**2017 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates**

**CALMAC Study ID SDGE0309**

**CONFIDENTIAL pursuant to PU Code Section 583**

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# Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company’s (“SDG&E”) voluntary residential time-of-use (TOU) and critical peak pricing (CPP) rates for 2017. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015.

## ES.1 Resources Covered

The summer TOU periods in the two rates are centered around an on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. CPP events may be called during the 11 a.m. to 6 p.m. period on any day (including weekends) throughout the year, whenever a Reduce Your Use (RYU) event is called. In 2017, SDG&E called three CPP events, August 31st, September 1st, and September 2nd, which was a weekend event.

In the future, the on-peak periods will be different. Specifically, SDG&E has made changes, effective Dec 1, 2017, in the hours of the pricing periods of its TOU rates, which now have an on-peak period of 4 p.m. to 9 p.m., beginning and ending later than the rates evaluated in this PY2017 study. These rate changes have arisen from recent changes in the patterns of the utility’s and the state’s system load profiles due to increases in solar generation (both central station and rooftop photovoltaics). These increases in solar tend to delay peak demands for purchased power to later in the day than the previous norm, as solar production falls in the evening hours.

## ES.2 Evaluation Methodologies

The *ex-post* impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that involve selecting quasi-experimental matched control groups and then comparing the usage of treatment and control group customers on relevant days or time periods, where the comparisons are then adjusted by usage differences on pre-treatment or non-event days. The control groups were selected by matching each treatment customer to one of an initial sample of eligible non-treatment customers in relevant population segments (*e.g.*, climate zone, CARE status, and enrollment in SDG&E’s Reduce Your Use, or RYU, program), based on the closest match of load profiles.

## ES.3 Ex-Post Load Impacts

### CPP (TOU-DR-P)

Table ES.1 summarizes average event-hour reference load and CPP load impact results for the CPP customers on the average weekday event in 2017. Results are shown by Coastal and Inland climate zones. The first two columns show the climate zone and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MW. The next two columns show the same variables for the average customer, in units of kW. The last two columns show the load impacts as a percentage of the reference loads, and the average temperature during the event window.

Table ES.1: Average CPP Event-Hour Load Impacts – *Average Weekday Event*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Climate Zone** | **Enrolled** | **Ref. Load (MWh/h)** | **Load Impact (MWh/h)** | **Ref. Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** | **Ave. Event Temp.** |
| Coastal | 2,847 | 3.36 | 0.47 | 1.18 | 0.17 | 14% | 89 |
| Inland | 2,089 | 3.43 | 0.44 | 1.64 | 0.21 | 13% | 95 |
| **All** | **4,935** | **6.76** | **0.90** | **1.37** | **0.18** | **13%** | **92** |

Program enrollment was 4,935 customers, skewed somewhat toward the Coastal climate zone.[[1]](#footnote-1) The aggregate reference load was 6.76 MWh/h. Per-customer load impacts averaged 0.17 kWh/h for customers in the Coastal climate zone, representing 14 percent of their reference load, and 0.21 kWh/h, or 13 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 89 degrees, than the 95-degree temperature for the Inland zone.

### TOU peak load impacts – TOU (TOU-DR)

Table ES.2 summarizes the average reference loads and load impacts for customers on the TOU-DR rate for the TOU peak period (*i.e.*, 11 a.m. to 6 p.m. for May through October, and 5 to 8 p.m. for November through April), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with the first month included in the analysis (October 2016). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 653 in October 2016 to 1,559 in September 2017.[[2]](#footnote-2) Due to the relatively small number of treatment customers, percentage load impacts were constrained in estimation to be the same across months in each season. The estimated seasonal percentage load impacts were approximately 6.0 percent in summer and negative 3.1 percent (*i.e*., a load increase) in winter.[[3]](#footnote-3)

Table ES.2: TOU Peak Load Impacts for TOU Customers – *Average Weekday by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Oct-16 | All | 653 | 0.47 | 0.03 | 0.71 | 0.042 | 6.0% | 76 |
| Nov-16 | All | 689 | 0.71 | -0.02 | 1.03 | -0.031 | -3.0% | 65 |
| Dec-16 | All | 726 | 0.88 | -0.03 | 1.21 | -0.037 | -3.0% | 59 |
| Jan-17 | All | 755 | 0.88 | -0.03 | 1.16 | -0.035 | -3.0% | 56 |
| Feb-17 | All | 795 | 0.79 | -0.02 | 0.99 | -0.030 | -3.1% | 59 |
| Mar-17 | All | 860 | 0.75 | -0.02 | 0.88 | -0.027 | -3.1% | 65 |
| Apr-17 | All | 897 | 0.71 | -0.02 | 0.79 | -0.024 | -3.1% | 67 |
| May-17 | All | 934 | 0.57 | 0.03 | 0.61 | 0.036 | 6.0% | 69 |
| Jun-17 | All | 1,002 | 0.77 | 0.05 | 0.77 | 0.046 | 6.0% | 74 |
| Jul-17 | All | 1,130 | 1.19 | 0.07 | 1.06 | 0.064 | 6.0% | 80 |
| Aug-17 | All | 1,412 | 1.46 | 0.09 | 1.04 | 0.063 | 6.1% | 79 |
| Sep-17 | All | 1,559 | 1.37 | 0.08 | 0.88 | 0.053 | 6.0% | 78 |

Table ES.3 shows peak load impact results by season and climate zone. Because of relatively low enrollment in October 2016 and the discontinuity between that month and the summer of 2017, the results for the summer season include only May through September of 2017. Summer peak load impacts were similar in percentage terms for the two climate zones. However, during the winter month peak periods, Coastal customers *increased* usage almost three times higher than Inland customers, though the increases were not statistically significant.

Table ES.3: TOU Peak Load Impacts for TOU Customers –   
*Average Weekday by Season & Climate Zone*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Season** | **Climate Zone** | **Enrolled (Average)** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Summer | Coastal | 692 | 0.60 | 0.03 | 0.81 | 0.038 | 4.6% | 76 |
| Inland | 515 | 0.52 | 0.03 | 0.97 | 0.061 | 6.3% | 78 |
| **All** | **1,207** | **1.12** | **0.06** | **0.88** | **0.048** | **5.4%** | **77** |
| Winter | Coastal | 443 | 0.46 | -0.02 | 1.05 | -0.047 | -4.5% | 63 |
| Inland | 344 | 0.33 | -0.01 | 0.95 | -0.015 | -1.6% | 62 |
| **All** | **787** | **0.79** | **-0.03** | **1.01** | **-0.033** | **-3.3%** | **62** |

Combining results across months and considering the effect of TOU on average *daily* usage, we find that TOU customers *increased* their energy consumption by an annual average of approximately 2 percent.

### TOU peak load impacts – CPP (TOU-DR-P)

Since TOU-DR-P customers experience TOU prices on all weekdays that are not RYU/CPP event days, it is of interest to examine their average usage changes on non-event days, similarly to TOU customers. Table ES.4 shows load and load impacts for the average summer (October 2016, and May through September 2017) and winter (November 2016 through April 2017) weekdays, by month. Enrollment in CPP grew from 2,724 in October 2016 to approximately 5,229 in September 2017.[[4]](#footnote-4) Summer TOU peak load impacts varied across months, with load reductions in all months except October. Load impacts in winter months were smaller.

Table ES.4: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Oct-16 | All | 2,724 | 1.80 | 0.00 | 0.66 | 0.00 | -0.1% | 76 |
| Nov-16 | All | 2,917 | 2.82 | -0.02 | 0.97 | -0.01 | -0.7% | 65 |
| Dec-16 | All | 3,053 | 3.29 | 0.11 | 1.08 | 0.04 | 3.3% | 59 |
| Jan-17 | All | 3,251 | 3.37 | 0.08 | 1.04 | 0.03 | 2.5% | 56 |
| Feb-17 | All | 3,466 | 3.30 | 0.17 | 0.95 | 0.05 | 5.2% | 59 |
| Mar-17 | All | 3,743 | 3.10 | 0.10 | 0.83 | 0.03 | 3.2% | 65 |
| Apr-17 | All | 3,938 | 3.06 | 0.07 | 0.78 | 0.02 | 2.2% | 67 |
| May-17 | All | 4,091 | 2.68 | 0.20 | 0.65 | 0.05 | 7.3% | 69 |
| Jun-17 | All | 4,323 | 3.48 | 0.23 | 0.80 | 0.05 | 6.6% | 75 |
| Jul-17 | All | 4,622 | 4.99 | 0.31 | 1.08 | 0.07 | 6.3% | 80 |
| Aug-17 | All | 4,984 | 4.93 | 0.12 | 0.99 | 0.02 | 2.5% | 80 |
| Sep-17 | All | 5,229 | 4.59 | 0.37 | 0.88 | 0.07 | 8.1% | 79 |

Table ES.5 summarizes CPP load impact results by season and climate zone. Both summer and winter peak load impacts are similar between the Coastal and Inland climate zones, with Coastal percentage load impacts slightly larger in the summer and slightly smaller in the winter, when the TOU period is shorter and later in the day.

Table ES.5: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Season & Climate Zone*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Season** | **Climate Zone** | **Enrolled (Average)** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Summer | Coastal | 2,701 | 2.22 | 0.14 | 0.81 | 0.051 | 6.3% | 76 |
| Inland | 1,948 | 1.98 | 0.11 | 1.00 | 0.055 | 5.5% | 78 |
| **All** | **4,650** | **4.21** | **0.25** | **0.89** | **0.053** | **5.9%** | **77** |
| Winter | Coastal | 1,973 | 1.78 | 0.04 | 0.90 | 0.019 | 2.2% | 63 |
| Inland | 1,422 | 1.38 | 0.05 | 0.97 | 0.033 | 3.4% | 62 |
| **All** | **3,395** | **3.16** | **0.09** | **0.93** | **0.025** | **2.8%** | **62** |

In contrast to the TOU customers, CPP customers decreased their *daily* energy consumption by small amounts for most months of the year (October, November, and August exhibited increases). The result is an average annual *decrease* of about 1.2 percent.

## ES.4 Ex-Ante Load Impacts

SDG&E called three RYU/CPP events in 2017, two of which were weekdays. We base forecasts going forward on the two weekday events. We developed load impacts for different weather scenarios by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads. Those were developed using regression models similar to those used in the *ex-post* analysis, and then simulating loads under the four alternative weather scenarios. SDG&E has updated the RYU/CPP event hours, reducing the event window of 11:00 a.m. to 6:00 p.m. (HE 12-18) to an event widow of 2:00 to 6:00 p.m. (HE 15-18). To apply *ex-post* load impacts that correspond to the updated event window, we categorize each hour of the day with relationship to the event window, and then apply percentage load impacts to the corresponding period in *ex-ante.* For example, the percentage load impact for the hour before the event in *ex-post* (HE 11) is applied the *ex-ante* reference load for the hour before the event in *ex-ante* (HE 14).

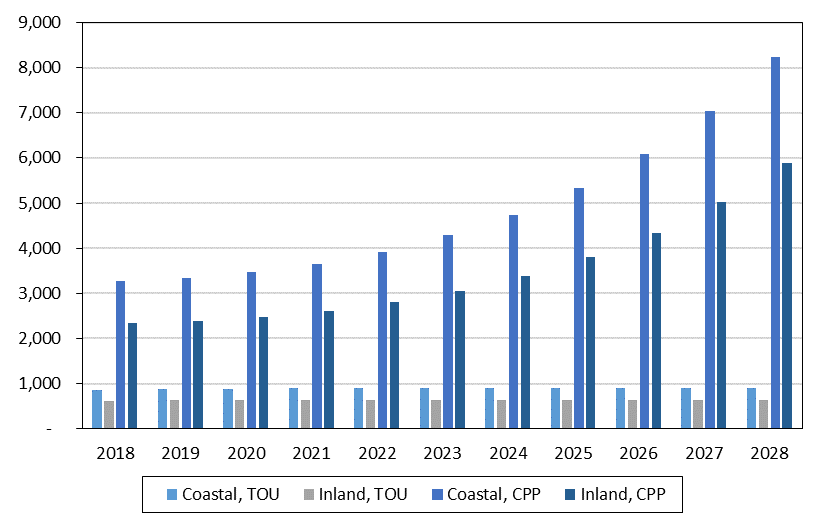
An issue in producing the *ex-ante* load impact forecasts for CPP is that the Protocols call for estimating load impacts for the Resource Adequacy (RA) hours of 1 to 6 p.m. during summer months, and 4 to 9 p.m. in winter months, while the CPP events are called during the program hours of 11 a.m. to 6 p.m. year-round. We simulate the load impacts using the event hours that are indicated by the tariff, but we summarize the load impacts across the RA window as required.

SDG&E has also made changes to the TOU periods to be used in *ex-ante*. For TOU rate and the TOU portion of the CPP rate, we apply percentage load impacts from the *ex-post* analysis (monthly values for CPP and seasonal values for TOU) to weather-sensitive reference loads in the corresponding TOU period (*e.g.,* peak, off-peak).

## ES.4.1 Enrollment forecast

Figure ES.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU after 2019, while enrollment in CPP is forecasted to nearly triple by the end of the forecast period. Enrollment is expected to be somewhat greater in the Coastal climate zone than in the Inland for both rates.

