



**2022 Load Impact Evaluation of Voluntary
Residential Critical Peak Pricing (CPP) and Time-of-
Use (TOU) Rates
for
San Diego Gas & Electric**

CALMAC Study ID SDG0345

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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 2022, along with their grandfathered counterparts. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015.

Both summer and winter TOU periods in the two 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. During the months of March and April, a super off-peak period is carved into the off-peak period between 10 a.m. and 2 p.m. Weekend and holiday hours are all off-peak. The analysis includes Net Energy Metered ("NEM") customers. These customers were estimated separately but included in the results for each rate using a customer-weighted average. The protocol tables contain separate results for NEM and Non-NEM customers, along with combined results of all customers regardless of NEM status.

The analysis also evaluates load impacts for TOU-DR-P customers on a "grandfathered" rate, which maintains the time of use period before it was changed in December 2017. The "grandfathered" summer TOU periods in the two rates are centered around an on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak. No additional customers may be added to the grandfathered rate after its inception, and all grandfathered customers transitioned to non-grandfathered rates beginning August 1, 2022.

Residential CPP events may be called during the 4 p.m. to 9 p.m. period on any day (including weekends) throughout the year. As of June 1, 2022, the CPP event window now coincides with the RA window of 4 to 9 p.m. period. In 2022, SDG&E called five CPP events. These events took place on September 3, 4, 5, 6, and 7.

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, NEM, CARE status), based on the closest match of load profiles.

In 2022, the ex-post CPP average weekday event load impacts indicate that, on average, customers reduced their usage by 0.12 kWh/h for customers in the Coastal climate zone and 0.17 kWh/h for the Inland climate zone. CPP enrollment averaged 15,862 customers on the weekday event days, with a nearly even split between climate zones. The aggregate reference load was 30.29 MWh/h for all climate zones.

TOU enrollment rose from 13,830 customers in October 2021 to 27,722 in September 2022. Per-customer seasonal load impacts were about 0.03 kWh/h in summer and about 0.05 kWh/h in

winter. Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers *increased* their energy consumption by an annual average of approximately 0.91 kWh/h.

Similarly, we evaluated the TOU load impacts for CPP customers. Enrollment in CPP declined from 22,405 in October 2021 to approximately 15,868 in September 2022. Customers shifted from TOU-DR-P to TOU-DR by enrolling in a CCA between April 2022 and June 2022. This caused a decline in CPP customers. CPP customers reduced peak hour usage by about 0.10 kWh/h during the summer months and 0.02 kWh/h during the winter months. Inland TOU and CPP customers displayed a similar trend of having higher summer load impacts than winter load impacts. However, the Coastal CPP customers had higher summer load impacts than winter, while the Coastal TOU customers had the inverse relation. The overall daily effect for CPP customers was an average annual *increase* of 0.15 kWh/h per-customer.

Among grandfathered customers, average enrollment in winter was 393 customers while average summer enrollment was 389 customers. Grandfathered customers exhibited a per-customer load *increase* of 0.99 kWh/h for the winter season and 0.38 kWh/h for the summer season during the TOU peak period. The overall effect of *daily* usage is an average annual *increase* of 9.95 kWh/h per customer.

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 2022. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015. 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 permitted certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions until July 31, 2022.

ES.1 Resources Covered

The TOU periods for the two 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 weekend and holidays as well as during the months of March and April. The CPP rate may be called during the 4 p.m. to 9 p.m. period on any day (including weekends) throughout the year. As of June 1, 2022, the CPP event window now coincides with the RA window of 4 to 9 p.m. period. In 2022, SDG&E called five CPP events. These events took place on September 3rd, 4th, 5th, 6th, and 7th.

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 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 solar PV size), based on the closest match of load profiles.

ES.3 Ex-Post Load Impacts

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

Table ES.1 summarizes average event-hour reference load and residential CPP load impact results for the residential CPP customers on the average weekday event in 2022.¹ Results are shown by Coastal and Inland climate zones. The first two columns show the climate zone and

¹ CPP residential customers are those that voluntarily enrolled on rate TOU-DR-P.

numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in units of MW. Note that here, and throughout the report, a positive load impact denotes a decrease in energy consumption. The next two columns show the same variables for the average customer, in units of kW. The last two columns show the load impacts as a percentage of the reference loads, and the average temperature during the event window. Load impacts for events are not reported as a percentage due to the presence of NEM customers in the sample described by the table.² An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. All three geographic categories have load impacts which are statistically significant at the 10% level.

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

Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
		Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	7,908	12.85	0.94*	1.63	0.12*	84
Inland	7,954	17.46	1.37*	2.20	0.17*	89
All	15,862	30.29	2.27*	1.91	0.14*	87

Program enrollment was 15,862 customers, skewed slightly toward the Inland climate zone.³ The aggregate reference load was 30.29 MWh/h. Per-customer load impacts averaged 0.12 kWh/h for customers in the Coastal climate zone and 0.17 kWh/h for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 84 degrees, than the 89-degree temperature for the Inland zone.

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

Table ES.2 summarizes the average reference 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 2021). The winter months are indicated by light blue shading. Enrollment continued throughout the analysis period, with the numbers of enrolled customers rising from 13,830 in October 2021 to 27,722 in September 2022.⁴ The estimated seasonal load impacts were largest during the summer months. An asterisk next to a load impact

² Since NEM customers experience reference loads that become negative when the sun is out, the load impact as a percentage of the reference load increases dramatically as the reference load approaches zero. Throughout the report, only level load impacts are displayed when NEM customers are included in the data being presented.

³ These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (*e.g.*, all selected event-like days, as well as the event day).

⁴ 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 247 winter and 277 summer incremental NEM and Non-NEM 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.

indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Oct-21	All	13,830	10.95	0.52	0.79	0.04	67
Nov-21	All	14,095	13.35	0.63	0.95	0.04	62
Dec-21	All	14,373	17.23	0.72	1.20	0.05	55
Jan-22	All	14,653	14.60	0.67	1.00	0.05	58
Feb-22	All	14,947	13.44	0.66	0.90	0.04	59
Mar-22	All	15,706	9.93	1.20	0.63	0.08	63
Apr-22	All	16,504	7.42	1.25	0.45	0.08	66
May-22	All	24,540	10.12	0.96	0.41	0.04	65
Jun-22	All	26,521	17.29	0.83	0.65	0.03	71
Jul-22	All	26,974	19.95	0.87	0.74	0.03	72
Aug-22	All	27,384	30.36	0.95	1.11	0.03	77
Sep-22	All	27,722	25.50	0.94	0.92	0.03	73

Table ES.3 shows peak load impact results by season and climate zone. Both the Inland and the Coastal climate zone exhibit higher aggregate reference loads during the summer than during winter, with Coastal reference loads higher than Inland reference loads during both periods. Customers in both climate zones decrease load during peak periods in the summer for an overall average load impact of 0.03 kwh/h. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	14,754	10.69	0.31	0.72	0.02	72
	Inland	9,732	10.11	0.52	1.04	0.05	74
	All	24,486	20.81	0.83	0.85	0.03	73
Winter	Coastal	9,276	7.30	0.87	0.79	0.09	61
	Inland	7,127	4.95	-0.06	0.69	-0.01	62
	All	16,403	12.24	0.82	0.75	0.05	62

Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers increased their energy consumption by an annual average of approximately 0.91 kWh/h.

ES.3.3 TOU peak load impacts – CPP (TOU-DR-P)

TOU-DR-P customers experience TOU prices on all weekdays that are not residential CPP event days. CA Energy Consulting examined the average usage changes on non-event days for this customer group, similar to TOU-only customers. Table ES.4 shows average monthly load and load impacts for summer (October 2021, and June through September 2022) and winter (November 2021 through May 2022) weekdays. Enrollment in CPP declined from 22,405 in October 2021 to approximately 15,868 in September 2022. Peak load impacts were around 0.10 kWh/h per customer during the summer months and around 0.02 kWh/h during the winter. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. Summer load impacts are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Oct-21	All	22,405	17.35	1.53*	0.77	0.07*	67
Nov-21	All	22,521	18.06	0.47	0.80	0.02	63
Dec-21	All	22,583	22.79	0.56	1.01	0.02	55
Jan-22	All	23,448	20.27	0.52	0.86	0.02	58
Feb-22	All	24,249	19.35	0.52	0.80	0.02	59
Mar-22	All	24,718	15.88	0.56	0.64	0.02	64
Apr-22	All	24,799	14.01	0.54	0.56	0.02	66
May-22	All	24,464	13.28	0.46	0.54	0.02	65
Jun-22	All	16,279	14.82	1.56*	0.91	0.10*	73
Jul-22	All	15,609	15.87	1.56*	1.02	0.10*	74
Aug-22	All	15,763	22.34	1.75*	1.42	0.11*	78
Sep-22	All	15,868	17.91	1.56*	1.13	0.10*	74

Table ES.5 summarizes TOU load impact results for residential CPP customers by season and climate zone. Inland customers had a dramatically lower load impact in the winter compared to the summer. Both Coastal and Inland customers have reduced reference loads during the winter relative to the summer. On average, CPP customers *increased* their load by 0.15 kWh/h per-customer per day over the course of the study period. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. Summer load impacts for the Inland climate zone and All customers are statistically significant at the 10% level.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	8,998	7.81	0.41	0.87	0.05	72
	Inland	8,186	9.99	1.31*	1.22	0.16*	74
	All	17,185	17.81	1.72*	1.04	0.10*	73
Winter	Coastal	14,219	10.24	0.45	0.72	0.03	62
	Inland	9,606	7.45	0.09	0.78	0.01	62
	All	23,826	17.68	0.54	0.74	0.02	62

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

Table ES.6 summarizes TOU peak-period load impact results for grandfathered customers by season and climate zone. The grandfathered summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays. The grandfathered winter TOU on-peak period is 5 p.m. to 8 p.m. on non-holiday weekdays. Monthly results are identical within each season because level load impacts were estimated by season. Load impacts are also the same in each climate zone because results were not estimated separately by climate zone. In both seasons, grandfathered customers exhibited an *increase* in usage during peak hours. Winter per-customer reference loads were much higher than the summer. The overall effect of *daily* usage is an average annual *increase* of about 9.95 kWh/h per customer. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

**Table ES.6: TOU Peak Load Impacts for Grandfathered Residential CPP Customers
– Average Weekday by Season & Climate Zone**

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	180	-0.37	-0.07	-2.04	-0.38	74
	Inland	209	-0.38	-0.08	-1.83	-0.38	76
	All	389	-0.75	-0.15	-1.93	-0.38	75
Winter	Coastal	183	0.04	-0.18	0.20	-0.99	62
	Inland	210	0.04	-0.21	0.17	-0.99	62
	All	393	0.07	-0.39	0.18	-0.99	62

ES.4 Ex-Ante Load Impacts

The ex-ante analysis for CPP events applies the PY2022 ex-post CPP event load impacts to reference loads calculated using PY2022 customer load data. Load impacts for different weather scenarios were developed by applying the estimated load impact from the ex-post analysis to weather-sensitive reference loads. The reference loads were developed by obtaining weather-specific coefficients using regression models like those used in the ex-post analysis and applying the coefficients to four alternative weather scenarios.

