2019 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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Table of Contents

List of Tables

List of Figures

Abstract

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 2019, along with their grandfathered counterparts.

The (non-grandfathered) TOU and CPP 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 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.[1] The analysis includes Net Energy Metered ("NEM") customers. 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.

In addition, this report includes *ex-post* and *ex-ante* load impacts for Grandfathered customers on the rate GTOU-DR-P. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under Grandfathered TOU period definitions until July 31, 2027.

The TOU periods for all non-Grandfathered rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year. SDG&E did not call any CPP events in 2019.

For Grandfathered customers, the summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak.

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

[1] CPP *ex-post* load impacts are not estimated in this evaluation because no CPP events occurred in 2019. TOU load impacts are estimated using customers who enrolled in either of the rates after October 1, 2018, also referred to as *incremental* TOU customers. The *incremental* TOU load impacts are applied to all customers on SPP rates (TOU-DR and TOU-DR-P).

enrollment in SDG&E's Reduce Your Use, or RYU, program), based on the closest match of load profiles.

SDG&E did not call any CPP events in 2019, so no *ex-post* analysis is performed to estimate a CPP load impact.

TOU enrollment rose from 3,150 customers in October 2018 to 6,720 in September 2019. The estimated seasonal percentage load impacts were approximately 15.1 percent in summer and 13.9 percent in winter. Summer peak load impacts were similar in percentage terms for the two climate zones. Combining results across months and considering the effect of TOU on average *daily* usage, we find that TOU customers *decreased* their energy consumption by an 0.9 kWh per day.

Similarly, we evaluated the TOU load impacts for CPP customers. Enrollment in CPP grew from 6,987 in October 2018 to 13,917 in September 2019. Summer TOU peak load impacts varied slightly across months, with load reductions in all months. Aggregate load impacts in winter months were smaller due to lower enrollment numbers. However, summer and winter peak *per-customer* load impacts are similar, 5.1 percent and 4.6 percent, respectively.

Among Grandfathered customers, average enrollment in winter was 564 customers while average summer enrollment had increased to 595 customers. The Coastal climate zone saw a larger TOU reduction than the Inland climate zone during the summer season, while during the winter, customers in both climate zones *increased* usage by an average 0.24 kWh/h.

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 2019, along with their grandfathered counterparts.

The (non-grandfathered) TOU and CPP 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 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.[2] The analysis includes Net Energy Metered ("NEM") customers. 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.

In addition, this report includes *ex-post* and *ex-ante* load impacts for Grandfathered customers on the rate GTOU-DR-P. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under Grandfathered TOU period definitions until July 31, 2027.

ES.1 Resources Covered

The TOU periods for all non-Grandfathered rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year. SDG&E did not call any CPP events in 2019.

For Grandfathered customers, the summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak.

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

[2] CPP *ex-post* load impacts are not estimated in this evaluation because no CPP events occurred in 2019. TOU load impacts are estimated using customers who enrolled in either of the rates after October 1, 2018, also referred to as *incremental* TOU customers. The *incremental* TOU load impacts are applied to all customers on SPP rates (TOU-DR and TOU-DR-P).

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, solar PV size, and enrollment in SDG&E's Peak Time Rebate Reduce Your Use, or PTR-RYU, program), based on the closest match of load profiles.

ES.3 Ex-Post Load Impacts

ES.3.1 CPP event load impacts (TOU-DR-P and GTOU-DR-P)

SDG&E did not call any CPP events in 2019.

ES.3.2 TOU peak load impacts – TOU (TOU-DR)

Table ES.1 summarizes the average reference loads and load impacts for customers on the TOU-DR rate for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m. for all months), 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 2018). The winter months are indicated by light blue shading. Enrollment additions continued throughout the period, with the numbers of enrolled customers rising from 3,150 in October 2018 to 6,720 in September 2019.[3] The estimated seasonal percentage load impacts were similar between winter and summer. All months experienced a load reduction during the TOU period.

[3] 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 773 incremental customers on the TOU-DR 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.

Table ES.1: TOU Peak Load Impacts for TOU Customers – *Average Weekday by Month*

Month	Climate Zone	Enrolled	Aggregate: Peak Ref. Load (MWh/h)	Aggregate: Peak Load Impact (MWh/h)	Per-Customer: Peak Ref. Load (kWh/h)	Per-Customer: Peak Load Impact (kWh/h)	Ave. Temp.
Oct-18	All	3,150	3.09	0.43	0.98	0.14	69
Nov-18	All	3,472	4.06	0.42	1.17	0.12	62
Dec-18	All	3,544	4.95	0.45	1.40	0.13	55
Jan-19	All	3,650	4.50	0.46	1.23	0.13	55
Feb-19	All	3,762	4.49	0.48	1.19	0.13	52
Mar-19	All	3,992	2.90	0.64	0.73	0.16	58
Apr-19	All	4,436	2.28	0.68	0.51	0.15	64
May-19	All	4,872	2.20	0.56	0.45	0.12	63
Jun-19	All	5,321	2.87	0.75	0.54	0.14	69
Jul-19	All	5,836	5.12	0.85	0.88	0.15	76
Aug-19	All	6,277	7.03	0.93	1.12	0.15	77
Sep-19	All	6,720	8.01	0.98	1.19	0.15	74

Table ES.2 shows peak load impact estimates by season and climate zone. The summer load impact results are not starkly different between climate zones, though the average summer temperature differs by seven degrees. The winter load impacts differ more, with greater per-customer load impacts occurring in the inland climate zone.

Table ES.2: TOU Peak Load Impacts for TOU Customers –
Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate: Peak Ref. Load (MWh/h)	Aggregate: Peak Load Impact (MWh/h)	Per-Customer: Peak Ref. Load (kWh/h)	Per-Customer: Peak Load Impact (kWh/h)	% Peak Load Impact	Ave. Temp.
Summer	Coastal	2,725	2.35	0.34	0.86	0.12	14.4%	70
	Inland	2,735	2.87	0.45	1.05	0.16	15.6%	77
	All	**5,461**	**5.23**	**0.79**	**0.96**	**0.14**	**15.1%**	**74**
Winter	Coastal	1,963	1.71	0.13	0.87	0.06	7.4%	60
	Inland	1,998	1.89	0.37	0.94	0.19	19.7%	58
	All	**3,961**	**3.60**	**0.50**	**0.91**	**0.13**	**13.9%**	**59**

Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers decreased their energy consumption in 2019 by 0.9 kWh/day.

ES.3.3 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, similar to TOU-only customers. Table ES.3 shows load and load impacts for the average summer (October 2018, and June through September 2019) and non-summer (November 2018 through May 2019) weekdays, by month. Enrollment in CPP grew from 6,987 in October 2018 to 13,917 in September 2019.[4] Peak load impacts varied across months, with estimated load reductions in all months.

Table ES.3: 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)	Ave. Temp.
Oct-18	All	6,987	6.81	0.33	0.97	0.05	69
Nov-18	All	7,199	7.28	0.42	1.01	0.06	62
Dec-18	All	7,414	8.65	0.41	1.17	0.05	55
Jan-19	All	7,769	8.14	0.35	1.05	0.04	56
Feb-19	All	8,161	8.45	0.20	1.04	0.03	52
Mar-19	All	8,834	7.27	0.31	0.82	0.03	58
Apr-19	All	10,061	7.37	0.40	0.73	0.04	64
May-19	All	11,104	7.54	0.43	0.68	0.04	63
Jun-19	All	11,945	7.88	0.34	0.66	0.03	69
Jul-19	All	12,702	10.89	0.68	0.86	0.05	74
Aug-19	All	13,417	12.79	0.68	0.95	0.05	76
Sep-19	All	13,917	13.56	0.69	0.97	0.05	74

Table ES.4 summarizes TOU load impact for estimates for CPP customers by season and climate zone. Winter load impacts are similar between the Coastal and Inland climate zones; while summer load impacts are larger for the inland climate zone.

[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.

Table ES.4: TOU Peak Load Impacts for RYU/CPP Customers – *Average Weekday by Season & Climate Zone*

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	7,075	5.70	0.19	0.81	0.03	70
	Inland	4,719	4.68	0.34	0.99	0.07	77
	All	**11,794**	**10.38**	**0.53**	**0.88**	**0.05**	**73**
Winter	Coastal	5,120	4.57	0.20	0.89	0.04	60
	Inland	3,529	3.24	0.16	0.92	0.05	58
	All	**8,649**	**7.81**	**0.36**	**0.90**	**0.04**	**59**

ES.3.4 TOU peak load impacts – Grandfathered (GTOU-DR & GTOU-DR-P)

Table ES.5 summarizes TOU peak-period load impact estimates for Grandfathered customers by season and climate zone. All Grandfathered customers are NEM customers that installed their solar systems before January 31, 2017. The coastal climate zone had a per-customer load impact of 0.40 kWh/h in the summer period and a 0.35 kWh/h *increase* in usage during the winter period, whereas the inland climate zone exhibited smaller TOU peak-period load impacts in the summer, with smaller increases in the winter.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	285	-0.22	0.11	-0.76	0.40	74
	Inland	310	-0.14	0.03	-0.46	0.11	83
	All	**595**	**-0.36**	**0.15**	**-0.61**	**0.25**	**79**
Winter	Coastal	270	0.25	-0.09	0.92	-0.35	59
	Inland	294	0.37	-0.04	1.26	-0.15	57
	All	**564**	**0.62**	**-0.14**	**1.10**	**-0.24**	**58**

ES.4 Ex-Ante Load Impacts

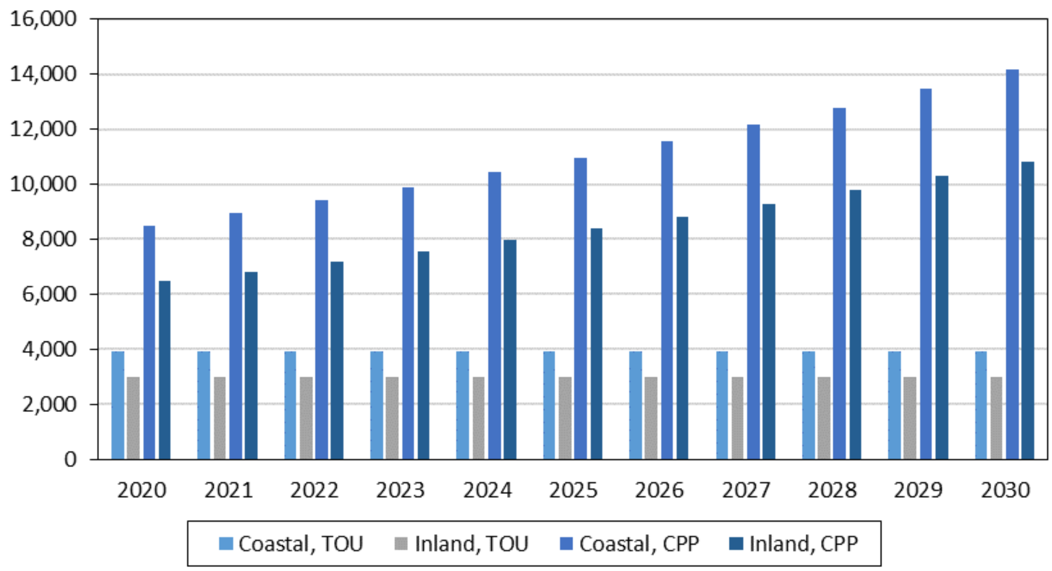
Since no CPP events took place in 2019, the *ex-ante* analysis for CPP events applies CPP event load impacts from PY2018 to reference loads calculated using PY2019 customer load data. The forecasts are based on analyses of per-customer load impact findings from *ex-post* evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

For the *ex-ante* analysis of each rate's TOU load impact, hourly percentage load impacts from the *ex-post* analysis (developed from monthly values for CPP and seasonal values for TOU) are applied to weather-sensitive reference loads.

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 increase by nearly 6,000 customers by the end of the forecast period. Enrollment is expected to be greater in the Coastal climate zone than in the Inland for both rates. Enrollment for Grandfathered customers (GDRTOPH) is assumed to remain constant at 623 customers until the grandfathering term expires on July 31, 2027.

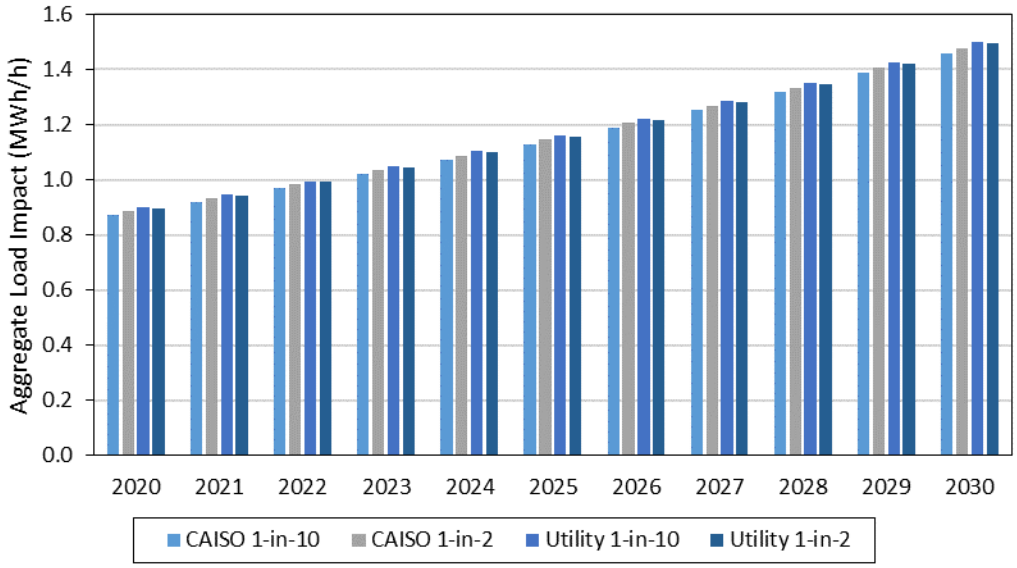
Figure ES.1: Enrollments in TOU and CPP Rates



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. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

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

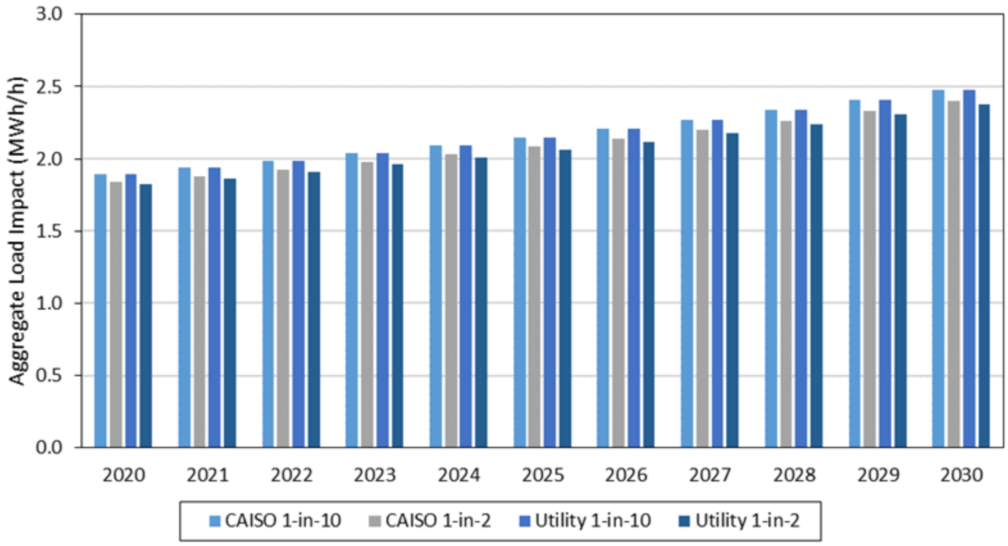


The *ex-ante* CPP load impact forecast for Grandfathered customers is assumed to remain constant during the RA window for each weather scenario and year up to the Grandfathered term expiration on July 31, 2027.