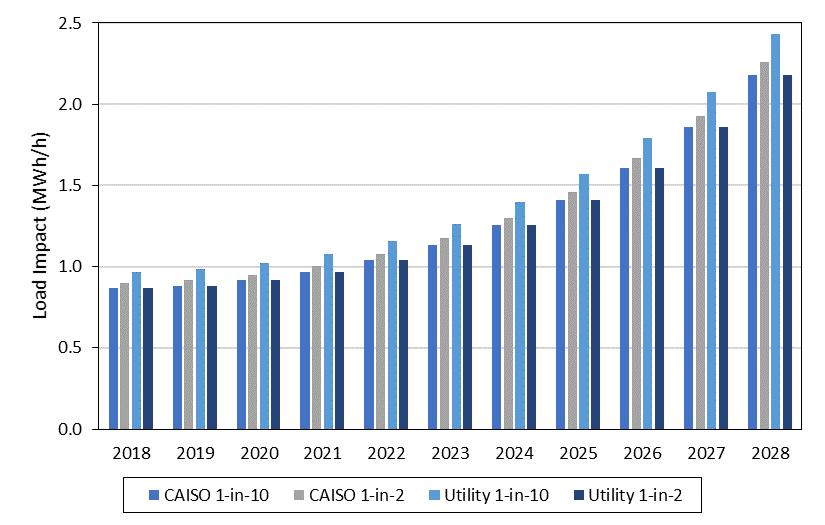
Figure ES.1: Enrollments in TOU and CPP Rates



## ES.4.2 Ex-ante load impacts – Residential CPP

Figure ES.2 illustrates the growth in forecast CPP load impacts over the forecast period, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to grow from just less than 0.87 MWh/h in 2018 to over 2.18 MWh/h in 2028.

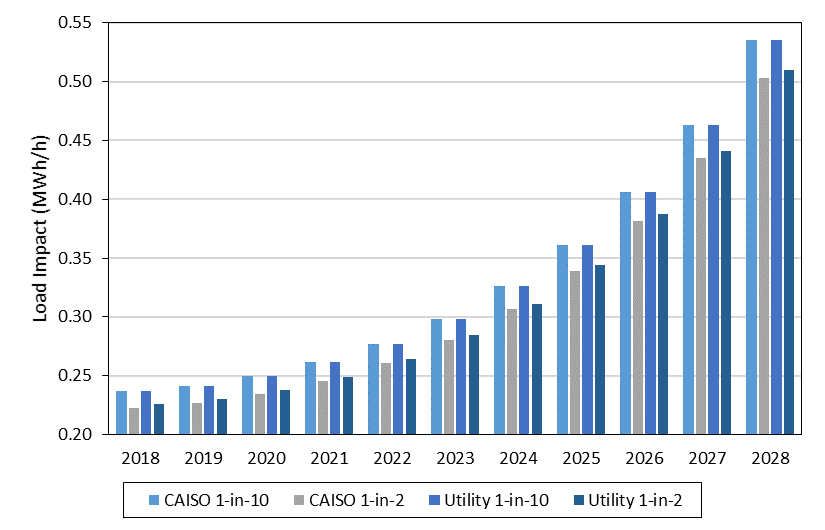
Figure ES.2: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario (*SDG&E 1-in-2 Peak Day, RA Window*)



## ES.4.3 Ex-Ante load impacts – Residential TOU

Aggregate peak load impacts for TOU customers are forecast to remain constant after 2019, given the flat enrollment forecast. Figure ES.3 shows differences in the aggregate peak load impact forecasts for CPP customers over the entire period. Values for the two 1-in-10 scenarios are identical, rising to nearly 0.53 MWh/h in the final year. Load impacts in the SDG&E 1-in-2 scenario are nearly identical to the CAISO 1-in-2 scenario as well, rising to just over 0.51 MWh/h in 2028.[[5]](#footnote-5)

Figure ES.3: Aggregate TOU Load Impacts (MWh/h), by Year and Weather Scenario –   
*TOU-DR and TOU-DR-P* Customers (*SDG&E 1-in-2 Average Weekday, RA Window*)



1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company’s (“SDG&E”) voluntary residential time of use (TOU) and critical peak pricing (CPP) rates for 2017. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component).[[6]](#footnote-6) Both rates are voluntary and became active in February 2015. Since the TOU/CPP customers experience TOU rates on days that are not CPP event days, TOU load impacts are estimated for customers enrolled in both rates, while CPP load impacts are estimated only for CPP customers.[[7]](#footnote-7) The evaluation also develops *ex-ante* load impacts for both rates, with the evaluations conforming to the Load Impact Protocols adopted by the CPUC in D-08-04-050.

The summer TOU periods in the two rates are centered around an on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. The CPP rate may be called during the 11 a.m. to 6 p.m. period on any day (including weekends) throughout the year.

In the future, the on-peak periods will be different. Specifically, SDG&E has made changes, effective Dec 1, 2017, in the hours of the pricing periods of its TOU rates, which now have an on-peak period of 4 p.m. to 9 p.m., beginning and ending later than the rates evaluated in this PY2017 study. These rate changes have arisen from recent changes in the patterns of the utility’s and the state’s system load profiles due to increases in solar generation (both central station and rooftop photovoltaics). These increases in solar tend to delay peak demands for purchased power to later in the day than the previous norm, as solar production falls in the evening hours.

The report is organized as follows. Section 2 contains descriptions of the TOU and CPP rates; Section 3 describes the evaluation methods used in the study; Section 4 contains the CPP *ex-post* load impact results; and Section 5 contains the TOU *ex-post* load impact results. Section 6 describes the methods used to develop the CPP and TOU *ex-ante* load impacts and the associated results. Section 7 provides a series of comparisons of *ex-post* and *ex-ante* results. Section 8 provides recommendations.

# 2. Description of SPP Rates

As noted in the introduction, the current TOU on-peak period in summer is 11 a.m. to 6 p.m. on non-holiday weekdays, with morning and evening semi-peak periods before and after, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. CPP events are called in conjunction with SDG&E’s Reduce Your Use (RYU) program, a peak time rebate program. Up to 18 RYU events can be triggered per year, on any day of the week, at any time during the year. Three RYU/CPP events were called in 2017, on the consecutive days of August 31, September 1, and September 2, which was a Saturday.

TOU prices apply only to SDG&E’s commodity energy charges, which are $0.183, $0.131, and $0.092 per kWh for the summer on-peak, semi-peak, and off-peak periods respectively. Thus, the peak to off-peak price ratio is approximately two-to-one.[[8]](#footnote-8) Summer TOU commodity prices for CPP (TOU-DR-P) customers are somewhat lower, at $0.138, $0.127, and $0.057 per kWh, implying a peak to off-peak price ratio of approximately 2.4 to one. In addition, a CPP event-period adder of $1.16/kWh applies on event days.

CPP participants are generally notified of events by 3 p.m. on the business day prior to the event, and several notification options are available, including email and text. For the first full season following their enrollment, CPP participants are eligible for *bill protection*, which guarantees that their bill will be no larger than what it would have been under their otherwise applicable tariff.

In addition to the upcoming changes to the TOU and CPP pricing periods, SDG&E has also changed the terminology describing the periods. The former *semi-peak* period will be re-labeled *off-peak*, and the former *off-peak* period will be called the *super off-peak* period. The changes include the following:

1. Change the summer on-peak period to 4 p.m. to 9 p.m. on weekdays, weekends, and holidays;
2. Change the winter on-peak period to 4 p.m. to 9 p.m. on weekdays, weekends, and holidays;
3. Change the super off-peak period to 12 a.m. to 6 a.m. on weekdays, and 10 a.m. to 2 a.m. on March and April weekdays, and 12 a.m. to 2 p.m. on weekends and holidays;
4. All hours not in the above on-peak and super-off-peak periods are off-peak;
5. The CPP period is reduced to 2 p.m. to 6 p.m. year-round.

Since the recent changes in peak pricing periods had not yet been approved during the PY2017 period, SDG&E has delayed active marketing of the SPP rates to avoid confusion on the part of customers should the rates change. Instead, it has enrolled customers primarily in response to high bill complaints.

# 3. *Ex-Post* Evaluation Methodology

The primary objectives of the *ex-post* impact evaluation were described in Section 1. This section describes the data and specific methods that were used in the study.

## 3.1 Data

An analysis that addresses each of the load impact objectives listed in Section 1 requires the following types of data:

* *Customer* information for the residential TOU and CPP enrollees and potential control group customers (*e.g*., location indicator for matching to climate zone, and a summary indicator of their usage level);
* Billing-based *interval load data* (*i.e.*, hourly loads for each TOU and CPP enrollee, and potential control group customers), for November 2015 through September 2017;
* *Weather* *data* (*i.e.*, hourly temperatures and other variables for the relevant time period, for both climate zones—coastal and inland);
* *Program event data* (*i.e.*, dates and hours of CPP events, and event triggers).

## 3.2 Analysis Methods

The evaluation approach used in this study, as in the previous (2016) evaluation, includes implementing a difference-in-differences regression analysis using data for TOU and CPP participants and matched control group customers. The analysis involves three steps. First, we request hourly load data for the TOU and CPP enrollees, and potential control group customers, for the current year and the previous year (pre-enrollment year for new enrollees). Second, we select matched control group customers for the TOU and CPP enrollees, as described below. Third, we estimate fixed-effects panel regression models, which produce difference-in-differences estimates of event-day load impacts (for CPP), and average TOU period load impacts (for both TOU and for CPP non-event days).

### 3.2.1 Evaluation design and control group matching

The difference-in-differences evaluation is a quasi-experimental approach that compares the usage of treatment and matched control group customers on relevant days or time periods, adjusted by their usage differences on pre-treatment or non-event days. The control groups were selected by matching each treatment customer to one of a sample of eligible non-treatment customers in relevant population segments (*e.g.*, climate zone, CARE status, and enrollment in RYU), based on the closest match of load profiles. The initial samples of eligible control group customers were developed as seven-to-one samples by segment from the eligible population of SDG&E residential customers.

The matching process differed for customers on the two rates. Since the CPP (TOU-DR-P) customers experienced TOU rates on all non-event days, and the CPP rate on event days, we treat those customers as CPP customers when evaluating CPP load impacts, and as TOU customers when evaluating TOU impacts.

For analyzing CPP impacts, the CPP customers were matched to potential control group customers using loads on selected event-like non-event days (*e.g.*, days with temperatures most like those on the event days). Figure 3.1 displays the average event-hour temperature for all weekday and weekends between October 2015 and November 2017. Red diamond markers indicate weekend non-event days while blue circles indicate weekday non-event days. The red and blue X represent weekend and weekday event days, respectively.

Figure 3.1: Average Event-Hour Temperatures

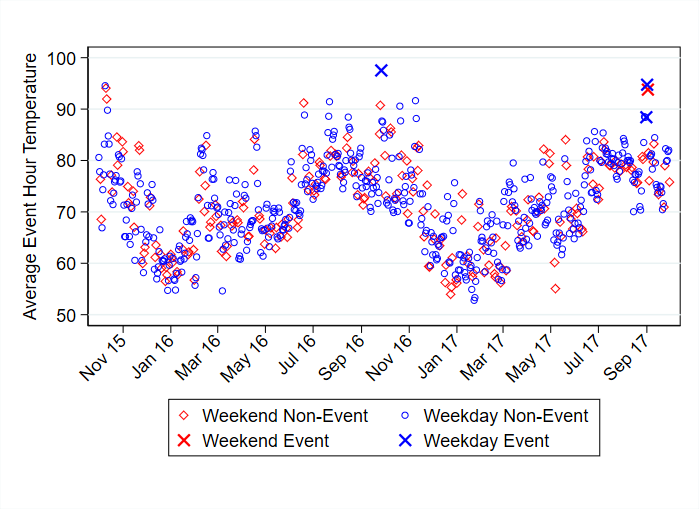


Figure 3.1 demonstrates that the event days in 2017 were among the hottest days during 2017. As there were more hot days during 2016, we choose event-like non-event days during the summers of 2016 and 2017, including weekends because September 2nd, 2017 was a weekend event. The list of chosen event-like non-event days is provided in Table 3.1. Separate event-like days were chosen for CPP customers that were dually enrolled in Summer Saver (81 customers) because many of the hottest dates chosen were also Summer Saver event days.

Table 3.1: List of Selected Event-Like Days

|  |  |  |  |
| --- | --- | --- | --- |
| **Non-SS Customers** | | **Dually Enrolled SS Customers** | |
|
| **Weekday** | **Weekend** | **Weekday** | **Weekend** |
| 9/28/2016 | 9/24/2016 | 9/28/2016 | 9/24/2016 |
| 10/20/2016 | 9/25/2016 | 9/29/2016 | 9/25/2016 |
| 10/21/2016 | 8/8/2016 | 9/30/2016 | 10/8/2016 |
| 6/26/2017 | 8/19/2016 | 10/20/2016 | 10/9/2016 |
| 7/7/2017 | 7/8/2017 | 10/21/2016 | 7/8/2017 |
| 8/2/2017 | 7/9/2017 | 6/26/2017 | 7/9/2017 |
| 8/3/2017 | 7/23/2017 | 7/7/2017 | 7/23/2017 |
| 8/29/2017 | 8/27/2017 | 7/10/2017 | 8/27/2017 |
| 8/30/2017 | 9/9/2017 | 8/4/2014 | 9/9/2017 |
| 9/11/2017 | 9/10/2017 | 8/30/2014 | 9/10/2017 |

For analyzing TOU impacts, for both CPP and TOU customers, only incremental treatment customers were used in the analysis and matched based on loads in the pre-treatment period (November 2015 through September 2016). We use only incremental customers in the TOU load impact study because these customers have enough pre-treatment data to provide a quality difference-in-difference analysis. The matching and regression analysis is separated by season, thus allowing different threshold dates that define incremental customers. Specifically, incremental customers for the winter analysis are those that enrolled after May 1, 2016 while incremental customers for the summer analysis are those that enrolled after September 1, 2016. The incremental TOU customers were matched based on two pairs of hourly loads for each season – one for all weekdays, and one for a subset of the hottest (or coldest) weekdays. Matching for the *winter* season used data for November 2015 through April 2016, while that for the *summer* season used data for May through August of 2016.

