2016 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates

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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") new voluntary residential time of use (TOU) and critical peak pricing (CPP) rates for 2016. 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.

SDG&E anticipates a change in the peak-period definition could affect how the rates are rolled out in the future. These proposed actions 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. As a result, SDG&E has applied in A-15-04-012 for changes in the hours of the pricing periods of its TOU rates. The proposed on-peak period of 4 p.m. to 6 p.m. begin and end later than the existing rates.

ES.2 Evaluation Methodologies

The *ex-post* impact evaluations for the TOU and CPP rates apply difference-in-differences 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 their 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 RYU), based on the closest match of load profiles. This difference-in-differences approach with matched control groups is available for this study since both rates are new, meaning that customers' pre-treatment data are recent, and hourly interval load data are available for all of SDG&E's customers.

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 one RYU/CPP event day in 2016, which occurred in late September. 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 – *September 26 Event*

Climate Zone	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
		Ref. Load (MW)	Load Impact (MW)	Ref. Load (kW)	Load Impact (kW)		
Coastal	1,773	1.91	0.30	1.08	0.17	16%	98
Inland	1,290	1.62	0.15	1.25	0.11	9%	102
All	3,063	3.51	0.44	1.15	0.14	13%	99

Program enrollment was 3,063 customers, skewed somewhat toward the Coastal climate zone.[1] The aggregate reference load was 3.51 MW. Per-customer load impacts averaged 0.17 kW for customers in the Coastal climate zone, representing 16 percent of their reference load, and 0.11 kW, or 9 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 98 degrees, than the 102-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 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.[2] The months are shown starting with the first month included in the analysis (October 2015). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from

[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). SDG&E reported that enrollment reached nearly 3,150 by the end of September.

[2] Note that due to the relatively small enrollment numbers and therefore aggregate load levels, the aggregate loads, as well as the per-customer loads, are shown in units of kWh per hour, or kW.

204 in October 2015 to 819 in September 2016.[3] Due to the relatively small number of treatment customers, percentage load impacts were constrained in estimation to be the same across months in both seasons. The estimated average peak reductions were approximately 4.4 percent in winter and 5.4 percent in summer.

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

			Aggregate		Per-Customer			
Month	Climate Zone	Enrolled	Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Oct-15	All	204	144	7.7	0.71	0.038	5.4%	79
Nov-15	All	254	276	12.0	1.09	0.047	4.3%	64
Dec-15	All	296	366	16.1	1.24	0.055	4.4%	59
Jan-16	All	328	365	16.0	1.11	0.049	4.4%	60
Feb-16	All	411	412	17.5	1.00	0.042	4.2%	66
Mar-16	All	468	409	17.1	0.87	0.037	4.2%	63
Apr-16	All	510	430	18.3	0.84	0.036	4.3%	67
May-16	All	549	330	17.5	0.60	0.032	5.3%	68
Jun-16	All	599	498	26.7	0.83	0.045	5.3%	74
Jul-16	All	670	722	39.0	1.08	0.058	5.4%	77
Aug-16	All	745	792	42.8	1.06	0.057	5.4%	78
Sep-16	All	819	715	38.4	0.87	0.047	5.4%	78

Table ES.3 shows peak load impact results by season and climate zone. Because of relatively low enrollment in October 2015 and the discontinuity between that month and the summer of 2016, the results for the summer season include only May through September of 2016. Summer peak load impacts were similar in percentage terms for the two climate zones. However, winter percentage peak load impacts were larger in the Coastal zone than in the Inland zone.

[3] As for CPP, 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.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Coastal	382	318	17.4	0.79	0.043	5.5%	73
	Inland	294	313	17.8	1.04	0.059	5.7%	78
	All	676	630	35.1	0.90	0.050	5.6%	75
Winter	Coastal	213	201	10.7	0.90	0.048	5.3%	65
	Inland	165	184	6.1	1.10	0.036	3.3%	63
	All	378	384	16.7	0.99	0.043	4.3%	64

Combining results across months and considering the effect of TOU on average *daily* usage, we find that TOU customers *reduced* their energy consumption by an annual average of approximately 0.1 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 loads and load reductions for the average summer (October 2015, and May through September 2016) and winter (November 2015 through April 2016) weekdays, by month. Enrollment in CPP grew from 940 in October 2015 to approximately 3,100 in September 2016.[4] Estimated peak load impacts for CPP customers were smaller during the winter period than for the TOU customers. Summer peak load impacts were fairly consistent across months (except for September), ranging from less than 5 percent to nearly 7 percent of the reference load.

[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.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct-15	All	940	746	41.7	0.79	0.044	5.6%	79
Nov-15	All	1,109	1,158	22.0	1.04	0.020	1.9%	64
Dec-15	All	1,282	1,489	3.1	1.16	0.002	0.2%	60
Jan-16	All	1,428	1,533	26.6	1.07	0.019	1.7%	60
Feb-16	All	1,689	1,613	-5.8	0.96	-0.003	-0.4%	67
Mar-16	All	1,888	1,646	42.6	0.87	0.023	2.6%	63
Apr-16	All	2,047	1,691	27.2	0.83	0.013	1.6%	67
May-16	All	2,213	1,305	61.9	0.59	0.028	4.7%	68
Jun-16	All	2,399	1,933	110.4	0.81	0.046	5.7%	74
Jul-16	All	2,592	2,609	179.0	1.01	0.069	6.9%	77
Aug-16	All	2,851	2,755	172.3	0.97	0.060	6.3%	78
Sep-16	All	3,108	2,331	4.2	0.75	0.001	0.2%	78

Table ES.5 summarizes CPP load impact results by season and climate zone. Summer percentage peak load impacts are similar between the Coastal and Inland climate zones, while winter load impacts for the shorter and later peak period average twice as large for the Inland climate zone (1.8 percent) than the Coastal zone (0.9 percent).

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 (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Summer	Coastal	1,533	1,170	55.7	0.75	0.037	4.9%	73
	Inland	1,099	1,061	48.1	0.94	0.045	4.7%	78
	All	2,633	2,231	103.8	0.83	0.040	4.8%	75
Winter	Coastal	914	893	9.4	0.96	0.009	0.9%	65
	Inland	660	661	11.1	0.98	0.017	1.8%	63
	All	1,574	1,554	20.5	0.97	0.012	1.3%	64

In contrast to the TOU customers, CPP customers increased their energy consumption by small amounts in each month of the year, resulting in an average annual *increase* of just under 1 percent.

ES.4 Ex-Ante Load Impacts

Since SDG&E called only one RYU/CPP event in 2016, we have only that event on which to base forecasts going forward. As a result, 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.

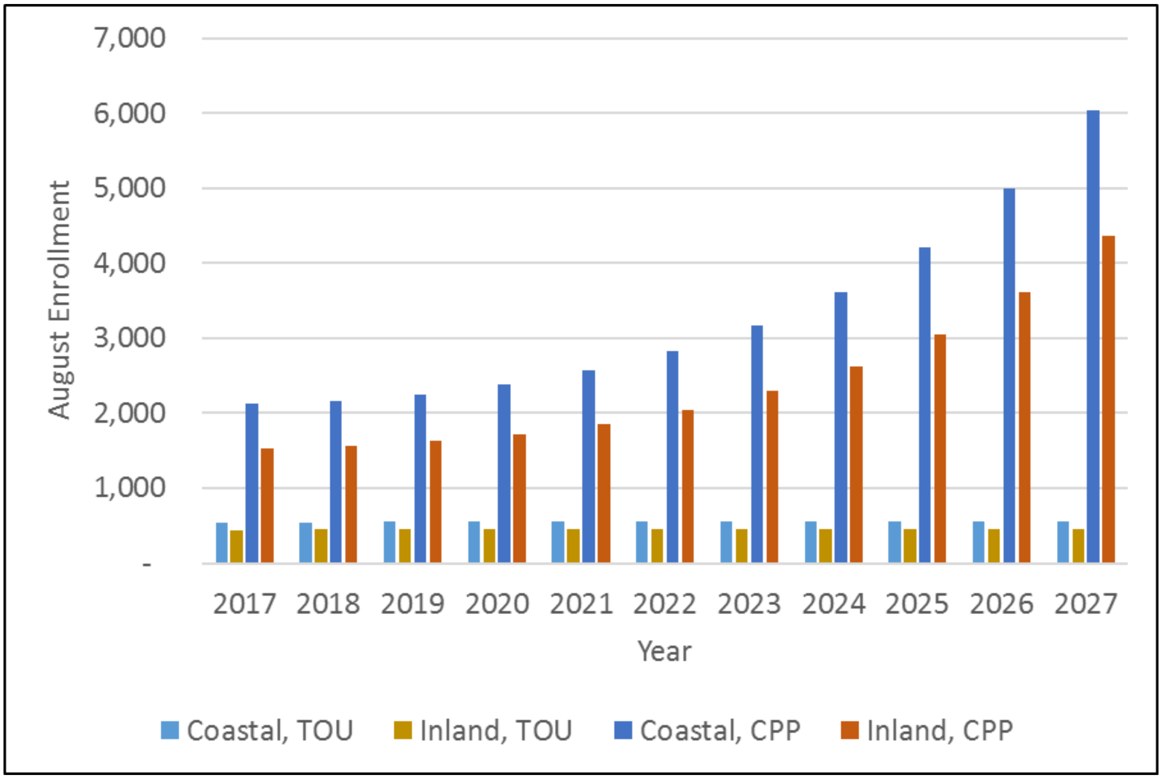
An issue in producing the *ex-ante* load impact forecasts for CPP is that the Protocols call for estimating load impacts for the Resource Adequacy (RA) hours of 1 to 6 p.m. during summer months, and 4 to 9 p.m. in winter months, while the CPP events are called during the program hours of 11 a.m. to 6 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.

For TOU rate and the TOU portion of the CPP rate, 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 were developed as described above.

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.

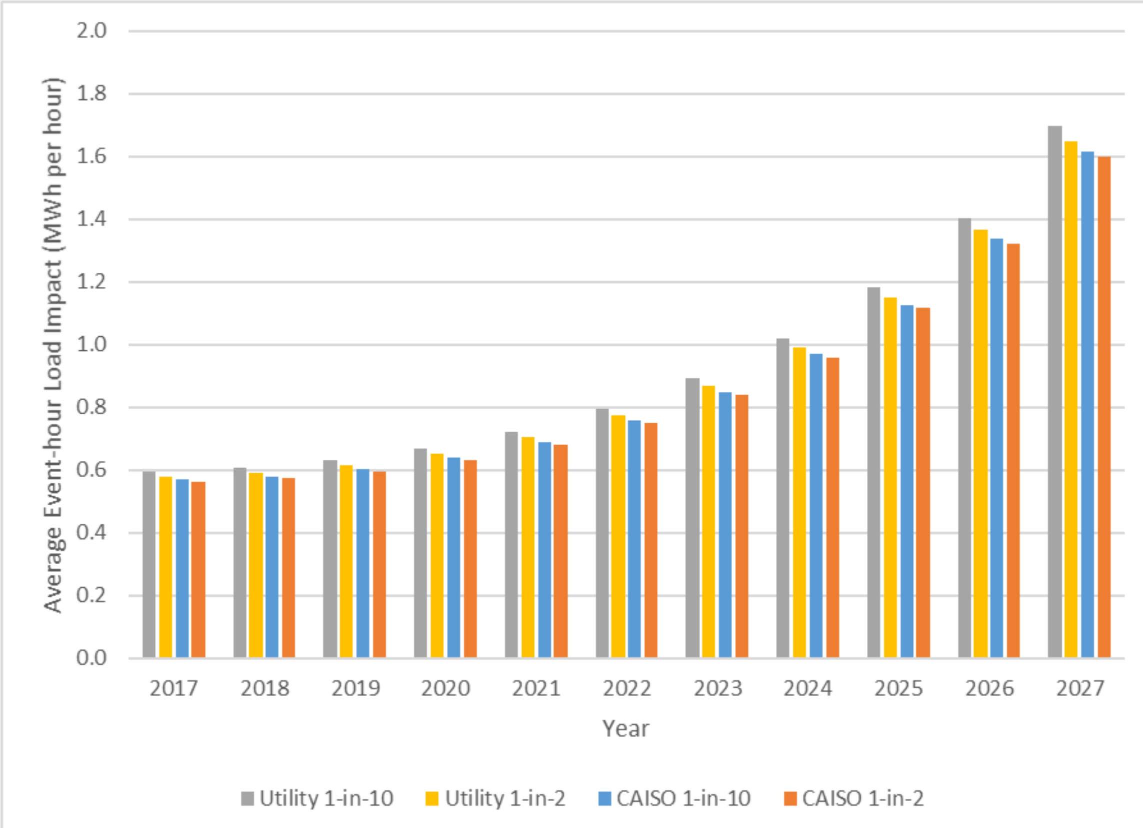
Figure ES.1: Enrollments in TOU and CPP



ES.4.2 *Ex-ante* load impacts – 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 0.6 MW in 2017 to over 1.6 MW in 2027.