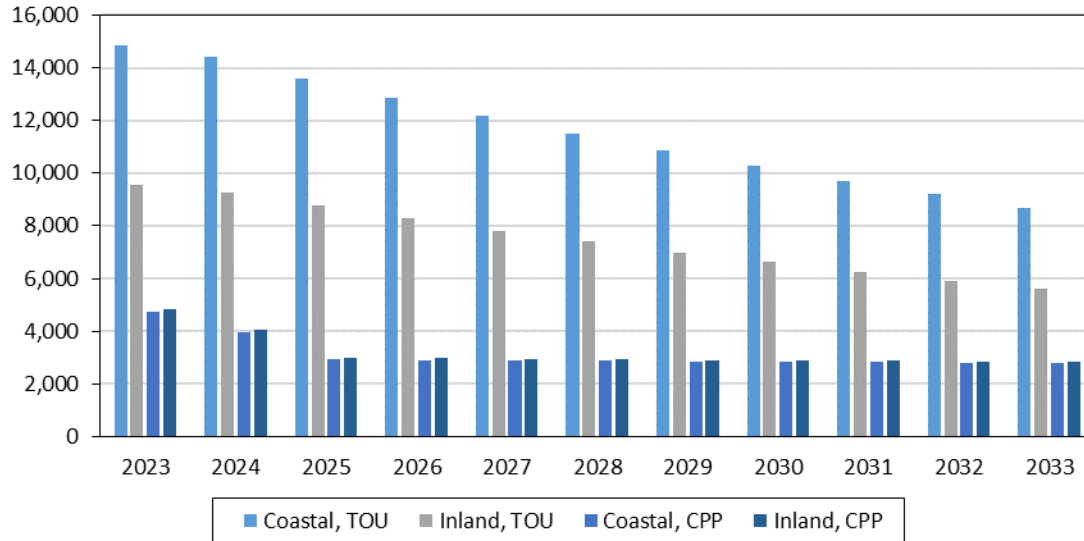
As of June 1, 2022, the CPP event window now coincides with the RA window, such that ex-ante results will report load impacts over the 4 to 9 p.m. period.

For the TOU rate and the TOU portion of the CPP rate, hourly percentage load impacts from the ex-post analysis are applied to weather-sensitive reference loads that were developed as described above. Level load impacts from ex-post are used for NEM customers.

ES.4.1 Enrollment forecast

Figure ES.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment for TOU is anticipated to be slightly declining after 2023. Enrollment is expected to be greater in the Coastal climate zone than in the Inland for TOU customers but smaller in the Coastal climate zone for TOU-DR-P. This mirrors the fact that the rates have different enrollment ratios in the two climate zones. There is no enrollment forecast for the grandfathered rate, which ended on July 31, 2022.

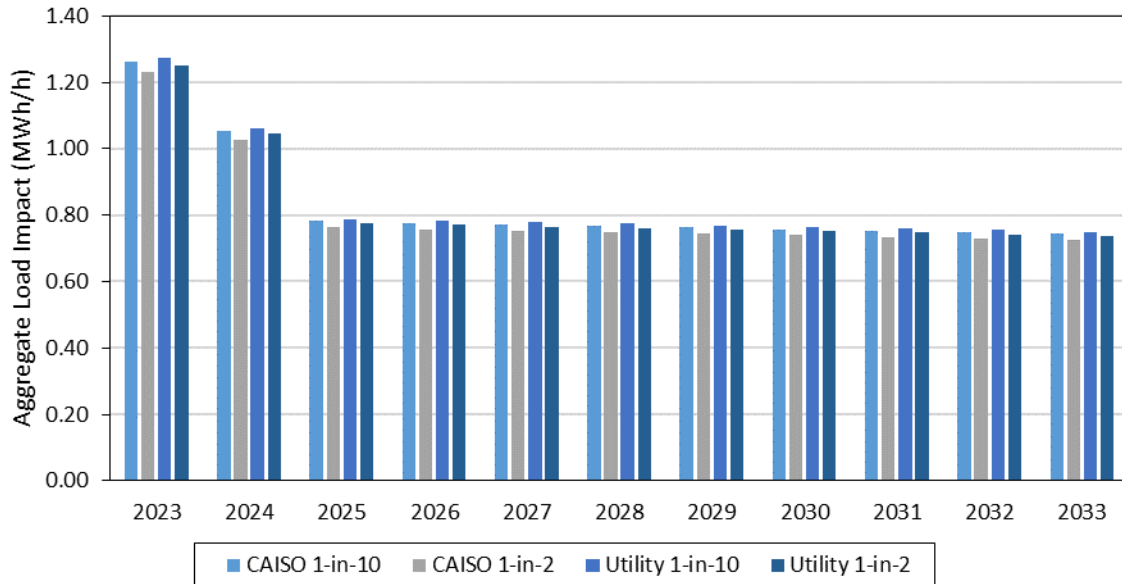
Figure ES.1: Enrollments in TOU and CPP Rates



ES.4.2 Ex-Ante load impacts – Residential CPP

Figure ES.2 illustrates the decline in forecasted aggregate CPP load impacts over the forecast period. The figure also shows relatively minor differences between the aggregate ex-ante load impacts for the alternative weather scenarios. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to decrease from 1.26 MWh/h in 2023 to 0.74 MWh/h in 2033.

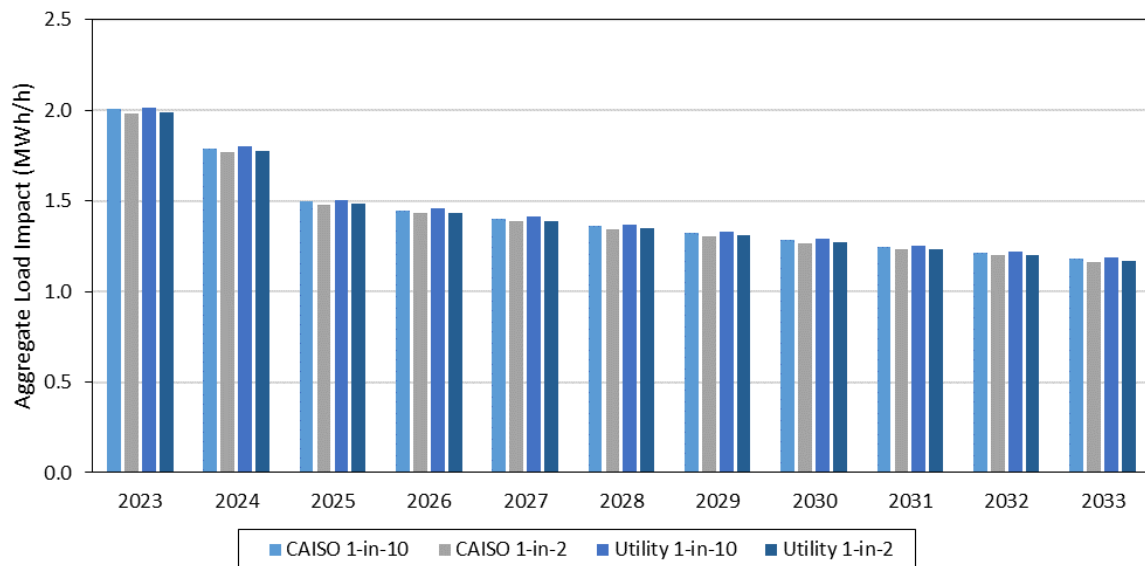
Figure ES.2: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario (August Peak Day, RA Window)



ES.4.3 Ex-Ante load impacts – Residential TOU

Aggregate peak load impacts for TOU customers are forecast to slightly decline after 2023. Figure ES.3 shows differences in the aggregate peak TOU load impact forecasts for customers enrolled in the SPP rates (representing both TOU-DR and TOU-DR-P customers) over the entire period for the average August weekday weather scenarios. Values for each of the weather scenarios are nearly identical.

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)



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 2022. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component).⁵ Both rates are voluntary and became active in February 2015. Since the TOU-DR-P 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 residential TOU-DR-P customers.⁶ 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 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 weekend and holidays as well as during the months of March and April. The CPP rate may be called during the 4 p.m. to 9 p.m. period on any day (including weekends) throughout the year.

The analysis also evaluates ex-post load impacts for TOU-DR-P customers on a "grandfathered" rate, which maintained the time of use period before it was changed in December 2017. The "grandfathered" summer TOU periods in the two rates are centered around an on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak.

Net Energy Metered (NEM) customers constitute a significant proportion of residential TOU-DR customers, as shown in the Table 1.1 below. Some TOU-DR-P customers transitioned to a CCA between April 2022 and June 2022. CCA customers cannot be enrolled in the CPP program and thus become just TOU-DR customers. This is the cause for the large shift in enrollments during this time. Also, customers who are both TOU-DR and TOU-DR-P in a given month are counted as an enrollment in both rates. Thus, counting certain customers on each rate in May 2022 causes the high enrollments in both rates for that month. The results for NEM customers are presented separately from Non-NEM customers in the protocol tables associated with this report, in addition to all customers being presented together. The average NEM share of enrollment during the study period was 45% for TOU-DR customers and 25% for TOU-DR-P customers.

⁵ Results are also reported for a subset of CPP customers who also participated in the Technology Deployment (TD) program.

⁶ TOU load ex-post load impacts are estimated for only customers who enrolled in either SPP rate during the October 2021 to September 2022 period, 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, by Rate

Date	TOU-DR			TOU-DR-P		
	Non-NEM Enrollments	NEM Enrollments	Total Enrollments	Non-NEM Enrollments	NEM Enrollments	Total Enrollments
Oct-21	7,293	6,537	13,830	18,144	4,261	22,405
Nov-21	7,336	6,759	14,095	18,074	4,447	22,521
Dec-21	7,398	6,975	14,373	17,978	4,605	22,583
Jan-22	7,520	7,133	14,653	18,684	4,764	23,448
Feb-22	7,385	7,562	14,947	19,341	4,908	24,249
Mar-22	7,640	8,066	15,706	19,778	4,940	24,718
Apr-22	7,975	8,529	16,504	19,864	4,935	24,799
May-22	15,349	9,191	24,540	19,520	4,944	24,464
Jun-22	16,911	9,610	26,521	10,815	5,464	16,279
Jul-22	16,922	10,052	26,974	10,127	5,482	15,609
Aug-22	16,873	10,511	27,384	10,350	5,413	15,763
Sep-22	16,839	10,883	27,722	10,539	5,329	15,868

The report is organized as follows. Section 2 contains descriptions of the TOU and CPP rates; Section 3 describes the evaluation methods used in the study; Section 4 contains the CPP ex-post load impact results; Section 5 contains the TOU ex-post load impact results; Section 6 describes the methods used to develop the CPP and TOU ex-ante load impacts; Section 7 contains the TOU and CPP ex-ante load impact results; Section 8 provides a series of comparisons of ex-post and ex-ante results; Section 9 provides recommendations.

2 DESCRIPTION OF SPP RATES

The current TOU on-peak period in summer is 4 p.m. 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 weekend and holidays as well as during the months of March and April. In 2022, SDG&E called five CPP events. These events took place on September 3rd, 4th, 5th, 6th, and 7th. Two events took place on the weekend, September 3rd and 4th, while one event, September 5th, was Labor Day.