Matching was based on Euclidean distance minimization between treatment and potential control group customer loads. This approach minimizes the difference between a standardized usage metric of the treatment and potential control group customers as shown in the equation below.

In this equation, the *T* variables represent treatment customer characteristics and the *C* variables represent the corresponding eligible control group customer characteristics. As described, separate matches and therefore sets of variables are used for the for the CPP and TOU analyses. For matching in the CPP analysis, the customer characteristics include the average hourly usage on weekdays and weekends (48 variables). For the TOU analysis, the customer characteristics include the average hourly usage on weekdays and hot/cold days for the summer/winter match (48 variables). Treatment and potential control customers are also segmented by climate zone, CARE status, and enrollment in RYU. Each enrolled customer is compared to each potential control group customer within their segment, using the distance measure. When the minimum distance statistic is found, the potential control group customer associated with that value is selected as the match for that TOU customer. Potential control group customers were allowed to be matched with replacement (*i.e.*, matched to multiple enrolled customers).

### 3.2.2 Fixed-effects panel regression models

The formal *ex-post* load impact estimates are based on *fixed-effects* panel regression models. These models are appropriate in situations like the current study, in which observed data are available for both multiple individual customers (cross-section) and multiple days, or time periods (time-series). The advantages of estimating such models include: 1) accounting for the effect of relevant factors on the variation in usage across customers and days, 2) accounting for the effects of weather conditions on usage, and 3) the availability of standard errors around the estimated load impact coefficients, thus allowing construction of *confidence intervals*.

We estimated two versions of fixed-effects models. The first version was used to estimate CPP event-day hourly load impacts (for only TOU-DR-P customers). The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR and TOU-DR-P customers).

In the first model, which addresses the objective of estimating hourly *ex-post* load impacts at the program level, we estimated a set of twenty-four separate fixed-effects models, one for each hour of the day. These models allow customer-specific constant terms, but estimate the same coefficient, effectively representing an average load impact across the included treatment customers, for variables that do not vary across customers (*e.g.*, the occurrence of an event day).

### 3.2.3 *Ex-post* models for estimating CPP load impacts

The load impact estimation model for CPP accounts for customer-specific and date-specific fixed effects (which include weather and day-type factors) and effectively estimates the CPP load impact as the difference between CPP and control-group customer loads on event days, controlling for the aforementioned fixed effects. This can be described as a difference-in-differences estimate (the difference between treatment and control group usage on event days, adjusted for differences on non-event days). The primary customer-level fixed-effects regression model used in the analysis is shown below, where the equation is estimated separately for each of the 24 hours. This model produces load impact estimates for each hour of every event:

*kWh*c,d = β0 + ΣEvts(i) (β1,i x *CPP*c,d x *Evt*i,d) + β2 x CPPc,d + ΣCust (β3,Cust x *Cc*)   
+ Σday (β4,day x *Dday,d*) + β5 x *SS\_Evt*c,d + β6 x *SCTD\_Evt*c,d + εc,d

The variables and coefficients in the equation are described in Table 3.1.

Table 3.1: Description of Variables Used in the CPP Analysis Regressions

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *kWh*c,d | Load in a particular hour for customer *c* on day *d* |
| *CPPc,d* | Variable indicating whether customer *c* is a CPP (1) or Control (0) customer on day *d* |
| *Evti,d* | Variable indicating that day *d* is the *i*th event day (1=*i*th event, 0 if not) |
| *SCTD*\_*Evt*c,d | Variable indicating that day *d* is a *SCTD* event day (1= event, 0 if not) for customer *c* |
| *SS\_Evt*c,d | Variable indicating that day *d* is *a* *Summer Saver* event day (1=event, 0 if not) for customer *c* |
| β0 | Estimated constant coefficient |
| β 1,d | Estimated load impact for event *d* |
| β2 | Estimated non-event day response for incremental CPP customers |
| β3,Cust andβ4,day | Customer and day fixed-effects |
| β 5,d | Estimated average *SCTD* load impact for event *d* |
| β 6,d | Estimated average *Summer Saver* load impact for event *d* |
| *Cc* | Variable indicating that the observation is for customer *c* |
| *Dday,d* | Date indicator variable (1 = date *d* equals date *day*) |
| εc,d | Error term |

### 3.2.4 *Ex-post* models for TOU load impacts

To obtain TOU load impacts (for both TOU-DR and TOU-DR-P customers), we estimate a distinct model for each required result. For example, to obtain the average TOU load impacts on August non-holiday weekdays, we estimate a model that includes only days of that day-type.[[9]](#footnote-9) In this case, we simplify the model to include customer and day fixed effects, plus a variable to estimate the load impact (*i.e.*, the coefficient *β 1*). Separate models are estimated by hour, month, day-type (*i.e.*, average weekday versus peak month day), applicable customer groups (*e.g.*, climate zone and CARE status), where the customer-level fixed-effects models are of the following form:[[10]](#footnote-10)

*kW*c,d = β0 + β1 x (*TOU*c x *Postc*,d) + ΣCust (β2,Cust x *Cc*) + Σdays (β3,*day* x *Dday*)   
 + β4 x *Evt*c,d + β5 x *SS\_Evt*c,d + β6 x *SCTD\_Evt*c,d + εc,d

The variables and coefficients in the equation are described in Table 3.2. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

Table 3.2: Description of Variables Used in the TOU Analysis Regressions

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *kW*c,d | Load in a particular hour for customer *c* on day *d* |
| *TOUc* | Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer |
| *Evtc,d* | Variable indicating whether day *d* is an event day for customer *c* [[11]](#footnote-11) |
| *Postc,d* | Variable indicating that day *d* is in the post-enrollment period for customer *c* |
| *SCTD*\_*Evt*c,d | Variable indicating that day *d* is a *SCTD* event day (1= event, 0 if not) for customer *c* |
| *SS\_Evt*c,d | Variable indicating that day *d* is *a* Summer Saver event day (1=event, 0 if not) for customer *c* |
| β0 | Estimated constant coefficient |
| β 1 | Estimate of TOU load impact |
| β2,Cust and β3,day | Estimated customer and day fixed effects |
| β 4 | Estimate of average event-day load impact |
| β 5 and β 6 | Estimated average *SCTD* and SS event event-day load impacts |
| *Cc* | Variable indicating that the observation is associated with customer *c* |
| *Dday* | Variable indicating that the observation is for day *d* |
| εc,d | Error term |

### 3.2.5 Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of *ex-post* load impacts, the coefficients that represent the estimated load impacts in the fixed-effects regressions are not estimated with certainty, but with a range of uncertainty indicated by the variance of the estimates. Therefore, we base the uncertainty-adjusted load impacts on the variances associated with the estimated load impact coefficients (*e.g.*, the event-day or treatment-period coefficients in the twenty-four hourly regressions).

The uncertainty-adjusted scenarios are then simulated under the assumption that each hour’s load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

To develop the uncertainty-adjusted load impacts associated with the *average* CPP event hour or by TOU pricing period (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), we estimated additional sets of regression models in which the load impact variable is constrained to be the same across the applicable hours (*e.g.*, we directly estimate an average event-hour CPP load impact). The associated standard errors are used to develop the uncertainty-adjusted load impacts in the same manner described above.

### 3.2.6 Validity assessment

Because we are employing a control-group approach, our validity assessment focuses on comparisons of treatment and control-group loads for selected event-like non-event days (for CPP) or pre-treatment loads (TOU). We also report statistics such as the mean absolute percentage error (MAPE) and mean percent error (MPE), which provide formal estimates of the percent differences between treatment and control group loads. The MAPE offers a measure of accuracy while MPE offers a measure of bias.

# 4. CPP *Ex-Post* Load Impact Study Findings

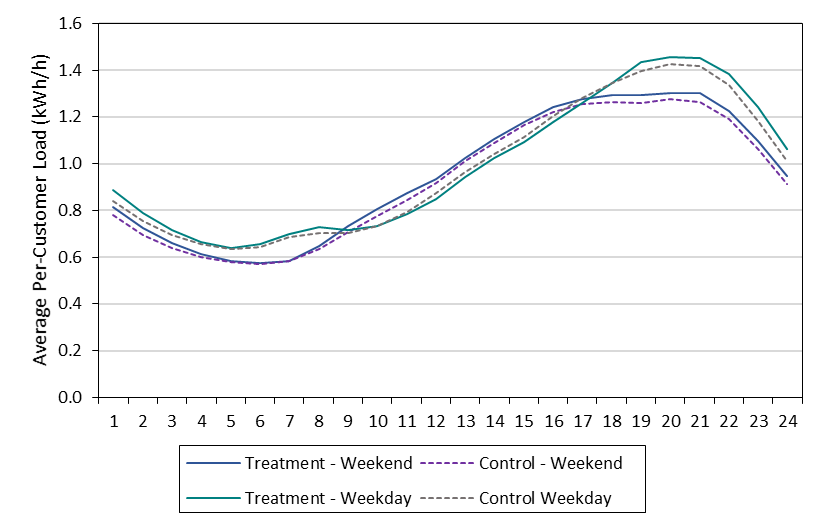
This section documents the findings from the *ex-post* load impact evaluation analysis of the CPP portion of the TOU-DR-P rate. For CPP, the primary load impact results include average estimated event-hour load impacts (*i.e.*, the average of the hourly load impacts estimated for the seven-hour event window from 11 a.m. to 6 p.m.), in aggregate and per-customer, for each event day. Results of the analysis of the TOU portion of the rate (*i.e.,* peak load impacts on non-event days) are presented in Section 5, along with results for the TOU-DR rate.

Results for all hours are also illustrated in figures. Detailed results for each hour in electronic form may be found in Protocol table generators provided along with this report. As described in Section 3, all of the above results were estimated using fixed-effects regression analysis of hourly data for treatment and matched control group customers.

## 4.1 Control group matching results

Figures 4.1 and 4.2 illustrate the quality of the matches for the CPP (TOU-DR-P) customers in the context of estimating load impacts on the CPP event day. The figures show the average CPP and matched control-group customer load profiles for the selected event-like non-event days. Across all 24 hours, the mean percentage error (MPE) of the CPP profile compared to the control-group profile is 2.4 percent on weekdays and 1.3 percent on weekends, while the mean absolute percentage error (MAPE) is 2.4 percent on weekdays and 2.5 percent on weekends. For the CPP event window (11 a.m. to 6:00 p.m.), the MPE is 1.6 percent on weekdays and -1.8 percent on weekends, while the MAPE is 1.6 percent on weekdays and 1.8 percent on weekends.

Figure 4.1: CPP and Matched Control Group Load Profiles – *Average Event-Like Day*



## 4.2 CPP load impacts

This section summarizes average event-hour reference loads[[12]](#footnote-12) and load impacts, at an aggregate and per-customer basis, for the three 2017 CPP events called on August 31, September 1, and September 2, which was a Saturday. Results for the average weekday event are also reported.

Table 4.1 summarizes reference load and CPP load impact results for CPP customers, by climate zone. The first three columns show the climate zone, event date, and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/h. The next two columns show the same variables for the average customer, in units of kWh/h. The last two columns show the load impacts as a percentage of the reference loads and the average temperature during the event window.

Table 4.1: Average CPP Event-Hour Load Impacts

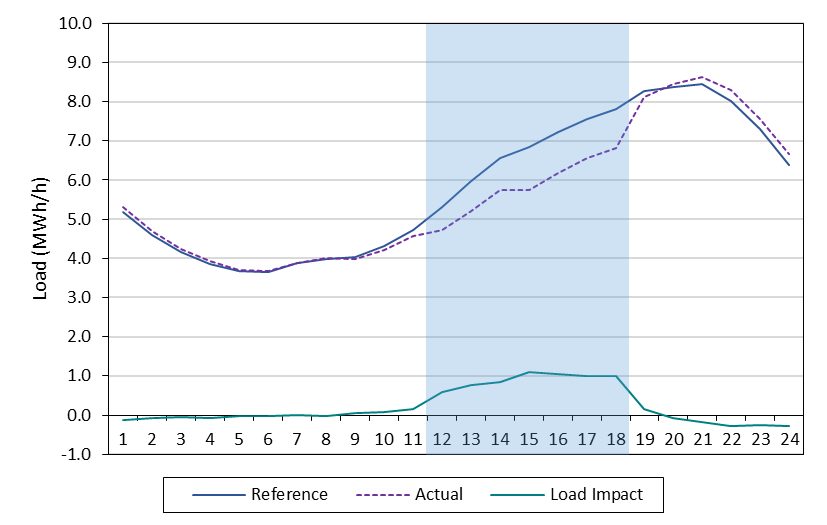
|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Climate Zone** | **Date** | **Enrolled** | **Ref. Load (MWh/h)** | **Load Impact (MWh/h)** | **Ref. Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** | **Ave. Event Temp.** |
| Coastal | Aug 31, 2017 | 2,847 | 3.09 | 0.41 | 1.09 | 0.15 | 13% | 86 |
| Sep 1, 2017 | 2,844 | 3.64 | 0.53 | 1.28 | 0.18 | 14% | 93 |
| Sep 2, 2017 | 2,849 | 4.05 | 0.46 | 1.42 | 0.16 | 11% | 92 |
| **Average Weekday Event** | **2,847** | **3.36** | **0.47** | **1.18** | **0.17** | **14%** | **89** |
| Inland | Aug 31, 2017 | 2,087 | 3.18 | 0.39 | 1.52 | 0.19 | 12% | 92 |
| Sep 1, 2017 | 2,090 | 3.69 | 0.48 | 1.77 | 0.23 | 13% | 98 |
| Sep 2, 2017 | 2,106 | 4.21 | 0.25 | 2.00 | 0.12 | 6% | 96 |
| **Average Weekday Event** | **2,089** | **3.43** | **0.44** | **1.64** | **0.21** | **13%** | **95** |
| All | Aug 31, 2017 | 4,931 | 6.23 | 0.80 | 1.26 | 0.16 | 13% | 88 |
| Sep 1, 2017 | 4,939 | 7.28 | 1.00 | 1.47 | 0.20 | 14% | 95 |
| Sep 2, 2017 | 4,963 | 8.19 | 0.72 | 1.65 | 0.14 | 9% | 94 |
| **Average Weekday Event** | **4,935** | **6.76** | **0.90** | **1.37** | **0.18** | **13%** | **92** |

Program enrollment was 4,931 customers for the first event, skewed somewhat toward the Coastal climate zone.[[13]](#footnote-13) On the average weekday event, August 31 and September 1, the aggregate reference load for all customers was 6.76 MWh/h. Per-customer load impacts averaged 0.17 kW for customers in the Coastal climate zone, representing 14 percent of their reference load, and 0.21 kW, or 13 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 89 degrees, than the 95-degree temperature for the Inland zone. Both customer groups, inland and climate, respond similarly in percentage terms to the average weekday event.