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

Figure ES.3 shows differences in the aggregate peak TOU load impact forecasts for customers enrolled in rates TOU-DR and TOU-DR-P over the entire forecast period for the average August weekday weather scenarios. The load impacts are largest for the CAISO and Utility 1-in-10 scenarios, which have equivalent temperatures for the average August weekday.

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



The *ex-ante* TOU load impact forecast for Grandfathered customers is assumed to remain constant in the summer months, at 0.05 MWh/h, and constant in the winter months at -0.15 MWH/h. Similar to the CPP load impact forecast for Grandfathered customers, the TOU load impact does not vary by weather scenario and year. Therefore, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2027.

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 2019, along with their grandfathered counterparts.

The (non-grandfathered) TOU and CPP 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 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.[5] 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 TOU periods in the two rates are centered around an on-peak period of 4 to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 2 to 6 p.m. period on any day (including weekends) throughout the year.

Given a rapid increase in Net Energy Metered (NEM) enrollments in 2019, NEM customers now constitute a significant proportion of residential TOU customers, as shown in the Table 1.1 below. The increased proportion of NEM customers is much more dramatic for the TOU-only rate (TOU-DR).

[5] CPP *ex-post* load impacts are not estimated in this evaluation because no CPP events occurred in 2019. TOU load impacts are estimated using customers who enrolled in either of the rates after October 1, 2018, also referred to as *incremental* TOU customers. The *incremental* TOU load impacts are applied to all customers on SPP rates (TOU-DR and TOU-DR-P).

Table 1.1: NEM and Non-NEM Customer Enrollments

Date	TOU			TOU + CPP		
	Non-NEM Enrolled	NEM Enrolled	NEM Share of Enrolled	Non-NEM Enrolled	NEM Enrolled	NEM Share of Enrolled
Oct-18	1,424	1,726	54.8%	6,430	557	8.0%
Nov-18	1,341	2,131	61.4%	6,573	626	8.7%
Dec-18	1,297	2,247	63.4%	6,724	690	9.3%
Jan-19	1,287	2,363	64.7%	6,999	770	9.9%
Feb-19	1,300	2,462	65.4%	7,329	832	10.2%
Mar-19	1,409	2,583	64.7%	7,904	930	10.5%
Apr-19	1,667	2,769	62.4%	9,011	1,050	10.4%
May-19	1,919	2,953	60.6%	9,917	1,187	10.7%
Jun-19	2,170	3,151	59.2%	10,615	1,330	11.1%
Jul-19	2,440	3,396	58.2%	11,229	1,473	11.6%
Aug-19	2,620	3,657	58.3%	11,809	1,608	12.0%
Sep-19	2,837	3,883	57.8%	12,181	1,736	12.5%

Grandfathered versions of the voluntary residential TOU and CPP rates also exist (GTOU-DR and GTOU-DR-P). This report also provides *ex-post* and *ex-ante* load impacts for the Grandfathered customers. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions until July 31, 2027. All Grandfathered customers are NEM customers. The grandfathered summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak under the Grandfathered rates.

While the SPP rates are voluntary TOU rates, as part of the Residential Rate Reform decision the CPUC ruled that the California Investor-Owned Utilities were to implement default TOU rates. In 2016 SDG&E began conducting its Opt-In TOU pilot, and in 2018 its Default TOU pilot which was considered phase 1 of the full TOU rollout which begins in March of 2019. SDG&E plans to default more than 750,000 residential customers by 2021.

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; and Section 4 contains the TOU *ex-post* load impact results. Section 5 describes the methods used to develop the CPP and TOU *ex-ante* load impacts and the associated results. Section 6 provides a series of comparisons of *ex-post* and *ex-ante* results. Section 7 provides recommendations.

2. Description of Rates

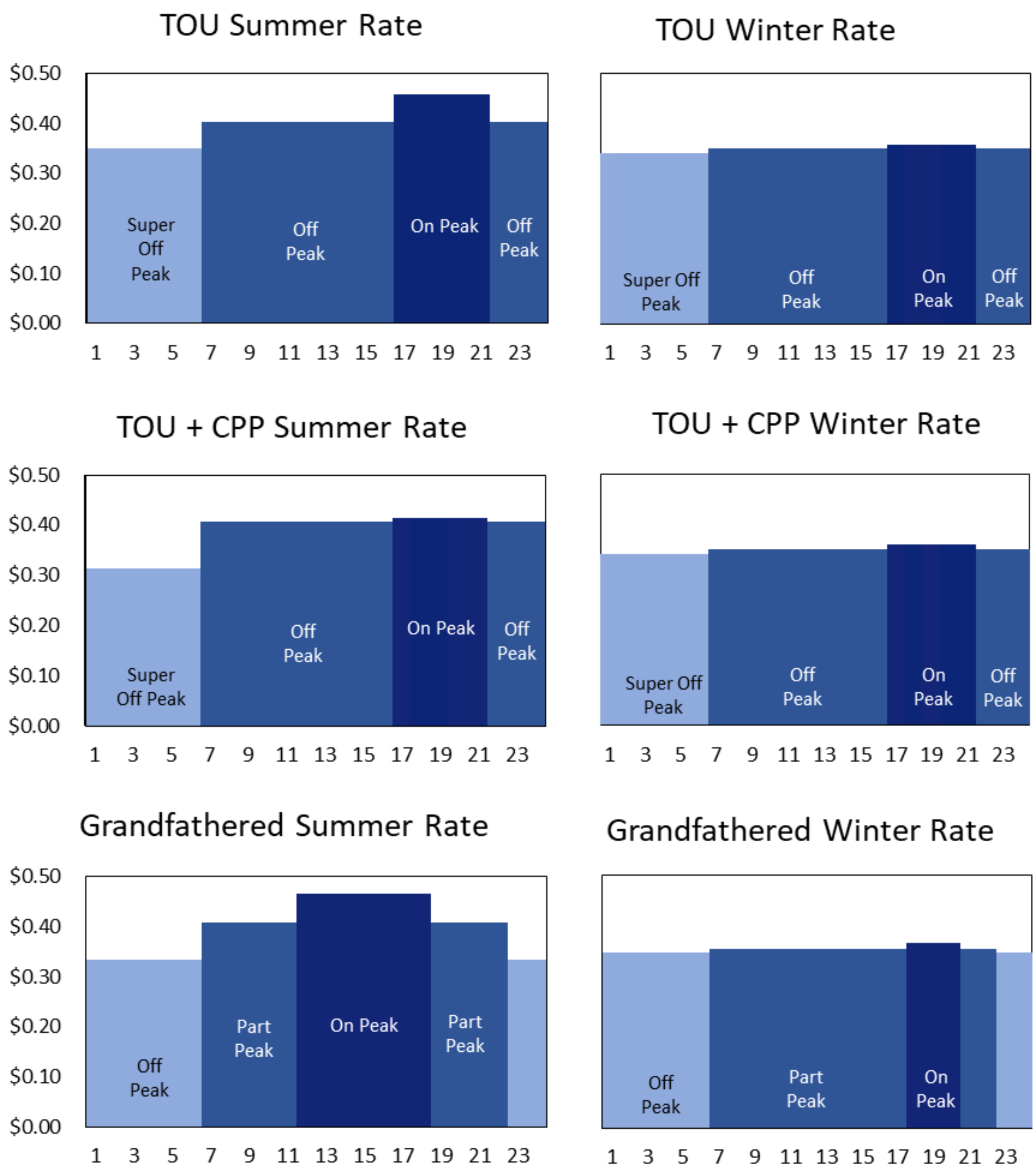
As noted in the introduction, the current TOU on-peak period in summer is 4 to 9 p.m. on non-holiday weekdays, with morning and evening off-peak periods before and after, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. 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. No CPP events were called in 2019.[6]

The total TOU charges TOU (TOU-DR) customers are $0.458, $0.404, and $0.350 per kWh for the summer on-peak, off-peak, and super-peak periods respectively. Thus, the peak to super-off-peak price ratio is 1.31 to one. Summer TOU charges for CPP (TOU-DR-P) customers are somewhat lower, at $0.414, $0.407, and $0.313 per kWh, implying a peak to off-peak price ratio of 1.32 to one. Summer prices for Grandfathered CPP (GTOU-DR-P) customers are $0.465, $0.409, and $0.334 for summer on-peak, semi-peak, and off-peak periods, respectively. In addition, a CPP event-period adder of $1.16 per kWh applies on event days for both CPP and Grandfathered CPP customers. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.[7]

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.

[6] Note that the *Ex-Ante* analysis is based on six CPP events in 2018: 7/6, 7/24, 7/25, 8/6, 8/7, and 8/9.
[7] The super-off-peak period includes 10 a.m. to 2 p.m. in March and April for non-Grandfathered customers, which is not represented by the winter rates in Figure 2.1.

Figure 2.1: Rate Time-of-Use Periods and Prices



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. Note that this section includes a description of methodology for an *ex-post* analysis of CPP events even though no CPP events took place in 2019 – an explanation of methodology is included as background because 2018 load impacts were employed in the current year's *ex-ante* analysis.

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 (including Grandfathered customers) and potential control group customers (*e.g*., location indicator for matching to climate zone, CARE status, NEM status and characteristics);
- Billing-based *interval load data* (*i.e.*, hourly loads for each TOU and CPP enrollee, and potential control group customers), for October 2017 through September 2019;
- *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 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, CA Energy Consulting requests 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, matched control group customers are selected for the TOU and CPP enrollees, as described below. Third, fixed-effects panel regression models are estimated, 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 PTR-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.

Since the CPP (TOU-DR-P) customers experienced TOU rates on all non-event days, and the CPP rate on event days, those customers are treated 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). Although no CPP events occurred in 2019, this match was performed in studies in prior years.

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 (October 2017 through September 2018). Only incremental customers are used 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 analyses are separated by season, thus allowing different threshold dates that define incremental customers.[8] Specifically, incremental customers for the winter analysis are those that enrolled after June 1, 2018 while incremental customers for the summer analysis are those that enrolled after October 1, 2018. 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 2017 through May 2018, while the *summer* season used data for October 2017 and June through September of 2018.

The grandfathered rate prevents new customers from joining the rate from a standard tiered rate (*e.g.,* DR). As a result, all Grandfathered customers are already treated (*i.e.,* either on the Grandfathered or TOU rate) during the pre-treatment matching periods mentioned above. To estimate TOU load impacts for these customers, TOU load impacts are estimated using PY2017 incremental customers that are now Grandfathered customers.[9] The PY2017 pre-treatment analysis periods cover October 2015 through September 2016. The post-treatment analysis period for these customers, however, covers October 2018 through September 2019.[10] Current Grandfathered customers that enrolled in either TOU-DR or TOU-DR-P after May 1, 2016 are incremental customers for the grandfathered winter analysis and those that enrolled after September 1, 2016 are incremental customers for the grandfathered summer analysis.

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.

$$Distance_{T,C} = \sqrt{(T_1 - C_1)^2 + (T_2 - C_2)^2 \ldots + (T_n - C_n)^2}$$

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 CPP and

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[8] The seasons defined for matching are summer (June through October) and winter (November through May).

[9] PY2017 incremental customer are used to estimate grandfathered load impacts because it was the last year that any Grandfathered customers switched from a standard tiered rate to a TOU rate.

[10] The gap in data between the pre- and post-treatment period requires that incremental customers exist for the entire period. Otherwise, the method is equivalent to the other difference-in-difference analyses.

TOU analyses. 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).[11] In prior years, for matching in the CPP analysis, the customer characteristics included the average hourly usage on event-like non-event weekdays (24 variables). Again, this match was not performed for the current study because no CPP events occurred in 2019. Treatment and potential control customers are also segmented by climate zone, CARE status, and enrollment in PTR-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).

NEM customers are matched similarly, with three major distinctions. First, only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included.[12] Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.[13] Third, customers with large changes in net profiles between periods are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system. The methodology and thresholds used for identifying NEM customers with large changes in usage and subsequently removed from the analysis is explained in more detail in Appendix C. Each of these requirements helps prevent estimating load impacts (TOU or RYU/CPP) that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to only a behavioral response to TOU rates or CPP events.[14]

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

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[11] Hot/cold days are among the highest/lowest 20th percentile in terms of CDD or HDD temperature values. Hot/cold days are selected separately by climate zone.

[12] With a matched control group, it is essential to create a counterfactual that mimics any changes a treatment customer faces. It becomes increasingly unlikely to find a suitable match for customers that become NEM during the analysis period or change their solar PV characteristics because the best practice would be to search for a control customer that made comparable changes at parallel points in time. Additionally, including controls in a regression for these changes is limited by the amount of overlap between the change and becoming a TOU customer. Essentially, it is more difficult to statistically disentangle effects the closer they occur to each other.

[13] NEM customers are segmented only by solar PV size, rounded to the next integer level (capacity sizes greater than 12 kW are a separate segment).

[14] For example, a high premise usage treatment customer with a larger solar generation system may be matched to a lower premise usage control customer with a smaller solar generation system based on similar net load profiles. If conditions are met so that solar generation is larger in the post-period, then any analysis based on net load profiles will exhibit that the treatment customer reduced their usage, relative to their own pre-treatment usage as well as relative to the control customer's usage.

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 discuss two versions of fixed-effect regression models. The first version is typically used to estimate CPP event-day hourly load impacts (estimated separately for TOU-DR-P and Grandfathered customers). This regression was not estimated because there were no CPP events in 2019; nevertheless, we present the methodology because we employ the results of these regressions used in the PY2018 analysis. The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR, TOU-DR-P, and Grandfathered customers). In addition to estimating each load impact type separately by rate, the load impacts were estimated separately for NEM customers within each rate.