The total TOU summer rate charges as of June 1, 2022⁷, for TOU (TOU-DR) customers are \$0.565, \$0.494, and \$0.416 per kWh for the summer on-peak, off-peak, and super-peak periods respectively. Thus, the peak to super-off-peak price ratio is 1.35-to-1. Summer TOU charges for CPP (TOU-DR-P) customers are somewhat lower, at \$0.495, \$0.470, and \$0.362 per kWh, implying a peak to off-peak price ratio of 1.37-to-1. Summer prices for Grandfathered CPP (GTOU-DR-P) customers are \$0.562, \$0.480, and \$0.389 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

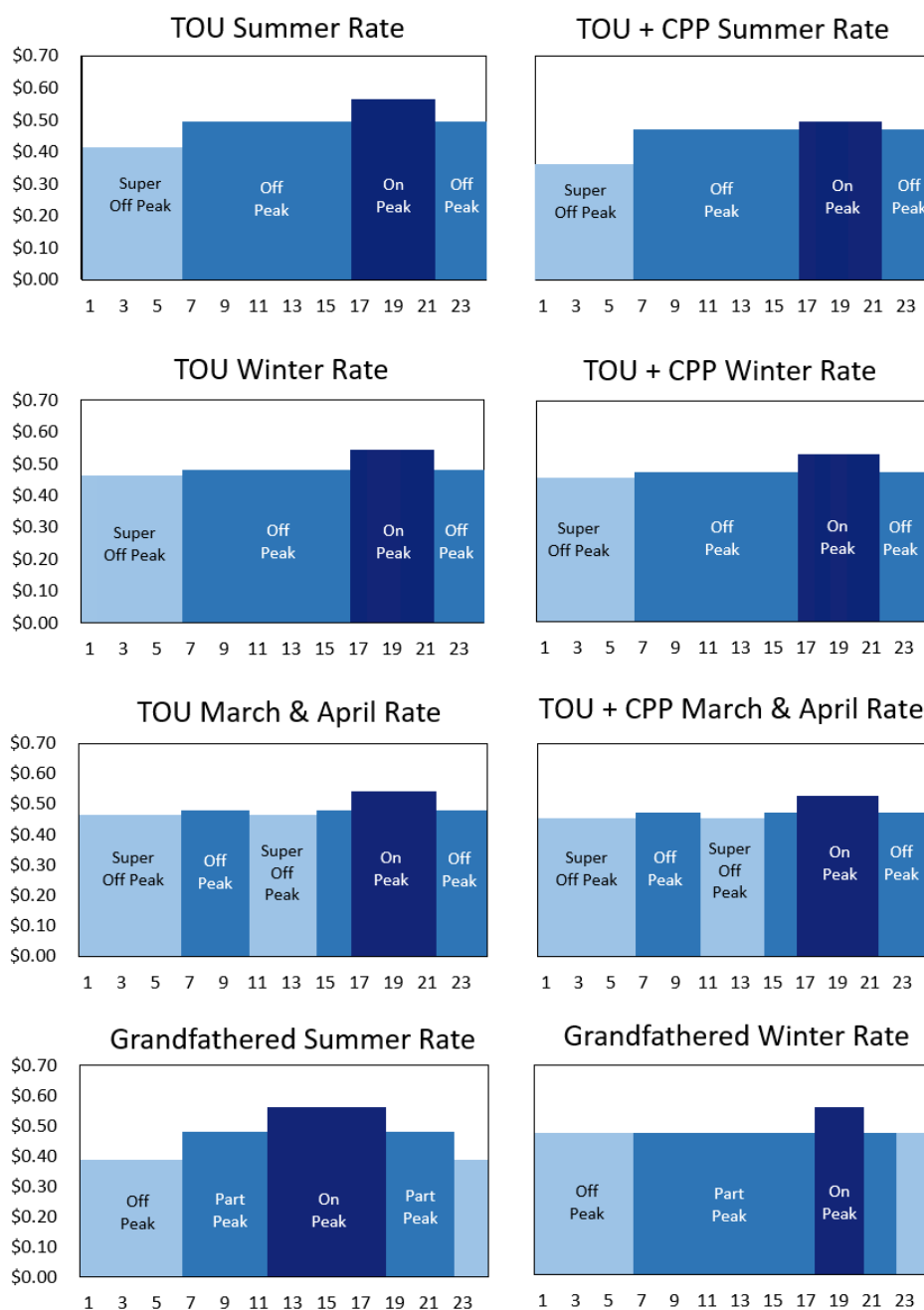
⁷ <https://www.sdge.com/total-electric-rates>

event days for both CPP and Grandfathered CPP customers. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.⁸

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.

⁸ 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 Prices⁹



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.

⁹ <https://www.sdge.com/total-electric-rates>

3.1 Data

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

- *Customer* information for the residential TOU and CPP enrollees and potential control group customers (e.g., location indicator for matching to climate zone, CARE status, PV size);
- Billing-based *interval load data* (i.e., hourly loads for each TOU and CPP enrollee, and potential control group customers), for October 2020 through September 2022;
- *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, notification status of customers in 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. 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

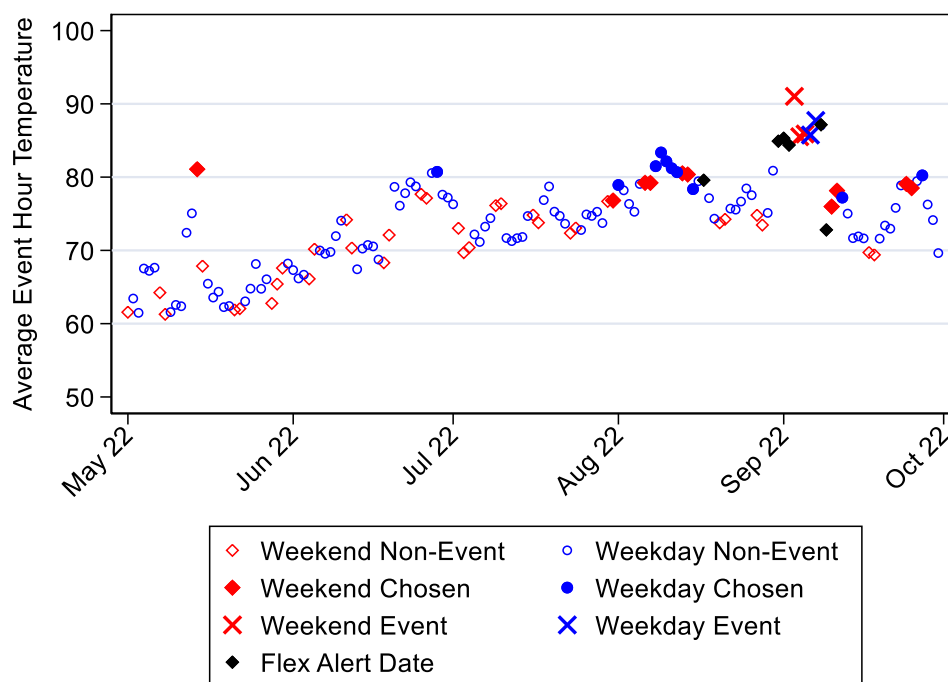
The difference-in-differences evaluation is a quasi-experimental approach that compares the usage of treatment and matched control group customers on relevant days or time periods, adjusted by their usage differences on pre-treatment or non-event days. The control groups were selected by matching each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

The matching process differed for customers on the two rates. Since the CPP (TOU-DR-P) customers experienced TOU rates on all non-event days, and the CPP rate on event days, those customers were 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). Figure 3.1 displays the average event-hour temperature for all weekday and weekends between May 2022 and September 2022. Red diamond markers indicate weekend non-event days while blue circles indicate weekday non-event days. The red and blue X

markers represent weekend and weekday event days, respectively. The event days in 2022 were among the hottest days during 2022. The black filled in markers are Flex Alert days, which are excluded from the set of possible chosen non-event days. The filled in blue circles and red diamonds represent weekday and weekend/holiday, respectively, event-like non-event days that were chosen.¹⁰

Figure 3.1: Average Event-Hour Temperatures



Note: Averaged over event hours HE 17-21

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 2020 through September 2021). 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 analysis are separated by season, thus allowing different threshold dates that define incremental customers.¹¹ The incremental 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 *non-summer* season used data for November 2020 through May 2021, while matching for the *summer* season used data for October 2020 and June through September of 2021.

¹⁰ The weekday event-like dates were 6/28, 8/1, 8/8, 8/9, 8/10, 8/11, 8/12, 8/15, 9/12, and 9/27. The weekend/holiday event-like dates were 5/14, 7/31, 8/6, 8/7, 8/13, 8/14, 9/10, 9/11, 9/24, and 9/25.

¹¹ The seasons defined for matching are summer (June through October) and winter (November through May). Therefore, incremental customers for the summer analysis are those that enrolled after October 1, 2020, while incremental customers for the winter analysis are those that enrolled after November 1, 2020. Customers must also be on a non-TOU rate (e.g., DR) for the pre-treatment period to be a valid incremental customer.

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.¹² The PY2017 pre-treatment analysis periods cover October 2015 through September 2016. The post-treatment analysis period for these customers, however, covers October 2021 through September 2022. 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.

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

In this equation, the T variables represent treatment customer characteristics, and the C variables represent the corresponding eligible control group customer characteristics. For the TOU analysis, the relevant customer characteristics include the average hourly usage on weekdays and hot/cold days for the summer/winter match (48 variables).¹³ Treatment and potential control customers are also segmented by climate zone and CARE status. 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 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.¹⁴ Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.¹⁵ 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 that are confounded by differences in solar

¹² 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.

¹³ 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.

¹⁴ Treatment or control customers with large changes in their PV system during the analysis period are not used when creating estimates.

¹⁵ NEM customers are segmented only by solar PV size, segmented into three groups.

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.¹⁶

3.2.2 Fixed-effects panel regression models

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

Two versions of fixed-effects models were estimated. The first version was used to estimate residential CPP event-day hourly load impacts. Weekend CPP events were estimated separately from weekday events, as load usage may vary between weekdays and weekend days. The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR and TOU-DR-P customers). In addition to estimating each load impact type separately by rate, the load impacts were estimated separately for NEM customers within each rate.

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

3.2.3 Ex-post models for estimating CPP load impacts

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

$$kWh_{c,d} = \beta_0 + \sum_{Evts(i)} (\beta_{1,i} \times CPP_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)} (\beta_{2,i} \times TD_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)} (\beta_{3,i} \times CPP_Control_{c,d} \times Evt_{i,d}) + \sum_{Evts(i)} (\beta_{4,i} \times TD_Control_{c,d} \times Evt_{i,d}) + \beta_5 \times CPP_{c,d} + \beta_6 \times SS_Evt_{c,d} + \sum_{Cust} (\beta_{7,Cust} \times C_c) + \sum_{date} (\beta_{8,date} \times D_{date,d}) + \epsilon_{c,d}$$

¹⁶ 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.

The variables and coefficients in the equation are described in Table 3.1. Results are scaled to enrollment numbers because a portion of residential CPP customers are removed from the analysis based upon load quality and NEM customer restrictions (see Appendix C). We also use a similar specification to estimate CPP load impact among specific subsets of customers (e.g., notified vs non-notified, dual enrollment).¹⁷

¹⁷ For example, in the case of notification status, each event day will have a separate coefficient estimated for notified and non-notified customers. Similar to how the above specification separates each event day load impact coefficient for CPP customers not on TD versus CPP customers on TD.