The average per-customer reference load was higher during the weekend event in both climate zones. Nonetheless, the load impacts were smaller during the weekend event. Inland customers responded less during the weekend event, providing a 6% load reduction compared to 13% during the weekday events. Coastal customers reduced usage by 11% during the weekend event, down from 14% during the weekday events.

Figure 4.2 shows aggregate hourly loads and load impacts for the average weekday event. The largest hourly load impact was 1.09 MWh/h in hour-ending 15 (2 to 3 p.m.).

Figure 4.2: Aggregate CPP Hourly Loads and Load Impacts (MWh/h)  
 – *Average Weekday Event*



## 4.3 SCTD Load Impacts

This section compares the CPP load impact estimates for customers that were dually enrolled in CPP and the Small Customer Technology Deployment (“SCTD”) program during 2017. Customers enrolled in SCTD had events that were on the same days as CPP events, August 31st, September 1st, and September 2nd. The SCTD event hours were 2 to 6 p.m., shorter than the CPP event window of 11 a.m. to 6 p.m.

Table 4.2 summarizes reference loads and load impacts for customers that are dually enrolled in CPP and SCTD, during the SCTD event-hour window of 2 to 6 p.m. The number of dually enrolled customers by the last event date was 342 (which is about 7% of all CPP customers). The load impacts in the first panel of Table 4.2, labeled SCTD, represent the incremental load impacts of SCTD relative to CPP. The second panel labeled CPP + SCTD represents the combined effect of calling a CPP and SCTD event on the same day for customers dually enrolled. On average, customers dually enrolled in SCTD and CPP have larger reference loads than customers only enrolled in CPP.

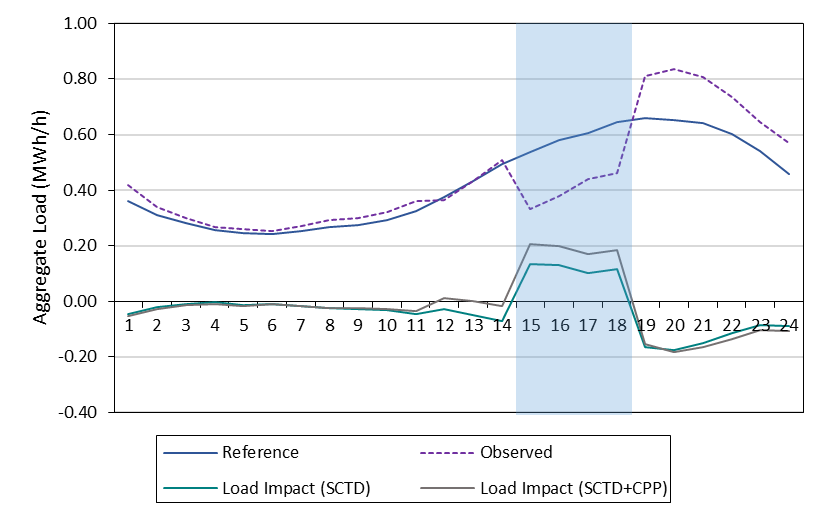
The lowest SCTD load impact of 0.08 kWh/h occurred on the weekend event. The combined CPP and SCTD weekday load impacts are approximately three times as large than the CPP load impacts reported in Table 4.1.

Table 4.2: Comparison of Average SCTD Event-Hour Load Impacts   
for Customers Dually Enrolled in SCTD and CPP

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Load Impact Type** | **Date** | **Enrolled** | **Ref. Load (MWh/h)** | **Load Impact (MWh/h)** | **Ref. Load (kWh/h)** | **Load Impact (kWh/h)** | **% Load Impact** | **Ave. Event Temp.** |
| SCTD | Aug 31, 2017 | 341 | 0.55 | 0.12 | 1.61 | 0.36 | 22.3% | 90 |
| Sep 1, 2017 | 342 | 0.63 | 0.12 | 1.85 | 0.34 | 18.4% | 96 |
| Sep 2, 2017 | 342 | 0.69 | 0.03 | 2.01 | 0.08 | 3.9% | 96 |
| **Average Weekday Event** | **342** | **0.59** | **0.12** | **1.73** | **0.35** | **20.2%** | **93** |
| CPP + SCTD | Aug 31, 2017 | 341 | 0.55 | 0.18 | 1.61 | 0.54 | 33.3% | 90 |
| Sep 1, 2017 | 342 | 0.63 | 0.20 | 1.85 | 0.57 | 30.9% | 96 |
| Sep 2, 2017 | 342 | 0.69 | 0.08 | 2.01 | 0.24 | 12.1% | 96 |
| **Average Weekday Event** | **342** | **0.59** | **0.19** | **1.73** | **0.55** | **32.0%** | **93** |

Figure 4.3 shows aggregate hourly loads and load impacts for customers dually enrolled in CPP and SCTD for the 2017 average weekday event. The shaded hours indicate the SCTD event-hours (*i.e.,* 2 to 6 p.m.). The load impact estimates are shown separately for the incremental SCTD event (the lower green line) and the combined SCTD and CPP event (the upper gray line). The largest hourly incremental SCTD load impact was 0.13 MWh/h in the first SCTD event-hour (2 to 3 p.m.).

Figure 4.3: CPP+SCTD Hourly Loads and Load Impacts for Dually Enrolled Customers   
– *Average Weekday Event*



# 5. TOU *Ex-Post* Load Impact Study Findings

This section presents the match quality and estimates of monthly peak TOU load impacts for the TOU (TOU-DR) customers and for customers enrolled in CPP (TOU-DR-P).

## 5.1 TOU control group matching results for TOU customers

Figures 5.1 and 5.2 illustrate the quality of the matches for the TOU (TOU-DR) customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is 2.5 percent, while the mean absolute percentage error (MAPE) is 2.7 percent. In the winter months, the MPE is 2.5 percent and the MAPE is 3.0 percent.

Figure 5.1: TOU and Matched Control Group Load Profiles – *Summer*

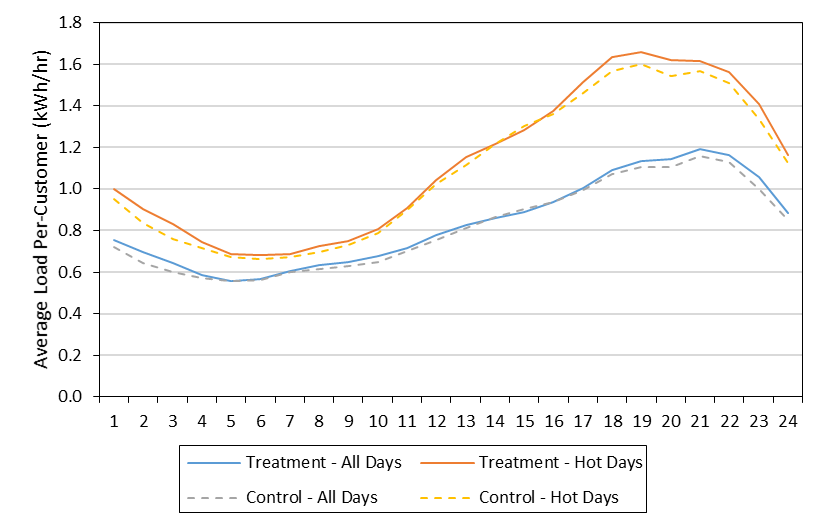
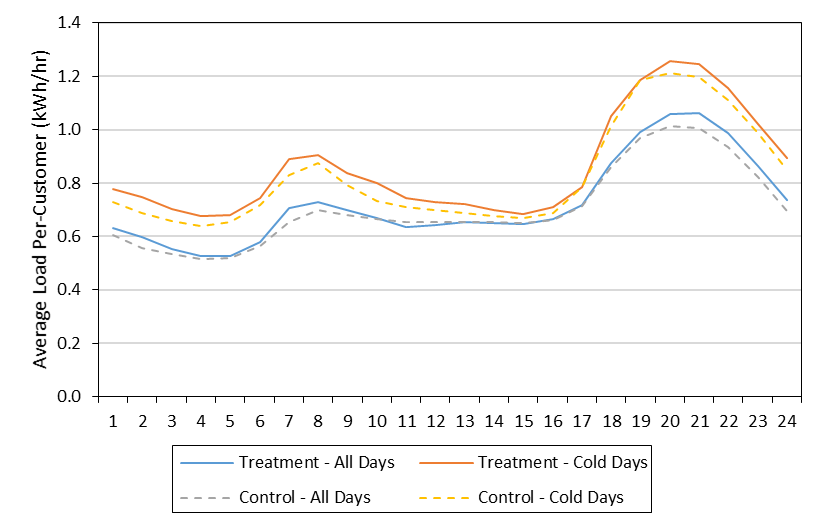


Figure 5.2: TOU and Matched Control Group Load Profiles – *Winter*



## 5.2 Ex-post TOU load impacts for TOU customers

This sub-section shows *ex-post* TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 11 a.m. to 6 p.m. for May through October, and 5 to 8 p.m. for November through April), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with the first month included in the analysis (October 2016). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 653 in October 2016 to 1,559 in September 2017.[[14]](#footnote-14) Percentage load impacts were essentially the same for the summer and winter months due to the estimation method that combined data for all months in the relevant season, and constrained the estimated percentage peak load impact to be the same across months. The estimated seasonal percentage load impacts were approximately 6.0 percent in summer and -3.1 percent, an increase in usage, during the winter.[[15]](#footnote-15)

Table 5.1: TOU Peak Load Impacts for TOU Customers – *Average Weekday by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Oct-16 | All | 653 | 0.47 | 0.03 | 0.71 | 0.042 | 6.0% | 76 |
| Nov-16 | All | 689 | 0.71 | -0.02 | 1.03 | -0.031 | -3.0% | 65 |
| Dec-16 | All | 726 | 0.88 | -0.03 | 1.21 | -0.037 | -3.0% | 59 |
| Jan-17 | All | 755 | 0.88 | -0.03 | 1.16 | -0.035 | -3.0% | 56 |
| Feb-17 | All | 795 | 0.79 | -0.02 | 0.99 | -0.030 | -3.1% | 59 |
| Mar-17 | All | 860 | 0.75 | -0.02 | 0.88 | -0.027 | -3.1% | 65 |
| Apr-17 | All | 897 | 0.71 | -0.02 | 0.79 | -0.024 | -3.1% | 67 |
| May-17 | All | 934 | 0.57 | 0.03 | 0.61 | 0.036 | 6.0% | 69 |
| Jun-17 | All | 1,002 | 0.77 | 0.05 | 0.77 | 0.046 | 6.0% | 74 |
| Jul-17 | All | 1,130 | 1.19 | 0.07 | 1.06 | 0.064 | 6.0% | 80 |
| Aug-17 | All | 1,412 | 1.46 | 0.09 | 1.04 | 0.063 | 6.1% | 79 |
| Sep-17 | All | 1,559 | 1.37 | 0.08 | 0.88 | 0.053 | 6.0% | 78 |

Table 5.2 shows results by season and climate zone. Because of relatively low enrollment in October 2016 and the discontinuity between that month and the summer of 2017, the results for the summer season include only May through September of 2017. Summer peak load impacts were similar in percentage terms for the two climate zones.

Table 5.2: TOU Peak Load Impacts for TOU Customers – *Average Weekday by Season & Climate Zone*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Season** | **Climate Zone** | **Enrolled (Average)** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Summer | Coastal | 692 | 0.60 | 0.03 | 0.81 | 0.038 | 4.6% | 76 |
| Inland | 515 | 0.52 | 0.03 | 0.97 | 0.061 | 6.3% | 78 |
| **All** | **1,207** | **1.12** | **0.06** | **0.88** | **0.048** | **5.4%** | **77** |
| Winter | Coastal | 443 | 0.46 | -0.02 | 1.05 | -0.047 | -4.5% | 63 |
| Inland | 344 | 0.33 | -0.01 | 0.95 | -0.015 | -1.6% | 62 |
| **All** | **787** | **0.79** | **-0.03** | **1.01** | **-0.033** | **-3.3%** | **62** |

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers increased their energy consumption in each month of the year, with larger increases during the winter months.[[16]](#footnote-16) The overall change was an average annual *increase* of 2.5 percent.