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

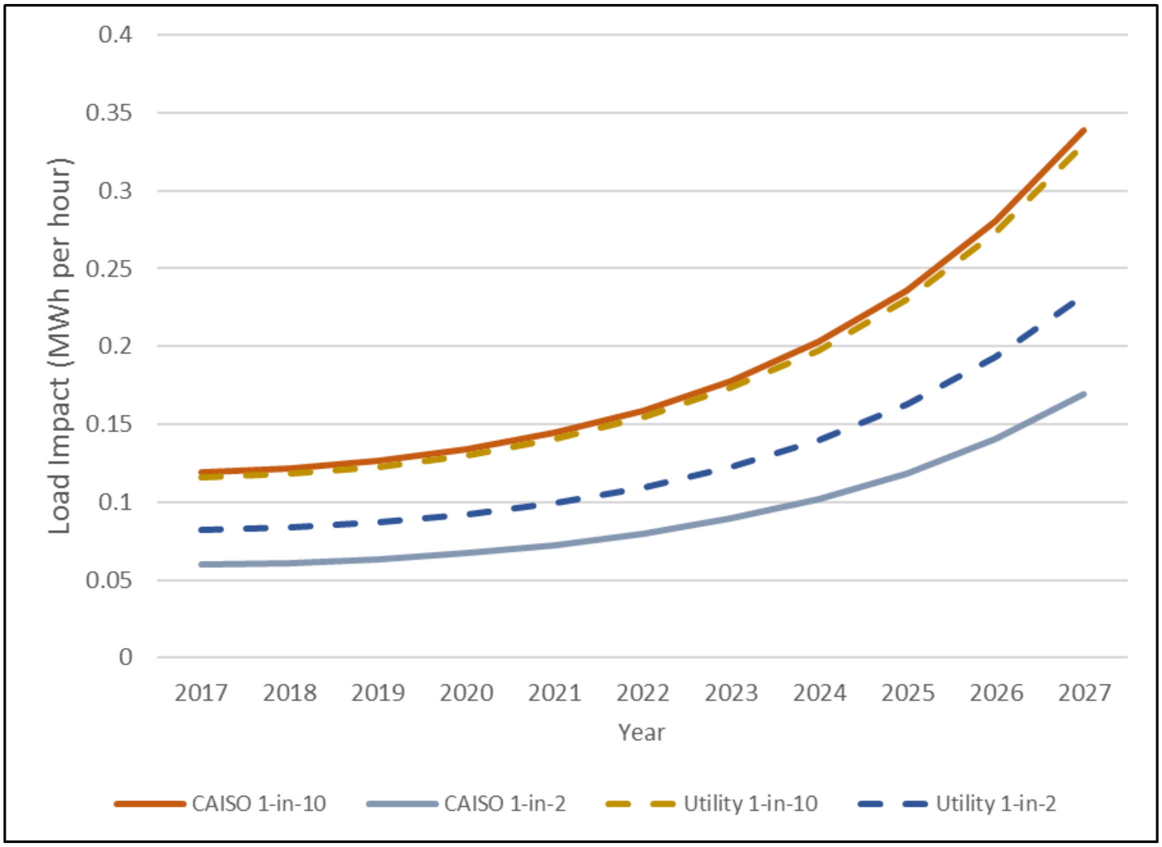


ES.4.3 *Ex-Ante* load impacts – Residential TOU

Aggregate peak load impacts for TOU customers are forecast to remain constant after 2019, given the flat enrollment forecast. The value for 2020 in the SDG&E 1-in-2 scenario is 0.03 MW. 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 nearly identical, rising to nearly 0.35 MW in the final year, while load impacts in the SDG&E 1-in-2 scenario are larger than in the CAISO 1-in-2 scenario, rising to between 0.2 and 0.25 MW in 2027.[5]

[5] SDG&E expects to move to default TOU pricing for its residential customers in 2019, which is not modeled in this report. That rate will likely incorporate the later peak pricing period discussed earlier.

Figure ES.3: Aggregate Load Impacts (MW), by Year and Weather Scenario – CPP (*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") new voluntary residential time of use (TOU) and critical peak pricing (CPP) rates for 2016. 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.

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.

The rollout of these two voluntary rates has been affected by likely regulatory actions in the near future. SDG&E anticipates a change in the peak-period definition could affect how the rates are rolled out in the future. These proposed actions 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. As a result, SDG&E has applied in A-15-04-012 for changes in the hours of the pricing periods of its TOU rates. The proposed on-peak period of 4 p.m. to 9 p.m. begin and end later than the existing rates.

This evaluation study involves estimation of *ex-post* load impacts for the TOU and CPP rates for program year 2016, and development of *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 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. Up to 18 RYU events can be triggered per year, on any day of the week, at any time during the year. A CPP event period adder of $1.16/kWh applies on event days. In return, enrollees receive credits on their electric commodity cost during all TOU pricing periods on non-RYU event days.

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 proposed changes to the TOU and CPP pricing periods, SDG&E has proposed a terminology change in which the current *semi-peak* period will be re-labeled *off-peak*, and the current *off-peak* period will be called the *super off-peak* period. The proposed changes are the following:

1. Change the summer on-peak period to 4 p.m. to 9 p.m. on weekdays;
2. Change the winter on-peak period to 4 p.m. to 9 p.m. on weekdays;
3. Change the super off-peak period to 12 a.m. to 6 a.m. on 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 proposed changes in peak pricing periods have not yet been approved, 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 we used.

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 2014 through September 2016;

- *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

This section describes the process that was followed to estimate program load impacts. Estimating load impacts using data for both participants and matched control group customers 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 pre-enrollment year. Second, we select matched control group customers for the TOU and CPP enrollees, as described below. Third, we estimate fixed-effects panel regression models, representing 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

We conducted the *ex-post* load impact evaluations for the TOU and CPP rates using difference-in-differences evaluation approaches that compare the usage of treatment and quasi-experimental 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 ten-to-one samples by segment from the eligible population of SDG&E residential customers. This difference-in-differences approach is available since both rates are new, meaning that their pre-treatment data are recent, and hourly interval load data are available for all of SDG&E's 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 day) in 2016.[6]

For analyzing TOU impacts, for both CPP and TOU customers, the treatment customers were matched on the basis of loads in the pre-treatment period (November 2014 through September 2015). The TOU customers were matched separately by season, 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

[6] The event-like non-event days in 2016 were 7/20, 7/21, 7/26, 7/27, 7/28, 8/16, 8/17, 9/28, 9/29, and 9/30.

for November 2014 through April 2015, while that for the *summer* season used data for May through September of 2015.

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. In this case, the standardized metric combines the 48 hourly load difference statistics for the two average weekday load profiles for the TOU customers into a single value equal to the square root of the sum of squared differences between the load statistics. That is, each enrolled customer is compared to each potential control group customer, 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 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 in general produces load impact estimates for each hour of every event, though only one event was called in 2016:

$$kW_{c,d} = \beta_0 + \Sigma_{Evts(i)} (\beta_{1,i} \times CPP_{c,d} \times Evt_{i,d}) + \beta_2 \times CPP_{c,d} + \Sigma_{Cust} (\beta_{3,Cust} \times C_c) + \Sigma_{day} (\beta_{4,day} \times D_{day,d}) + \beta_5 \times SS\_Evt_{c,d} + \beta_6 \times SCTD\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in the following table:

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
$CPP_{c,d}$	Variable indicating whether customer *c* is a CPP (1) or Control (0) customer on day *d*
$Evt_{i,d}$	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*
β_0	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event *d*
β_2	Estimated TOU response
$\beta_{3,Cust}$ and $\beta_{4,day}$	Customer and day fixed-effects
$\beta_{5,d}$	Estimated average *SCTD* load impact for event *d*
$\beta_{6,d}$	Estimated average *Summer Saver* load impact for event *d*
C_c	Variable indicating that the observation is for customer *c*
$D_{day,d}$	Date indicator variable (1 = date *d* equals date *day*)
$\varepsilon_{c,d}$	Error term

Since only one event was called, we can produce estimates of load impacts for the average event by customer type (*e.g.*, Climate zone and CARE status) simply by estimating separate models for each type and reporting the estimated impacts.

3.2.4 *Ex-post* models for TOU load impacts

To obtain TOU load impacts (for both the TOU and CPP customers), we estimate a distinct model for each required result. For example, to get the average TOU load impacts on August non-holiday weekdays, we estimate a model that includes only days of that day type.[7] 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

[7] In cases where insufficient numbers of observations were available, we modified the approach by combining day-types. For example, for TOU 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*.

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:[8]

$$kW_{c,d} = \beta_0 + \beta_1 \times (TOU_c \times Post_d) + \Sigma_{Cust} (\beta_{2,Cust} \times C_c) + \Sigma_{days} (\beta_{3,day} \times D_{day}) \\ + \beta_4 \times Evt_{c,d} + \beta_5 \times SS\_Evt_{c,d} + \beta_6 \times SCTD\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in the following table:

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
TOU_c	Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer
$Evt_{c,d}$	Variable indicating whether day *d* is an event day for customer *c* [9]
$Post_d$	Variable indicating that day *d* is in the post-enrollment period
$SCTD\_Evt_{c,d}$	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*
β_0	Estimated constant coefficient
β_1	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,day}$	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
C_c	Variable indicating that the observation is associated with customer *c*
D_{day}	Variable indicating that the observation is for day *d*
$\varepsilon_{c,d}$	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).

[8] Note that the customer and day fixed effects remove the need for us to include stand-alone TOU_c and $Post_d$ 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.

[9] 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.

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 10^{th}, 30^{th}, 70^{th}, and 90^{th} percentile scenarios are generated from these distributions.

In order to develop the uncertainty-adjusted load impacts associated with the *average* 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 relative root mean square error and mean percent error, which provide formal estimates of the percent differences between treatment and control group loads.

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

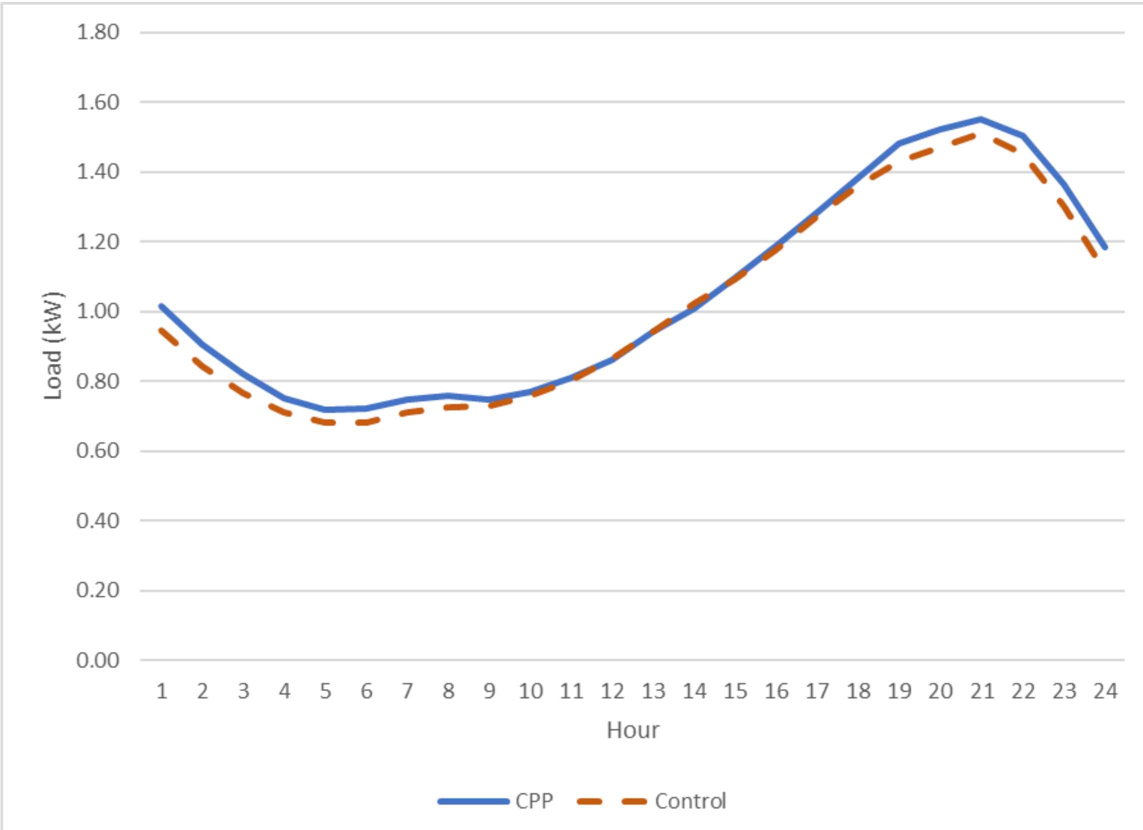
This section documents the findings from the *ex-post* load impact evaluation analysis of the CPP portion of the TOU-DR-P rate. For CPP, the primary load impact results include average estimated event-hour load impacts (*i.e.*, the average of the hourly load impacts estimated for the seven-hour event window from 11 a.m. to 6 p.m.), in aggregate and per-customer, for the single event day on September 26, 2016. 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 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/RYU event day. The figures show the average CPP and matched control-group customer load profiles for the selected event-like non-event days in 2016. Across all 24 hours, the mean percentage error (MPE) of the CPP profile compared to the control-group profile is 3.2 percent, while the mean absolute percentage error (MAPE) is 3.4 percent. For the CPP event window (11 a.m. to 6:00 p.m.), the MPE is 0.2 percent and the MAPE is 0.8 percent.