Each model addresses the objective of estimating hourly *ex-post* load impacts at the program level by estimating 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 TOU load impacts

To obtain TOU load impacts (for TOU-DR, TOU-DR-P, and Grandfathered customers), a distinct model is estimated for each required result. For example, to obtain the average TOU load impacts on August non-holiday weekdays, a model is estimated that includes only days of that day type.[15] In this case, the model is simplified to include customer and date fixed effects, plus a variable to estimate the load impact (*i.e.*, the coefficient β_1). Separate models are estimated by rate (*e.g.,* TOU-DR, TOU-DR-P, Grandfathered), hour, month, day-type (*i.e.*, average weekday versus peak month day), applicable customer groups (*e.g.*, climate zone, NEM), where the customer-level fixed-effects models are of the following form:[16]

[15] In cases where insufficient numbers of observations were available, the approach was modified by combining day-types into seasons that correspond to TOU periods (*i.e.,* summer is June through October, winter is November through February and May, and a separate winter season for March and April). Specifically, observations were combined for all season-specific weekdays to estimate a constant season percentage load impact (*i.e.,* $PctLI_{Season} = LI_{Season}/(Obs_{Season} + LI_{Season})$). The season-specific percentage load impacts are then used to calculate monthly average weekday or system peak day reference loads (*i.e.,* $Ref_{Daytype}=Obs_{Daytype}/(1\text{-}PctLI_{Season})$ and level load impacts (*i.e.,* $LI_{Daytype} = Ref_{Daytype}*PctLI_{Season}$). This method was used for each season for TOU-DR, Grandfathered, NEM, and electric vehicle customers.

[16] Note that the customer and date fixed effects remove the need for us to include stand-alone TOU_c and $Post_{c,d}$ variables. The former is perfectly collinear with the customer's fixed effect and the latter is perfectly collinear with a combination of date fixed effects.

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

The variables and coefficients in the equation are described in Table 3.1. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
TOU_c	Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer
$Evt_{c,d}$	Variable indicating whether date ***d*** is an event day for customer ***c*** [17]
$Post_{c,d}$	Variable indicating that date ***d*** is in the post-enrollment period for customer ***c***
$TD\_Evt_{c,d}$	Variable indicating that date ***d*** is a *TD* event day (1= event, 0 if not) for customer ***c***
$SS\_Evt_{c,d}$	Variable indicating that date ***d*** is an *AC Saver Day Of* event day (1=event, 0 if not) for customer ***c***
β_0	Estimated constant coefficient
β_1	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
β_4	Estimate of average event-day load impact
β_5 and β_6	Estimated average *TD* and SS event event-day load impacts
C_c	Variable indicating that the observation is associated with customer ***c***
D_{date}	Variable indicating that the observation is for date ***d***
$\varepsilon_{c,d}$	Error term

3.2.4 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, the uncertainty-adjusted load impacts are based 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

[17] For CPP customers, the *Evt* variable indicates that a day is a CPP event day. For TOU customers who are also enrolled to receive PTR-RYU alerts, that variable indicates that a day is a PTR-RYU event day.

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 (in 2018) or by TOU pricing period (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), additional sets of regression models are estimated in which the load impact variable is constrained to be the same across the applicable hours (*e.g.*, an average event-hour CPP load impact is directly estimated). The associated standard errors are used to develop the uncertainty-adjusted load impacts in the same manner described above.

3.2.5 Validity assessment

Because a control-group approach is being employed, the 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). 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, are also reported. The MAPE offers a measure of accuracy while MPE offers a measure of bias.

4. 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), CPP (TOU-DR-P), and Grandfathered customers.

4.1 TOU control group matching results for TOU customers

Figures 4.1 and 4.2 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 1.2 percent, while the mean absolute percentage error (MAPE) is 1.7 percent. In the winter months, the MPE is 3.6 percent and the MAPE is 3.6 percent.[18]

[18] The MPE and MAPE statistics for the TOU matches are calculated over the two 24-hour load profiles, all days and hot/cold days.

Figure 4.1: TOU and Matched Control Group Load Profiles – *Summer*

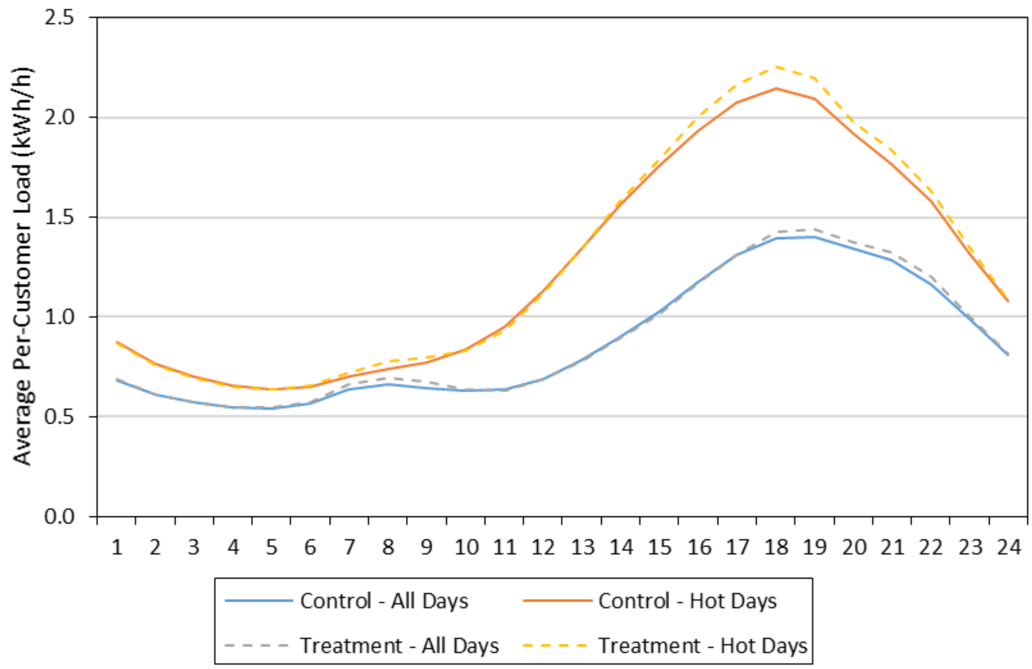
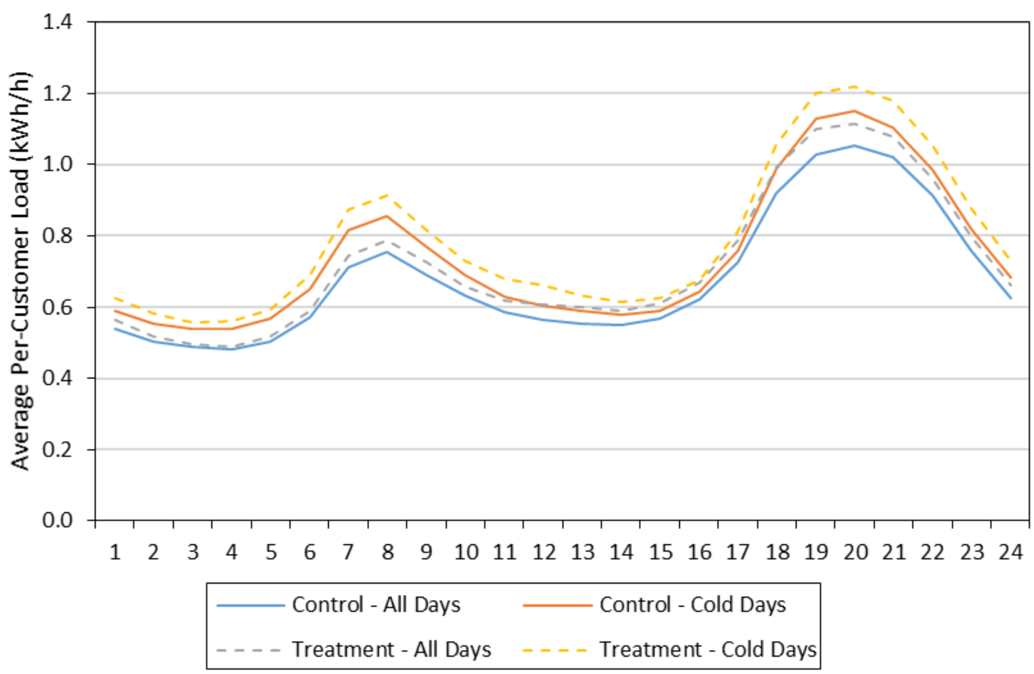


Figure 4.2: TOU and Matched Control Group Load Profiles – *Winter*



4.2 Ex-post TOU load impacts for TOU customers

This sub-section details *ex-post* TOU load impact estimates for those customers enrolled in the TOU (TOU-DR) rate. Table 4.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m.), 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 2018). The winter months are indicated by light blue shading. Enrollment additions continued throughout the period, with the numbers of enrolled customers rising from 3,150 in October 2018 to 6,720 in September 2019.[19] The estimation methodology for TOU non-NEM customers included applying seasonal (March and April as a separate season) percentage load impacts to monthly reference loads. Similarly, the seasonal *level* load impacts are used for NEM customers. Therefore, differences in percentage load impacts across seasons are driven by load impacts of NEM customers. The per-customer load impacts are relatively similar across all seasons. The largest per-customer load impact of 0.159 kWh/h occurs in March.

Table 4.1: 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)	Ave. Peak Temp.
Oct-18	All	3,150	3.09	0.43	0.98	0.14	69
Nov-18	All	3,472	4.06	0.42	1.17	0.12	62
Dec-18	All	3,544	4.95	0.45	1.40	0.13	55
Jan-19	All	3,650	4.50	0.46	1.23	0.13	55
Feb-19	All	3,762	4.49	0.48	1.19	0.13	52
Mar-19	All	3,992	2.90	0.64	0.73	0.16	58
Apr-19	All	4,436	2.28	0.68	0.51	0.15	64
May-19	All	4,872	2.20	0.56	0.45	0.12	63
Jun-19	All	5,321	2.87	0.75	0.54	0.14	69
Jul-19	All	5,836	5.12	0.85	0.88	0.15	76
Aug-19	All	6,277	7.03	0.93	1.12	0.15	77
Sep-19	All	6,720	8.01	0.98	1.19	0.15	74

[19] 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 773 incremental non-NEM customers on the TOU-DR rate with quality load data that were used in estimating the TOU load impacts. Many NEM customers could not be used in the analysis because they changed their NEM status at some point during the two-year study period. Specifically, only 57 NEM TOU customers are included in the regressions. The aggregate TOU load impacts are then scaled to total enrollments.

Table 4.2 shows results by season and climate zone. The summer load impacts are not starkly different between climate zones, though the average summer temperature differs by seven degrees. The winter load impacts differ more, with greater per-customer load impacts occurring in the inland climate zone.

Table 4.2: TOU Peak Load Impacts for TOU Customers – *Average Weekday by Season & Climate Zone*

Season	Climate Zone	Enrolled (Average)	Aggregate: Peak Ref. Load (MWh/h)	Aggregate: Peak Load Impact (MWh/h)	Per-Customer: Peak Ref. Load (kWh/h)	Per-Customer: Peak Load Impact (kWh/h)	Ave. Temp.
Summer	Coastal	2,725	2.35	0.34	0.86	0.12	70
	Inland	2,735	2.87	0.45	1.05	0.16	77
	All	**5,461**	**5.23**	**0.79**	**0.96**	**0.14**	**74**
Winter	Coastal	1,963	1.71	0.13	0.87	0.06	60
	Inland	1,998	1.89	0.37	0.94	0.19	58
	All	**3,961**	**3.60**	**0.50**	**0.91**	**0.13**	**59**

Table 4.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their energy consumption in all months, with an average daily decrease of 0.90 kWh.

Table 4.3: TOU Average *Daily* Load Impacts for TOU Customers, *by Month*

Month	Climate Zone	Enrolled	Aggregate: Daily Ref. Load (MWh/h)	Aggregate: Daily Load Impact (MWh/h)	Per-Customer: Daily Ref. Load (kWh/h)	Per-Customer: Daily Load Impact (kWh/h)	Ave. Daily Temp.
Oct-18	All	3,150	22.05	1.73	7.00	0.55	65
Nov-18	All	3,472	29.69	2.98	8.55	0.86	60
Dec-18	All	3,544	49.67	3.18	14.02	0.90	53
Jan-19	All	3,650	41.05	3.27	11.25	0.90	53
Feb-19	All	3,762	36.09	3.39	9.59	0.90	49
Mar-19	All	3,992	15.84	7.68	3.97	1.92	54
Apr-19	All	4,436	0.79	8.24	0.18	1.86	59
May-19	All	4,872	7.57	4.05	1.55	0.83	60
Jun-19	All	5,321	11.64	3.32	2.19	0.62	66
Jul-19	All	5,836	26.77	3.56	4.59	0.61	70
Aug-19	All	6,277	45.47	3.87	7.24	0.62	71
Sep-19	All	6,720	61.69	4.06	9.18	0.60	70

Figure 4.3 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 4.4 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a reduction in load during the peak hours as well as during a portion of the partial peak hours (*i.e.,* HE 7-16 and HE 22-24). The greatest decrease in usage occurs during the peak period, and there is not much evidence of load shifting to non-peak hours as represented by similar reference and observed loads during the super off-peak periods.

Figure 4.3: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers (*Average Weekday, August 2019*)

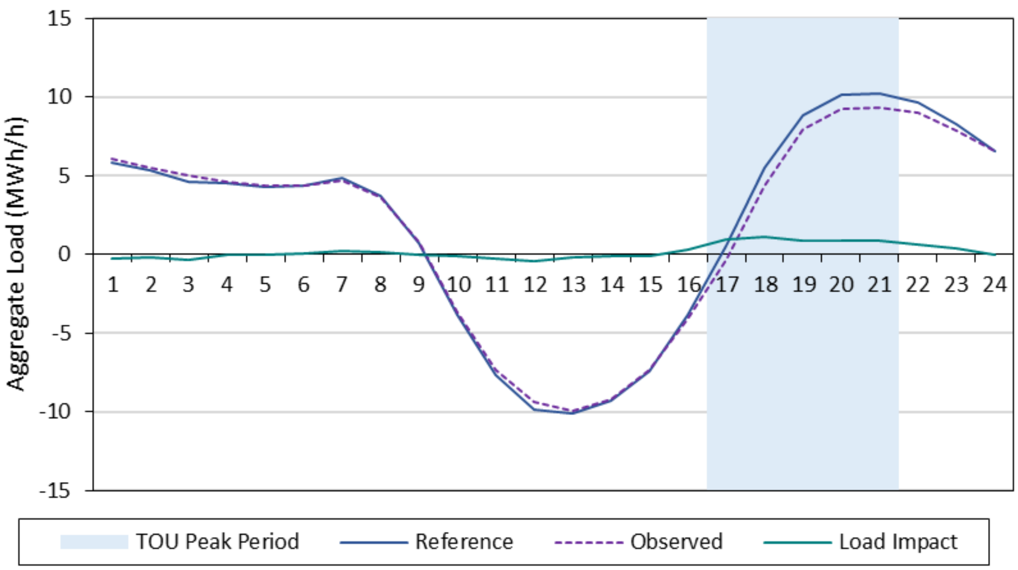
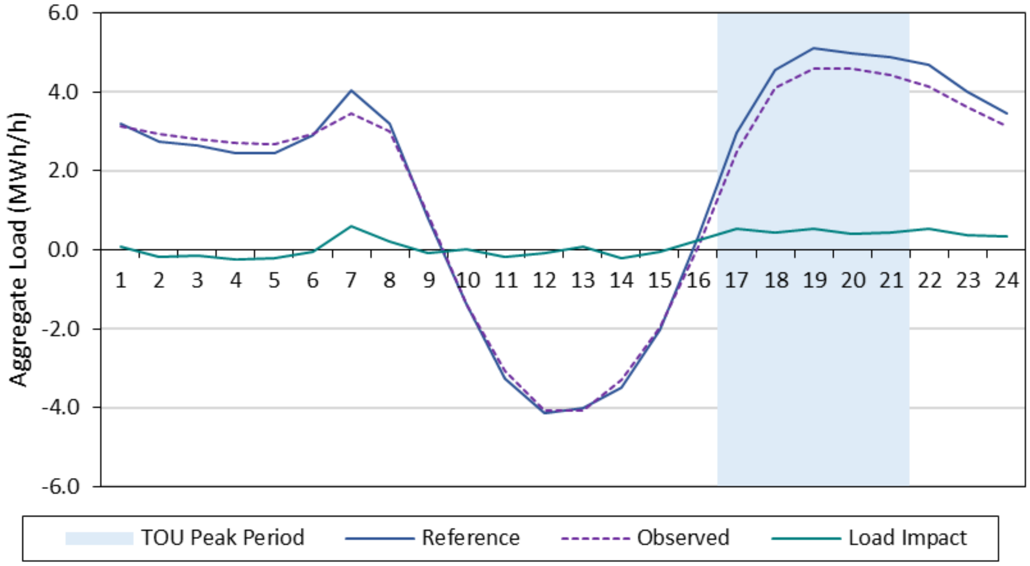


Figure 4.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers (*Average Weekday, January 2019*)



4.3 TOU control group matching results for CPP customers

Figures 4.5 and 4.6 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 2.5 percent, while the mean absolute percentage error (MAPE) is 3.1 percent. In the winter months, the MPE is 2.9 percent and the MAPE is 2.9 percent.

