Appendix A for a description of how the proxy event days were selected. [↑](#footnote-ref-12)
13. The original ex ante weather conditions used in DR load impact evaluations were developed in 2009. [↑](#footnote-ref-13)