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



4.2 CPP load impacts

This section summarizes average event-hour reference loads[10] and load impacts, at an aggregate and per-customer basis, for the one CPP event called on September 26, 2016. Results for all hours of the event day are also illustrated.

Table 4.1 summarizes reference load and load impact results for CPP customers, by climate zone. 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

[10] 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.

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 – *September 26 Event*

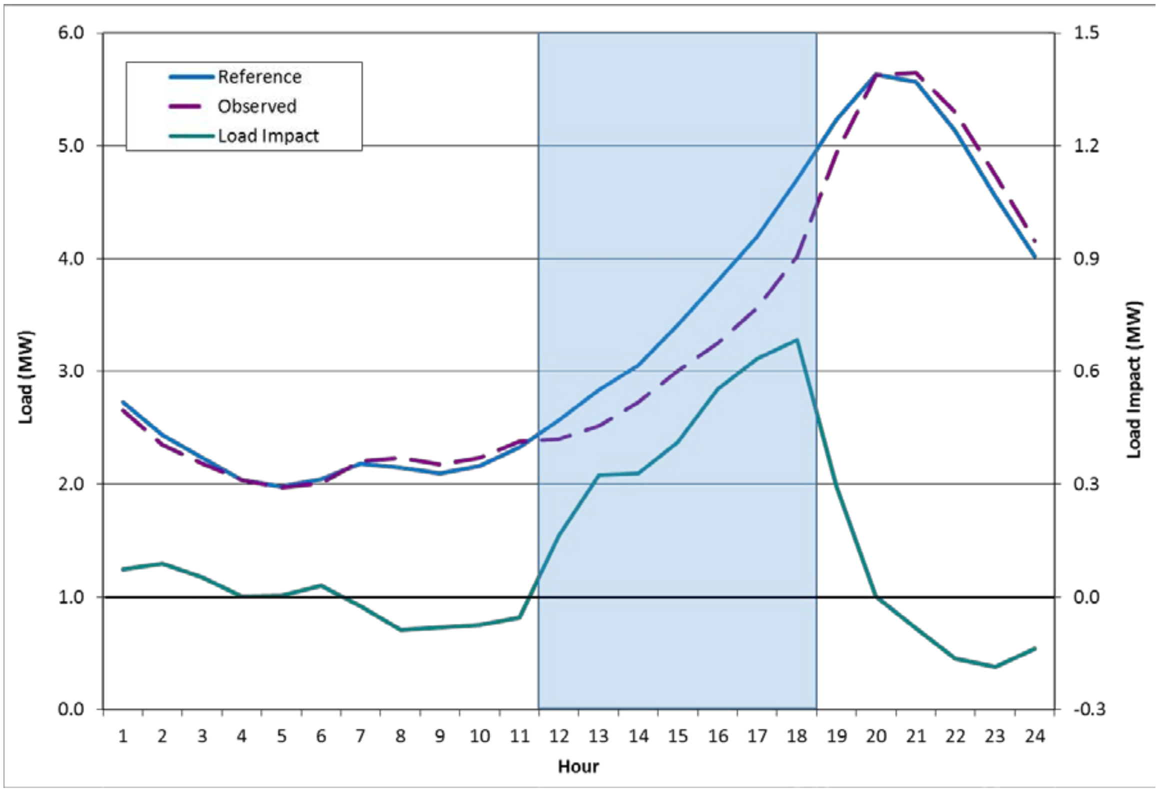
Climate Zone	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
		Ref. Load (MW)	Load Impact (MW)	Ref. Load (kW)	Load Impact (kW)		
Coastal	1,773	1.91	0.30	1.08	0.17	16%	98
Inland	1,290	1.62	0.15	1.25	0.11	9%	102
All	3,063	3.51	0.44	1.15	0.14	13%	99

Program enrollment was 3,063 customers, skewed somewhat toward the Coastal climate zone.[11] The aggregate reference load was 3.51 MW. Per-customer load impacts averaged 0.17 kW for customers in the Coastal climate zone, representing 16 percent of their reference load, and 0.11 kW, or 9 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 98 degrees, than the 99-degree temperature for the Inland zone. The substantially greater responsiveness of the Coastal customers is somewhat surprising, with no obvious explanation.

Figure 4.2 shows aggregate hourly loads and load impacts for the one event. The largest hourly load impact was 0.68 MW in hour-ending 18 (5 to 6 p.m.).

[11] This enrollment number differs 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). SDG&E reported that enrollment reached nearly 3,150 by the end of September.

Figure 4.2: CPP Hourly Loads and Load Impacts for September 26 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 2016. Customers enrolled in SCTD had one event called on September 26. The event hours are 2 to 6 p.m., shorter than the CPP event window of 11 a.m. to 6 p.m.

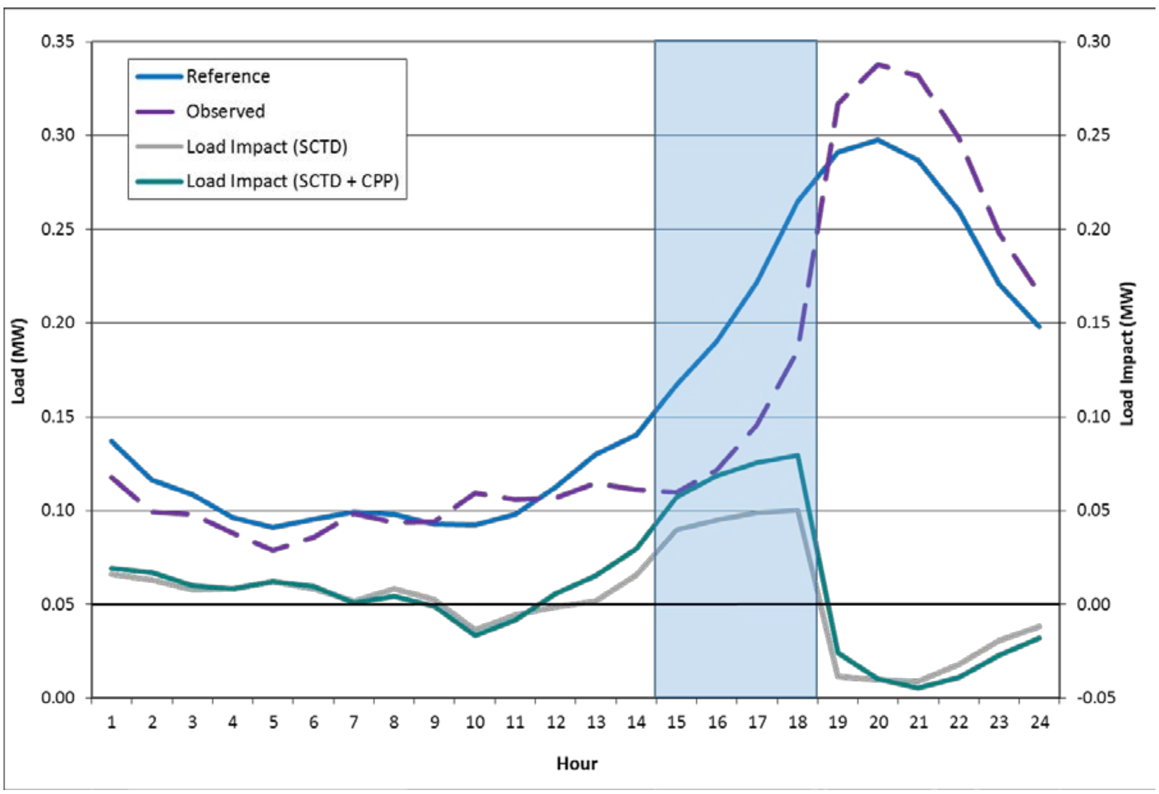
Table 4.2 summarizes reference loads and load impacts for all CPP customers along with customers dually enrolled in CPP and SCTD, during the CPP event-hour window. Program enrollment in CPP and SCTD was 130 customers, a small proportion of the 3,062 customers enrolled in CPP. The average per-customer peak-hour reference load and load impact estimate is larger for dually enrolled customers. Nevertheless, the percentage load impact also remains larger, at 16.3 versus 12.6 percent.

Table 4.2: Comparison of Average CPP Event-Hour Load Impacts for Customers Dually Enrolled in SCTD and CPP – *September 26 Event*

Group	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
ALL CPP	3,063	3,511	442.7	1.15	0.14	13%	99
CPP+SCTD	130	175	28.5	1.35	0.22	16%	100

Figure 4.3 shows aggregate hourly loads and load impacts for only customers dually enrolled in CPP and SCTD during the September 26 event. The event hours are displayed for the SCTD event (*i.e.,* 2 to 6 p.m.). The load impact estimates are illustrated for the SCTD event (gray) and a combination of the SCTD and CPP event estimates (green). The largest hourly SCTD load impact was 0.5 MW in hour-ending 18 (5 to 6 p.m.).

Figure 4.3: CPP+SCTD Hourly Loads and Load Impacts for Dually Enrolled Customers – September 26 Event



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

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

5.1 Control group matching results – TOU

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 1.3 percent, while the mean absolute percentage error (MAPE) is 2.2 percent. In the winter months, the MPE is 2.9 percent and the MAPE is 3.4 percent.

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

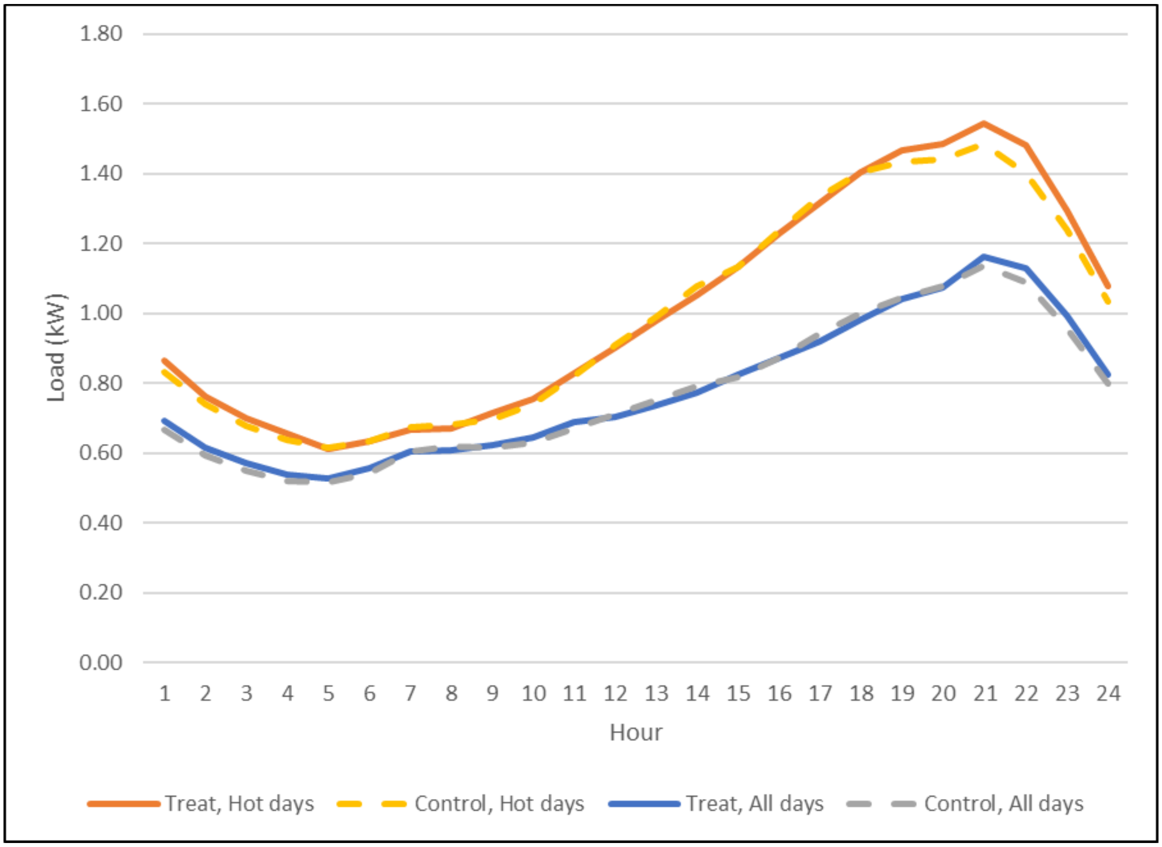
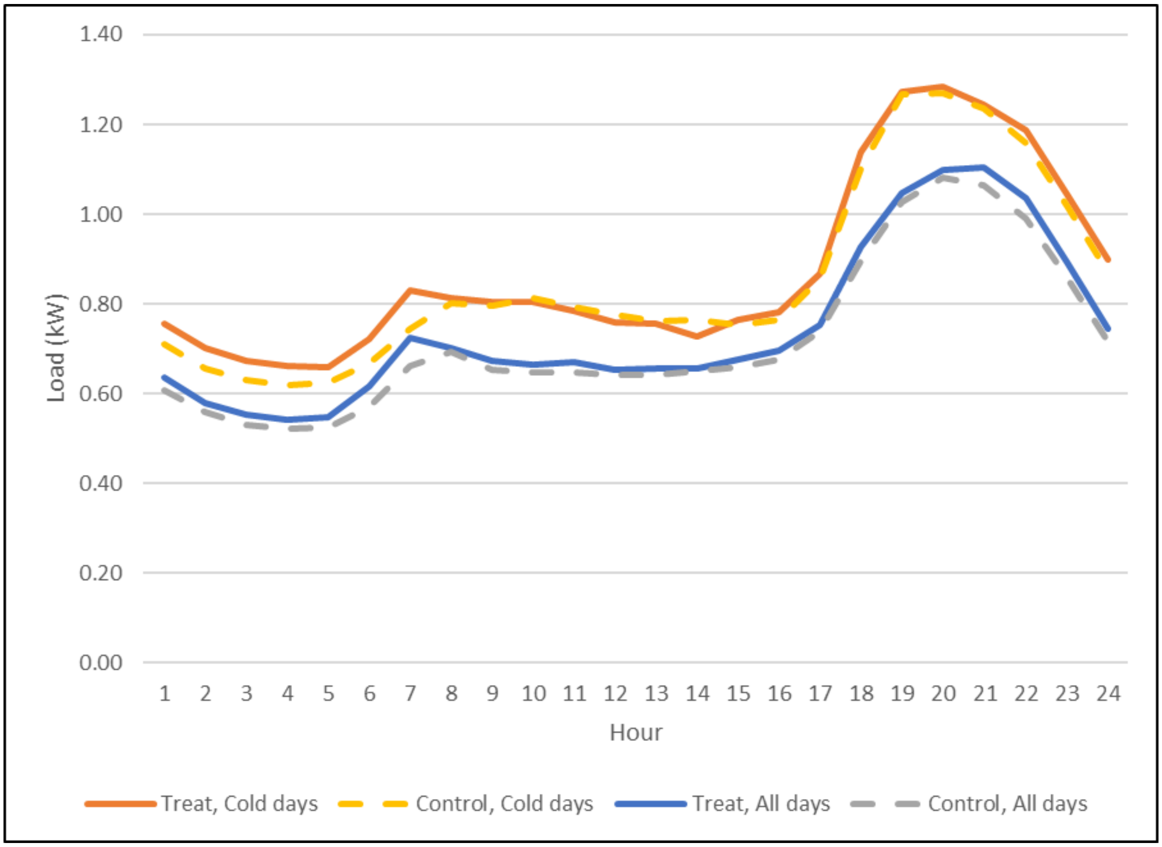