Figure 4.5: CPP and Matched Control Group Load Profiles – *Summer*

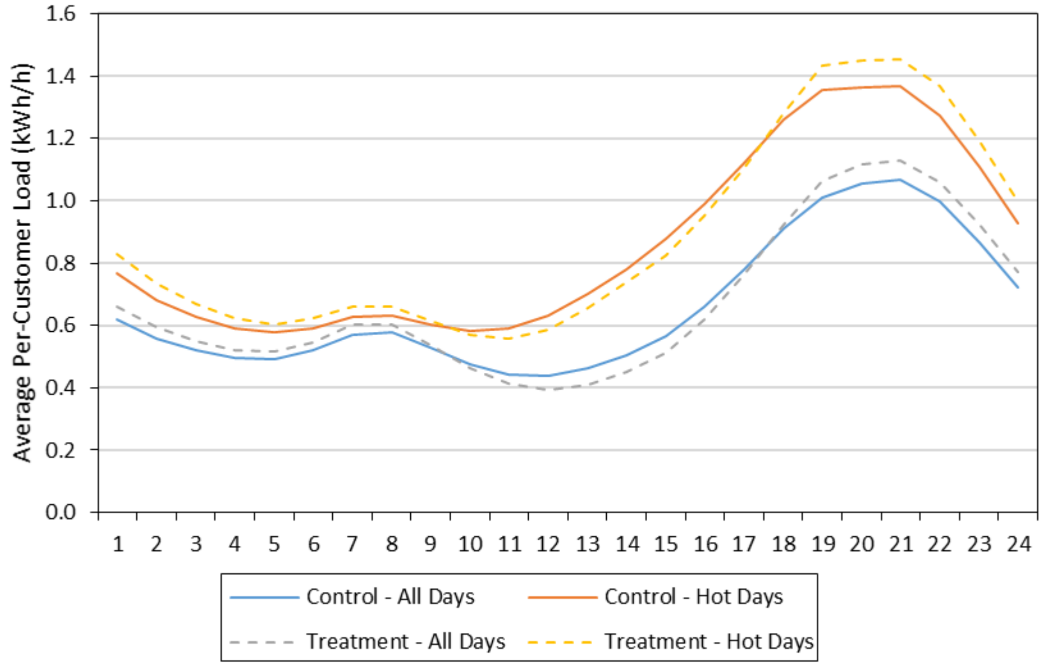
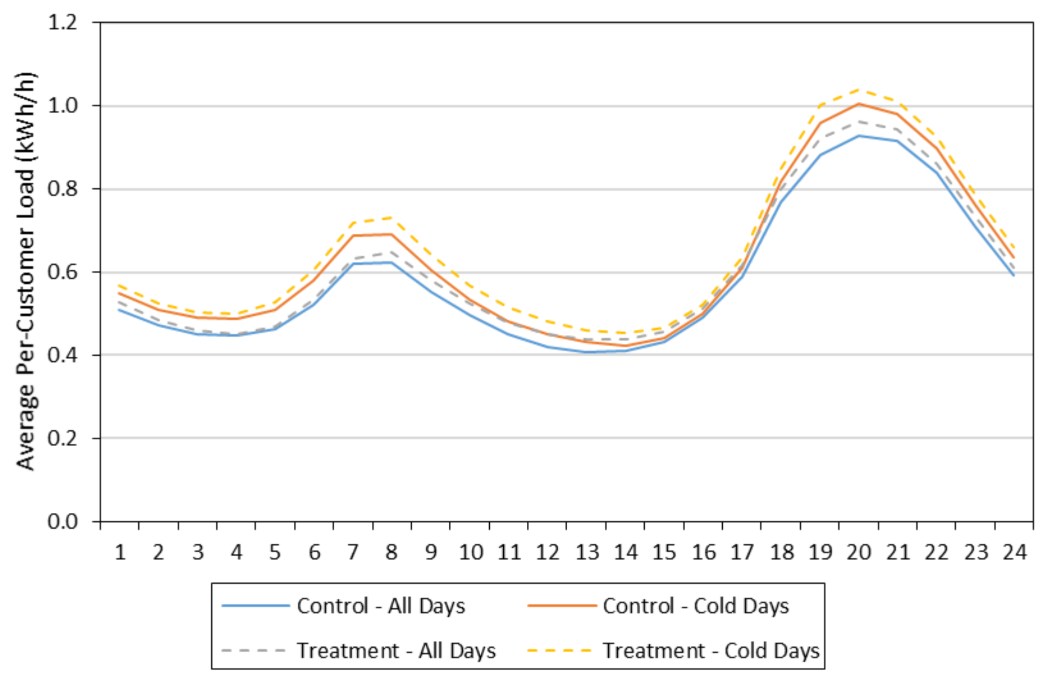


Figure 4.6: CPP and Matched Control Group Load Profiles – *Winter*



4.4 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, similar to TOU customers. This sub-section reports *ex-post* TOU load impact estimates for those customers enrolled on the CPP (TOU-DR-P) rate. Table 4.4 summarizes peak-period loads and load impacts for the average summer (October 2018, and June through September 2019) and winter (November 2018 through May 2019) weekdays, by month. Reported enrollment in CPP grew from 6,987 in October 2018 to shy of 14,000 in September 2019.[20] Peak load impacts appear similar across months, with small estimated load reductions in all months. The largest load reduction occurred in November.

Table 4.4: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Month*

Month	Climate Zone	Enrolled	Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	Ave. Temp.
Oct-18	All	6,987	6.81	0.33	0.97	0.05	69
Nov-18	All	7,199	7.28	0.42	1.01	0.06	62
Dec-18	All	7,414	8.65	0.41	1.17	0.05	55
Jan-19	All	7,769	8.14	0.35	1.05	0.04	56
Feb-19	All	8,161	8.45	0.20	1.04	0.03	52
Mar-19	All	8,834	7.27	0.31	0.82	0.03	58
Apr-19	All	10,061	7.37	0.40	0.73	0.04	64
May-19	All	11,104	7.54	0.43	0.68	0.04	63
Jun-19	All	11,945	7.88	0.34	0.66	0.03	69
Jul-19	All	12,702	10.89	0.68	0.86	0.05	74
Aug-19	All	13,417	12.79	0.68	0.95	0.05	76
Sep-19	All	13,917	13.56	0.69	0.97	0.05	74

Table 4.5 summarizes results by season and climate zone. Summer per-customer load impacts are more than twice as large in the Inland zone, which also experiences an average peak temperature seven degrees higher than the Coastal zone. Winter temperatures and load impacts are more similar.

[20] There were 5,337 incremental customers on the TOU-DR-P rate with quality load data that were used in the regressions for estimating the TOU load impact for CPP customers. The number of CPP customers included in the regressions is substantially smaller than the number that would be 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 would be required for measuring CPP load impacts.

Table 4.5: TOU Peak Load Impacts for CPP Customers – *Average Weekday by Season & Climate Zone*

Season	Climate Zone	Enrolled (Average)	Aggregate: Peak Ref. Load (MWh/h)	Aggregate: Peak Load Impact (MWh/h)	Per-Customer: Peak Ref. Load (kWh/h)	Per-Customer: Peak Load Impact (kWh/h)	Ave. Temp.
Summer	Coastal	7,075	5.70	0.19	0.81	0.03	70
	Inland	4,719	4.68	0.34	0.99	0.07	77
	All	**11,794**	**10.38**	**0.53**	**0.88**	**0.05**	**73**
Winter	Coastal	5,120	4.57	0.20	0.89	0.04	60
	Inland	3,529	3.24	0.16	0.92	0.05	58
	All	**8,649**	**7.81**	**0.36**	**0.90**	**0.04**	**59**

Table 4.6 shows the effect of TOU on average daily usage by month. CPP customers exhibit the highest daily usage during winter months, driven mostly by a smaller daytime NEM effect than the summer period. The overall effect is an average annual usage *increase* of about 0.5 percent.

Table 4.6: TOU Average *Daily* Load Impacts for CPP Customers, *by Month*

Month	Climate Zone	Enrolled	Aggregate: Daily Ref. Load (MWh/h)	Aggregate: Daily Load Impact (MWh/h)	Per-Customer: Daily Ref. Load (kWh/h)	Per-Customer: Daily Load Impact (kWh/h)	Ave. Daily Temp.
Oct-18	All	6,987	113.78	-1.86	16.28	-0.27	64
Nov-18	All	7,199	118.26	1.33	16.43	0.18	60
Dec-18	All	7,414	141.63	1.09	19.10	0.15	54
Jan-19	All	7,769	137.71	-0.15	17.73	-0.02	53
Feb-19	All	8,161	145.23	-1.94	17.80	-0.24	49
Mar-19	All	8,834	128.46	-0.77	14.54	-0.09	55
Apr-19	All	10,061	127.32	0.30	12.66	0.03	60
May-19	All	11,104	133.90	-0.46	12.06	-0.04	60
Jun-19	All	11,945	135.87	-2.25	11.37	-0.19	65
Jul-19	All	12,702	174.75	-1.19	13.76	-0.09	70
Aug-19	All	13,417	198.36	-2.25	14.78	-0.17	71
Sep-19	All	13,917	212.77	-1.55	15.29	-0.11	70

Figure 4.7 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 4.8 shows the same information for the average weekday in January. The average weekday in August loads illustrates a load shift out of the peak period to the super off-peak periods. The August and January average loads exhibit an increase in

usage during the overnight and morning hours, and a TOU effect that is highly concentrated around peak hours.

Figure 4.7: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers (*Average Weekday, August 2019*)

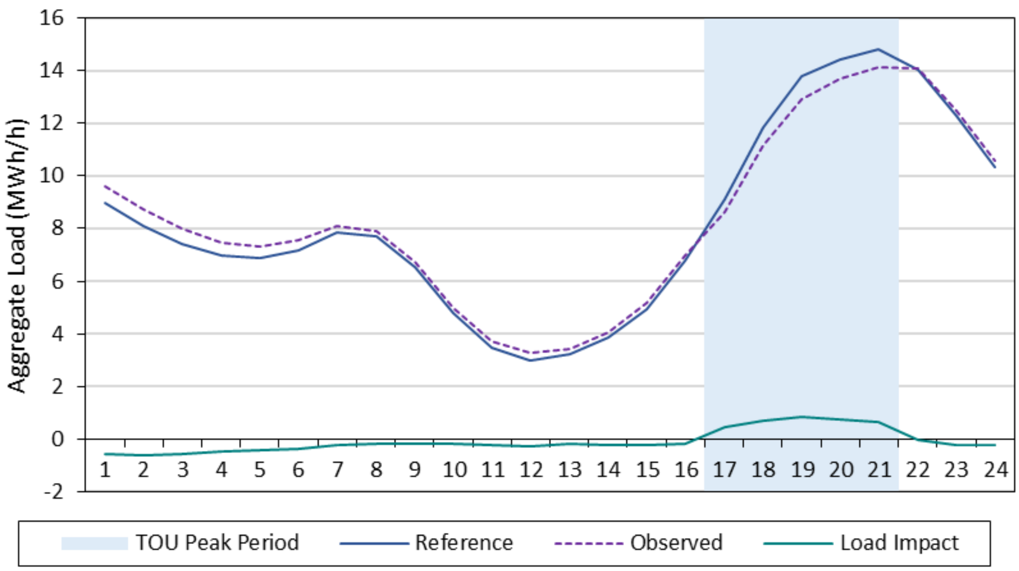
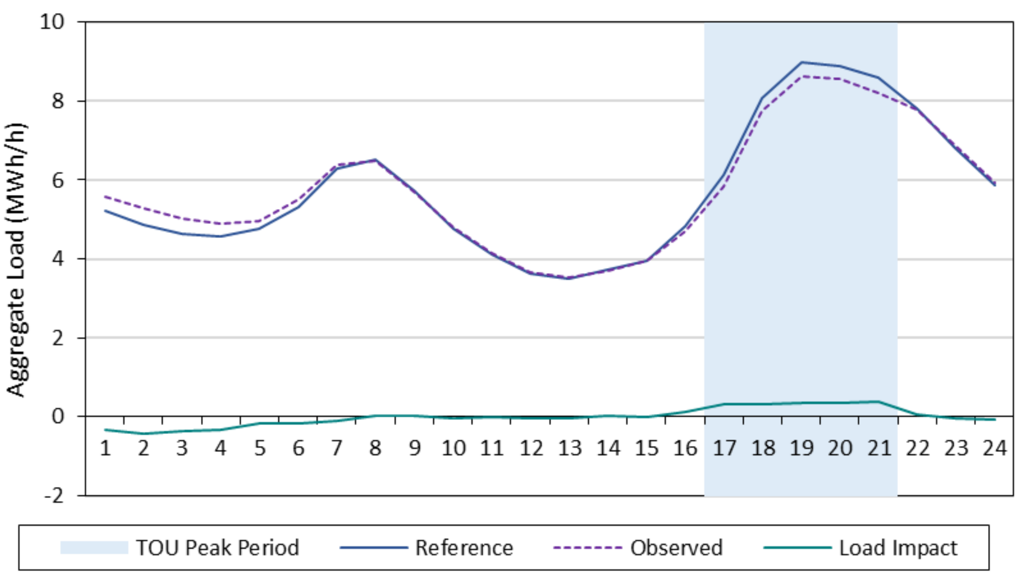


Figure 4.8: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers (*Average Weekday, January 2019*)



4.5 TOU control group matching results for Grandfathered customers

Figures 4.9 and 4.10 illustrate the quality of the matches for the Grandfathered customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average grandfathered 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 error (ME) of the TOU profile compared to the control-group profile is 0.10 kWh/h, while the mean absolute error (MAE) is 0.11 kWh/h. In the winter months, the ME is -0.002 kWh/h and the MAE is 0.04 kWh/h.