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer c on date d
$CPP_{c,d}$	Variable indicating whether customer c is only a <i>CPP</i> customer (<i>i.e.</i> , not also dually enrolled in <i>TD</i>) on date d (1 = yes, 0 if not)
$TD_{c,d}$	Variable indicating whether customer c is a dually enrolled <i>CPP</i> and <i>TD</i> customer on date d (1 = yes, 0 if not)
$CPP_Control_{c,d}$	Variable indicating whether customer c is a control customer matched to a <i>CPP</i> customer who is not dually enrolled, on date d (1 = yes, 0 if not)
$TD_Control_{c,d}$	Variable indicating whether customer c is a control customer matched to a dually-enrolled <i>CPP</i> and <i>TD</i> customer, on date d (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date d is the i^{th} event day (1= i^{th} event, 0 if not)
$SS_Evt_{c,d}$	Variable indicating that date d is a <i>Summer Saver</i> event day (1=event, 0 if not) for customer c
β_0	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event d for <i>CPP</i> only customers
$\beta_{2,d}$	Estimated load impact for event d for dually enrolled <i>CPP</i> and <i>TD</i> customers
$\beta_{3,d}$	Estimated load impact for event d for control customers matched to <i>CPP</i> only customers
$\beta_{4,d}$	Estimated load impact for event d for control customers matched to dually enrolled <i>CPP</i> and <i>TD</i> customers
β_5	Estimated non-event day response for incremental <i>CPP</i> customers
β_6	Estimated average <i>Summer Saver</i> load impact
$\beta_{7,Cust}$ and $\beta_{8,date}$	Customer and date fixed effects
C_c	Variable indicating that the observation is for customer c
$D_{date,d}$	Date indicator variable (1 = date d equals date <i>day</i>)
$\epsilon_{c,d}$	Error term

3.2.4 Ex-post models for estimating TOU load impacts

To obtain TOU load impacts (for TOU-DR, TOU-DR-P, and GTOU-DR-P 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.¹⁸ Event days are removed from the dataset when estimating TOU load impacts. In this

¹⁸ 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 core 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

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). The model is estimated separately by rate (*e.g.*, TOU-DR, TOU-DR-P, GTOU-DR-P), hour, month, day-type (*i.e.*, average weekday versus peak month day), and applicable customer groups (*e.g.*, climate zone, NEM). The customer-level fixed-effects models are of the following form:¹⁹

$$kWh_{c,d} = \beta_0 + \beta_1 \times (TOU_c \times Post_{c,d}) + \sum_{Cust} (\beta_{2,Cust} \times C_c) + \sum_{dates} (\beta_{3,dates} \times D_{dates}) + \epsilon_{c,d}$$

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

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

Symbol	Description
$kWh_{c,d}$	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
$Post_{c,d}$	Variable indicating that date d is in the post-enrollment period 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
C_c	Variable indicating that the observation is associated with customer c
D_{date}	Variable indicating that the observation is for date d
$\epsilon_{c,d}$	Error term

3.2.5 Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of ex-post load impacts, the coefficients that represent the estimated load impacts in the fixed-effects regressions are not estimated with certainty, but with a range of uncertainty indicated by the variance of the estimates. Therefore, 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 of the variances of the errors

percentage load impacts are then used to calculate monthly average weekday or system peak day reference loads (*i.e.*, $RefDaytype = ObsDaytype / (1 - PctLISeason)$) and level load impacts (*i.e.*, $LIDaytype = RefDaytype * PctLISeason$). This method was used for each season for TOU-DR, GTOU-DR-P, and NEM customers.

¹⁹ 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.

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 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 peak-hour TOU load impact is directly estimated). The associated standard errors are used to develop the uncertainty-adjusted load impacts in the same manner described above.

3.2.6 Validity assessment

Because a control-group approach is being employed, the validity assessment focuses on comparisons of treatment and control-group loads for 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 CPP EX-POST LOAD IMPACT STUDY FINDINGS

This section documents the findings from the ex-post load impact evaluation analysis of the CPP portion of the TOU-DR-P rate. The grandfathered CPP rate ended prior to any CPP events in 2022, so analysis was not performed for the grandfathered rate. For CPP, the primary load impact results include average estimated event-hour load impacts (*i.e.*, the average of the hourly load impacts estimated for the five-hour event window from 4 p.m. to 9 p.m.), in aggregate and per-customer, for each event day. Results of the analysis of the TOU portion of each rate (*i.e.*, peak load impacts on non-event days) are presented in Section 5, along with results for the TOU-DR rate.

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

4.1 Control group matching results

Figure 4.1 illustrates the quality of the matches for the Non-NEM residential CPP (TOU-DR-P) customers in the context of estimating load impacts on the CPP event day. The figure shows the average CPP and matched control-group customer load profiles for the selected event-like non-event days. Across all 24 hours, both the mean percentage error (MPE) and mean absolute percentage error (MAPE) of the CPP profile compared to the control-group profile are 2.2 percent. For the CPP event window (4 p.m. to 9 p.m.), the MPE and MAPE are 1.3 percent.

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

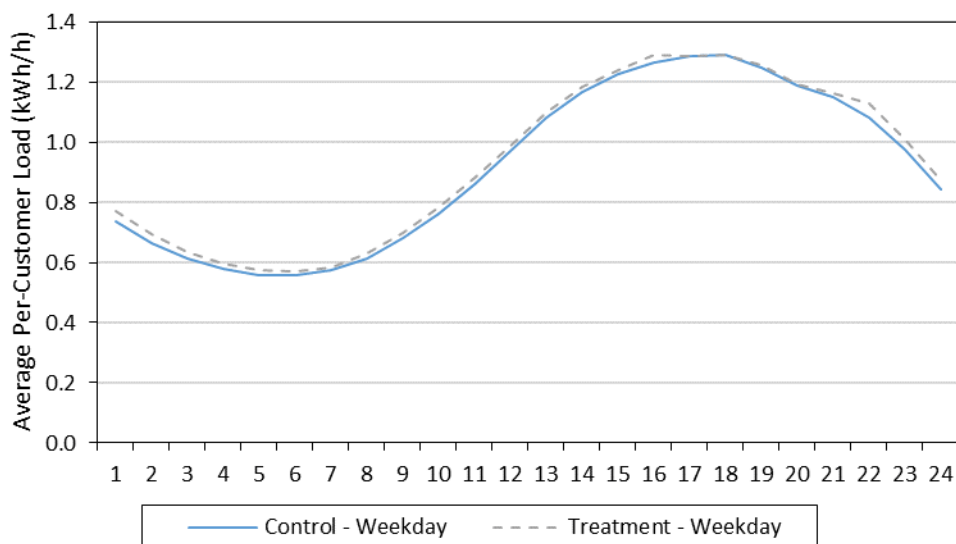
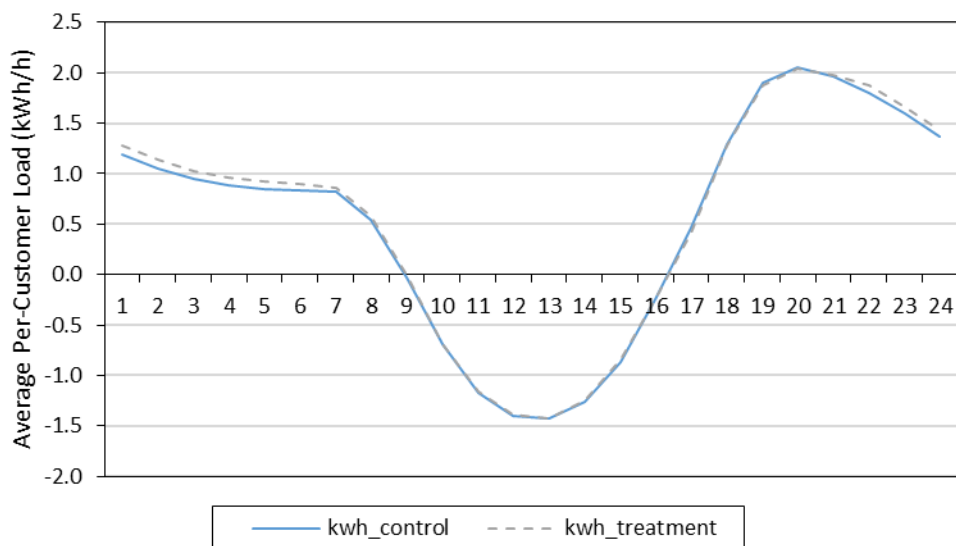


Figure 4.2 similarly illustrates the match quality for NEM residential CPP customers, as NEM customers were matched separately from Non-NEM customers. Across all 24 hours, the mean error (ME) of the CPP profile compared to the control-group profile is 0.03 kWh/h, while the mean absolute error (MAE) is 0.04 kWh/h. For the CPP event window (4 p.m. to 9 p.m.), the ME is -0.01 kWh/h while the MAE is 0.02 kWh/h.²⁰

Figure 4.2: NEM CPP and Matched Control Group Load Profiles – Average Event-Like Day



²⁰ The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which disproportionately distort percentage values.

4.2 CPP load impacts

This section summarizes average event-hour reference loads²¹ and load impacts, at an aggregate and per-customer basis, for the five 2022 CPP events called on Sep 3rd, Sep 4th, Sep 5th, Sep 6th, and Sep 7th. Each event had an event-window of 4 p.m. to 9 p.m. (HE 17-21). Two events took place on the weekend, September 3rd and 4th, while one event, September 5th, was Labor Day.

Table 4.1 summarizes reference load and CPP load impact results for all CPP customers, by climate zone.²² The first three columns show the climate zone, event date, and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/h. The next two columns show the same variables for the average customer, in units of kWh/h. The last two columns show the load impacts as a percentage of the reference loads and the average temperature during the event window. Rows highlighted in blue signify weekend event days. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. All results are statistically significant at the 10% level.

²¹ Reference loads represent estimates of the counter-factual loads that would have prevailed on an event day if the event had not been called. Mechanically, the reference loads are constructed by adding the estimated load impacts (developed in the difference-in-differences regression analysis) to the observed load of the treatment customers on the relevant event day. Alternatively, if percentage load impacts are estimated, then the reference loads are calculated by dividing the observed load by one minus the percentage load impact.

²² Technology Deployment customers are included in these results.

Table 4.1: Average CPP Event-Hour Load Impacts

Climate Zone	Date	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	Sep 3, 2022	7,908	14.63	2.03*	1.85	0.26*	89
	Sep 4, 2022	7,908	14.01	1.86*	1.77	0.24*	84
	Sep 5, 2022	7,908	14.15	1.43*	1.79	0.18*	85
	Sep 6, 2022	7,908	12.19	0.85*	1.54	0.11*	83
	Sep 7, 2022	7,908	13.52	1.02*	1.71	0.13*	85
	Typical Weekday Event	7,908	12.85	0.94*	1.63	0.12*	84
	Typical Weekend Event	7,908	14.26	1.78*	1.80	0.22*	86
Inland	Sep 3, 2022	7,954	18.80	1.43*	2.36	0.18*	93
	Sep 4, 2022	7,954	17.83	1.51*	2.24	0.19*	87
	Sep 5, 2022	7,954	17.48	1.05*	2.20	0.13*	87
	Sep 6, 2022	7,954	16.62	1.21*	2.09	0.15*	88
	Sep 7, 2022	7,954	18.30	1.52*	2.30	0.19*	90
	Typical Weekday Event	7,954	17.46	1.37*	2.20	0.17*	89
	Typical Weekend Event	7,954	18.04	1.33*	2.27	0.17*	89
All	Sep 3, 2022	15,862	33.45	3.49*	2.11	0.22*	91
	Sep 4, 2022	15,862	31.90	3.43*	2.01	0.22*	86
	Sep 5, 2022	15,862	31.68	2.53*	2.00	0.16*	86
	Sep 6, 2022	15,862	28.77	2.02*	1.81	0.13*	86
	Sep 7, 2022	15,862	31.81	2.53*	2.01	0.16*	88
	Typical Weekday Event	15,862	30.29	2.27*	1.91	0.14*	87
	Typical Weekend Event	15,862	32.35	3.15*	2.04	0.20*	87

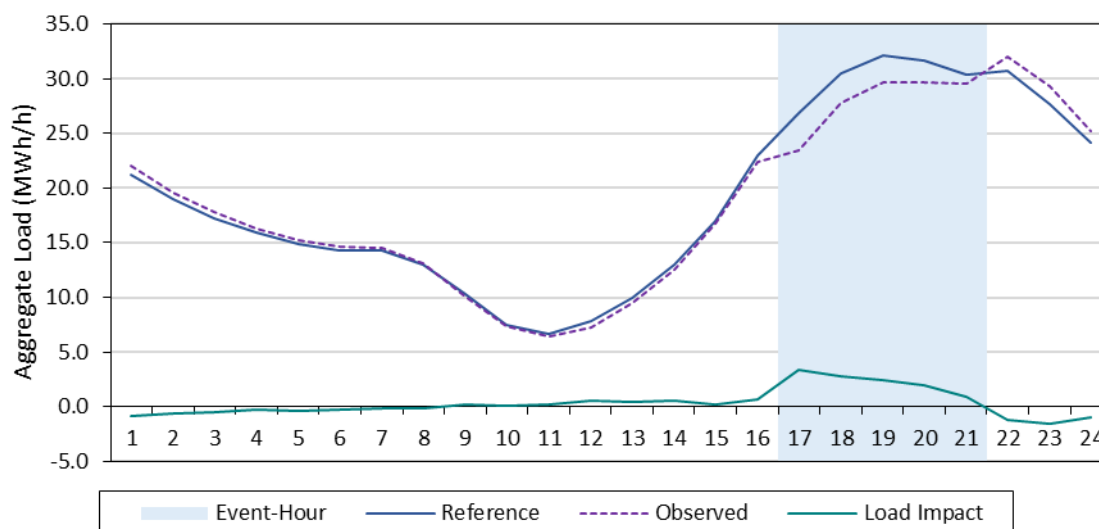
Program enrollment was 15,862 customers, which were fairly evenly distributed between the inland and coastal climate zones.²³ On a Typical Weekday Event Day (*i.e.*, the average event), the per-customer reference load during event hours for all customers was 1.91 kWh/h with a per-customer load impact of 0.14 kWh/h. Per-customer load impacts averaged 0.12 kWh/h for customers in the Coastal climate zone and 0.17 kWh/h for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 84 degrees, than the 89-degree temperature for the Inland zone. The first three event days, Sep 3rd, Sep 4th, and Sep

²³ These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (e.g., all selected event-like days, as well as the event day). The number of CPP customers used in the regressions was 9,418. The CPP load impacts are scaled up to total program enrollments.