Figure 5.2: TOU and Control Group Load Profiles – *Winter*



5.2 Ex-post load impacts – TOU

This sub-section shows load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and 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 2015). The winter months are indicated by light blue shading.[12] Enrollment continued throughout the period, with the numbers of enrolled customers rising from 204 in October 2015 to 819 in September 2016.[13] 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 5.4 percent in summer and 4.4 percent in winter.

[12] Note that due to the relatively small enrollment numbers and therefore aggregate load levels, the aggregate loads are shown in units of kWh per hour, or kW.

[13] As for CPP, 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; SDG&E reported that enrollment in TOU-DR reached 824 in late September.

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

Month	Climate Zone	Enrolled	Aggregate: Peak Ref. Load (kW)	Aggregate: Peak Load Impact (kW)	Per-Customer: Peak Ref. Load (kW)	Per-Customer: Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Oct-15	All	204	144	7.7	0.71	0.038	5.4%	79
Nov-15	All	254	276	12.0	1.09	0.047	4.3%	64
Dec-15	All	296	366	16.1	1.24	0.055	4.4%	59
Jan-16	All	328	365	16.0	1.11	0.049	4.4%	60
Feb-16	All	411	412	17.5	1.00	0.042	4.2%	66
Mar-16	All	468	409	17.1	0.87	0.037	4.2%	63
Apr-16	All	510	430	18.3	0.84	0.036	4.3%	67
May-16	All	549	330	17.5	0.60	0.032	5.3%	68
Jun-16	All	599	498	26.7	0.83	0.045	5.3%	74
Jul-16	All	670	722	39.0	1.08	0.058	5.4%	77
Aug-16	All	745	792	42.8	1.06	0.057	5.4%	78
Sep-16	All	819	715	38.4	0.87	0.047	5.4%	78

Table 5.2 shows results by season and climate zone. Because of relatively low enrollment in October 2015 and the discontinuity between that month and the summer of 2016, the results for the summer season include only May through September of 2016. Summer peak load impacts were similar in percentage terms for the two climate zones. However, winter percentage peak load impacts were larger in the Coastal zone (5.3%) than in the Inland zone (3.3%).

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Coastal	382	318	17.4	0.80	0.044	5.5%	73
	Inland	294	313	17.8	1.04	0.059	5.7%	78
	All	676	630	35.1	0.90	0.050	5.6%	75
Winter	Coastal	213	201	10.7	0.90	0.048	5.3%	65
	Inland	165	184	6.1	1.09	0.036	3.3%	63
	All	378	384	16.7	0.99	0.043	4.4%	64

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers changed their energy consumption by small amounts in each month of the year, with some increases and some reductions. The overall change was an average annual *reduction* of less than 0.1 percent.

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

			Aggregate		Per-Customer			
Month	Climate Zone	Enrolled	Daily Ref. Load (kWh)	Daily Load Impact (kWh)	Daily Ref. Load (kWh)	Daily Load Impact (kWh)	% Daily Load Impact	Ave. Daily Temp.
Oct-15	All	204	3,713	-17.1	18.20	-0.08	-0.5%	73
Nov-15	All	254	4,668	1.4	18.38	0.01	0.0%	62
Dec-15	All	296	6,145	3.0	20.76	0.01	0.0%	57
Jan-16	All	328	6,328	6.0	19.29	0.02	0.1%	58
Feb-16	All	411	7,193	0.7	17.50	0.00	0.0%	64
Mar-16	All	468	7,759	-9.7	16.58	-0.02	-0.1%	62
Apr-16	All	510	8,613	-2.4	16.89	0.00	0.0%	65
May-16	All	549	8,400	-32.7	15.30	-0.06	-0.4%	65
Jun-16	All	599	10,932	0.2	18.25	0.00	0.0%	69
Jul-16	All	670	14,918	24.3	22.27	0.04	0.2%	71
Aug-16	All	745	16,557	17.1	22.22	0.02	0.1%	72
Sep-16	All	819	15,880	-4.0	19.39	0.00	0.0%	72

Figure 5.3 shows aggregate hourly observed and estimated reference loads, along with hourly estimated 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. Each Figure illustrates a load shift out of the peak period to the off or super off peak periods.

Figure 5.3: Aggregate Hourly Loads and Load Impacts (MW) – TOU (*Average Weekday, August 2016*)

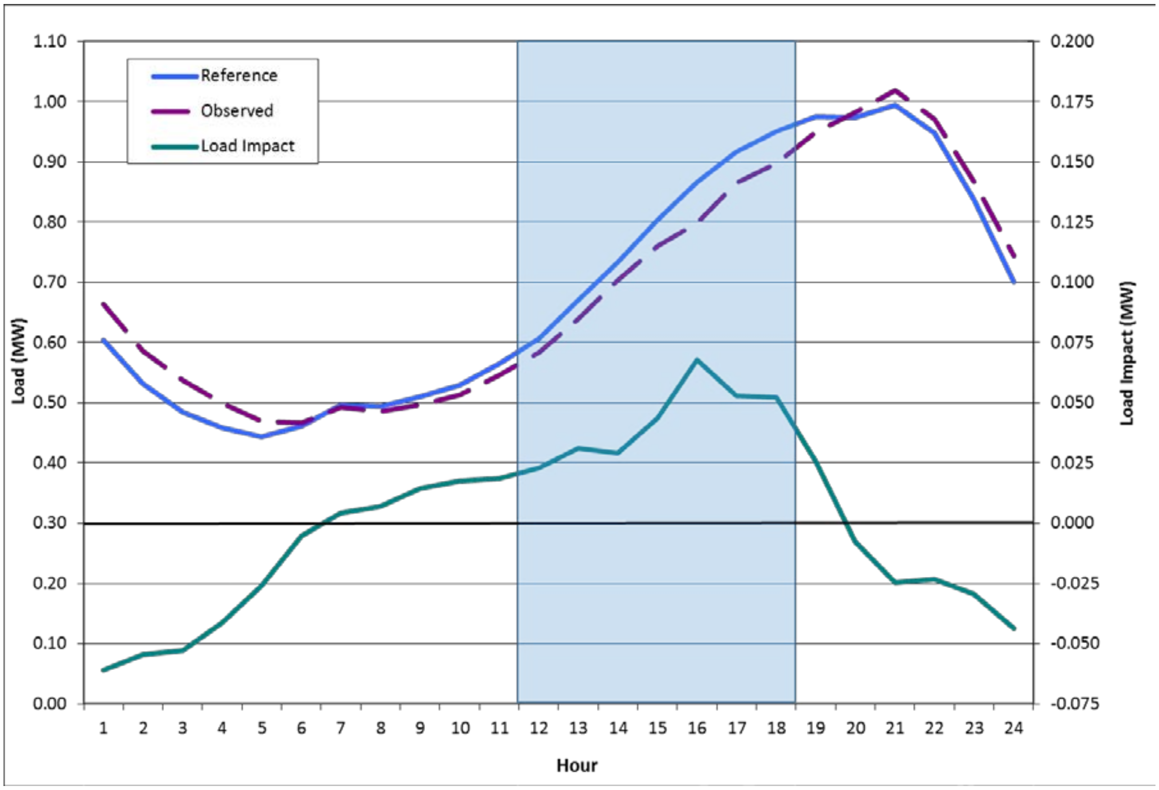
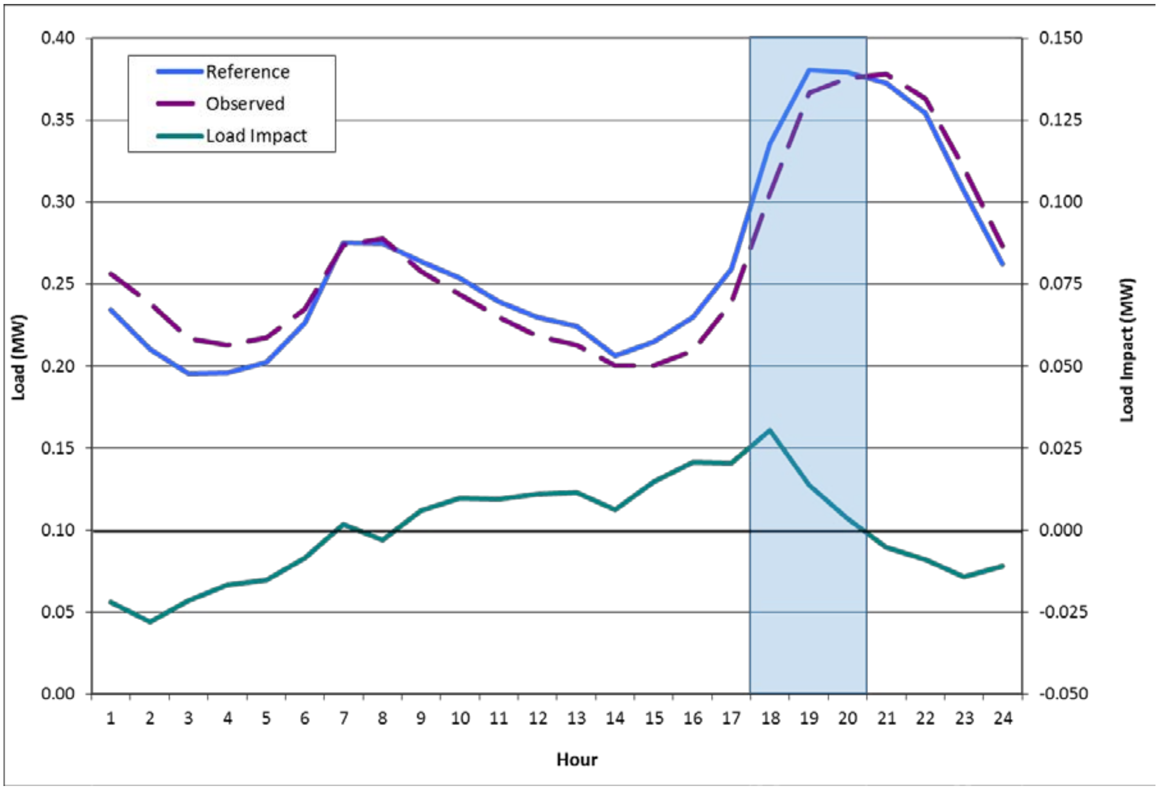


Figure 5.4: Aggregate Hourly Loads and Load Impacts (MW) – TOU
(*Average Weekday, January 2016*)



5.3 Control group matching results – CPP

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 1.3 percent, while the mean absolute percentage error (MAPE) is 1.8 percent. In the winter months, the MPE is 1.7 percent and the MAPE is 2.1 percent.