Table 5.3: TOU Average *Daily* Load Impacts for TOU Customers, *by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Daily Ref. Load (MWh/h)** | **Daily Load Impact (MWh/h)** | **Daily Ref. Load (kWh/h)** | **Daily Load Impact (kWh/h)** | **% Daily Load Impact** | **Ave. Daily Temp.** |
| Oct-16 | All | 653 | 12.15 | -0.11 | 18.60 | -0.18 | -0.9% | 67 |
| Nov-16 | All | 689 | 11.90 | -0.51 | 17.27 | -0.73 | -4.2% | 63 |
| Dec-16 | All | 726 | 14.38 | -0.64 | 19.81 | -0.89 | -4.5% | 57 |
| Jan-17 | All | 755 | 14.89 | -0.64 | 19.72 | -0.85 | -4.3% | 54 |
| Feb-17 | All | 795 | 13.88 | -0.62 | 17.46 | -0.78 | -4.5% | 57 |
| Mar-17 | All | 860 | 14.07 | -0.60 | 16.36 | -0.69 | -4.2% | 60 |
| Apr-17 | All | 897 | 13.68 | -0.57 | 15.25 | -0.64 | -4.2% | 63 |
| May-17 | All | 934 | 14.74 | -0.15 | 15.78 | -0.16 | -1.0% | 63 |
| Jun-17 | All | 1,002 | 18.03 | -0.11 | 17.99 | -0.11 | -0.6% | 68 |
| Jul-17 | All | 1,130 | 25.55 | -0.10 | 22.61 | -0.09 | -0.4% | 73 |
| Aug-17 | All | 1,412 | 31.70 | -0.14 | 22.45 | -0.10 | -0.4% | 73 |
| Sep-17 | All | 1,559 | 30.69 | -0.17 | 19.69 | -0.11 | -0.6% | 71 |

Figure 5.3 shows aggregate hourly observed and estimated reference loads, along with hourly estimated TOU load impacts for the TOU customers for the average weekday in August. Figure 5.4 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a load shift out of the peak period to the off-peak period, especially during the morning hours. However, comparison of the hourly TOU load impacts between the summer and winter month indicates that TOU-DR customers respond similarly during both seasons, perhaps indicating customers’ knowledge is fuzzy regarding the change in TOU periods between seasons.

Figure 5.3: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers  
(*Average Weekday, August 2017*)

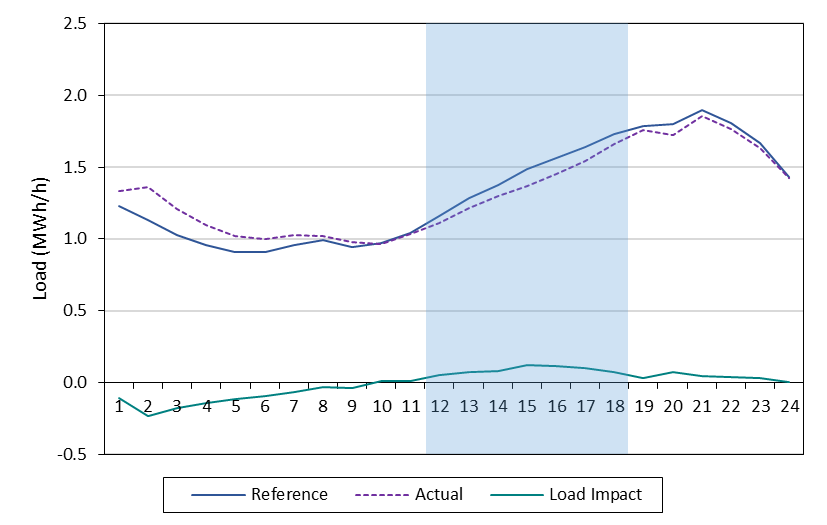
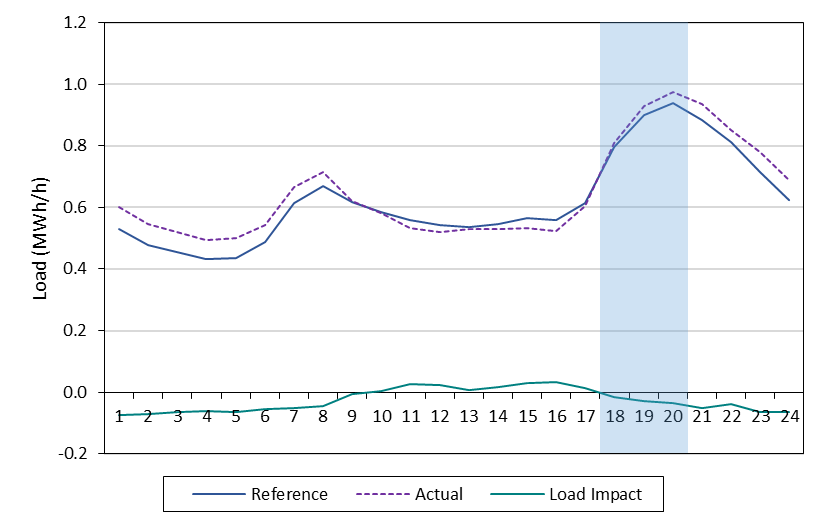


Figure 5.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers  
(*Average Weekday, January 2017*)



## 5.3 TOU control group matching results for CPP customers

Figures 5.5 and 5.6 illustrate the quality of the matches for the CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is 1.9 percent, while the mean absolute percentage error (MAPE) is 2.1 percent. In the winter months, the MPE is 0.6 percent and the MAPE is 2.0 percent.

Figure 5.5: CPP and Matched Control Group Load Profiles – *Summer*

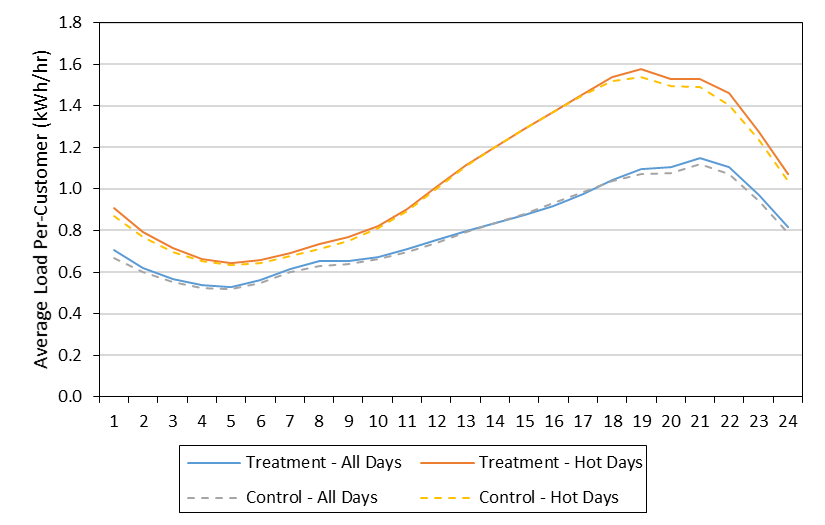
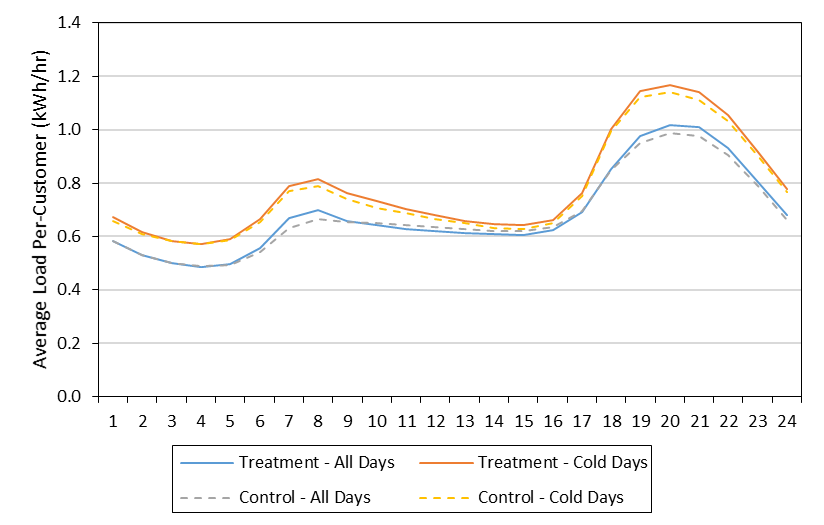


Figure 5.6: CPP and Matched Control Group Load Profiles – *Winter*



## 5.4 Ex-post TOU load impacts for CPP customers

Since TOU-DR-P customers experience TOU prices on all weekdays that are not RYU/CPP event days, it is of interest to examine their usage changes on non-event days, similarly to TOU customers. This sub-section reports *ex-post* TOU load impact results for those customers enrolled in the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average summer (October 2016, and May through September 2017) and winter (November 2016 through April 2017) weekdays, by month. Reported enrollment in CPP grew from 2,724 in October 2016 to just over 5,200 in September 2017.[[17]](#footnote-17) Peak load impacts varied across months, with estimated load reductions in all months except for October and November. Peak load reductions ranged from less than 2.2 percent (in April) to just over 8 percent of the reference load (in September).

Table 5.4: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Oct-16 | All | 2,724 | 1.80 | 0.00 | 0.66 | 0.00 | -0.1% | 76 |
| Nov-16 | All | 2,917 | 2.82 | -0.02 | 0.97 | -0.01 | -0.7% | 65 |
| Dec-16 | All | 3,053 | 3.29 | 0.11 | 1.08 | 0.04 | 3.3% | 59 |
| Jan-17 | All | 3,251 | 3.37 | 0.08 | 1.04 | 0.03 | 2.5% | 56 |
| Feb-17 | All | 3,466 | 3.30 | 0.17 | 0.95 | 0.05 | 5.2% | 59 |
| Mar-17 | All | 3,743 | 3.10 | 0.10 | 0.83 | 0.03 | 3.2% | 65 |
| Apr-17 | All | 3,938 | 3.06 | 0.07 | 0.78 | 0.02 | 2.2% | 67 |
| May-17 | All | 4,091 | 2.68 | 0.20 | 0.65 | 0.05 | 7.3% | 69 |
| Jun-17 | All | 4,323 | 3.48 | 0.23 | 0.80 | 0.05 | 6.6% | 75 |
| Jul-17 | All | 4,622 | 4.99 | 0.31 | 1.08 | 0.07 | 6.3% | 80 |
| Aug-17 | All | 4,984 | 4.93 | 0.12 | 0.99 | 0.02 | 2.5% | 80 |
| Sep-17 | All | 5,229 | 4.59 | 0.37 | 0.88 | 0.07 | 8.1% | 79 |

Table 5.5 summarizes results by season and climate zone. Both summer and winter peak load impacts are similar between the Coastal and Inland climate zones, with Coastal load impacts slightly larger in the summer and slightly smaller in the winter, when the TOU period is shorter and later in the day.

Table 5.5: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Season & Climate Zone*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Season** | **Climate Zone** | **Enrolled (Average)** | **Peak Ref. Load (MWh/h)** | **Peak Load Impact (MWh/h)** | **Peak Ref. Load (kWh/h)** | **Peak Load Impact (kWh/h)** | **% Peak Load Impact** | **Ave. Peak Temp.** |
| Summer | Coastal | 2,701 | 2.22 | 0.14 | 0.81 | 0.051 | 6.3% | 76 |
| Inland | 1,948 | 1.98 | 0.11 | 1.00 | 0.055 | 5.5% | 78 |
| **All** | **4,650** | **4.21** | **0.25** | **0.89** | **0.053** | **5.9%** | **77** |
| Winter | Coastal | 1,973 | 1.78 | 0.04 | 0.90 | 0.019 | 2.2% | 63 |
| Inland | 1,422 | 1.38 | 0.05 | 0.97 | 0.033 | 3.4% | 62 |
| **All** | **3,395** | **3.16** | **0.09** | **0.93** | **0.025** | **2.8%** | **62** |

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers changed their average daily usage by small amounts in the winter months, decreasing daily usage in all months but November. These customers also decreased their energy consumption by small amounts in each summer month (except August and October). The overall effect is an average annual *decrease* of about 1.2 percent.