Figure 4.9: Grandfathered CPP and Matched Control Group Load Profiles – *Summer*

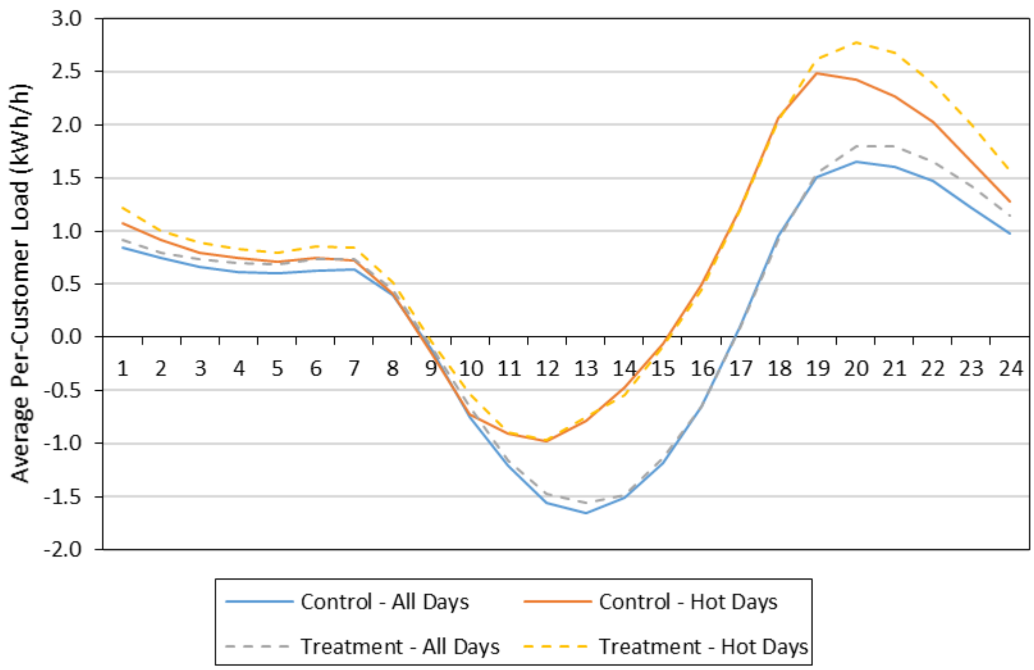
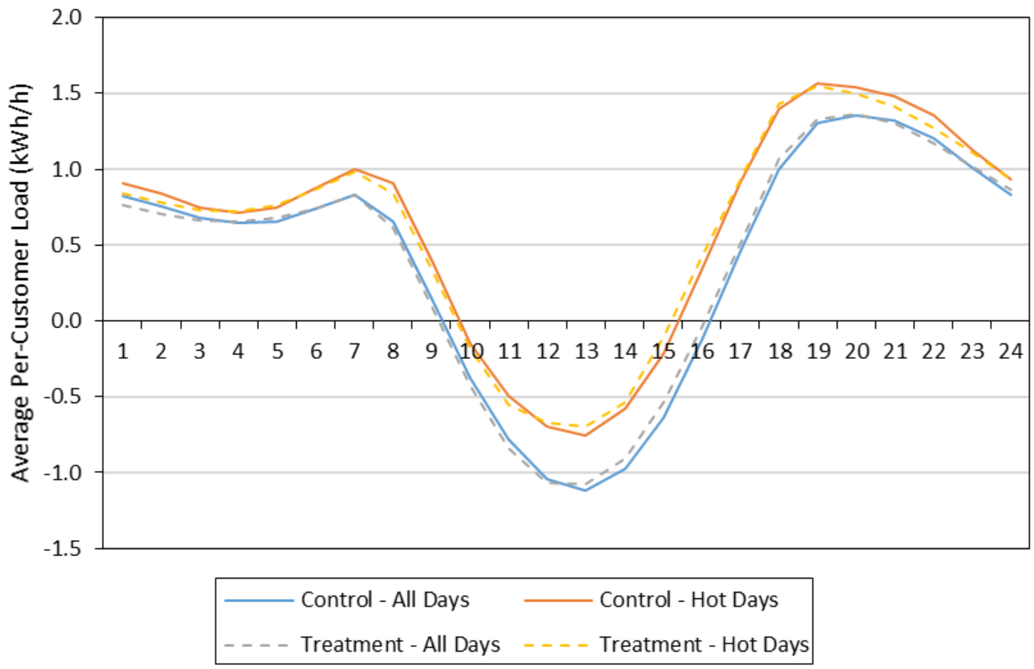


Figure 4.10: Grandfathered CPP and Matched Control Group Load Profiles – *Winter*



4.6 Ex-post TOU load impacts for Grandfathered customers

This sub-section shows *ex-post* TOU load impact estimates for Grandfathered customers. Table 4.7 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 11 a.m. to 6 p.m. during summer months, 5 to 8 p.m. during winter months), for the average weekday *by month*, on an aggregate and per-customer basis. The period covers October 2018 through November 2019 and the load impacts were estimated using customers that enrolled after October 2016; therefore, the pre-treatment period covers October 2015 through September 2016. The winter months are indicated by light blue shading.[21] Enrollments gradually increase throughout the period.[22] The per-customer load impacts remain constant by season because of the methodology implemented, resulting in per-customer load impacts of 0.22 kWh/h and -0.23 kWh/h for the summer and winter seasons, respectively. Positive reference loads during the winter and negative reference loads during the summer occur because of the different TOU peak periods, where the summer peak-period covers more of the day when customers are generating more than they are using.

[21] The summer and season month definitions differed during the PY2017 analysis. Specifically, May was categorized as a summer month, but is now included in the winter season period.

[22] 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 159 Grandfathered customers that were considered as incremental customers during the PY2017 analysis period. The aggregate TOU load impacts are then scaled to total enrollments during the PY2019 period.

Table 4.7: TOU Peak Load Impacts for Grandfathered Customers
– Average Weekday by Month

Month	Climate Zone	Enrolled	Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	Ave. Temp.
Oct-18	All	530	-0.27	0.12	-0.50	0.22	76
Nov-18	All	534	0.74	-0.12	1.39	-0.23	61
Dec-18	All	539	0.89	-0.13	1.65	-0.23	54
Jan-19	All	549	0.80	-0.13	1.45	-0.23	54
Feb-19	All	559	0.75	-0.13	1.34	-0.23	51
Mar-19	All	578	0.51	-0.13	0.89	-0.23	58
Apr-19	All	592	0.42	-0.14	0.70	-0.23	64
May-19	All	598	0.33	-0.14	0.55	-0.23	63
Jun-19	All	602	-0.61	0.13	-1.02	0.22	75
Jul-19	All	607	-0.50	0.13	-0.82	0.22	82
Aug-19	All	613	-0.28	0.14	-0.46	0.22	84
Sep-19	All	623	-0.07	0.14	-0.11	0.22	81

Table 4.8 summarizes results by season and climate zone. The coastal climate had a per-customer load impact of 0.40 kWh/h in the summer period and a 0.35 kWh/h *increase* in usage during the winter period, whereas the inland climate zone exhibited smaller TOU peak-period load impacts in the summer, with smaller increases in the winter.

Table 4.8: TOU Peak Load Impacts for Grandfathered Customers
– Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	285	-0.22	0.11	-0.76	0.40	74
	Inland	310	-0.14	0.03	-0.46	0.11	83
	All	**595**	**-0.36**	**0.15**	**-0.61**	**0.25**	**79**
Winter	Coastal	270	0.25	-0.09	0.92	-0.35	59
	Inland	294	0.37	-0.04	1.26	-0.15	57
	All	**564**	**0.62**	**-0.14**	**1.10**	**-0.24**	**58**

Table 4.9 shows the effect of TOU on average daily usage by month. Grandfathered customers *increased* overall usage during the summer months and *decreased* overall usage during the winter months. The winter load impacts exhibit a change in usage that is not accounted for in the regression model, which is best illustrated in the hourly load impacts.

Table 4.9: TOU Average *Daily* Load Impacts for Grandfathered Customers, *by Month*

Month	Climate Zone	Enrolled	Aggregate: Daily Ref. Load (MWh/h)	Aggregate: Daily Load Impact (MWh/h)	Per-Customer: Daily Ref. Load (kWh/h)	Per-Customer: Daily Load Impact (kWh/h)	Ave. Daily Temp.
Oct-18	All	530	5.43	0.27	10.25	0.51	65
Nov-18	All	534	4.24	-1.90	7.94	-3.55	60
Dec-18	All	539	8.34	-1.91	15.46	-3.55	53
Jan-19	All	549	5.99	-1.95	10.91	-3.55	52
Feb-19	All	559	4.23	-1.99	7.57	-3.55	49
Mar-19	All	578	0.07	-2.05	0.12	-3.55	54
Apr-19	All	592	-1.99	-2.10	-3.36	-3.55	59
May-19	All	598	-0.74	-2.12	-1.24	-3.55	60
Jun-19	All	602	3.77	0.31	6.27	0.51	66
Jul-19	All	607	5.14	0.31	8.47	0.51	70
Aug-19	All	613	7.75	0.31	12.64	0.51	71
Sep-19	All	623	10.39	0.32	16.68	0.51	70

Figures 4.11 and 4.12 show aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the Grandfathered customers for the average weekday in August and January, respectively. The TOU peak periods are represented by the hours with blue highlighting. The summer period appears to exhibit load shifting from the TOU peak period to off-peak hours. However, the winter load profile illustrates a larger response during the middle of the day, outside of the peak TOU period. As well, the winter load impacts exhibit an increase in usage over all hours of the day. This is likely a function of having a small sample size, which makes results more susceptible to outliers. Nevertheless, the shape of the winter load impact represents a shift in usage from the peak to off-peak period.

Figure 4.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (*Average Weekday, August 2019*)

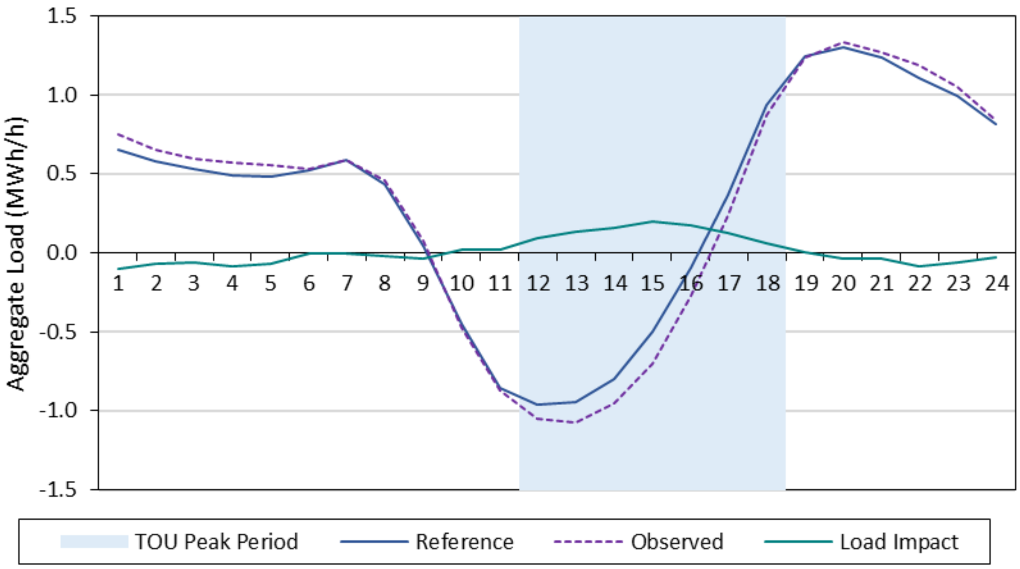
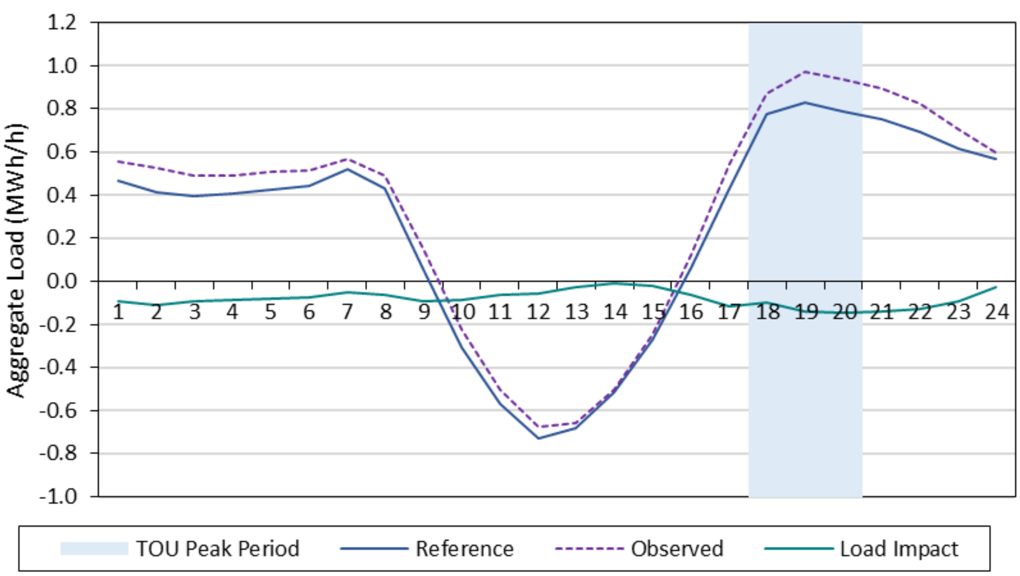


Figure 4.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (*Average Weekday, January 2019*)



5. *Ex-Ante* Load Impacts

This section describes the development of *ex-ante* load impact forecasts for the CPP and TOU rates (including Grandfathered TOU rates).

The first part of the section describes the methodologies used, followed by a presentation of 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. Since no CPP events took place in 2019, the *ex-ante* analysis for CPP events applies CPP event load impacts from PY2018 to reference loads calculated using PY2019 customer load data. 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.

5.1 Methodology

5.1.1 Per-customer load impacts

In cases where multiple events have been called in the historical period for event-based programs such as CPP, a relationship between the estimated event-day *ex-post* load impacts and the weather conditions is developed. That relationship is used to produce weather-sensitive *ex-ante* load impacts for the relevant weather scenarios. Although no CPP events occurred in 2019, SDG&E called six RYU/CPP events in 2018. Lacking more recent event load impacts, this study uses load impacts from the six events from the prior year as a basis for PY2019 *ex-ante* forecasts. The percentage load impact calculated in PY2018 is used for the average weekday event to simulate the *ex-ante* CPP load impact. CPP load impacts for different weather scenarios are developed by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads. Those reference loads are calculated using simulations derived from PY2019 data, since current customer load data exists even though no events occurred in 2019.