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

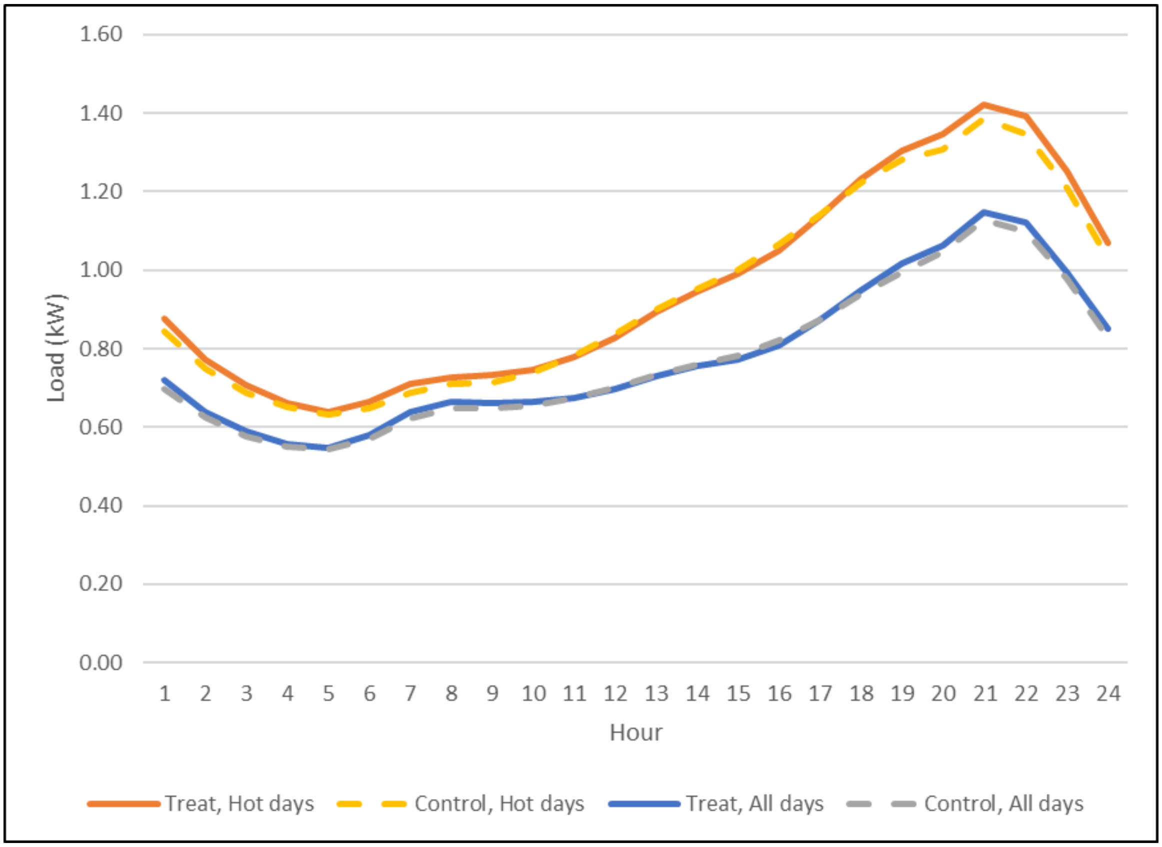
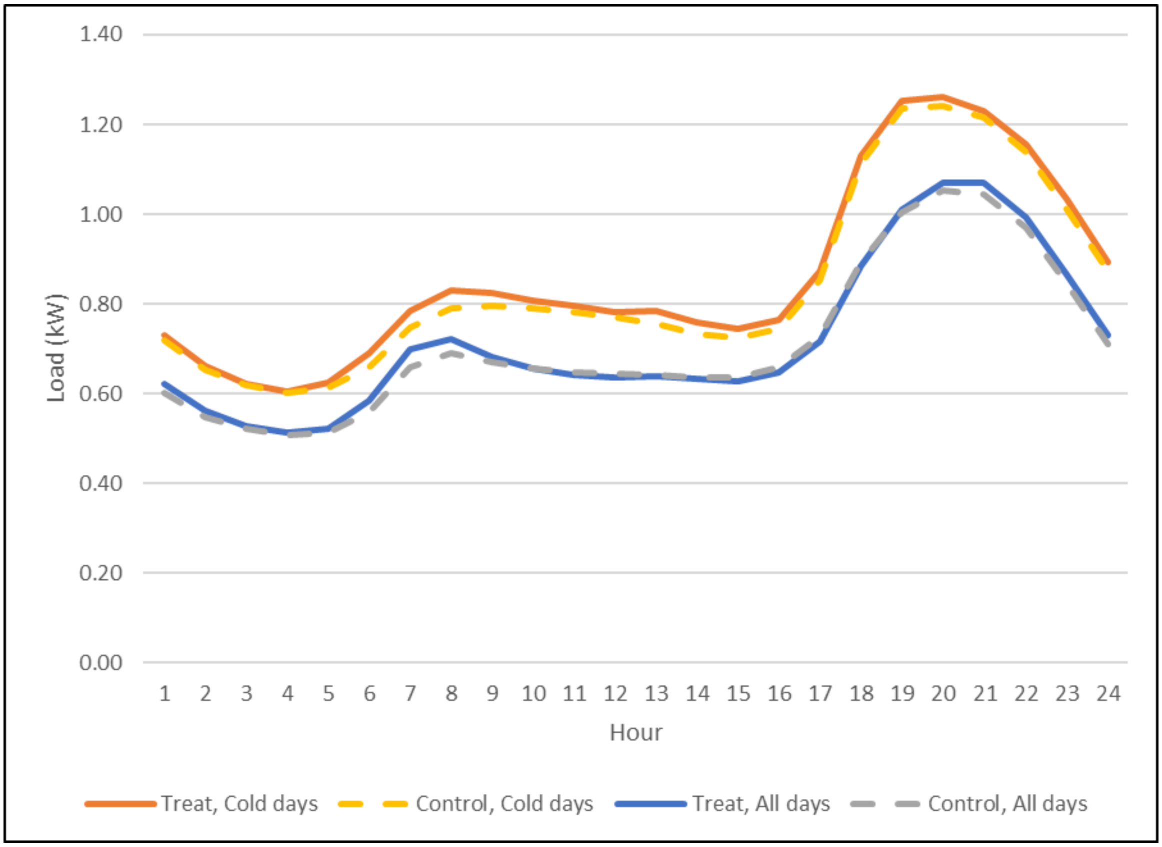


Figure 5.6: CPP and Control Group Load Profiles – *Winter*



5.4 Ex-post load impacts – CPP

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. Table 5.4 summarizes peak-period loads and load reductions for the average summer (October 2015, and May through September 2016) and winter (November 2015 through April 2016) weekdays, by month. Reported enrollment in CPP grew from 940 in October 2015 to just over 3,100 in September 2016.[14] Estimated peak-period load impacts for CPP customers were smaller during the winter period than for the TOU customers. Summer peak load impacts were fairly consistent across months (except for September), ranging from less than 5 percent to nearly 7 percent of the reference load.

[14] 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.

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

			Aggregate		Per-Customer			
Month	Climate Zone	Enrolled	Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Oct-15	All	940	746	41.7	0.79	0.044	5.6%	79
Nov-15	All	1,109	1,158	22.0	1.04	0.020	1.9%	64
Dec-15	All	1,282	1,489	3.1	1.16	0.002	0.2%	60
Jan-16	All	1,428	1,533	26.6	1.07	0.019	1.7%	60
Feb-16	All	1,689	1,613	-5.8	0.96	-0.003	-0.4%	67
Mar-16	All	1,888	1,646	42.6	0.87	0.023	2.6%	63
Apr-16	All	2,047	1,691	27.2	0.83	0.013	1.6%	67
May-16	All	2,213	1,305	61.9	0.59	0.028	4.7%	68
Jun-16	All	2,399	1,933	110.4	0.81	0.046	5.7%	74
Jul-16	All	2,592	2,609	179.0	1.01	0.069	6.9%	77
Aug-16	All	2,851	2,755	172.3	0.97	0.060	6.3%	78
Sep-16	All	3,108	2,331	4.2	0.75	0.001	0.2%	78

Table 5.5 summarizes results by season and climate zone. Summer peak load impacts are similar between the Coastal and Inland climate zones, while winter load impacts for the shorter and later peak period average nearly twice as large for the Inland zone (1.8 percent) than the Coastal zone (0.9 percent).

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (kW)	Peak Load Impact (kW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Coastal	1,533	1,170	55.7	0.75	0.037	4.9%	73
	Inland	1,099	1,061	48.1	0.94	0.045	4.7%	78
	All	2,633	2,231	103.8	0.83	0.040	4.8%	75
Winter	Coastal	914	893	9.4	0.96	0.009	0.9%	65
	Inland	660	661	11.1	0.98	0.017	1.8%	63
	All	1,574	1,554	20.5	0.97	0.012	1.3%	64

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, in both directions. However, they increased their energy consumption by small amounts in each summer month (except September). The overall effect is an average annual *increase* of just under 1 percent.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Daily Load Impact	Ave. Daily Temp.
			Daily Ref. Load (MWh)	Daily Load Impact (MWh)	Daily Ref. Load (kWh)	Daily Load Impact (kWh)		
Oct-15	All	940	18.64	-0.03	19.83	-0.03	-0.2%	73
Nov-15	All	1,109	19.64	0.24	17.71	0.22	1.2%	62
Dec-15	All	1,282	25.41	-0.04	19.82	-0.03	-0.2%	58
Jan-16	All	1,428	26.52	0.18	18.57	0.12	0.7%	58
Feb-16	All	1,689	28.27	-0.28	16.74	-0.17	-1.0%	64
Mar-16	All	1,888	30.25	0.10	16.02	0.05	0.3%	62
Apr-16	All	2,047	32.79	0.36	16.02	0.18	1.1%	65
May-16	All	2,213	33.15	0.46	14.98	0.21	1.4%	65
Jun-16	All	2,399	44.59	1.28	18.59	0.53	2.9%	69
Jul-16	All	2,592	57.66	1.57	22.24	0.60	2.7%	71
Aug-16	All	2,851	61.85	0.99	21.69	0.35	1.6%	72
Sep-16	All	3,108	57.85	-0.67	18.61	-0.22	-1.2%	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. The largest load reductions occur prior to the winter peak period but during the *summer* peak period, possibly suggesting some lack of awareness on the part of the enrolled customers of the change in peak period between seasons.

Figure 5.7: Aggregate Hourly Loads and Load Impacts (MW) – CPP
(*Average Weekday, August 2016*)