5th were weekend days and the first comparable event-window temperature compared to the weekday events across all customers.

Figure 4.3 shows aggregate hourly loads and load impacts for the average weekday event. The largest hourly load impact was 3.33 MWh/h in hour-ending 17 (4 p.m. to 5 p.m.).

Figure 4.3: Aggregate CPP Hourly Loads and Load Impacts – Average Weekday Event



4.3 Technology Deployment load impacts

This section compares the CPP load impact estimates for customers that were dually enrolled in CPP and the Technology Deployment ("TD") program, also known as AC Saver Day Ahead, during 2022. Customers dually enrolled in TD and CPP experienced the same CPP events and event-window (September 3, 4, 5, 6, 7 from 4 p.m. to 9 p.m.).

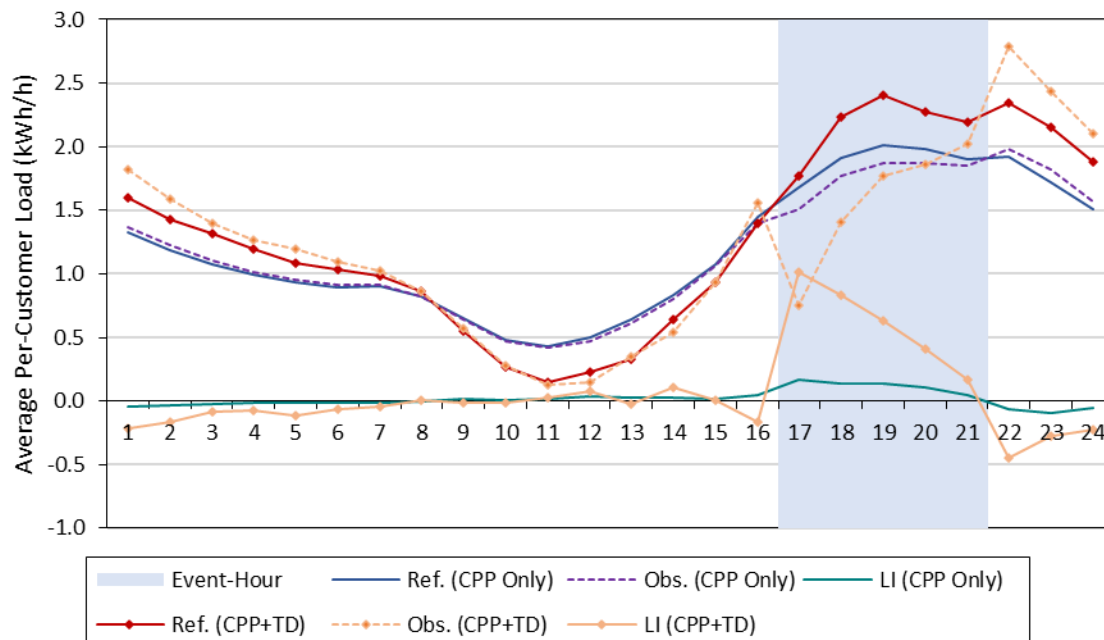
Table 4.2 summarizes reference loads and load impacts for customers by enrollment status during the event-hour window, bifurcating results for customers enrolled solely in CPP ("CPP Only") and customers dually enrolled in CPP and TD ("CPP+TD"). An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. All results are statistically significant at the 10% level. The average number of dually enrolled customers for a weekday event was 668, about 4.2% of all CPP customers. On average, customers dually enrolled in TD have larger reference loads and load impacts. For example, the average weekday per-customer event reference load and load impact for dually enrolled customers was 2.17 kWh/h and 0.61 kWh/h, respectively. The average weekday per-customer event reference load and load impact for non-dually enrolled customers was 1.90 kWh/h and 0.12 kWh/h, respectively. The per-customer load impact of dually enrolled customers is about quintuple that of non-dually enrolled customers for a typical weekday event.

Table 4.2: Comparison of Average CPP Event-Hour Load Impacts for TD and CPP Enrollment Type

Type	Date	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
CPP Only	Sep 3, 2022	15,192	31.86	3.03*	2.10	0.20*	91
	Sep 4, 2022	15,192	30.45	3.07*	2.00	0.20*	86
	Sep 5, 2022	15,192	30.13	2.09*	1.98	0.14*	86
	Sep 6, 2022	15,194	27.38	1.63*	1.80	0.11*	86
	Sep 7, 2022	15,195	30.25	2.05*	1.99	0.13*	88
	Typical Weekday Event	15,195	28.81	1.84*	1.90	0.12*	87
	Typical Weekend Event	15,192	30.82	2.73*	2.03	0.18*	87
CPP + TD	Sep 3, 2022	670	1.57	0.44*	2.34	0.65*	91
	Sep 4, 2022	670	1.44	0.35*	2.15	0.52*	86
	Sep 5, 2022	670	1.54	0.43*	2.29	0.64*	86
	Sep 6, 2022	668	1.37	0.38*	2.06	0.56*	86
	Sep 7, 2022	667	1.53	0.44*	2.29	0.66*	88
	Typical Weekday Event	668	1.45	0.41*	2.17	0.61*	87
	Typical Weekend Event	670	1.52	0.41*	2.26	0.60*	88

Figure 4.4 shows average per-customer hourly loads and load impacts for customers dually enrolled and not dually enrolled in CPP and TD for the 2022 average weekday event. The shaded hours indicate the event-hours (4 to 9 p.m.). The observed load of dually enrolled customers ("Obs. (CPP+TD)") illustrates that TD customers have pre-cooling in the hours before the event begins and a snapback effect in the hours after the event, whereas non-dually enrolled customers do not have pre-cooling but have a small amount of snapback. The largest hourly TD load impact was 0.85 kWh/h in the first hour of the event (4 to 5 p.m.).

Figure 4.4: CPP+TD Hourly Loads and Load Impacts for Dually Enrolled Customers



4.4 Notification status load impacts

This section compares the CPP load impact estimates for customers that were notified of an event and those that did not receive notification of the event. Customers who were not notified should not have known that a CPP event was occurring.

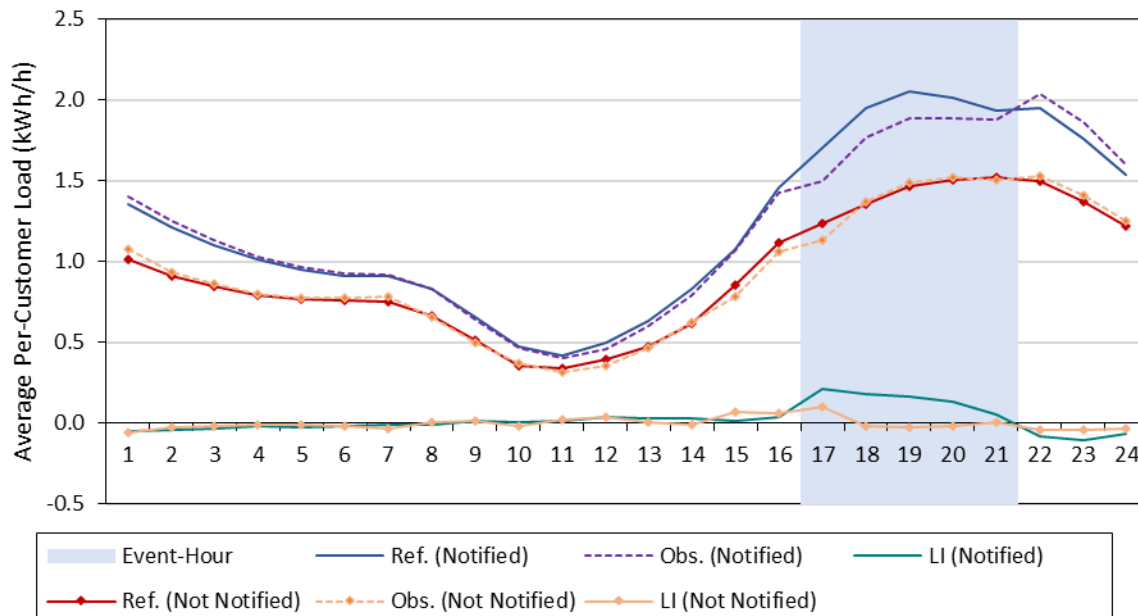
Table 4.3 summarizes reference loads and load impacts for customers by enrollment status during the event-hour window, bifurcating results for customers that were notified of an event and those that did not receive notification of the event. The average number of non-notified customers for a weekday event was 721 (which is about 4.5% of all CPP customers). On average, customers who were not notified had smaller reference loads and comparable load impacts. For example, the average weekday event reference load and load impact for non-notified customers was 1.41 kWh/h and 0.01 kWh/h, respectively. The average weekday event reference load and load impact for notified customers was 1.92 kWh/h and 0.15 kWh/h, respectively. The load impact of non-notified customers is negligible while for notified customers it is substantial. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. All load impacts of notified customers are statistically significant at the 10% level. However, all load impacts of non-notified customers are not statistically significant at the 10% level, which is in line with the intuition that customers should have a response indistinguishable from no response if they were not notified of the event.

Table 4.3: Comparison of Average CPP Event-Hour Load Impacts by Notification Status

Type	Date	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Notified	Sep 3, 2022	15,504	32.92	3.45*	2.12	0.22*	91
	Sep 4, 2022	15,510	31.41	3.42*	2.03	0.22*	86
	Sep 5, 2022	15,229	30.69	2.46*	2.02	0.16*	86
	Sep 6, 2022	15,106	27.72	1.99*	1.83	0.13*	86
	Sep 7, 2022	15,176	30.79	2.52*	2.03	0.17*	88
	Typical Weekday Event	15,141	29.26	2.26*	1.93	0.15*	87
	Typical Weekend Event	15,414	31.67	3.11*	2.05	0.20*	87
Non-Notified	Sep 3, 2022	358	0.52	0.03	1.44	0.08	91
	Sep 4, 2022	352	0.50	0.02	1.41	0.06	85
	Sep 5, 2022	633	1.01	0.08	1.59	0.13	86
	Sep 6, 2022	756	1.05	0.03	1.39	0.04	86
	Sep 7, 2022	686	0.99	-0.02	1.44	-0.03	88
	Typical Weekday Event	721	1.02	0.01	1.41	0.01	87
	Typical Weekend Event	448	0.67	0.05	1.50	0.10	87

Figure 4.5 shows average per-customer hourly loads and load impacts for CPP customers who were notified or not-notified for the 2022 average weekday event. The shaded hours indicate the event-hours (4 to 9 p.m.). The observed load of not-notified customers have a small dip in the first event hour before finishing the event with no effect.