Table 5.6: TOU Average *Daily* Load Impacts for CPP Customers, *by Month*

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **Aggregate** | | **Per-Customer** | |  |  |
| **Month** | **Climate Zone** | **Enrolled** | **Daily Ref. Load (MWh/h)** | **Daily Load Impact (MWh/h)** | **Daily Ref. Load (kWh/h)** | **Daily Load Impact (kWh/h)** | **% Daily Load Impact** | **Ave. Daily Temp.** |
| Oct-16 | All | 2,724 | 44.08 | -1.50 | 16.18 | -0.55 | -3.4% | 67 |
| Nov-16 | All | 2,917 | 47.88 | -0.87 | 16.41 | -0.30 | -1.8% | 63 |
| Dec-16 | All | 3,053 | 54.85 | 0.69 | 17.96 | 0.23 | 1.3% | 58 |
| Jan-17 | All | 3,251 | 57.57 | 0.20 | 17.71 | 0.06 | 0.3% | 54 |
| Feb-17 | All | 3,466 | 57.27 | 1.14 | 16.52 | 0.33 | 2.0% | 57 |
| Mar-17 | All | 3,743 | 58.00 | 0.29 | 15.50 | 0.08 | 0.5% | 60 |
| Apr-17 | All | 3,938 | 58.91 | 0.01 | 14.96 | 0.00 | 0.0% | 63 |
| May-17 | All | 4,091 | 64.20 | 1.93 | 15.69 | 0.47 | 3.0% | 63 |
| Jun-17 | All | 4,323 | 76.79 | 2.10 | 17.76 | 0.49 | 2.7% | 68 |
| Jul-17 | All | 4,622 | 103.28 | 2.92 | 22.35 | 0.63 | 2.8% | 74 |
| Aug-17 | All | 4,984 | 106.01 | -0.29 | 21.27 | -0.06 | -0.3% | 73 |
| Sep-17 | All | 5,229 | 102.35 | 2.95 | 19.57 | 0.56 | 2.9% | 72 |

Figure 5.7 shows aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the CPP customers for the average weekday in August. Figure 5.8 shows the same information for the average weekday in January. Each Figure illustrates a load shift out of the peak period to the off or super off-peak periods. The decrease in usage during the winter period occurs for a longer duration during the day, even before the TOU peak-period begins.

Figure 5.7: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers  
(*Average Weekday, August 2017*)

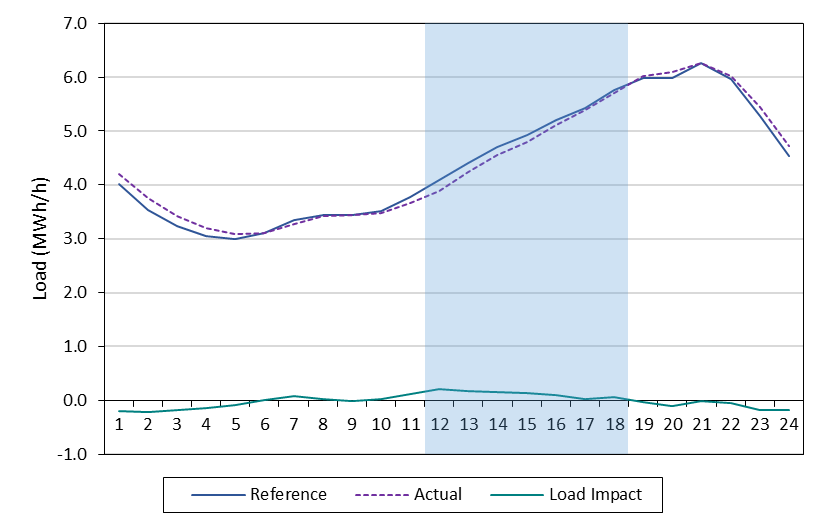
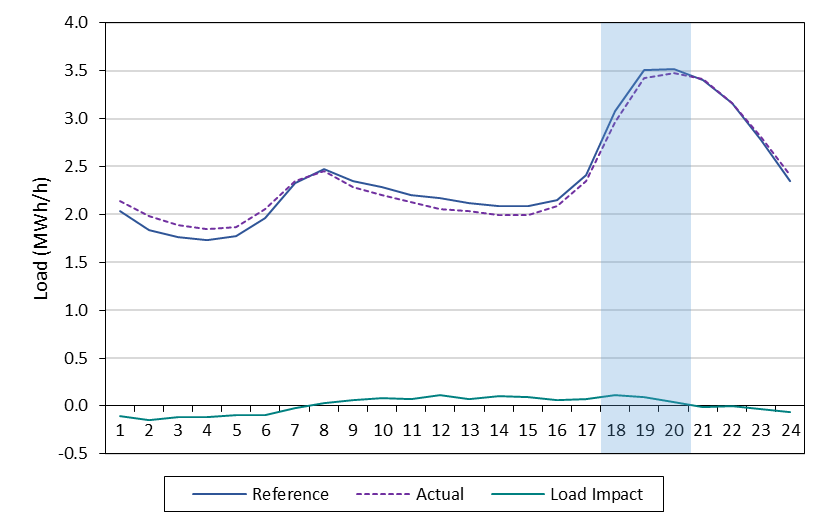


Figure 5.8: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers  
(*Average Weekday, January 2017*)



# 6. *Ex-Ante* Load Impacts

This section describes the development of *ex-ante* load impact forecasts for the CPP and TOU rates. We first describe the methodologies used and then present the resulting forecasts. *Ex-ante* load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on analyses of per-customer load impact findings from *ex-post* evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

## 6.1 Methodology

### 6.1.1 Per-customer load impacts

In cases where multiple events have been called in the historical period for event-based programs such as CPP, we generally attempt to develop a relationship between the estimated event-day *ex-post* load impacts and the weather conditions that held on those days. We then use that relationship to produce weather-sensitive *ex-ante* load impacts for the relevant weather scenarios. In 2017 SDG&E called three RYU/CPP events, which means we have three events on which to base the *ex-ante* forecasts. We determined that this provided too few observations on the relationship between load impacts and weather to be able to reliably produce a weather-dependent forecast (particularly since one of the event days took place on a weekend). Therefore, we use the percentage load impact for the average weekday event to simulate the *ex-ante* CPP load impact. We develop CPP load impacts for different weather scenarios by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads.

Beginning in December 1, 2017, SDG&E changed its CPP event hours, reducing the seven-hour event window of 11:00 a.m. to 6:00 p.m. (HE 12-18) to a four-hour event widow of 2:00 to 6:00 p.m. (HE 15-18). In order to apply *ex-post* load impacts that correspond to the updated CPP event hours, we first categorize each hour of the day with respect to the old and updated CPP event hours. Table 6.1 summarizes our categorization of each hour, with the *ex-post* column representing the old event hours and the *ex-ante* column representing the new CPP event window. The *ex-post* reference loads and load impacts are averaged over these periods to obtain percentage load impacts, which are then applied to *ex-ante* reference loads during the corresponding categorized period to calculate the *ex-ante* load impacts. For example, the percentage load impact for the hour before the event in *ex-post* (HE 11) is applied the *ex-ante* reference load for the hour before the event in *ex-ante* (HE 14).

Table 6.1: Hourly Categorization of Periods Relating to Changes in CPP Event Window

|  |  |  |
| --- | --- | --- |
| **Hour** | **Ex-Post** | **Ex-Ante** |
| 1 | beginning of event day | beginning of event day |
| 2 |
| 3 |
| 4 |
| 5 |
| 6 |
| 7 |
| 8 |
| 9 |
| 10 |
| 11 | pre-event hour |
| 12 | beginning of event |
| 13 |
| 14 | middle of event | pre-event hour |
| 15 | beginning of event |
| 16 | middle of event |
| 17 | end of event |
| 18 | end of event |
| 19 | hour-ending 19 | hour-ending 19 |
| 20 | hour-ending 20 | hour-ending 20 |
| 21 | hour-ending 21 | hour-ending 21 |
| 22 | hour-ending 22 | hour-ending 22 |
| 23 | hour-ending 23 | hour-ending 23 |
| 24 | hour-ending 24 | hour-ending 24 |

We also report portfolio-level load impacts for instances when a CPP event is called on the same day as a Summer Saver or SCTD event. For such days, we assume that Summer Saver and SCTD customers do not provide a load impact that can be attributable to CPP and therefore remove dually enrolled customers from the reference load and load impacts for portfolio-level estimates. The proportion of Summer Saver customers is assumed to be equivalent to *ex-post* enrollment numbers and is held constant throughout the *ex-ante* forecast.

An additional issue in producing the *ex-ante* load impact forecasts is that the Protocols call for estimating load impacts for the RA hours of 1 to 6 p.m. during summer months, and 4 to 9 p.m. in winter months, while the CPP events are called during the program hours of 2 p.m. to 6 p.m. year-round. We simulate the load impacts using the event hours that are indicated by the tariff, but we summarize the load impacts across the RA window as required.

For TOU load impacts (TOU-DR and TOU-DR-P customers), we apply percentage peak load impacts from the *ex-post* analysis (monthly values for CPP and seasonal values for TOU) to weather-sensitive reference loads that are developed as described in the following sub-section. SDG&E has also made changes to the TOU periods, as described in Section 2. We apply the *ex-post* TOU load impacts percentages to the updated TOU periods. For example, the summer peak-period has changed from hours-ending 12 through 18 to a later peak of hours-ending 17 through 21. Therefore, the *ex-post* percentage load impacts between HE 12-18 is applied to *ex-ante* reference loads during hours-ending 17-21 to obtain load impacts.

### 6.1.2 Per-customer reference loads

Weather-sensitive reference loads for the average customer in each of the two climate zones were developed through a regression analysis of hourly load data for weekday non-event days for the period of October 2016 through September 2017 for the CPP and TOU customers. Customers are first sorted as weather sensitive or not.[[18]](#footnote-18) Regression models were estimated separately for each hour of the day by weather sensitivity, using daily observations for weekdays, and a form similar to that of the *ex-post* load impact models. The primary differences between this analysis compared to the *ex-post* analysis are:

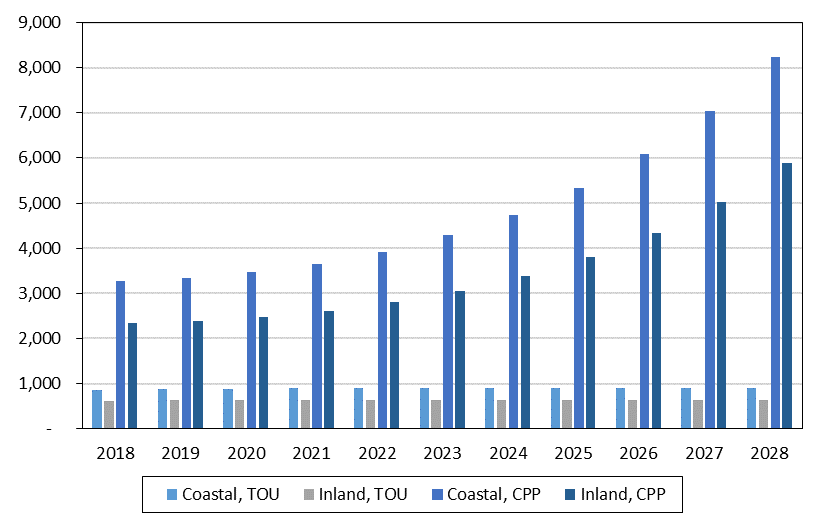
* The analysis included only the treatment customers;
* Weather variables were included (Mean17, CDH60, and HDH60)[[19]](#footnote-19);
* Data for all months were included, rather than estimating separate models by month or season; and
* Month-year indicator variables were added to account for monthly and yearly differences in usage patterns.

The resulting equations allow the simulation of “observed” (*i.e.*, post TOU load impacts) loads under the four different weather scenarios. Reference loads for the alternative scenarios were then obtained by adjusting the above observed loads by the relevant estimated percentage TOU load impacts from the *ex-post* analysis (seasonal values for TOU, and monthly values for CPP).[[20]](#footnote-20)

### 6.1.3 Enrollment forecast

Figure 6.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU, while enrollment in CPP is forecasted to nearly triple by the end of the forecast period. Enrollment is expected to be somewhat greater in the Coastal climate zone than in the Inland for both rates.

Figure 6.1: Enrollments in TOU and CPP Rates



## 6.2 Ex-Ante load impacts – Residential CPP

This subsection summarizes the *ex-ante* load impact forecasts for future CPP event days, for customers anticipated to be enrolled in CPP. Figure 6.2 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2018 in the SDG&E 1-in-2 weather scenario. The average event-period percentage load impact is 9 percent.

Figure 6.2: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) –   
(*August 2019 SDG&E 1-in-2 Peak Day*)

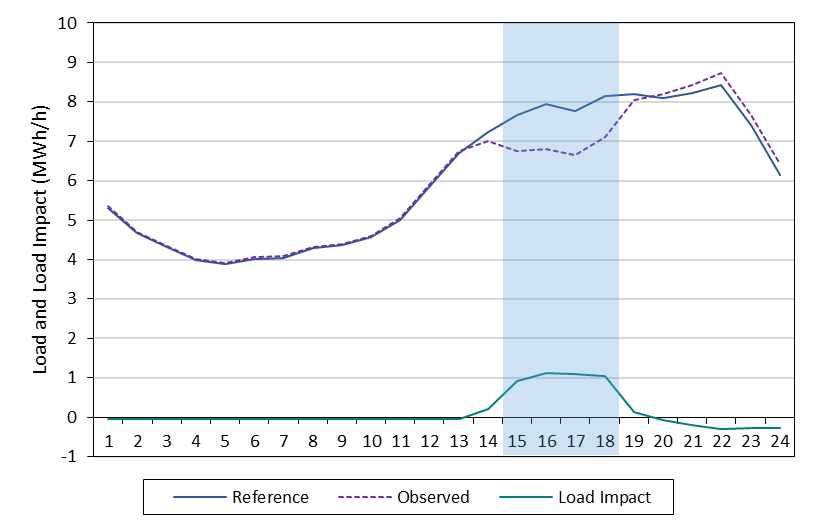


Figure 6.3 shows the monthly pattern of aggregate average *ex-ante* load impacts (RA window) in 2019 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in August.