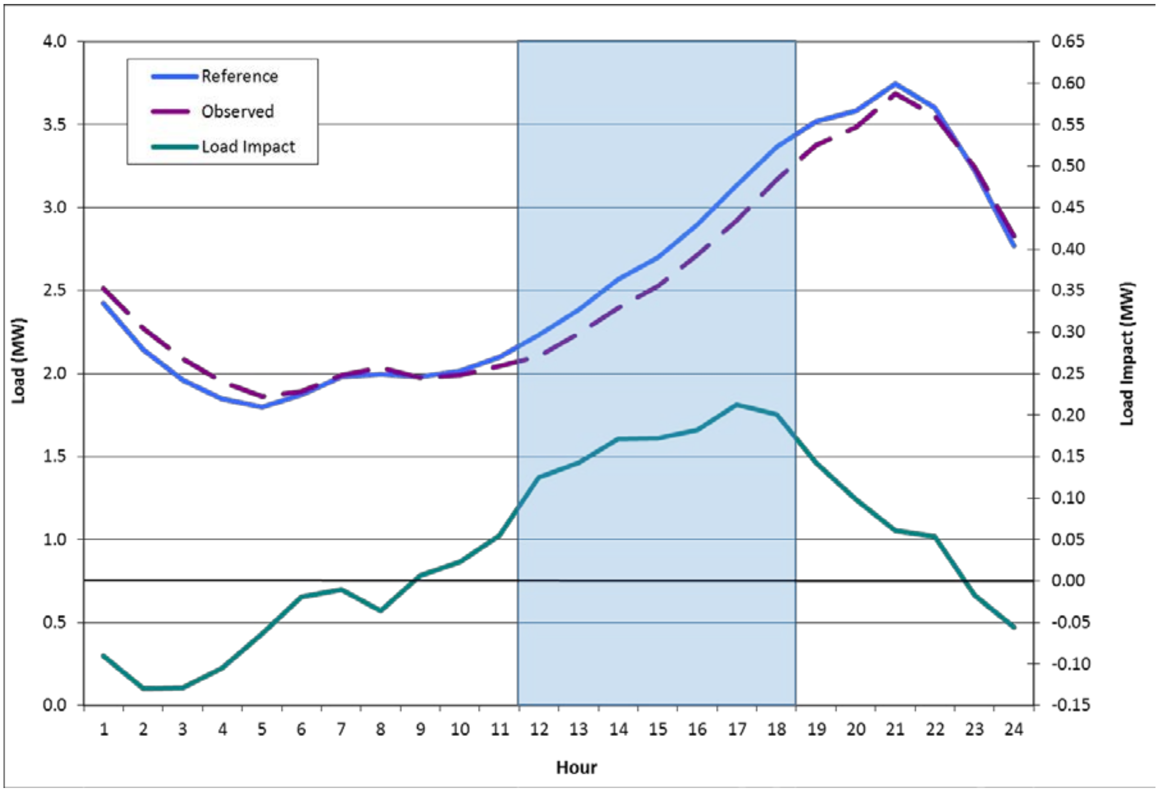
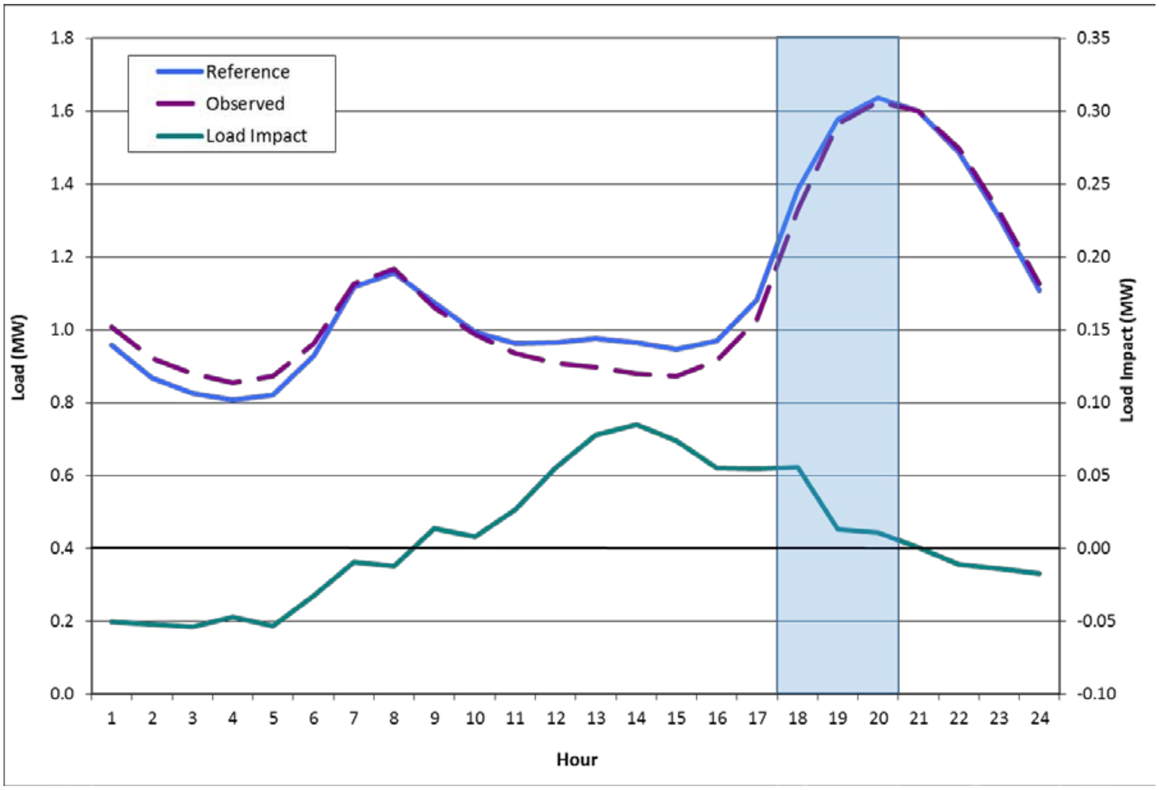


Figure 5.8: Aggregate Hourly Loads and Load Impacts (MW) – CPP
(*Average Weekday, January 2016*)



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. However, since SDG&E called only one RYU/CPP event in 2016, we have only that event on which to base forecasts going forward. As a result, we develop load impacts for different weather scenarios by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads. We also report portfolio-level load impacts for instances when a CPP event is called on the same day as a Summer Saver event. For such days, we assume that Summer Saver 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 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.

For TOU rate and the TOU portion of the CPP rate, 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.

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 2015 through September 2016 for the CPP and TOU customers. Regression models were estimated separately for each hour of the day, 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 (CDH65 and HDH65)[15];
- 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

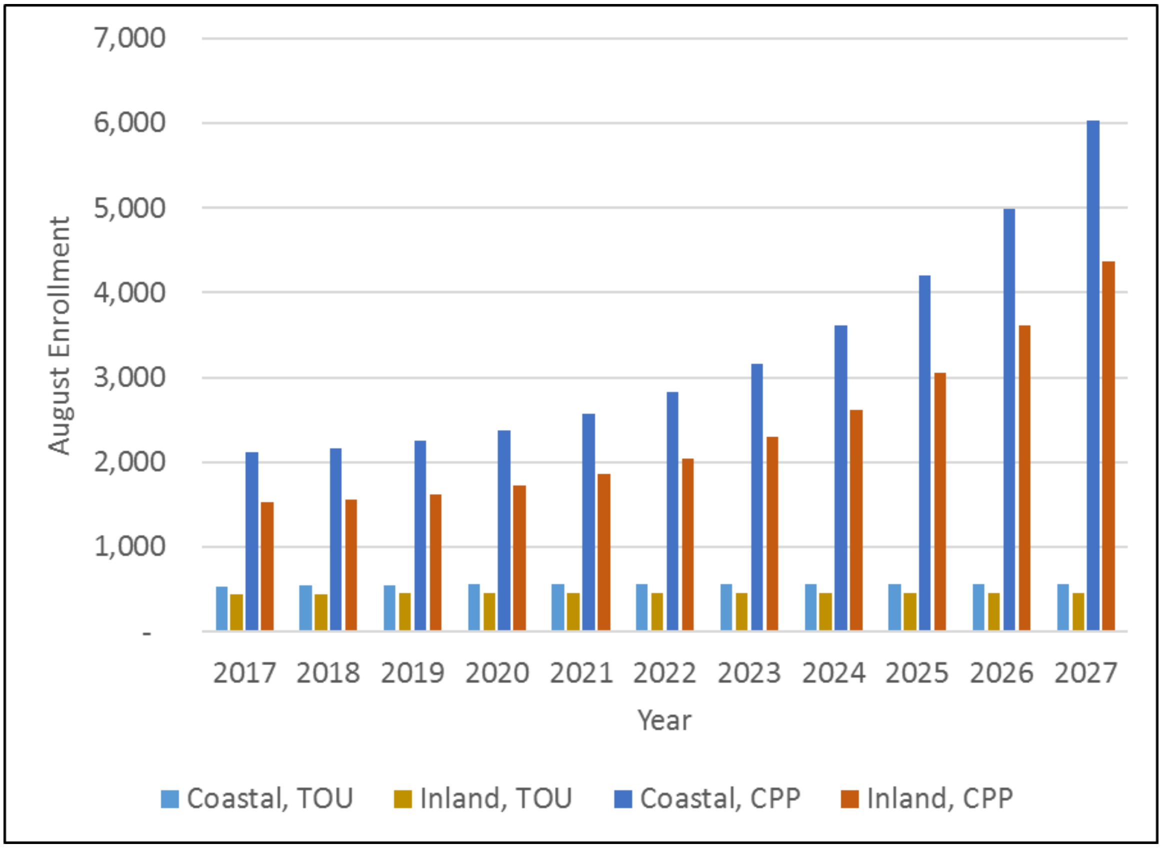
[15] Cooling degree hours (CDH) for each hour of the day are defined as: CDH65 = max(0,Temperature in °F – 65). Likewise, heating degree hours (HDH) for each hour of the day are defined as: HDH65 =max(0, 65 – Temperature in °F).

estimated percentage TOU load impacts from the *ex-post* analysis (seasonal values for TOU, and monthly values for CPP).[16]

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 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 6.1: Enrollments in TOU and CPP



6.2 Ex-Ante load impacts – 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

[16] 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.

2018 in the SDG&E 1-in-2 weather scenario. The average event-period percentage load impact is 12 percent.

Figure 6.2: Aggregate Hourly Loads and CPP Load Impacts (MW) – (*August 2018 SDG&E 1-in-2 Peak Day*)

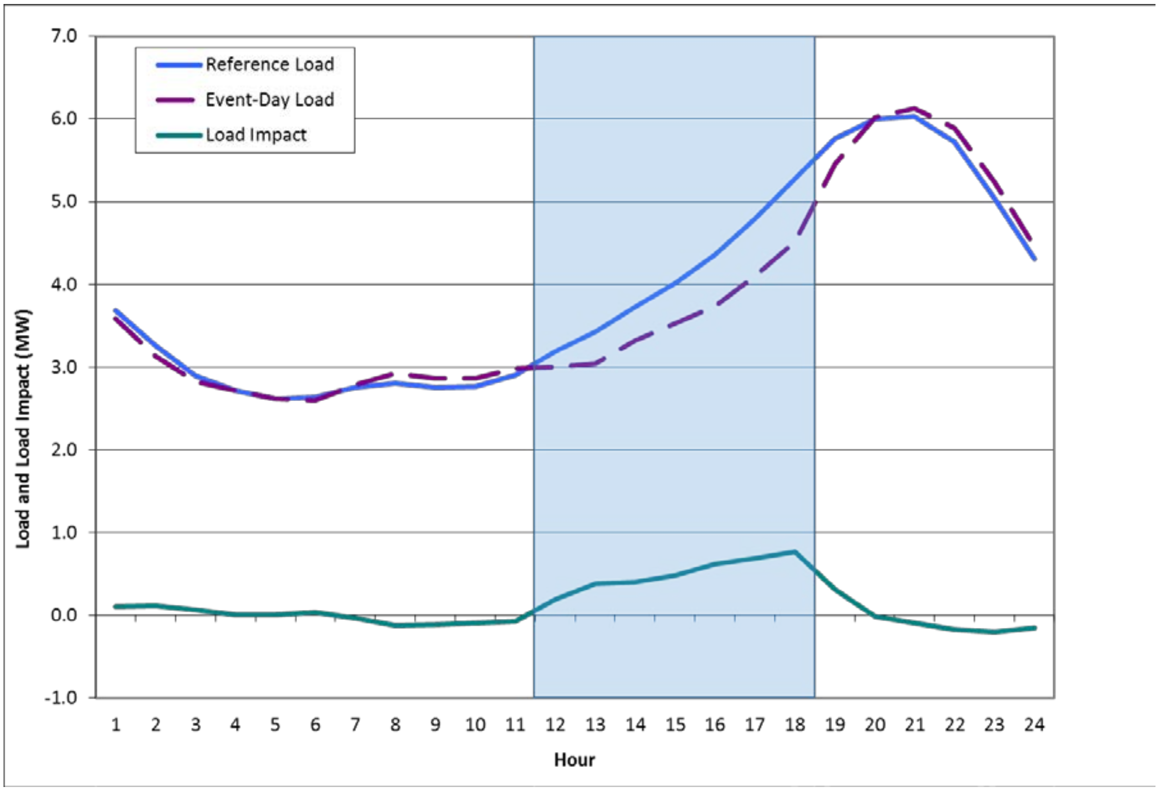


Figure 6.3 shows the monthly pattern of aggregate average *ex-ante* load impacts (RA window) in 2018 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in August.

Figure 6.3: Aggregate CPP Load Impacts (MW), by Month –
(*SDG&E 1-in-2 Peak Day, RA Window, 2018*)