Figure 4.5: Hourly Loads and Load Impacts for Notified and Non-Notified (NN) Customers



5 TOU EX-POST LOAD IMPACT STUDY FINDINGS

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

5.1 TOU control group matching results for TOU customers

Figure 5.1 and Figure 5.2 illustrate the quality of the matches for the TOU (TOU-DR) Non-NEM 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 days, 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 2.3 percent, while the mean absolute percentage error (MAPE) is 3.2 percent. In the winter months, the MPE is 1.2 percent and the MAPE is 3.9 percent.²⁴

²⁴ 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 5.1: Non-NEM TOU and Matched Control Group Load Profiles – Summer

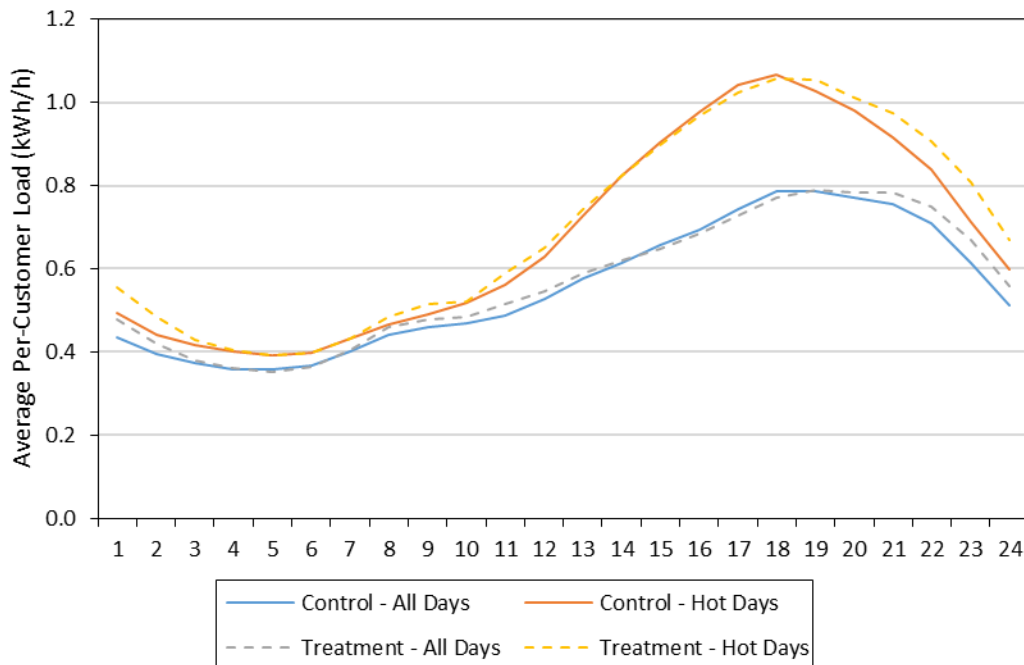


Figure 5.2: Non-NEM TOU and Matched Control Group Load Profiles – Winter

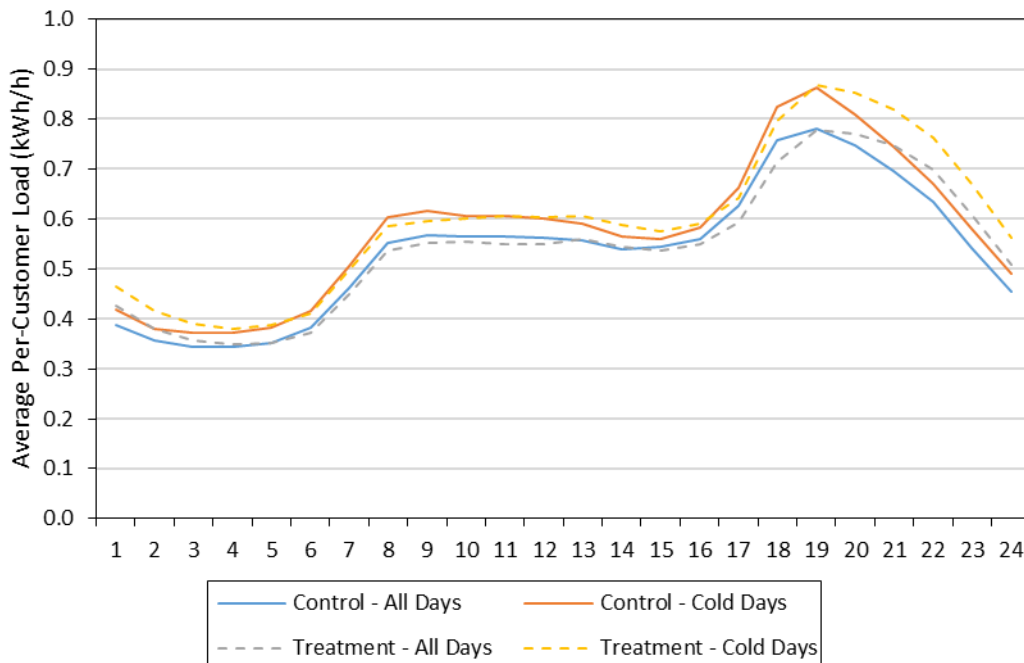


Figure 5.3 and Figure 5.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, which were matched separately from Non-NEM customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all days, 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 0.03 kWh/h, while the mean absolute error (MAE) is 0.05 kWh/h. In the winter months, the ME is -0.01 kWh/h and the MAE is 0.14 kWh/h.

Figure 5.3: NEM TOU and Matched Control Group Load Profiles - Summer

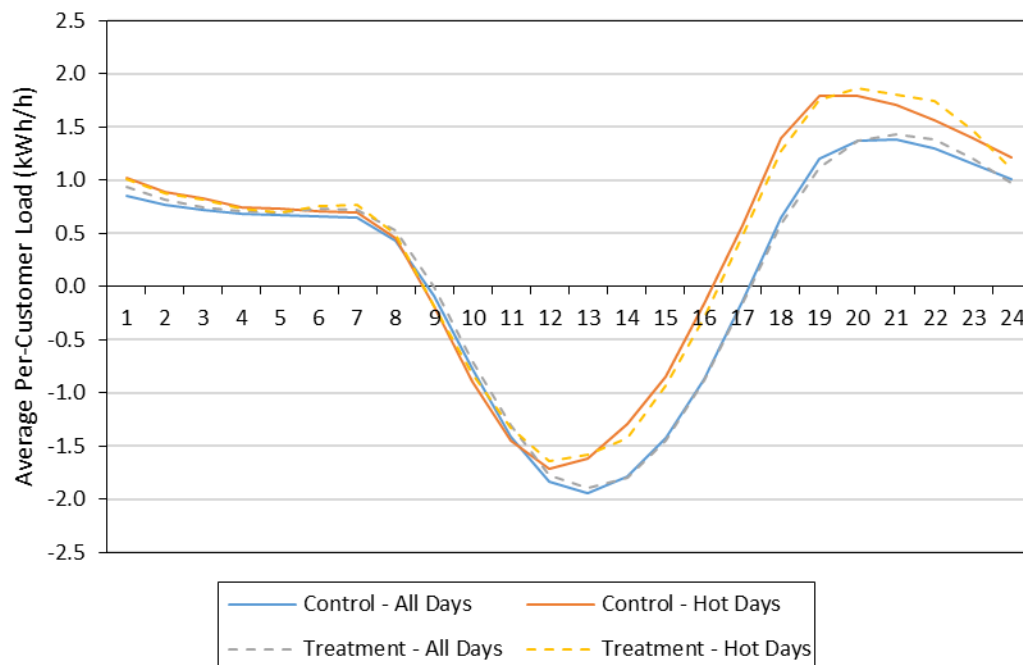
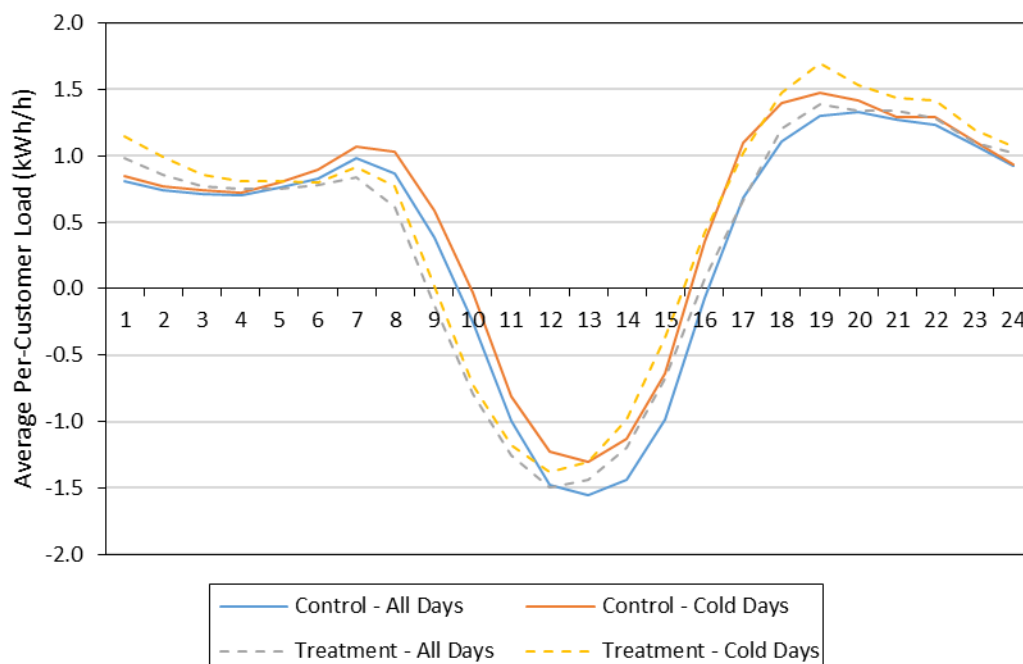


Figure 5.4: NEM TOU and Matched Control Group Load Profiles - Winter



5.2 Ex-post TOU load impacts for TOU customers

This sub-section shows ex-post TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 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 2021). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers increasing from 13,830 in October 2021 to 27,722 in September 2022.²⁵ 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. The seasonal level load impacts are similarly used for NEM customers. The per-customer load impacts are lower during the summer months at approximately 0.03 kWh/h. The highest load impact occurs during March and April when customers decrease usage by 0.08 kWh/h. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Oct-21	All	13,830	10.95	0.52	0.79	0.04	67
Nov-21	All	14,095	13.35	0.63	0.95	0.04	62
Dec-21	All	14,373	17.23	0.72	1.20	0.05	55
Jan-22	All	14,653	14.60	0.67	1.00	0.05	58
Feb-22	All	14,947	13.44	0.66	0.90	0.04	59
Mar-22	All	15,706	9.93	1.20	0.63	0.08	63
Apr-22	All	16,504	7.42	1.25	0.45	0.08	66
May-22	All	24,540	10.12	0.96	0.41	0.04	65
Jun-22	All	26,521	17.29	0.83	0.65	0.03	71
Jul-22	All	26,974	19.95	0.87	0.74	0.03	72
Aug-22	All	27,384	30.36	0.95	1.11	0.03	77
Sep-22	All	27,722	25.50	0.94	0.92	0.03	73

²⁵ 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 314 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 45 NEM TOU customers are included in the regressions. The aggregate TOU load impacts are then scaled to total enrollments.