Figure 6.3: Aggregate CPP Load Impacts (MWh/h), by Month –   
(*2019* *SDG&E 1-in-2 Peak Day, RA Window*)

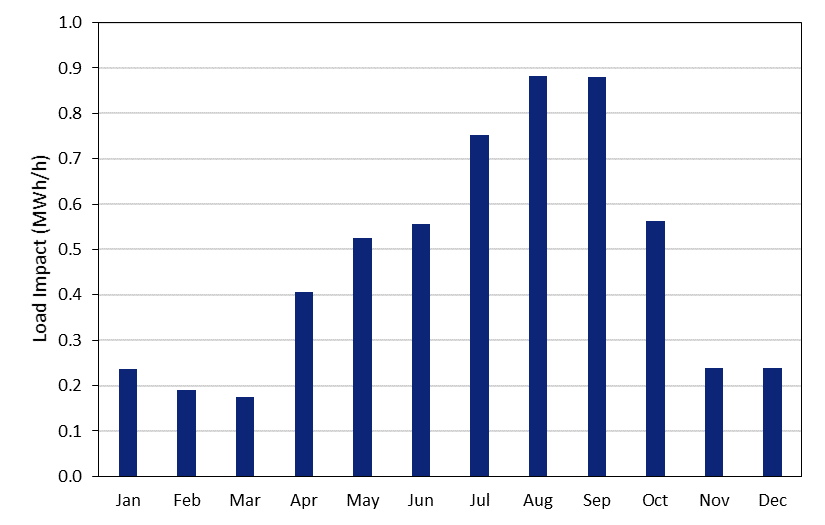
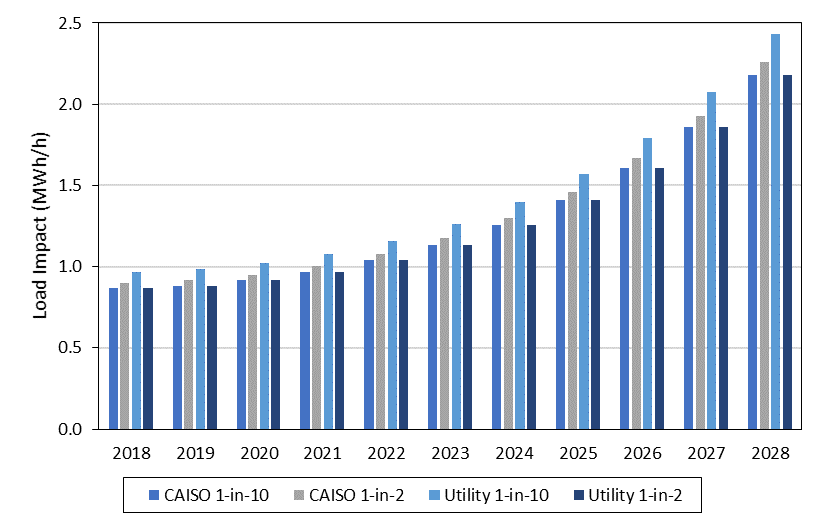


Figure 6.4 illustrates the growth in forecast CPP load impacts, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios over the forecast period.[[21]](#footnote-21) In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

Figure 6.4: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario – (*August Peak Day, RA Window*)



## 6.3 Ex-Ante load impacts – Residential TOU

This subsection summarizes the *ex-ante* TOU peak load impact forecasts for customers anticipated to be enrolled in both the TOU and CPP rates (TOU-DR and TOU-DR-P). Figure 6.5 shows aggregate loads and load impacts for TOU and CPP customers, in 2019 for an August SDG&E 1-in-2 peak day. The average peak load impact is 9 percent of the reference load.

Figure 6.5: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – *TOU-DR and TOU-DR-P Customers,* (*August 2019 SDG&E 1-in-2 Peak Day*)

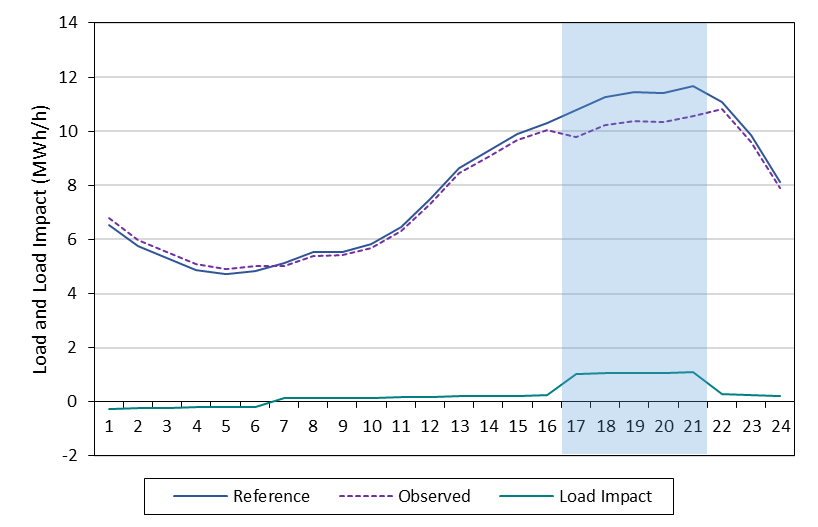


Figure 6.6 shows the monthly distributions of the peak load impacts (RA window) for TOU and CPP customers. Load impacts for CPP customers in particular are greatest in the summer months. Results for the winter months vary considerably. Customers on the CPP rate respond with a decrease in usage over the RA window, while TOU-only customers *increase* their usage both during the RA window and during the TOU period. The April load impact is reduced because the RA window for this month includes hour-ending 14, which is a super off-peak TOU period associated with an *increase* in usage.

Figure 6.6: Aggregate TOU Load Impacts (MWh/h) by Month – *TOU-DR and TOU-DR-P Customers,* (*2019 SDG&E 1-in-2 Average Weekday,* RA Window)

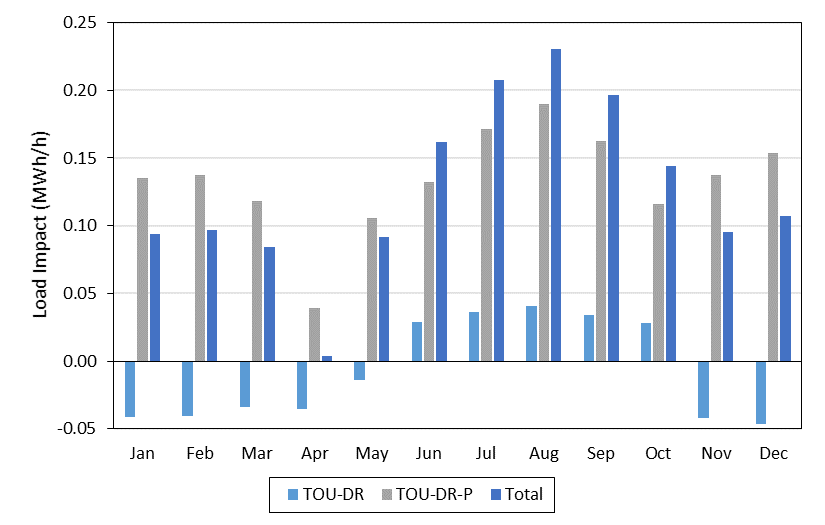
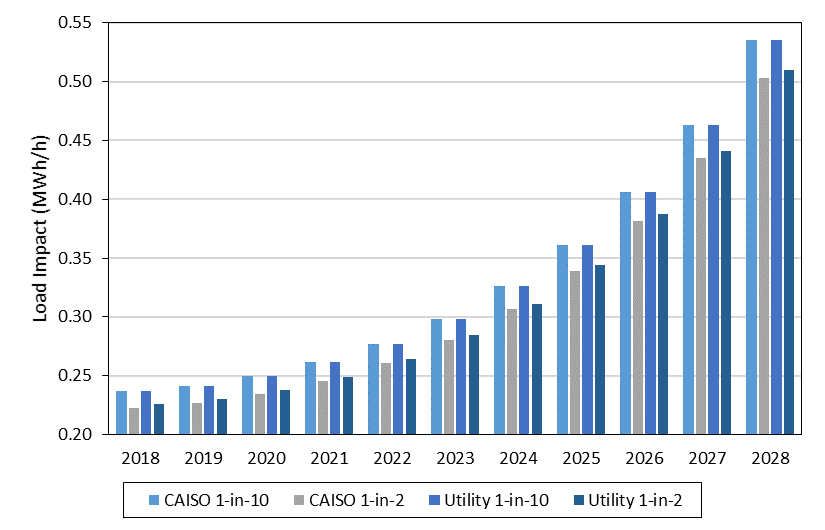


Figure 6.7 shows comparable information for customers enrolled on the DR-TOD and DR-TOD-P rates, but extended over the full period. Similar patterns hold for the differences between scenarios.

Figure 6.7: Aggregate TOU Load Impacts (MWh/h) – *TOU-DR and TOU-DR-P* Customers, by Year and Weather Scenario (*Average August Weekday, RA Window*)



# 7. Comparisons of Results

In this section, we present several comparisons of load impacts for each utility:

* *Ex-post* load impacts from the current and previous studies;
* *Ex-ante* load impacts from the current and previous studies;
* Previous *ex-ante* and current *ex-post* load impacts; and
* Current *ex-post* and *ex-ante* load impacts.

In the above list, “current study” refers to this report, which is based on findings from the 2017 program year; and “previous study” refers to the report that was developed following the 2016 program year.

## 7.1 Residential CPP

### 7.1.1 Previous versus current *ex-post*

Table 7.1 shows the average event-hour reference loads and CPP load impacts for the average weekday event during the current and previous program years. The aggregate enrollments increased in the current program which also increase reference loads and CPP load impacts. The per-customer reference load and load impact in the PY2017 study is larger, even with cooler temperatures. The percentage load impact is slightly larger in the current study at 13.38 percent versus 12.61 percent in the PY2016 study.

Table 7.1 Comparison of PY2016 *Ex-Post* and Current *Ex-Post* Load Impacts, *CPP Event*

|  |  |  |
| --- | --- | --- |
| **Result** | ***Ex-post for 2016 Weekday Event from PY2016 Study*** | ***Ex-post for 2017 Weekday Event from PY2017 Study*** |
|
| # Enrolled | 3,063 | 4,935 |
| Reference (MWh/h) | 3.51 | 6.76 |
| Load Impact (MWh/h) | 0.44 | 0.90 |
| Per-customer reference (kWh/h) | 1.15 | 1.37 |
| Per-customer load impact (kWh/h) | 0.14 | 0.18 |
| % Load Impact | 12.61% | 13.38% |
| Temperature | 99.9 | 91.6 |

### 7.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 7.2 reports the average event-hour load impacts for the August 2018 system peak day under utility-specific 1-in-2 weather conditions. The current study *ex-ante* forecasthas similar percentage load impacts. Per-customer reference loads and CPP load impacts are slightly higher in the current study. This is caused by the higher event-window temperatures as well as the shorter CPP event-window in the current study, covering the later event hours that typically correspond to higher reference loads and temperatures.

Table 7.2 Comparison of PY2016 *Ex-Ante* 2018 Forecast and Current *Ex-Ante* 2018 Forecast Load Impacts, *CPP Event*

|  |  |  |
| --- | --- | --- |
| **Result** | ***Ex-ante for 2018 System Peak Day from PY2016 Study*** | ***Ex-ante for 2018 System Peak Day from PY2017 Study*** |
|
| # Enrolled | 3,729 | 5,611 |
| Reference (MWh/h) | 4.11 | 7.72 |
| Load Impact (MWh/h) | 0.50 | 1.03 |
| Per-customer reference (kWh/h) | 1.10 | 1.38 |
| Per-customer load impact (kWh/h) | 0.14 | 0.18 |
| % Load Impact | 12.28% | 13.35% |
| Temperature | 85.3 | 87.1 |

### 7.1.3 Previous *ex-ante* versus current *ex-post*

Table 7.3 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study, averaged over the CPP event-window. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the 2017 average CPP event day. The increase in aggregate loads and load impacts in from the PY2017 study is mostly driven by difference in enrollment numbers. The percentage load impact is also higher which could be a result of the hotter temperatures realized in *ex-post*.

Table 7.3 Comparison of PY2016 *Ex-Ante* 2017 Forecast and Current *Ex-Post* Load Impacts, *CPP Event*

|  |  |  |
| --- | --- | --- |
| **Result** | ***Ex-ante for 2017 System Peak Day from PY2016 Study*** | ***Ex-post for 2017 Weekday Event  from PY2017 Study*** |
|
| # Enrolled | 3,656 | 4,935 |
| Reference (MWh/h) | 4.03 | 6.76 |
| Load Impact (MWh/h) | 0.49 | 0.90 |
| Per-customer reference (kWh/h) | 1.10 | 1.37 |
| Per-customer load impact (kWh/h) | 0.14 | 0.18 |
| % Load Impact | 12.28% | 13.38% |
| Temperature | 85.3 | 91.6 |

### 7.1.4 Current *ex-post* versus current *ex-ante*

Table 7.4 compares the CPP *ex-post* load impacts for the average weekday event against the *ex-ante* load impacts for 2018 (of the SDG&E 1-in-2 August peak day), from this study. The *ex-post* and first set of *ex-ante* load impacts are averaged over the CPP event hours while the second set of *ex-ante* load impacts are summarized over the shorter RA window. Since our *ex-ante* CPP load impacts are built on the 2017 *ex-post* values, the per-customer load impact percentages are similar during the event window. The RA window includes non-event hour-ending 14 which reduces the percentage load impacts. Aggregate reference loads and load impacts increase in *ex-ante* because of the increase in enrollments. The results are consistent between the *ex-post* and *ex-ante* analyses.