Portfolio-level load impacts are reported for instances when a CPP event is called on the same day as an AC Saver Day Of or TD event. For such days, it is assumed that AC Saver Day Of and TD customers do not provide a load impact that can be attributable to CPP; therefore, we remove dually enrolled customers from the reference load and load impacts for portfolio-level estimates. The proportion of AC Saver Day Of and TD 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 4 to 9 p.m., while the CPP events are called during the program hours of 2 to 6 p.m. year-round. Load impacts are simulated using the event hours that are indicated by the tariff, however the load impacts are summarized across the RA window as required.

For TOU load impacts (TOU-DR, TOU-DR-P, and Grandfathered customers), percentage peak load impacts from the *ex-post* analysis (monthly values for CPP and seasonal values for all else) are applied to weather-sensitive reference loads that are developed as described in the following sub-section.

NEM customer reference loads and load impacts are estimated separately from non-NEM customers. For both TOU and CPP load impacts, *ex-post* seasonal TOU load impacts and average CPP event-day load impacts are applied to reference loads and scaled to the count of enrolled customers. The proportion of NEM customers is assumed to remain constant throughout the forecast period. Non-NEM and NEM results are customer weighted to produce program TOU and CPP outcomes.

5.1.2 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 2018 through September 2019 for both the CPP and TOU customers. Customers are first sorted as weather sensitive or not.[23] 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, CDD65, HDD65, and HDH65)[24];
- 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 (monthly values for

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[23] 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:

$$Q_t = b^{Weather} \times Weather_t + \sum_{i=2}^{5}\left(b_i^{DTYPE} \times DTYPE_{i,t}\right) + \sum_{i=7}^{9}\left(b_i^{MONTH} \times MONTH_{i,t}\right) + \sum_{i=1}^{EVT}\left(b_i^{EVT} \times EVT_{i,t}\right) + e_t$$

, where Q_t represents the average customer usage during event hours on day t in the summer months of June through September. $DTYPE_{i,t}$ represents the day of week, while $MONTH_{i,t}$ represents each month. The $EVT_{i,t}$ variables control for any event days a customer faces (BIP, CPP, etc.). The variable of importance is $Weather_t$, 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 ($b^{Weather}$) is positive and statistically significant for any of the three separate weather specifications.

[24] Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree days (CDD) for day are defined as: CDD65 = max(0,((Day Maximum Temperature – Day Minimum Temperature in °F)/2) – 65). Likewise, heating degree days (HDD) for day are defined as: HDD65 = max(0,65 – ((Day Maximum Temperature – Day Minimum Temperature in °F)/2)). Heating degree hours (HDH) for each hour of the day are defined as: HDH65 =max(0, 65 – Temperature in °F).

CPP, and seasonal values for TOU and Grandfathered).[25] For NEM customers, reference loads are calculated by adjusting observed loads by the relevant seasonal *ex-post* level load impacts. The process for obtaining simulated reference and observed loads is completed separately for each reporting category.[26]

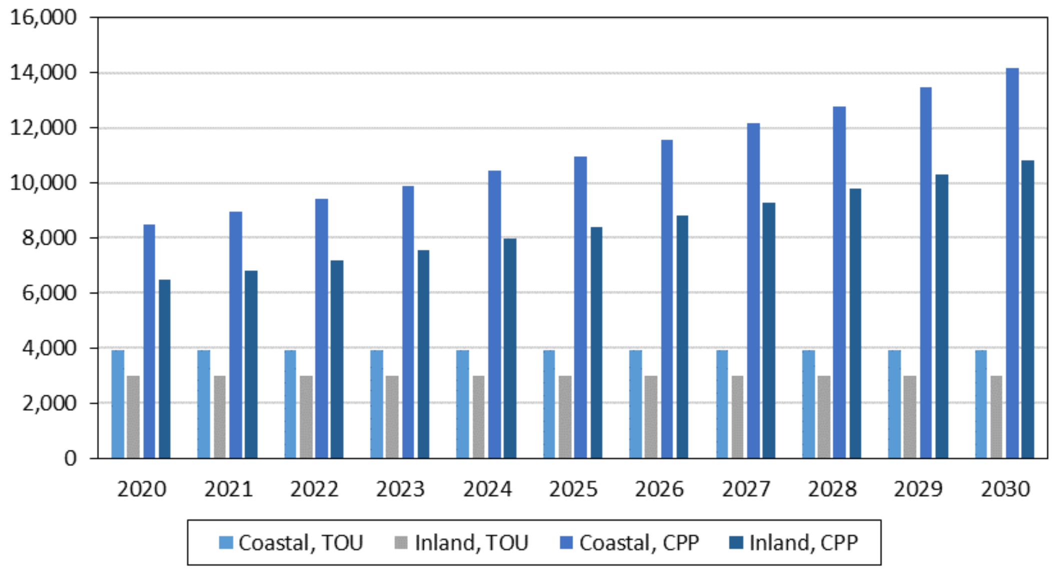
5.1.3 Enrollment forecast

Figure 5.1 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 double by the end of the forecast period. TOU enrollment is expected to be somewhat greater in the Coastal climate zone than in the Inland for both rates which is consistent with *ex-post*. Enrollment for Grandfathered customers is assumed to remain constant at 623 customers until the grandfathering term expires on July 31, 2027.

[25] The adjustment takes the form of Reference = Observed / (1 - %TOULoadImpact). CA Energy Consulting 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.

[26] The use of panel regressions limits results to only apply to the customer type included in the regressions, as opposed to customer-specific regressions for which sub-categories can created by combining pieces from the individual regressions. Therefore, any sub-categorization of results needs to be processed separately to account for possible differences in weather sensitivity and load profiles. For example, customers dually enrolled in CPP and TD have larger loads. Therefore, separate panel regressions including only dually enrolled CPP and TD customers would be estimated to simulate reference and observed loads for these customers.

Figure 5.1: Enrollments in TOU and CPP Rates



5.2 Ex-Ante load impacts – Residential CPP

This subsection summarizes the *ex-ante* load impact forecasts for future CPP event days, for all customers anticipated to be enrolled in CPP. Figure 5.2 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2021 for the SDG&E 1-in-2 weather scenario. The average event-period percentage load impact is 18 percent. Figure 5.3 illustrates the same details as Figure 5.2, but for the subset of CPP customers with TD. The aggregate CPP load impact for customers with TD is 0.32 MWh/h over the event-period.

Figure 5.2: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) –
***All CPP Customers*, (*August 2021 SDG&E 1-in-2 Peak Day*)**

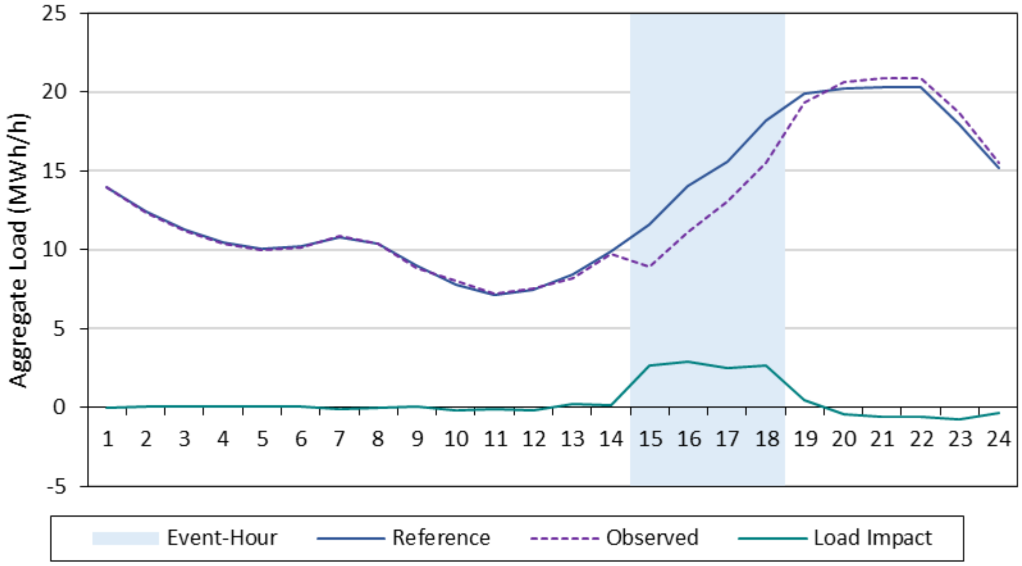


Figure 5.3: Aggregate Hourly Load and CPP Load Impacts (MWh/h) –
***CPP Customers with TD,* (*August 2021 SDG&E 1-in-2 Peak Day*)**

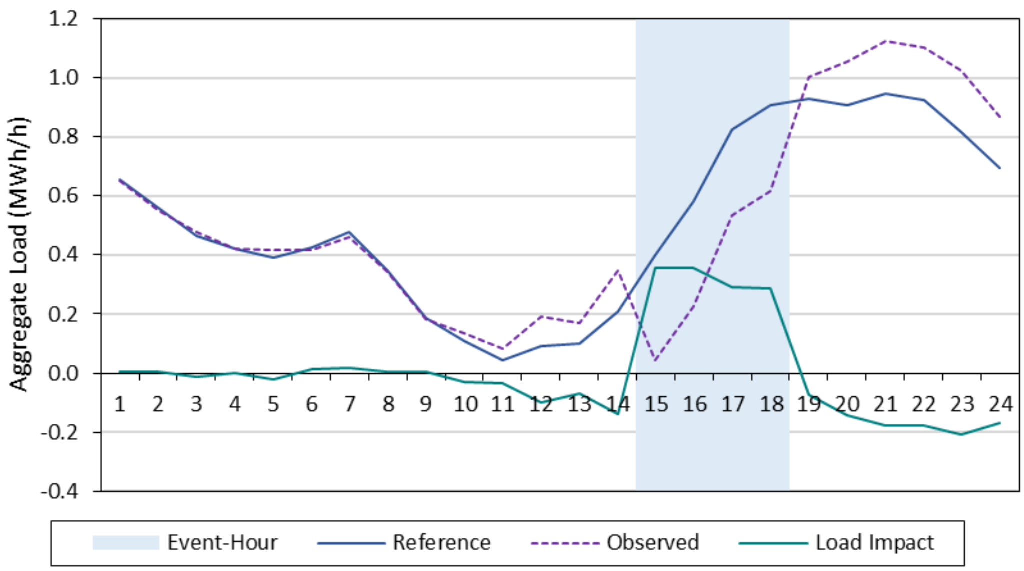


Figure 5.4 shows the monthly pattern of aggregate average *ex-ante* load impacts (RA window) in 2021 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in September. The difference in load impacts between months also indicates the seasonal pattern in customer reference loads.

Figure 5.4: Aggregate CPP Load Impacts (MWh/h), by Month –
***All CPP Customers*, (*2021 SDG&E 1-in-2 Peak Day, RA Window*)**

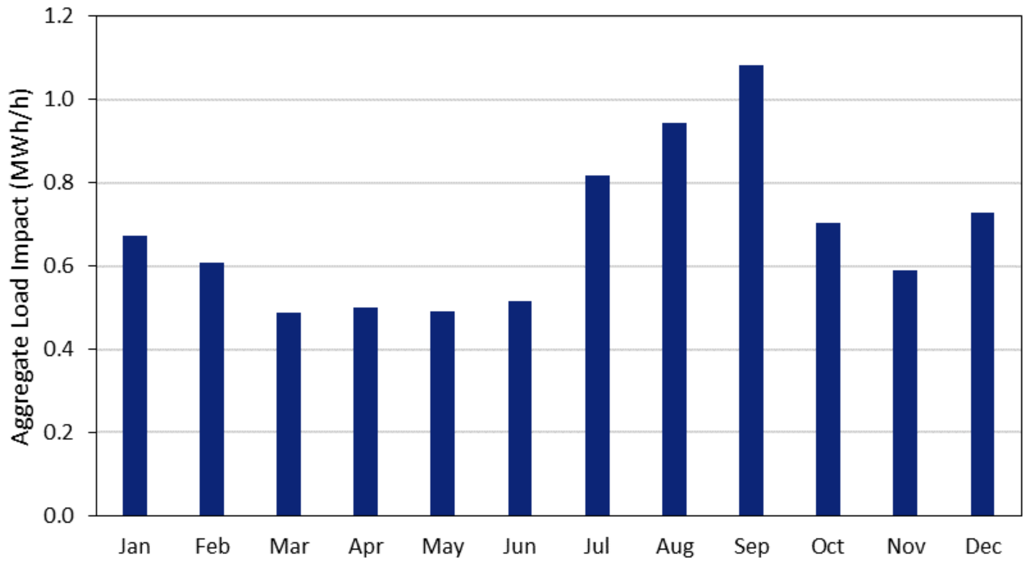
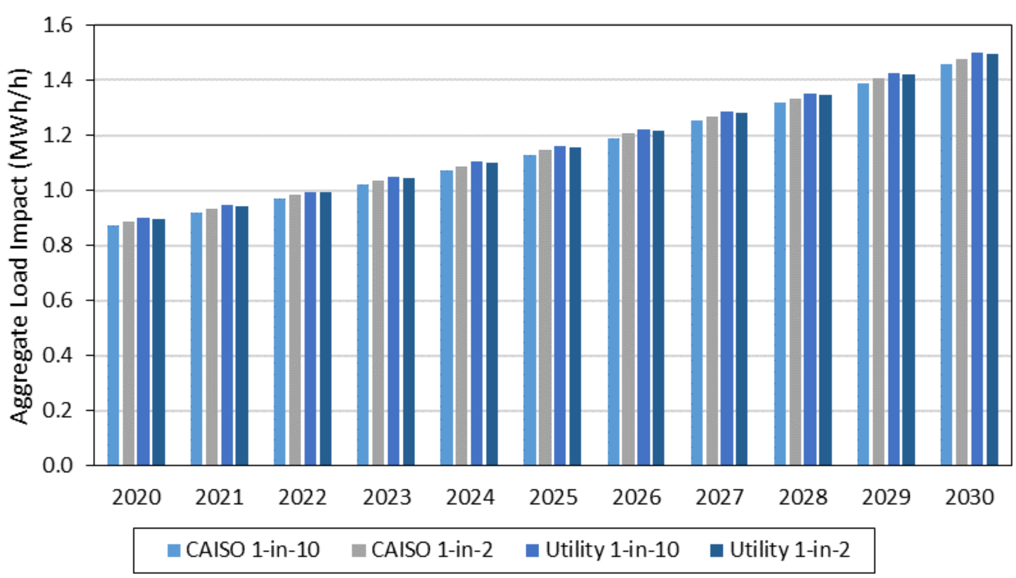


Figure 5.5 illustrates the growth in forecast CPP load impacts, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios over the forecast period. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

Figure 5.5: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario –
***All CPP Customers*, (*August Peak Day, RA Window*)**



5.3 Ex-Ante load impacts – Residential TOU

This subsection summarizes the *ex-ante* TOU peak load impact forecasts for customers anticipated to be enrolled in the TOU and CPP rates (TOU-DR and TOU-DR-P). *Ex-ante* TOU reference loads and load impacts are estimated separately for the TOU and CPP rates and subsequently scaled to their respective rate enrollment forecast. Afterwards, the separate rate outcomes are combined to provide customer weighted TOU results over both rates. Figure 5.6 shows aggregate loads and load impacts for TOU and CPP customers, in 2021 for an August SDG&E 1-in-2 average weekday. The average peak load impact is 8 percent of the reference load.