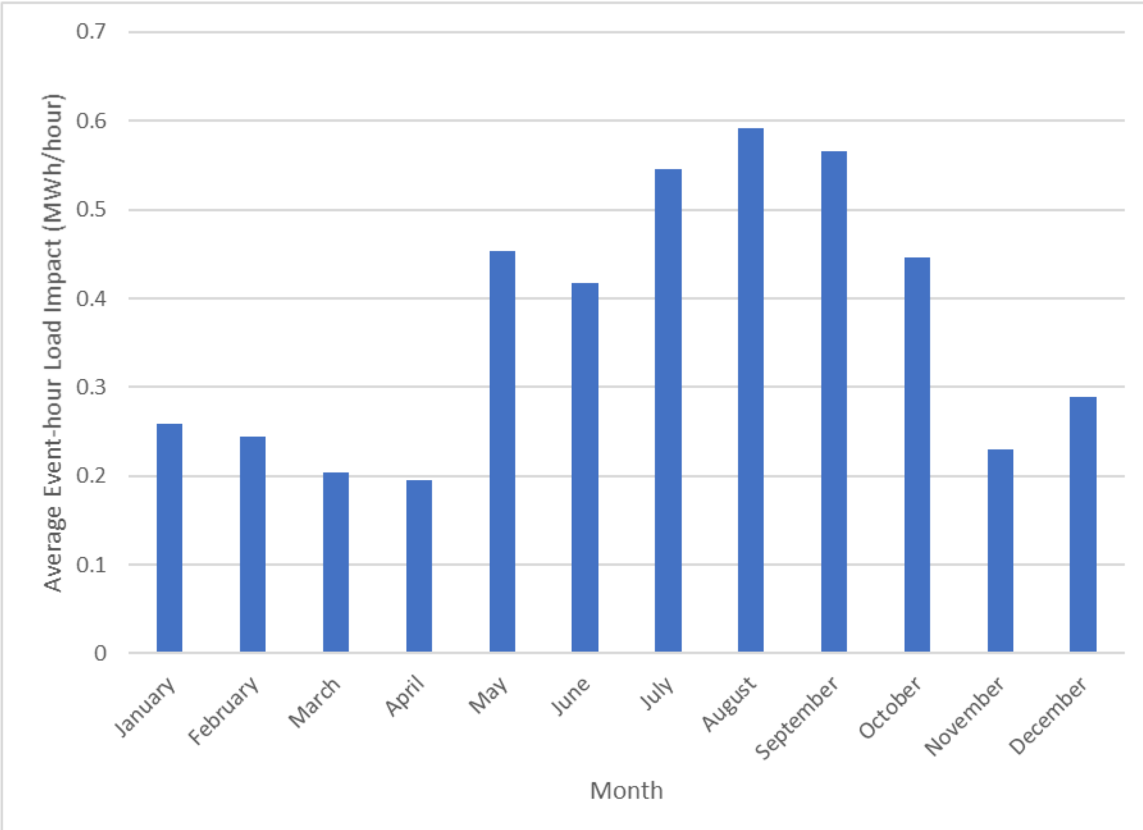
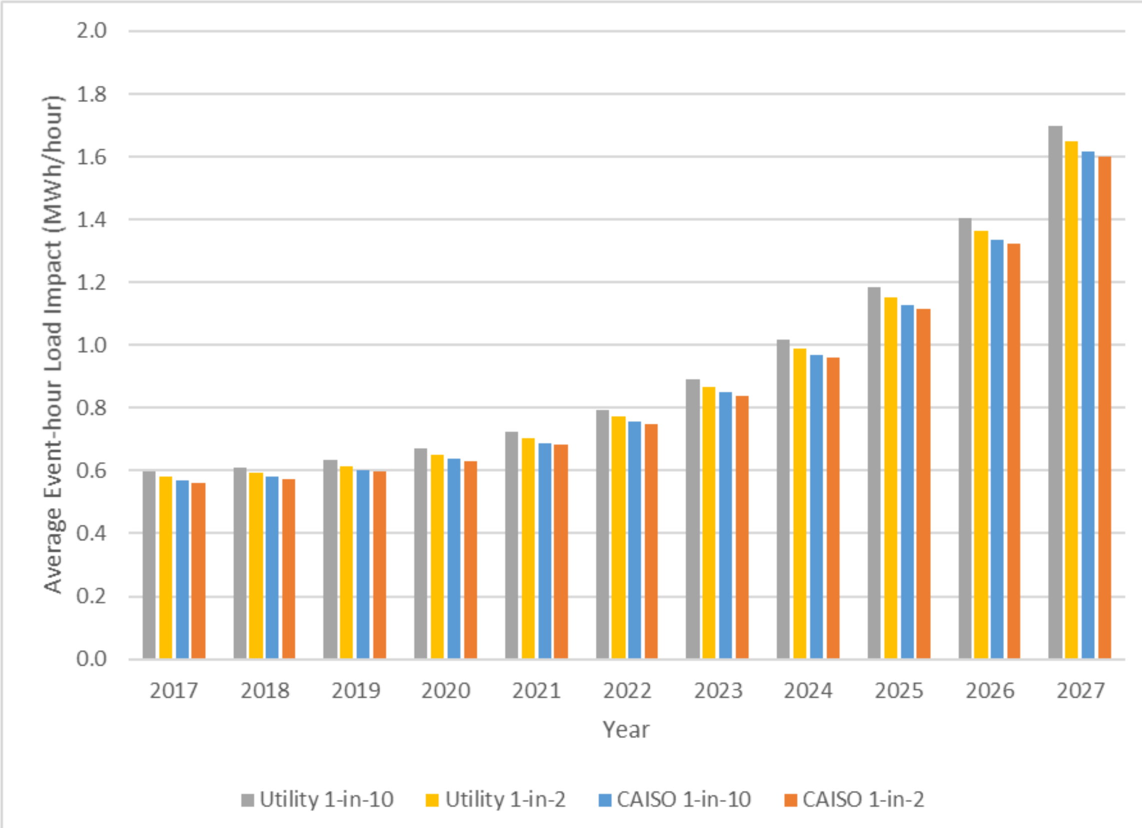


Figure 6.4 illustrates the growth in forecast CPP load impacts, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios over the forecast period.[17]

[17] The relatively minor differences are due in part to the assumed constant percentage load impact, due to the occurrence of only one event in 2016. As experience is gained from additional events, the load impacts will likely be found to be weather sensitive.

Figure 6.4: Aggregate CPP Load Impacts (MW), by Year and Weather Scenario – (*SDG&E 1-in-2 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. Results are reported separately for the two rates. Figure 6.5 shows aggregate loads and load impacts for TOU, in 2018 for an August SDG&E 1-in-2 peak day. The average peak load impact is 8 percent of the reference load. Figure 6.6 shows comparable information for CPP. The average peak load impact is 3.9 percent of the reference load.

Figure 6.5: Aggregate Hourly Loads and TOU Load Impacts (MW) for TOU Customers – (*August 2018 SDG&E 1-in-2 Peak Day*)

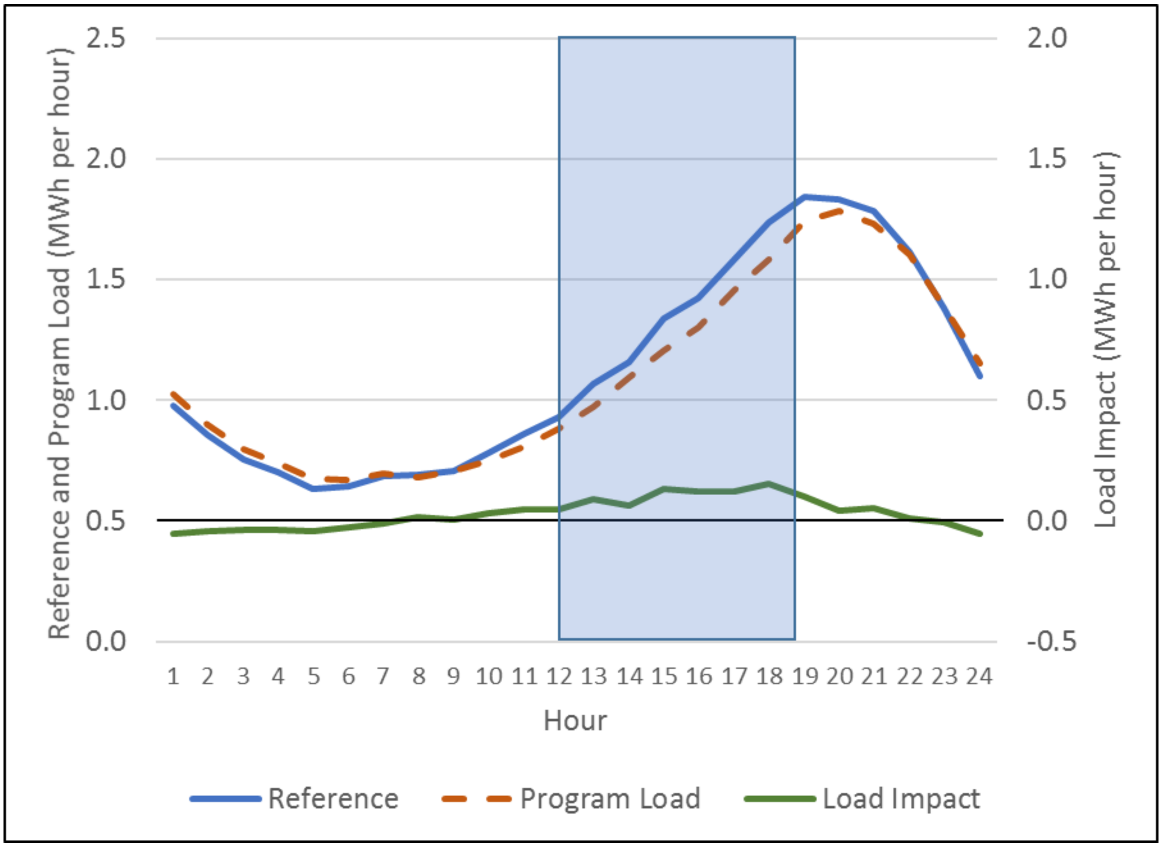


Figure 6.6: Aggregate Hourly Loads and TOU Load Impacts (MW) for CPP Customers – (*August 2018 SDG&E 1-in-2 Peak Day*)

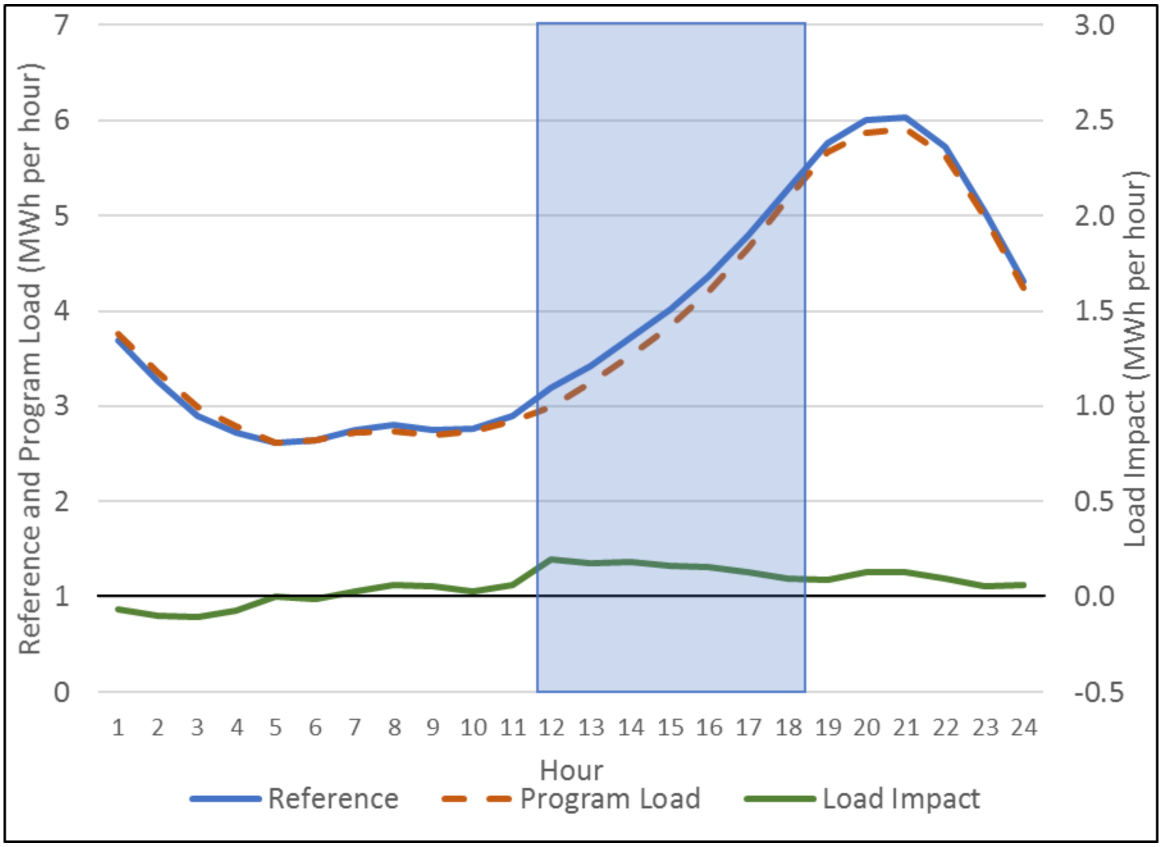


Figure 6.7 shows the monthly distributions of the peak load impacts (RA window) for TOU and CPP. Load impacts for CPP in particular are greatest in the summer months. Results for the winter months vary considerably, in part due to the mismatch between the TOU peak period (5 to 8 p.m.) and the RA window (4 to 9 p.m.).