Table 5.2 shows results by season and climate zone. Both the Inland and the Coastal climate zone exhibit higher reference loads during the summer than during winter, with Inland reference loads higher than Coastal reference loads during both periods. While customers in both climate zones decrease load during peak periods in the summer for an overall average load impact of 0.03 kwh/h, Inland customers have a larger load impact than Coastal customers in both summer and winter. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	14,754	10.69	0.31	0.72	0.02	72
	Inland	9,732	10.11	0.52	1.04	0.05	74
	All	24,486	20.81	0.83	0.85	0.03	73
Winter	Coastal	9,276	7.30	0.87	0.79	0.09	61
	Inland	7,127	4.95	-0.06	0.69	-0.01	62
	All	16,403	12.24	0.82	0.75	0.05	62

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their daily energy consumption in all months. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-21	All	13,830	82.94	-17.96	6.00	-1.30	63
Nov-21	All	14,095	102.41	-11.40	7.27	-0.81	61
Dec-21	All	14,373	211.55	-11.09	14.72	-0.77	54
Jan-22	All	14,653	137.22	-12.01	9.36	-0.82	55
Feb-21	All	14,947	78.81	-13.22	5.27	-0.88	55
Mar-22	All	15,706	23.41	-6.04	1.49	-0.38	59
Apr-22	All	16,504	-26.22	-6.48	-1.59	-0.39	62
May-22	All	24,540	36.30	-14.12	1.48	-0.58	62
Jun-22	All	26,521	120.42	-28.71	4.54	-1.08	68
Jul-22	All	26,974	180.73	-30.30	6.70	-1.12	70
Aug-22	All	27,384	331.16	-32.49	12.09	-1.19	74
Sep-22	All	27,722	245.08	-32.82	8.84	-1.18	71

Figure 5.5 shows aggregate (NEM and Non-NEM combined) hourly observed and estimated reference loads, along with hourly estimated TOU load impacts for the TOU-only customers for the average weekday in August. Figure 5.6 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a reduction in usage during the peak hours, though the reduction is not statistically significant. There appears to be evidence of statistically significant load shifting to super off-peak hours as reference loads are below observed loads in hours ending 1 through 7. The TOU load impacts during the winter are positive, but only statistically significant for hour ending 20. TOU customers did not shift to super off-peak hours in January.

Figure 5.5: Aggregate Hourly Loads and TOU Load Impacts(MWh/h) – TOU Customers (Average Weekday, August 2022)

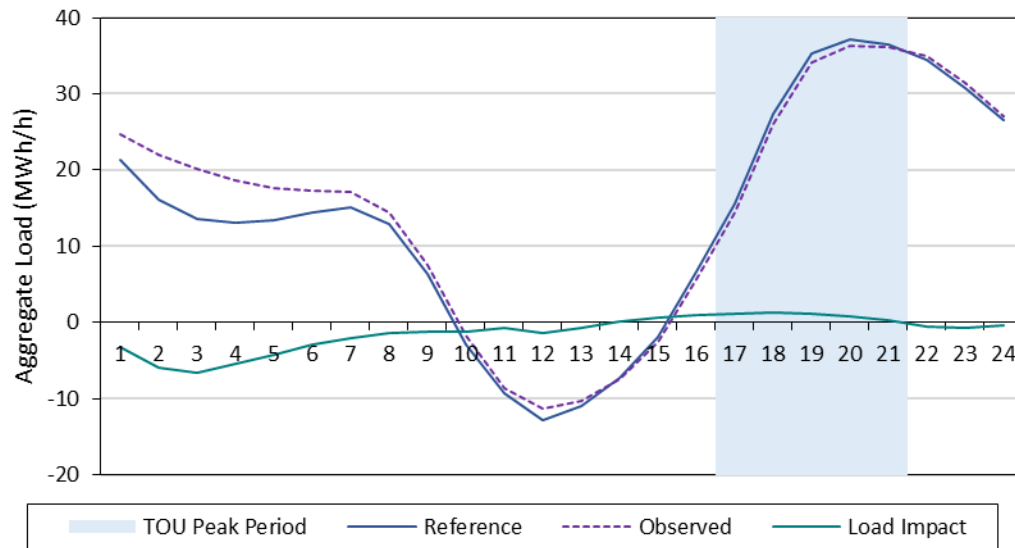
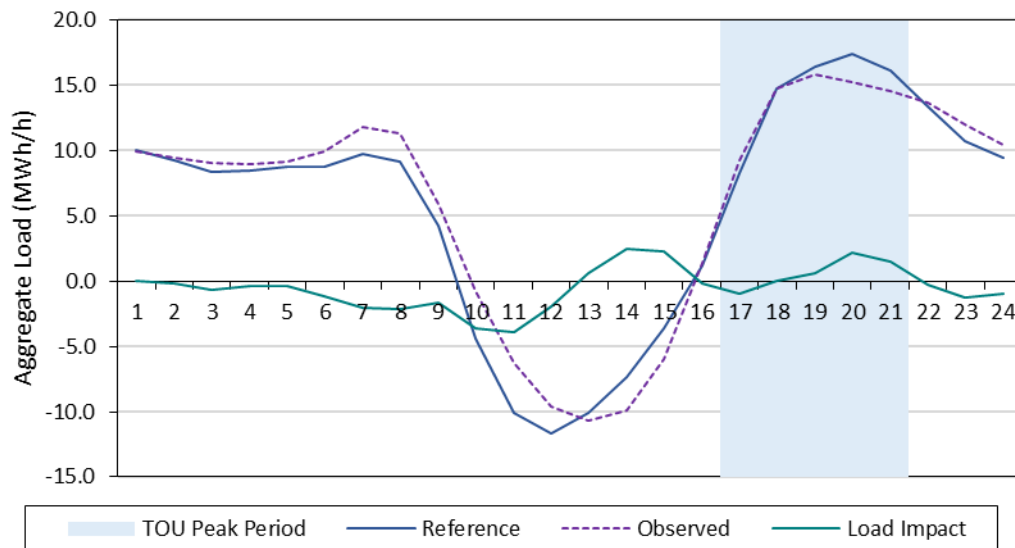


Figure 5.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers (Average Weekday, January 2022)



5.3 TOU control group matching results for CPP customers

Figure 5.7 and Figure 5.8 illustrate the quality of the matches for the Non-NEM residential 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 3.4 percent, while the mean absolute percentage error (MAPE) is 3.4 percent. In the winter months, the MPE is 2.0 percent and the MAPE is 2.9 percent.

Figure 5.7: Non-NEM CPP and Matched Control Group Load Profiles – Summer

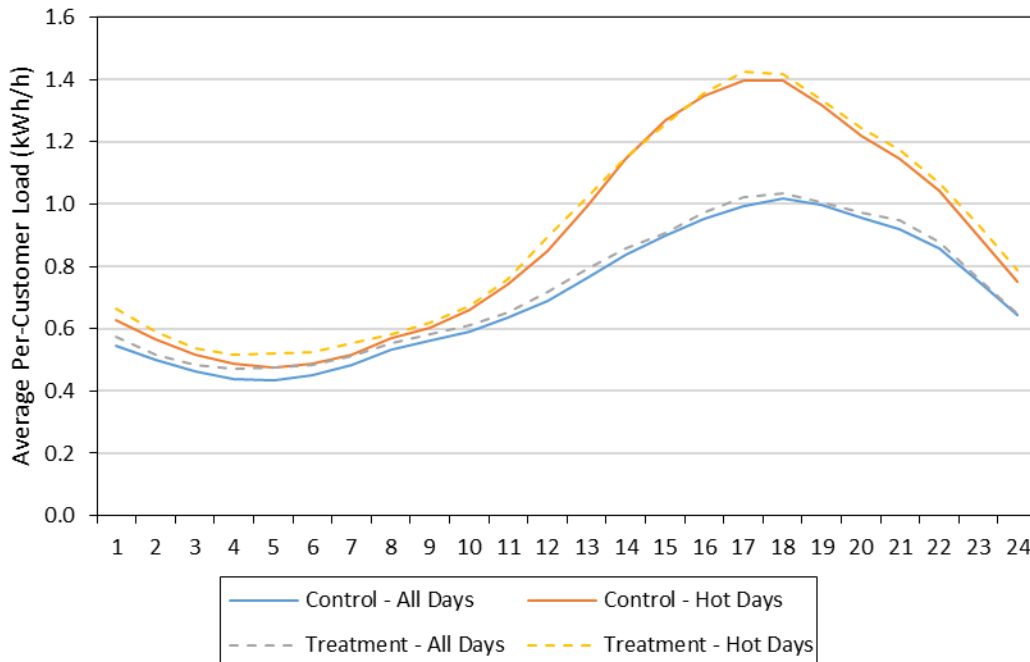


Figure 5.8: Non-NEM CPP and Matched Control Group Load Profiles – Winter

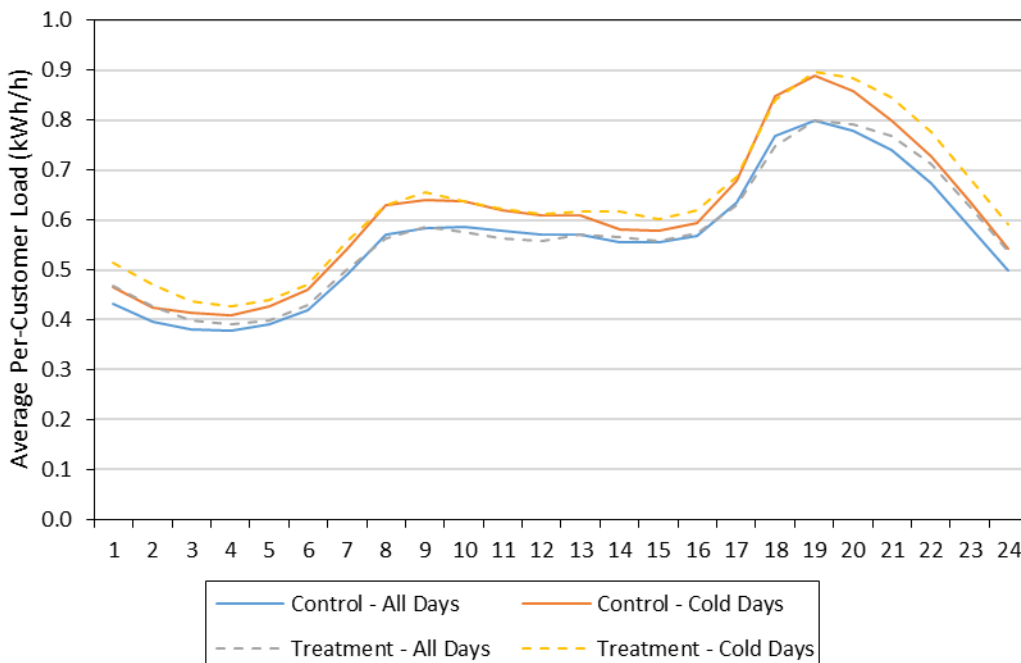


Figure 5.9 and Figure 5.10 illustrate the quality of the matches for the NEM residential CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU profile

compared to the control-group profile is 0.03 kWh/h, while the mean absolute error (MAE) is 0.05 kWh/h. In the winter months, the ME is 0.04 kWh/h, and the MAE is 0.09 kWh/h.