Figure 5.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – *TOU-DR and TOU-DR-P Customers,* (*August 2021 SDG&E 1-in-2 Average Weekday*)

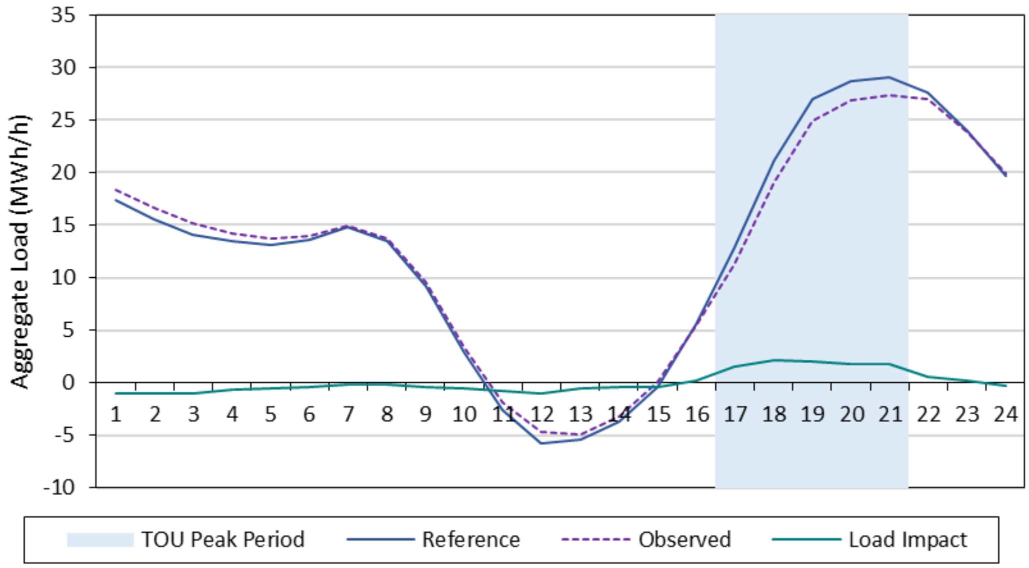


Figure 5.7 shows the monthly distributions of the peak-period TOU load impacts (TOU peak period aligns with the RA window) for TOU and CPP customers (not including Grandfathered or EVTOU customers). Load impacts are greatest in the summer months, particularly July, August, and September. Results for the winter months are somewhat smaller, with the smallest response in February. Higher peak load impacts are expected to occur during the summer months based on the higher peak-hour prices, relative to the standard non-TOU rate prices, of the summer rate schedule.

Figure 5.7: Aggregate TOU Load Impacts (MWh/h) by Month – *TOU-DR and TOU-DR-P Customers*, (*2021 SDG&E 1-in-2 Average Weekday,* RA Window)

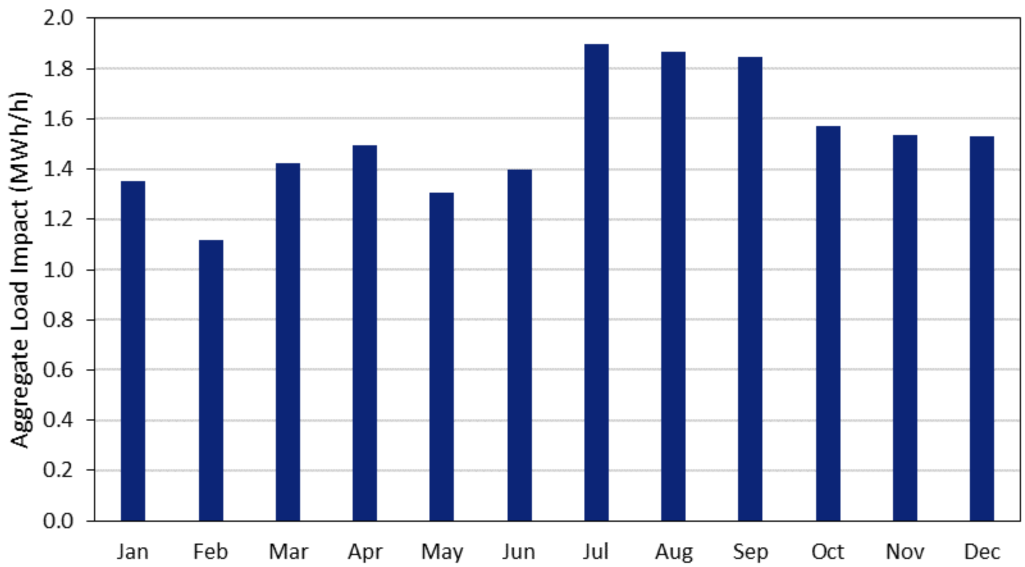
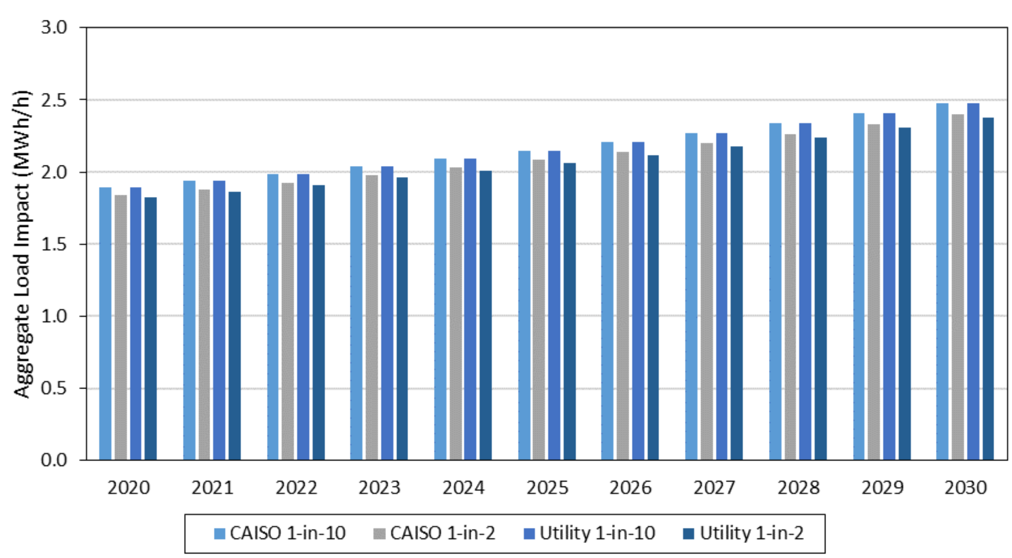


Figure 5.8 shows the aggregate average August weekday TOU load impacts over the forecast period, differentiated by weather scenario. The load impacts are largest for the CAISO and Utility 1-in-10 scenarios, which have equivalent temperatures for the average August weekday. (TOU load impacts are largest for the Utility 1-in-10 scenarios on monthly peak days.) The increase of enrollment numbers over time is greater for TOU-DR-P customers. Consequently, the *ex-ante* TOU load impact results reflect more of the *ex-post* TOU load impacts for TOU-DR-P customers has their relative proportion grows.

Figure 5.8: Aggregate TOU Load Impacts (MWh/h) – *TOU-DR and TOU-DR-P* Customers, by Year and Weather Scenario (*Average August Weekday, RA Window*)



5.4 Ex-Ante load impacts – Residential Grandfathered CPP

This subsection summarizes separately the *ex-ante* TOU and CPP load impact forecasts for Grandfathered customers. The enrollment forecast is assumed to remain constant at 623 customers, though some attrition is likely. Figure 5.9 shows monthly aggregate CPP loads and load impacts for Grandfathered customers, in 2021 for an August SDG&E 1-in-2 average weekday. The CPP load impact remains constant for all months because level load impacts from the *ex-post* analysis are applied to the number of customers within the program. Consequently, the load impacts also do not vary by weather scenario.[27] It is assumed that Grandfathered customers will have an aggregate CPP load impact of 0.018 MWh/h during the RA window. The aggregate CPP load impact forecast during the event window is 0.081 MWh/h.

Figure 5.9: Aggregate CPP Load Impacts (MWH/h) by Month– *Grandfathered Customers,* (*2021 SDG&E 1-in-2 Peak Day,* RA Window)

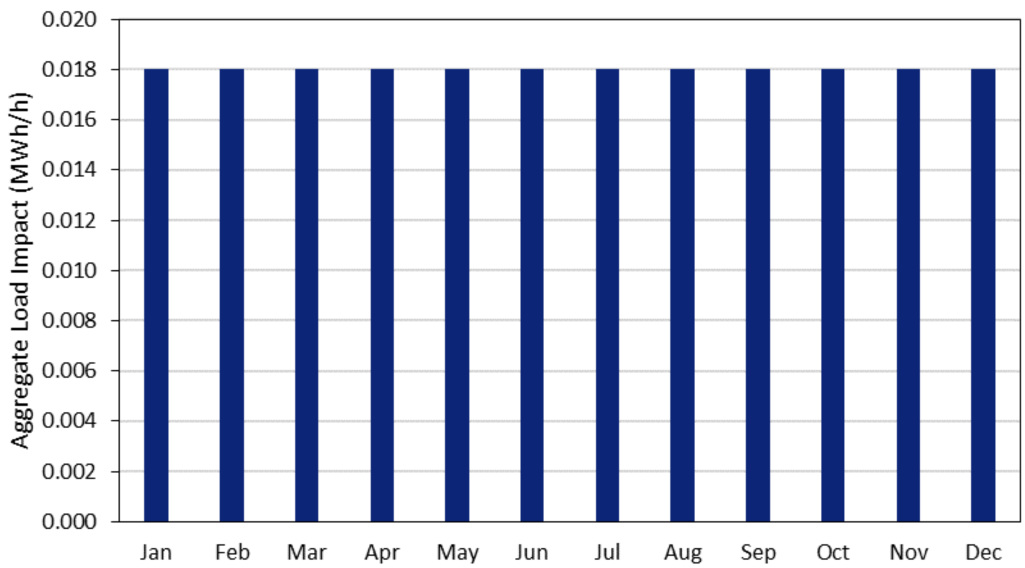
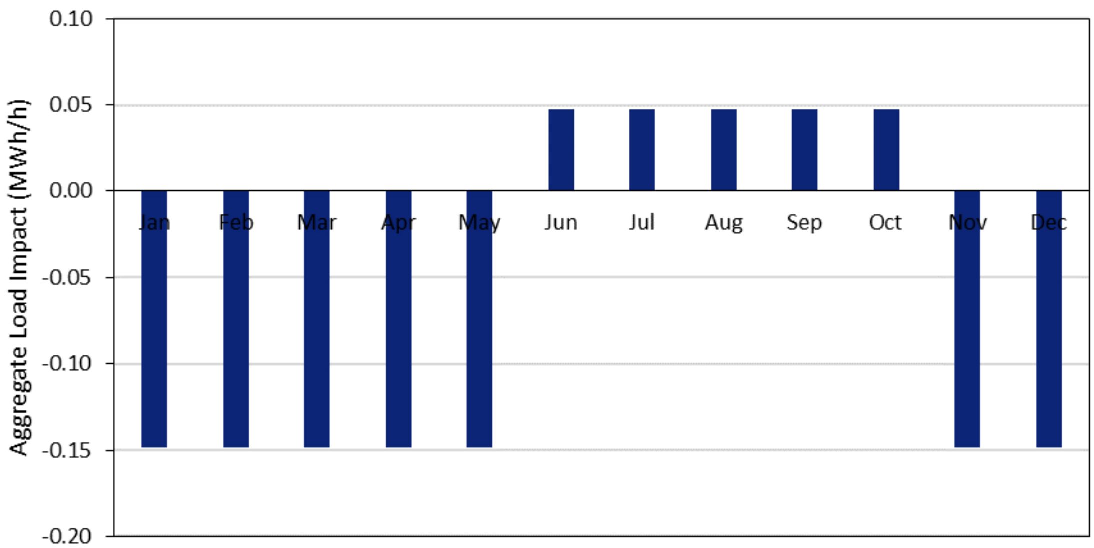


Figure 5.10 shows the monthly distributions of the peak-period TOU load impacts for Grandfathered customers. The Grandfathered TOU peak period does not coincide with the RA window. Load impacts are greatest in the summer months, June through October, at 0.05 MWh/h. Load impacts increase during the RA window in winter months. While load shifting does appear to exist during the winter months, the *ex-post* Grandfathered TOU load impacts exhibited an increase in usage over all hours. Results for the winter months are -0.15 MWH/h. Similar to the CPP load impact forecast for Grandfathered customers, the TOU load impact does not vary by weather scenario and

[27] CA Energy Consulting investigated the weather sensitivity of PY2018 CPP load impacts and determined that constant level load impacts provided a more accurate representation of forecast demand response for Grandfathered customers. This is due to a combination of the number of events and idiosyncratic patterns between events for the NEM customers lead to unexpected *a priori* results (*i.e.*, higher temperatures leading to smaller CPP load impacts).

year. Therefore, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2027.

Figure 5.10: Aggregate TOU Load Impacts (MWh/h) by Month – *Grandfathered Customers*, (*2021 SDG&E 1-in-2 Average Weekday,* RA Window)



6. Comparisons of Results

This section presents several comparisons of load impacts for SDG&E:

- *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 2019 program year; and "previous study" refers to the report that was developed following the 2018 program year.

6.1 Residential CPP

No CPP events were called in 2019; therefore, comparisons with the current study's *ex-post* do not exist. This section only includes comparisons for the previous versus current study *ex-ante* CPP load impacts.

6.1.1 Previous versus current *ex-ante*

In this sub-section, the *ex-ante* forecast prepared following PY2018 (the "previous study") are compared to the *ex-ante* forecast contained in this study (the "current study"). Table 6.1 reports the average event-hour load impacts for the August 2020 system peak day under utility-specific 1-in-2 weather conditions. The current study *ex-ante* forecast has slightly larger percentage load impacts, corresponding to slightly larger Utility 1-in-2 predicted temperatures. Per-customer reference loads are lower in the current study. The lower temperature in the current study causes a lower reference load; however, an increase in the proportion of NEM customers has also reduced the per-customer reference loads during event hours.

Table 6.1 Comparison of PY2018 *Ex-Ante* 2020 Forecast and Current *Ex-Ante* 2020 Forecast Load Impacts, *CPP Event*

Result	*Ex-ante for 2020 System Peak Day from PY2018 Study*	*Ex-ante for 2020 System Peak Day from PY2019 Study*
# Enrolled	8,736	14,990
Reference (MWh/h)	10.93	14.14
Load Impact (MWh/h)	1.72	2.56
Per-customer reference (kWh/h)	1.25	0.94
Per-customer load impact (kWh/h)	0.20	0.17
% Load Impact	16%	18%
Temperature	86.9	90.4

6.2 Residential TOU

6.2.1 Previous versus current *ex-post*

Table 6.2 shows the average reference loads and load impacts for the average August and January weekday during the current and previous program years, averaged over the RA window. While the summer percentage load impact appears similar between both years, the winter percentage load impact for the current study period appears significantly larger in PY2019. A potential cause for this difference is the default TOU marketing campaign that took place to increase customer awareness of TOU periods and prices since the previous study period. For instance, the TOU response in the current study exhibited decrease in usage that is highly concentrated around the peak hours. This year's study reflects a dramatic rise in NEM customers that have joined TOU rates since 2018. Enrollment numbers have increased resulting in higher aggregate reference loads.