Table 7.4: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, *CPP Event*

|  |  |  |  |
| --- | --- | --- | --- |
| **Result** | ***Ex-post* for 2017 (Event Window)** | ***Ex-ante* for 2018 Peak Day (Event Window)** | ***Ex-ante* for 2018 Peak Day (RA Window)** |
|
| # Enrolled | 4,935 | 5,611 | 5,611 |
| Reference (MWh/h) | 6.76 | 7.72 | 7.60 |
| Load Impact (MWh/h) | 0.90 | 1.03 | 0.87 |
| Per-customer reference (kWh/h) | 1.37 | 1.38 | 1.35 |
| Per-customer load impact (kWh/h) | 0.18 | 0.18 | 0.15 |
| % Load Impact | 13.38% | 13.35% | 11.39% |
| Temperature | 91.6 | 87.1 | 87.6 |

Table 7.5 compares the key components of the two analyses. As the table describes, the two largest sources of differences between the *ex-post* and *ex-ante* load impacts are the enrollment level and the summary over the RA window for *ex-ante* versus the actual event hours for the *ex-post* impacts.

Table 7.5: *Ex-Post* versus *Ex-Ante* Factors, *CPP Event*

|  |  |  |  |
| --- | --- | --- | --- |
| **Factor** | ***Ex-Post*** | ***Ex-Ante*** | **Expected Impact** |
| Weather | 91.6 degrees Fahrenheit during HE 12-18. | 87.6 degrees Fahrenheit during HE 14-18 of a utility-specific 1-in-2 August peak day. | Cooler *ex-ante* weather decreases the reference load and load impact. |
| Event window | HE 12-18 for the average weekday event. | RA Window:  HE 14-18 in Apr-Oct;  HE 17-21 in Nov-Mar.  Event Window: HE 15-18. | The RA window covers HE 14 which is no longer an event hour, resulting in a lower load impact over the RA window. |
| % of resource dispatched | The entire program was dispatched on each of the days that comprise the average weekday event. | Assume all customers are called. | None. The *ex-ante* method assumes that all enrolled customers are dispatched. |
| Enrollment | 4,935 customers enrolled. | 5,611 customers. | The increase in *ex-ante* enrollments increases the total load impact proportionately relative to *ex-post*. |
| Methodology | Climate-zone-specific regressions using a matched control-group and difference-in-differences analysis on event and event-like non-event days. | Treatment only customer regressions to estimate observed loads. | No effect to percentage load impacts. The *ex-post* percentage load impacts are applied to reference loads of the various scenarios in the *ex-ante* study. |

## 7.2 Residential TOU

### 7.2.1 Previous versus current *ex-post*

Table 7.6 shows the average reference loads and load impacts for the average August weekday day during the current and previous program years, averaged over the RA window. Enrollment numbers have increased resulting in higher aggregate reference loads. The per-customer reference loads have remained about the same; however, the load impact and load impact percentage during the RA window decreased in the PY2017 study.

Table 7.6 Comparison of PY2016 *Ex-Post* and PY2017 *Ex-Post* TOU Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Season** | **Result** | ***Ex-post for 2016 Aug. Avg. Weekday from PY2016 Study*** | ***Ex-post for 2017 Aug. Avg. Weekday from PY2017 Study*** |
|
| **Summer (August)** | # Enrolled | 3,596 | 6,396 |
| Reference (MWh/h) | 3.79 | 6.77 |
| Load Impact (MWh/h) | 0.24 | 0.19 |
| Per-customer reference (kWh/h) | 1.05 | 1.06 |
| Per-customer load impact (kWh/h) | 0.07 | 0.03 |
| % Load Impact | 6.25% | 2.87% |
| Temperature | 77.4 | 79.8 |

### 7.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 7.7 reports the average RA-window load impacts for the August 2018 average weekday under utility-specific 1-in-2 weather conditions. The TOU peak-period has shifted to a later period (4 to 9 p.m.) in the PY2017 *ex-ante* analysis, while the peak period used in the PY2016 *ex-ante* analysis has hours that completely overlap with the RA-window, contributing to a larger percentage load impact.

Table 7.7 Comparison of PY2016 *Ex-Ante* 2018 Forecastand PY2017 *Ex-Ante* 2018 Forecast TOU Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Season** | **Result** | ***Ex-ante for 2018 Avg. Weekday from PY2016 Study*** | ***Ex-ante for 2018 Avg. Weekday from PY2017 Study*** |
|
| **Summer (August)** | # Enrolled | 4,722 | 7,096 |
| Reference (MWh/h) | 4.93 | 7.31 |
| Load Impact (MWh/h) | 0.31 | 0.23 |
| Per-customer reference (kWh/h) | 1.05 | 1.03 |
| Per-customer load impact (kWh/h) | 0.07 | 0.03 |
| % Load Impact | 6.34% | 3.09% |
| Temperature | 77.4 | 80.6 |

### 7.2.3 Previous *ex-ante* versus current *ex-post*

Table 7.8 provides a comparison of the *ex-ante* forecast of 2017 TOU load impacts prepared following PY2016 and the PY2017 TOU load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August average weekday during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the August weekday. Increased enrollments lead to larger aggregate load impacts and reference loads. However, the current *ex-post* analysis has smaller percentage load impacts, even though TOU peak periods are identical between these comparisons.

Table 7.8 Comparison of PY2016 *Ex-Ante* 2017 Forecastand PY2017 *Ex-Post* TOU Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Season** | **Result** | ***Ex-ante for 2017 Avg. Weekday from PY2016 Study*** | ***Ex-post for 2017 Avg. Weekday from PY2017 Study*** |
|
| **Summer (August)** | # Enrolled | 4,639 | 6,396 |
| Reference (MWh/h) | 4.85 | 6.77 |
| Load Impact (MWh/h) | 0.31 | 0.19 |
| Per-customer reference (kWh/h) | 1.05 | 1.06 |
| Per-customer load impact (kWh/h) | 0.07 | 0.03 |
| % Load Impact | 6.34% | 2.87% |
| Temperature | 77.4 | 79.8 |

### 7.3.4 Current *ex-post* versus current *ex-ante*

Table 7.9 compares the PY2017 *ex-post* TOU load impacts for the August average weekday with the corresponding *ex-ante* forecast for 2018 (of the SDG&E 1-in-2 August average weekday) produced in this study. The TOU load impacts are presented for all TOU customers and are averaged over the RA window.[[22]](#footnote-22) Recall that SDG&E has made changes to the TOU periods (*e.g.* peak, off-peak); therefore, the TOU periods differ between the *ex-post* and ex*-ante* analyses. The *ex-ante* load impacts are based upon *ex-post* percentage load impacts for each TOU period. Per-customer reference loads are slightly lower in *ex-ante* while percentage load impacts are slightly higher during the RA-window.

Table 7.9: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Season** | **Result** | ***Ex-post* for 2017 Avg. Weekday *from* PY2017 Study** | ***Ex-ante for 2018 Avg. Weekday from PY2017 Study*** |
| **Summer (August)** | # Enrolled | 6,396 | 7,096 |
| Reference (MWh/h) | 6.77 | 7.31 |
| Load Impact (MWh/h) | 0.19 | 0.23 |
| Per-customer reference (kWh/h) | 1.06 | 1.03 |
| Per-customer load impact (kWh/h) | 0.03 | 0.03 |
| % Load Impact | 2.87% | 3.09% |
| Temperature | 79.8 | 80.6 |

# 8. Recommendations

Calling more CPP event days (as appropriate) would provide a basis to estimate how CPP load impacts vary with weather conditions or day type (*e.g.*, month of year or day of week). This evaluation provided clear evidence of CPP demand response, but the fact that only one event was called in 2016, and only three events were called in 2017 limited our ability to explore the weather sensitivity of estimated load impacts, and to vary load impacts across *ex-ante* scenarios.

# Appendices

The following Appendices are Excel files that can produce the tables required by the Protocols.

Appendix A Residential TOU and CPP *Ex-Post* Load Impact Tables

Appendix B Residential TOU and CPP *Ex-Post* Load Impact Tables

1. These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (*e.g.*, all selected event-like days, as well as the event day). [↑](#footnote-ref-1)
2. The enrollment numbers shown differ from the number of customers used in the regression models, which use only those customers with sufficient program-year and pre-treatment period load data needed for matching to control groups and estimating load impacts. Specifically, there were 296 incremental customers on the DR-TOD rate with quality load data that were used in estimating the TOU load impacts. The aggregate TOU load impacts are then scaled to total enrollments. [↑](#footnote-ref-2)
3. The estimated load increases in the winter season were not statistically significant. [↑](#footnote-ref-3)
4. The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days in 2016 were required for measuring CPP load impacts. [↑](#footnote-ref-4)
5. SDG&E expects to move to default TOU pricing for its residential customers in 2019, which is not modeled in this report. [↑](#footnote-ref-5)
6. Results are also reported for a subset of CPP customers who also participated in the Small Customer Technology Deployment (SCTD) program. [↑](#footnote-ref-6)
7. CPP *ex-post* load impacts are estimated for *all* customers enrolled in CPP (TOU-DR-P) during the 2017 program year. *Incremental* TOU load impacts are estimated for only those customers who enrolled in either of the rates during the September 2016 to September 2017 period. The *incremental* TOU load impacts apply to all customers on SPP rates (TOU-DR and TOU-DR-P). [↑](#footnote-ref-7)
8. Non-commodity prices of approximately $0.263 per kWh in the summer are not time-differentiated, implying that the total peak-to-off-peak price ratio is less than two-to-one. [↑](#footnote-ref-8)
9. In cases where insufficient numbers of observations were available, we modified the approach by combining day-types. For example, for TOU-DR customers, we combined observations for all summer weekdays to estimate a constant summer percentage load impact. Day-type specific reference load is calculated as the day-type observed load divided by one minus the percentage load impact (*i.e.,* Ref=Obs/(1-PctLI)). We can then apply the estimated percentage load impact to reference loads for the average weekday for each month to obtain monthly load impact *levels*. [↑](#footnote-ref-9)
10. Note that the customer and day fixed effects remove the need for us to include stand-alone *TOUc* and *Postc,d* variables. The former is perfectly collinear with the customer’s fixed effect and the latter is perfectly collinear with a combination of day fixed effects. [↑](#footnote-ref-10)
11. For CPP customers, the *Evt* variable indicates that a day is a CPP event day. For TOU customers who are also enrolled to receive RYU alerts, that variable indicates that a day is a PTR/RYU event day. [↑](#footnote-ref-11)
12. Reference loads represent estimates of the counter-factual loads that would have prevailed on an event day if the event had not been called. Mechanically, the *reference* loads are constructed by adding the estimated load impacts (developed in the difference-in-differences regression analysis) to the *observed* load of the treatment customers on the relevant event day. Alternatively, if percentage load impacts are estimated, then the *reference* loads are calculated by dividing the *observed* load by one minus the percentage load impact. [↑](#footnote-ref-12)
13. These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (*e.g.*, all selected event-like days, as well as the event day). The number of CPP customers used in the regressions was 4,087. The CPP load impacts are scaled up to total program enrollments. [↑](#footnote-ref-13)
14. The enrollment numbers in the tables differ from the number of customers used in the regression models, which is a subset of customers that have all the required data for conducting the *ex-post* load impact analysis. Specifically, there were 296 incremental customers on the DR-TOD rate with quality load data that were used in estimating the TOU load impacts. The aggregate TOU load impacts are then scaled to total enrollments. [↑](#footnote-ref-14)
15. The winter TOU load impacts demonstrating an increase in usage during the TOU peak-period are not statistically significant. [↑](#footnote-ref-15)
16. The increase in usage during the winter period occurs mostly during the morning and evening hours. [↑](#footnote-ref-16)
17. The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days were required for measuring CPP load impacts. There were 2,627 incremental customers on the DR-TOD-P rate with quality load data that were used in the regressions for estimating the TOU load impact for CPP customers. [↑](#footnote-ref-17)
18. Customer-specific regressions are implemented to categorize customers as weather sensitive or not. Weather sensitive customers change usage in response to changes in the weather, while non-weather sensitive customers do not. Determining which customers are non-weather sensitive allows for a more parsimonious regression model by not including weather variables as explanatory variables for these customers. The following regression specification is used to determine whether a customer is weather sensitive:

    , where *Qt* represents the average customer usage during event hours on day *t* in the summer months of June through September. *DTYPEi,t* represents the day of week, while *MONTHi,t* represents each month. The *EVTi,t* variables control for any event days a customer faces (DBP, BIP, CPP, etc.). The variable of importance is *Weathert*, which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient (*bWeather*) is positive and statistically significant for any of the three separate weather specifications. [↑](#footnote-ref-18)
19. Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree hours (CDH) for each hour of the day are defined as: CDH60 = max(0,Temperature in °F – 60). Likewise, heating degree hours (HDH) for each hour of the day are defined as: HDH60 =max(0, 60 – Temperature in °F). [↑](#footnote-ref-19)
20. The adjustment takes the form of Reference = Observed / (1 - %TOULoadImpact). We examined several alternative approaches to developing the weather-sensitive reference load, including the same type of regression analysis using load data for the matched control group customers. The resulting reference loads were not very sensitive to the data and approach used, although the selected approach produced more accurate loads during the swing months. [↑](#footnote-ref-20)
21. The relatively minor differences are due in part to the assumed constant percentage load impact that was applied from the average weekday events. As experience is gained from additional events, the load impacts will likely be found to be weather sensitive. [↑](#footnote-ref-21)
22. A summary of load impacts over the peak periods would indicate equivalent percentage load impacts by design. [↑](#footnote-ref-22)