Figure 6.7: TOU Load Impacts (MW) by Month (RA Window) – *TOU and CPP* (*2018 SDG&E 1-in-2 Average Weekday*)

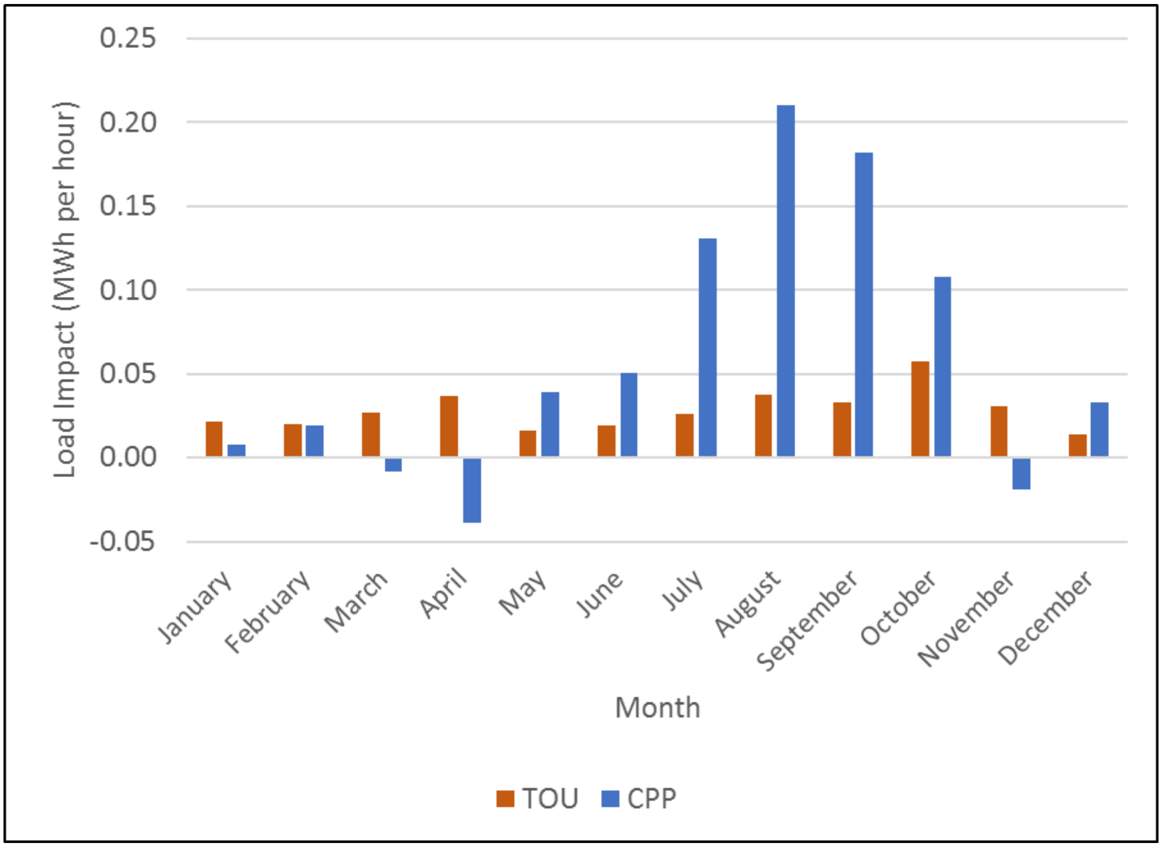


Figure 6.8 shows differences in the aggregate load impacts for TOU by weather scenario. Since the values remain constant after 2019, results are shown only for one year, in 2020. Values for the two 1-in-10 scenarios are nearly identical, while load impacts in the SDG&E 1-in-2 scenario are larger than in the CAISO 1-in-2 scenario. Figure 6.9 shows comparable information for CPP, but extended over the full period. Similar patterns hold for the differences between scenarios.

Figure 6.8: Aggregate TOU Load Impacts (MW) for TOU Customers, by Year and Weather Scenario – (*SDG&E 1-in-2 Average Weekday, RA Window*)

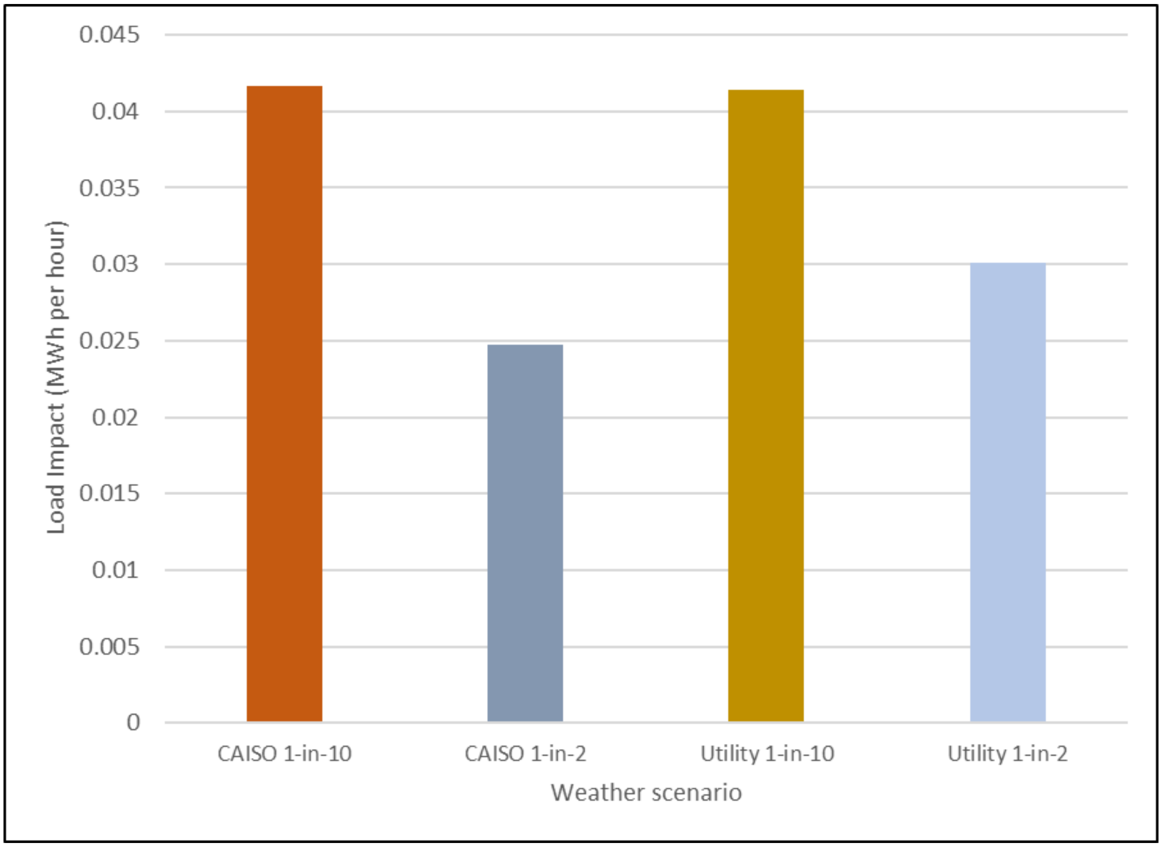
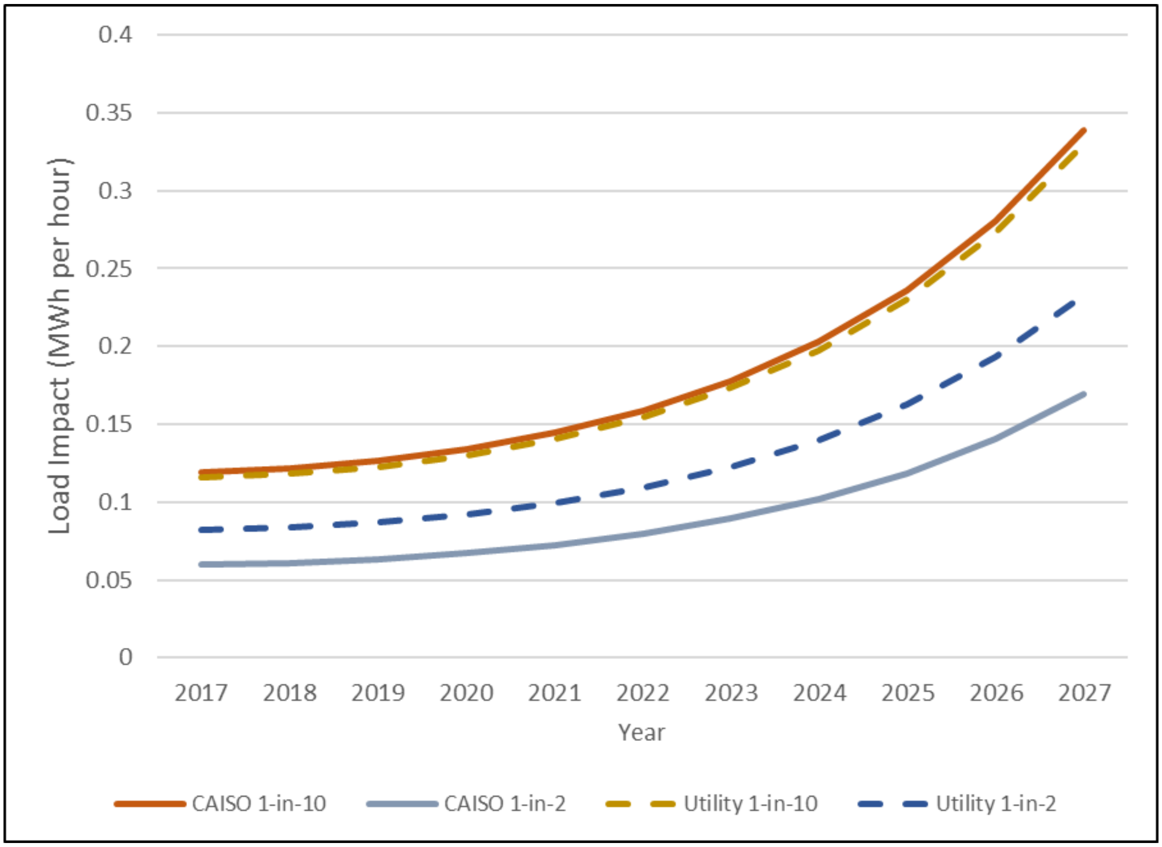


Figure 6.9: Aggregate TOU Load Impacts (MW) for CPP Customers, by Year and Weather Scenario – (*SDG&E 1-in-2 Average Weekday, RA Window*)



7. Comparisons of Results

In this section, we present and describe the relationship between the *ex-post* and *ex-ante* results. The comparison illustrates the linkage between the PY2016 *ex-post* load impacts and the *ex-ante* forecast for 2017.

7.1 CPP

Table 7.1 compares the *ex-post* load impacts for the CPP single event day on September 26, 2016 and *ex-ante* load impacts for 2017 (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* load impacts are built on the 2016 *ex-post* values, the per-customer load impact percentages are similar.

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

Season	Result	*Ex-post* for 2016 (Event Window)	*Ex-ante* for 2017 Peak Day (Event Window)	*Ex-ante* for 2017 Peak Day (RA Window)
Summer (August)	# SAIDs	3,063	3,656	3,656
	Reference (MW)	3.51	4.03	4.35
	Load Impact (MW)	0.44	0.49	0.58
	Per-SAID reference (kW)	1.15	1.10	1.19
	Per-SAID load impact (kW)	0.14	0.14	0.16
	% Load Impact	12.6%	12.3%	13.4%
	Temperature	99.2	85.3	85.2

Table 7.2 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 7.2: *Ex-Post* versus *Ex-Ante* Factors, CPP Event

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Weather	99.2 degrees Fahrenheit during HE 12-18.	85.2 degrees Fahrenheit during HE 14-18 of a utility-specific 1-in-2 August peak day.	Hotter *ex-post* weather increases the reference load and load impact.
Event window	HE 12-18 for the typical event day.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	The RA window covers a sub-set of the event window that tends to have higher usage, resulting in higher per-hour reference loads and load impacts in the *ex-ante* summaries.
% of resource dispatched	The entire program was dispatched on the one event day.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	3,063 customers enrolled.	3,656 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* impacts are to the various scenarios in the *ex-ante* study.

7.2 Residential TOU

Table 7.3 compares the TOU PY2016 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2017 (of the SDG&E 1-in-2 August average weekday) produced in this study. Likewise, Table 7.4 compare similar results for customers enrolled in the CPP rates.

The *ex-ante* forecast is based on the *ex-post* load impacts, so the differences between the two sets of results are due to two factors: weather conditions and enrollments, specifically the larger number of customers in each rate. Higher temperatures result in larger reference loads and level load impacts.

Table 7.3 Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts for TOU Customers

Season	Result	*Ex-post* for 2016 Avg. Weekday from PY2016 Study	*Ex-ante for 2017 Avg. Weekday from PY2016 Study*
Summer (August)	# SAIDs	745	983
	Reference (MW)	0.85	1.12
	Load Impact (MW)	0.05	0.07
	Per-SAID reference (kW)	1.15	1.14
	Per-SAID load impact (kW)	0.07	0.07
	% Load Impact	5.7%	6.0%
	Temperature	77.5	77.5
Winter (January)	# SAIDs	328	983
	Reference (MW)	0.35	1.05
	Load Impact (MW)	0.01	0.04
	Per-SAID reference (kW)	1.05	1.06
	Per-SAID load impact (kW)	0.04	0.04
	% Load Impact	3.7%	3.5%
	Temperature	60.0	59.0

Table 7.4 Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts for CPP Customers

Season	Result	*Ex-post* for 2016 Avg. Weekday from PY2016 Study	*Ex-ante for 2017 Avg. Weekday from PY2016 Study*
Summer (August)	# SAIDs	2,851	3,656
	Reference (MW)	2.93	3.73
	Load Impact (MW)	0.19	0.24
	Per-SAID reference (kW)	1.03	1.02
	Per-SAID load impact (kW)	0.07	0.07
	% Load Impact	6.4%	6.5%
	Temperature	77.3	77.4
Winter (January)	# SAIDs	1,428	3,656
	Reference (MW)	1.46	3.70
	Load Impact (MW)	0.03	0.07
	Per-SAID reference (kW)	1.02	1.01
	Per-SAID load impact (kW)	0.02	0.02
	% Load Impact	1.9%	1.9%
	Temperature	60.2	59.1

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 limited our ability to vary load impacts across *ex-ante* scenarios.

Appendices

Appendix A CPP *Ex-Post* Load Impact Tables
Appendix B TOU *Ex-Post* Load Impact Tables
Appendix C CPP *Ex-Ante* Load Impact Tables
Appendix D TOU *Ex-Ante* Load Impact Tables