Table 6.2 Comparison of PY2018 and PY2019 *Ex-Post* TOU Load Impacts

Season	Result	*Ex-post for 2018 Avg. Weekday from PY2018 Study*	*Ex-post for 2019 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	9,944	19,694
	Reference (MWh/h)	13.87	19.82
	Load Impact (MWh/h)	1.17	1.61
	Per-customer reference (kWh/h)	1.39	1.01
	Per-customer load impact (kWh/h)	0.12	0.08
	% Load Impact	8.5%	8.1%
	Temperature	78.9	76.5
Winter (January)	# Enrolled	6,097	11,419
	Reference (MWh/h)	5.61	12.64
	Load Impact (MWh/h)	0.06	0.81
	Per-customer reference (kWh/h)	0.92	1.11
	Per-customer load impact (kWh/h)	0.01	0.07
	% Load Impact	1.1%	6.4%
	Temperature	62.4	55.4

6.2.2 Previous versus current *ex-ante*

In this sub-section, the *ex-ante* forecast prepared following PY2018 (the “previous study”) are compared to the *ex-ante* forecast contained in this study (the “current study”). Table 6.3 reports the average RA-window load impacts for the August and January 2020 average weekday under utility-specific 1-in-2 weather conditions. The TOU peak-period and RA-window both remain the same in each forecast. The aggregate load impact forecasted in the current analysis is approximately 7 MWh/h larger than the forecast from the previous study, largely because of an increase in the number of enrolled customers. However, the per-customer load impacts are similar across studies during the summer period. During the winter period, the forecasted per-customer load impact is an order of magnitude higher in the current period. As mentioned previously, this may be a result of the increased marketing to inform customers of TOU periods. Another significant difference between studies is a vast increase in the number of NEM customers in the analysis.

Table 6.3 Comparison of PY2018 *Ex-Ante* 2020 Forecast and PY2019 *Ex-Ante* 2020 Forecast TOU Load Impacts

Season	Result	*Ex-ante for 2020 Avg. Weekday from PY2018 Study*	*Ex-ante for 2020 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	12,511	21,879
	Reference (MWh/h)	16.04	22.95
	Load Impact (MWh/h)	1.41	1.82
	Per-customer reference (kWh/h)	1.28	1.05
	Per-customer load impact (kWh/h)	0.11	0.08
	% Load Impact	8.8%	7.9%
	Temperature	76.6	77.3
Winter (January)	# Enrolled	12,511	21,879
	Reference (MWh/h)	12.46	21.67
	Load Impact (MWh/h)	0.04	1.32
	Per-customer reference (kWh/h)	1.00	0.99
	Per-customer load impact (kWh/h)	0.00	0.06
	% Load Impact	0.3%	6.1%
	Temperature	61.0	59.2

6.2.3 Previous *ex-ante* versus current *ex-post*

Table 6.4 provides a comparison of the *ex-ante* forecast of 2019 TOU load impacts prepared following PY2018 and the PY2019 *ex-post* TOU load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August and January average weekday during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on August and January weekdays. Increased enrollments lead to larger aggregate load impacts and reference loads. Even though the enrollments for January were slightly lower than the PY2018 forecast, the aggregate PY2019 *ex-post* reference loads were larger than predicted in the previous analysis thanks to a larger per-customer reference load in the winter months (partially caused by colder temperatures). The per-customer reference loads and load impacts were slightly smaller than forecasted during the summer months, though the average temperatures were nearly the same.

Table 6.4 Comparison of PY2018 *Ex-Ante* 2019 Forecast and PY2019 *Ex-Post* TOU Load Impacts

Season	Result	*Ex-ante for 2019 Avg. Weekday from PY2018 Study*	*Ex-post for 2019 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	12,305	19,694
	Reference (MWh/h)	15.79	19.82
	Load Impact (MWh/h)	1.39	1.61
	Per-customer reference (kWh/h)	1.28	1.01
	Per-customer load impact (kWh/h)	0.11	0.08
	% Load Impact	9%	8%
	Temperature	76.6	76.5
Winter (January)	# Enrolled	12,305	11,419
	Reference (MWh/h)	12.26	12.64
	Load Impact (MWh/h)	0.04	0.81
	Per-customer reference (kWh/h)	1.00	1.11
	Per-customer load impact (kWh/h)	0.00	0.07
	% Load Impact	0.3%	6.4%
	Temperature	61.0	55.4

7.2.4 Current *ex-post* versus current *ex-ante*

Table 6.5 compares the PY2019 *ex-post* TOU load impacts for the January and August average weekday with the corresponding *ex-ante* forecast for 2020 (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. The *ex-ante* load impacts are based upon *ex-post* percentage load impacts for each TOU period. Differences in percentage load impacts between *ex-post* and *ex-ante* occur because of changes in customer composition. The proportion of NEM customers grew slightly from January 2019 to September 2019. The *ex-ante* forecast assumes the same proportion of NEM customers recorded in the last month. Therefore, a greater proportion of NEM customers affect the January *ex-ante* load impacts, and NEM customers exhibited lower winter TOU load impacts.

Table 6.5: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts

Season	Result	*Ex-post for 2019 Avg. Weekday from PY2019 Study*	*Ex-ante for 2020 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	19,694	21,879
	Reference (MWh/h)	19.82	22.95
	Load Impact (MWh/h)	1.61	1.82
	Per-customer reference (kWh/h)	1.01	1.05
	Per-customer load impact (kWh/h)	0.08	0.08
	% Load Impact	8.1%	7.9%
	Temperature	76.5	82.3
Winter (January)	# Enrolled	11,419	21,879
	Reference (MWh/h)	12.64	21.67
	Load Impact (MWh/h)	0.81	1.32
	Per-customer reference (kWh/h)	1.11	0.99
	Per-customer load impact (kWh/h)	0.07	0.06
	% Load Impact	6.4%	6.1%
	Temperature	55.4	59.2

6.3 Grandfathered Customers

This section compares CPP and TOU load impacts for Grandfathered customers. No CPP events were called in 2019; consequently, the only comparison of results for the CPP load impacts is the previous versus current study *ex-ante* forecasts.

6.3.1 Previous versus current *ex-ante, CPP load impacts*

In this sub-section, the *ex-ante* forecast prepared following PY2018 (the "previous study") are compared to the *ex-ante* forecast contained in this study (the "current study"). Table 6.6 reports the average event-hour load impacts for the August 2020 system peak day under utility-specific 1-in-2 weather conditions. Both studies apply load impacts from the same *ex-post* CPP events from 2018. However, due to temperature increases in the utility-1-in-2 weather conditions, and also due to enrollment changes, the aggregate load impacts differ between studies. Lower enrollment in the current study causes a lower aggregate reference load; however, lower per-customer reference loads also exist because of a change in the composition of customers that persist. For instance, the customers that remain export more load onto the system.

Table 6.6: Comparison of Previous and Current *Ex-Ante* CPP Load Impacts for Grandfathered Customers

Result	*Ex-ante* for 2020 Peak Day from PY2018 Study	*Ex-ante* for 2020 Peak Day from PY2019 Study
# Enrolled	418	331
Reference (MWh/h)	0.42	0.18
Load Impact (MWh/h)	0.10	0.08
Per-customer reference (kWh/h)	1.00	0.53
Per-customer load impact (kWh/h)	0.25	0.25
Temperature	88.1	92.0

6.3.2 Previous versus current *ex-post, TOU load impacts*

Table 6.7 shows the average reference loads and load impacts for the average August and January weekday during the current and previous program years, averaged over the RA window. While the summer load impact appears similar between both years, the winter load impact for the current study period deviates from the previous analysis. Specifically, the results show an *increase* in usage during the winter peak period for PY2019. As described previously, the winter load impacts appear to be affected by unobserved factors, as is exhibited by an increase in usage across all hours even though the load impact shape suggests load shifting from peak to off-peak periods. Enrollment numbers have also increased, resulting in higher aggregate reference loads.

Table 6.7: Comparison of Previous and Current *Ex-Post* TOU Load Impacts for Grandfathered Customers

Season	Result	*Ex-post for 2018 Avg. Weekday from PY2018 Study*	*Ex-post for 2019 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	430	613
	Reference (MWh/h)	0.85	1.02
	Load Impact (MWh/h)	0.02	0.03
	Per-customer reference (kWh/h)	1.98	1.66
	Per-customer load impact (kWh/h)	0.04	0.04
	Temperature	79.4	78.1
Winter (January)	# Enrolled	469	549
	Reference (MWh/h)	0.66	0.72
	Load Impact (MWh/h)	0.01	-0.13
	Per-customer reference (kWh/h)	1.41	1.30
	Per-customer load impact (kWh/h)	0.03	-0.23
	Temperature	62.1	54.4

6.3.3 Previous versus current *ex-ante, TOU load impacts*

In this sub-section, the *ex-ante* forecast prepared following PY2018 (the "previous study") are compared to the *ex-ante* forecast contained in this study (the "current study") for Grandfathered customers. Table 6.8 reports the average RA-window load impacts for the August and January 2020 average weekday under utility-specific 1-in-2 weather conditions. The TOU peak-period and RA-window both remain the same in each forecast. The aggregate load impact in August forecasted in the current analysis is approximately 0.04 MWh/h larger than the forecast from the previous study, in part because of an increase in the number of enrolled customers. However, the per-customer load impacts are also larger across studies during the summer period. During the winter period, customers are forecasted to *increase* usage during the RA window, while last year's forecast estimated a 0.02 kWh/h load impact. This could be due to an increased marketing campaign that improves customer awareness of TOU periods.

Table 6.8: Comparison of Previous and Current *Ex-Ante* TOU Load Impacts for Grandfathered Customers

Season	Result	*Ex-Ante for 2020 Avg. Weekday from PY2018 Study*	*Ex-Ante for 2020 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	418	623
	Reference (MWh/h)	0.71	0.94
	Load Impact (MWh/h)	0.01	0.05
	Per-customer reference (kWh/h)	1.70	1.51
	Per-customer load impact (kWh/h)	0.03	0.08
	Temperature	77.2	78.0
Winter (January)	# Enrolled	418	623
	Reference (MWh/h)	0.58	0.68
	Load Impact (MWh/h)	0.01	-0.15
	Per-customer reference (kWh/h)	1.40	1.09
	Per-customer load impact (kWh/h)	0.02	-0.24
	Temperature	60.9	59.0

6.3.4 Previous *ex-ante* versus current *ex-post, TOU load impacts*

Table 6.9 provides a comparison of the *ex-ante* forecast of 2019 Grandfathered TOU load impacts prepared following PY2018 and the PY2019 *ex-post* TOU load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August and January average weekday during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on August and January weekdays. Slightly increased enrollments lead to larger aggregate load impacts in the summer and larger reference loads in both periods. The summer per-customer loads impacts are similar between the previous study *ex-ante* forecast and the current *ex-post* load impacts. The winter load impacts indicate *increased* usage, opposite of the previous forecast. The winter results, again, suggest that there are unaccounted for factors contributing to the change in usage.

Table 6.9: Comparison of Previous *Ex-Ante* and Current *Ex-Post* TOU Load Impacts for Grandfathered Customers

Season	Result	*Ex-Ante for 2019 Avg. Weekday from PY2018 Study*	*Ex-post for 2019 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	418	613
	Reference (MWh/h)	0.71	1.02
	Load Impact (MWh/h)	0.01	0.03
	Per-customer reference (kWh/h)	1.70	1.66
	Per-customer load impact (kWh/h)	0.03	0.04
	Temperature	77.2	78.1
Winter (January)	# Enrolled	418	549
	Reference (MWh/h)	0.58	0.72
	Load Impact (MWh/h)	0.01	-0.13
	Per-customer reference (kWh/h)	1.40	1.30
	Per-customer load impact (kWh/h)	0.02	-0.23
	Temperature	60.9	54.4

6.3.5 Current *ex-post* versus current *ex-ante, TOU load impacts*

Table 6.10 compares the Grandfathered customers' PY2019 *ex-post* TOU load impacts for the January and August average weekday with the corresponding *ex-ante* forecast for 2020 (of the SDG&E 1-in-2 August or January average weekday) produced in this study. The Grandfathered customers' TOU load impacts are presented for all Grandfathered customers and are averaged over the RA window. Differences between *ex-post* and *ex-ante* load impacts stem from changes in the number of customers within climate zones. There is a slight increase in the *ex-ante* enrollment numbers as a few more customers had switched to the Grandfathered rate towards the end of the program year.

Table 6.10: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts for Grandfathered Customers

Season	Result	*Ex-post for 2019 Avg. Weekday from PY2019 Study*	*Ex-ante for 2020 Avg. Weekday from PY2019 Study*
Summer (August)	# Enrolled	613	623
	Reference (MWh/h)	1.02	0.94
	Load Impact (MWh/h)	0.03	0.05
	Per-customer reference (kWh/h)	1.66	1.51
	Per-customer load impact (kWh/h)	0.04	0.08
	Temperature	78.1	78.0
Winter (January)	# Enrolled	549	623
	Reference (MWh/h)	0.72	0.68
	Load Impact (MWh/h)	-0.13	-0.15
	Per-customer reference (kWh/h)	1.30	1.09
	Per-customer load impact (kWh/h)	-0.23	-0.24
	Temperature	54.4	59.0

7. Recommendations

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

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-Ante* Load Impact Tables

Appendix C: NEM Customer Restrictions

NEM customers may introduce bias into the load impact estimates if changes occur to their solar PV generation that is not accounted for. CA Energy Consulting attempts to reduce this by 1) including only NEM customers that are NEM for the entire analysis period, 2) matching NEM customers to other NEM customer with similar size solar PV generation, and 3) removing customers that have large changes in usage between periods. To identify what constitutes a large change in usage and its possible effect on load impact estimates, a difference-in-difference of raw load profiles was calculated for different threshold restrictions (for each rate and season). Customers that have average usage (HE 12-18) differences, in absolute value, between periods below the threshold meet the requirement and are kept in the analysis.

Figure C.1 illustrates the difference-in-difference load profile based upon raw averages from TOU customer load profiles that meet specific thresholds over the summer period. For example, the line corresponding to a threshold of 4 indicates that customers with a change in usage between periods less than 4 kWh/h are kept in the analysis. The figure illustrates that there is not much difference between thresholds, which is to be expected because customers that made changes to their PV system were removed from the analysis prior to this additional restriction. In the PY2018 analysis, there wasn't sufficient information to remove customers that made changes to their PV system during the analysis period, which resulted in greater differences between the thresholds.

Figure C.1: Summer Period Difference-in-Difference for TOU Customers (TOU-DR)