Figure 5.9: NEM CPP and Matched Control Group Load Profiles – Summer

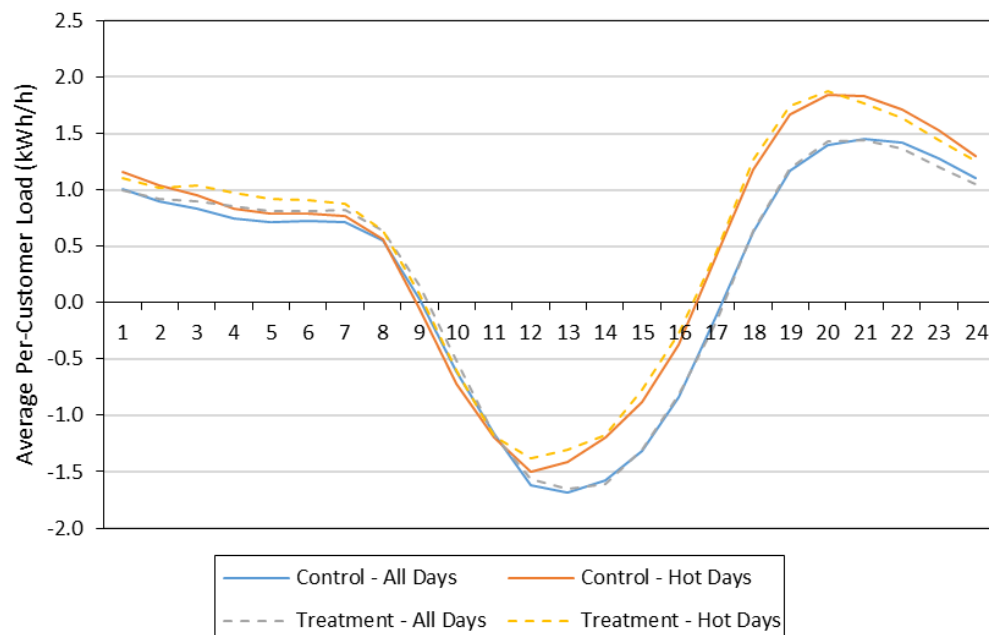
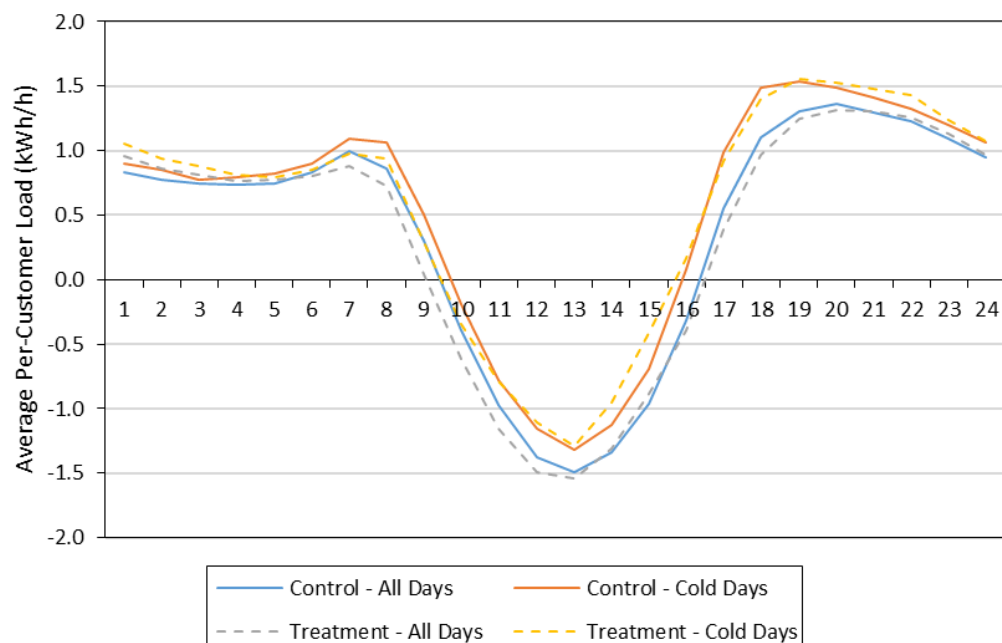


Figure 5.10: NEM CPP and Matched Control Group Load Profiles – Winter



5.4 Ex-post TOU load impacts for CPP customers

Since TOU-DR-P customers experience TOU prices on all weekdays that are not residential 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 results for those customers enrolled on the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average summer (October 2021, and June through September 2022) and winter (November 2021 through May 2022) weekdays, by month. Reported enrollment in CPP fell from 22,405 in October 2021 to 15,868 in September 2022.²⁶ Peak load impacts varied between seasons, with estimated load reductions of 0.10 kWh/h in all summer months and 0.02 kWh/h in all winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. Summer load impacts are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Oct-21	All	22,405	17.35	1.53*	0.77	0.07*	67
Nov-21	All	22,521	18.06	0.47	0.80	0.02	63
Dec-21	All	22,583	22.79	0.56	1.01	0.02	55
Jan-22	All	23,448	20.27	0.52	0.86	0.02	58
Feb-22	All	24,249	19.35	0.52	0.80	0.02	59
Mar-22	All	24,718	15.88	0.56	0.64	0.02	64
Apr-22	All	24,799	14.01	0.54	0.56	0.02	66
May-22	All	24,464	13.28	0.46	0.54	0.02	65
Jun-22	All	16,279	14.82	1.56*	0.91	0.10*	73
Jul-22	All	15,609	15.87	1.56*	1.02	0.10*	74
Aug-22	All	15,763	22.34	1.75*	1.42	0.11*	78
Sep-22	All	15,868	17.91	1.56*	1.13	0.10*	74

Table 5.5 summarizes results by season and climate zone. The two climate zones display different load impacts, with the Inland climate zone decreasing usage by 0.16 kwh/h compared to 0.05 kwh/h in the Coastal climate zone during the summer period. Load impacts both climate zones decrease between summer and winter. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. Summer load impacts for the Inland climate zone and for all climates are statistically significant at the 10% level.

²⁶ The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days were required for measuring CPP load impacts. There were 592 Non-NEM 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. As was the case with TOU-DR, a small group of 49 NEM TOU-DR-P customers were used to estimate the NEM regressions.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	8,998	7.81	0.41	0.87	0.05	72
	Inland	8,186	9.99	1.31*	1.22	0.16*	74
	All	17,185	17.81	1.72*	1.04	0.10*	73
Winter	Coastal	14,219	10.24	0.45	0.72	0.03	62
	Inland	9,606	7.45	0.09	0.78	0.01	62
	All	23,826	17.68	0.54	0.74	0.02	62

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers *increased* their average daily usage during all winter months and *decreased* their usage in all summer months. There is an overall annual load increase of approximately 0.15 kwh/h relative to the reference load. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-21	All	22,405	249.33	5.04	11.13	0.22	64
Nov-21	All	22,521	248.16	-9.67	11.02	-0.43	61
Dec-21	All	22,583	353.86	-9.94	15.67	-0.44	54
Jan-22	All	23,448	300.73	-10.54	12.83	-0.45	55
Feb-22	All	24,249	268.12	-11.01	11.06	-0.45	56
Mar-22	All	24,718	219.40	-6.32	8.88	-0.26	59
Apr-22	All	24,799	186.77	-6.17	7.53	-0.25	62
May-22	All	24,464	180.33	-11.04	7.37	-0.45	62
Jun-22	All	16,279	170.03	5.05	10.44	0.31	69
Jul-22	All	15,609	197.31	5.04	12.64	0.32	70
Aug-22	All	15,763	298.23	6.20	18.92	0.39	75
Sep-22	All	15,868	229.16	4.87	14.44	0.31	71

Figure 5.11 shows aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the residential CPP customers for the average weekday in August. Figure 5.12 shows the same information for the average weekday in January. The average weekday in August loads illustrates a slight load shift out of the peak period to the super off-peak period. The January average loads also exhibit load shifting during the super off-peak period and close to zero change during all other hours.

Figure 5.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers (Average Weekday, August 2022)

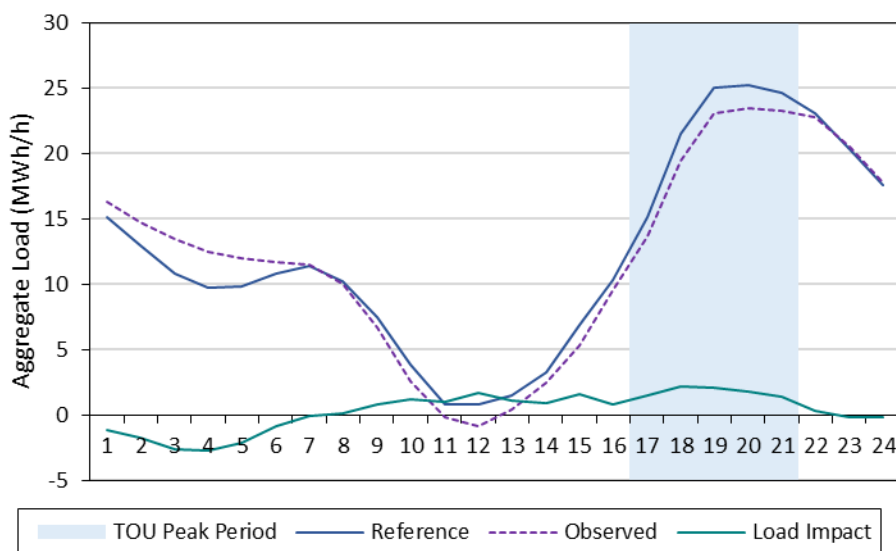
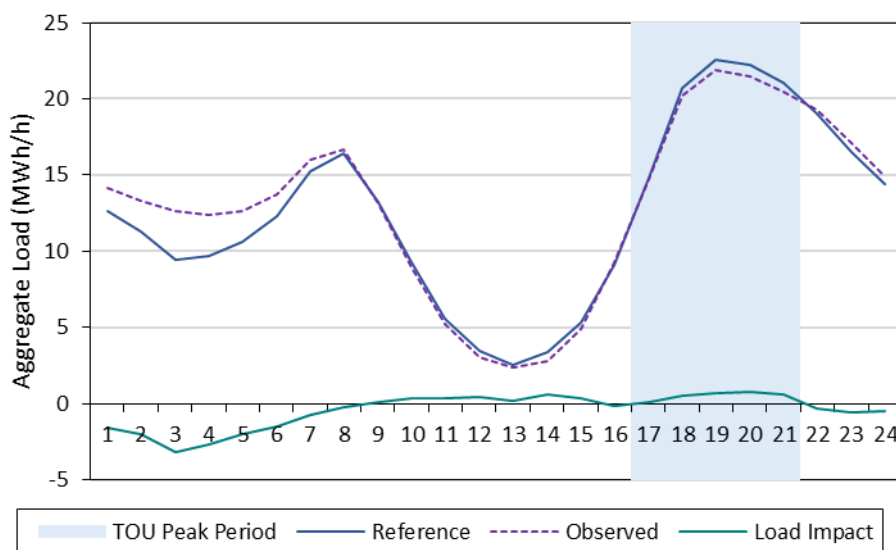


Figure 5.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers (Average Weekday, January 2022)



5.5 TOU control group matching results for Grandfathered customers

Figure 5.13 and Figure 5.14 illustrate the quality of the matches for the grandfathered CPP (GTOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average grandfathered 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 error (ME) of the TOU profile compared to the control-group profile is 0.057 kWh/h, while the mean absolute error (MAE) is 0.136 kWh/h. In the winter months, the ME is -0.13 kWh/h and the MAE is 0.26 kWh/h. In order to qualify as an eligible control customer for the grandfathered analysis, customers must have remained on the same rate, and not changed the size of their PV system, since 2015. The limited number of eligible control customers can result in lower quality matches relative to the non-grandfathered analysis.

Figure 5.13: Grandfathered CPP and Matched Control Group Load Profiles – Summer

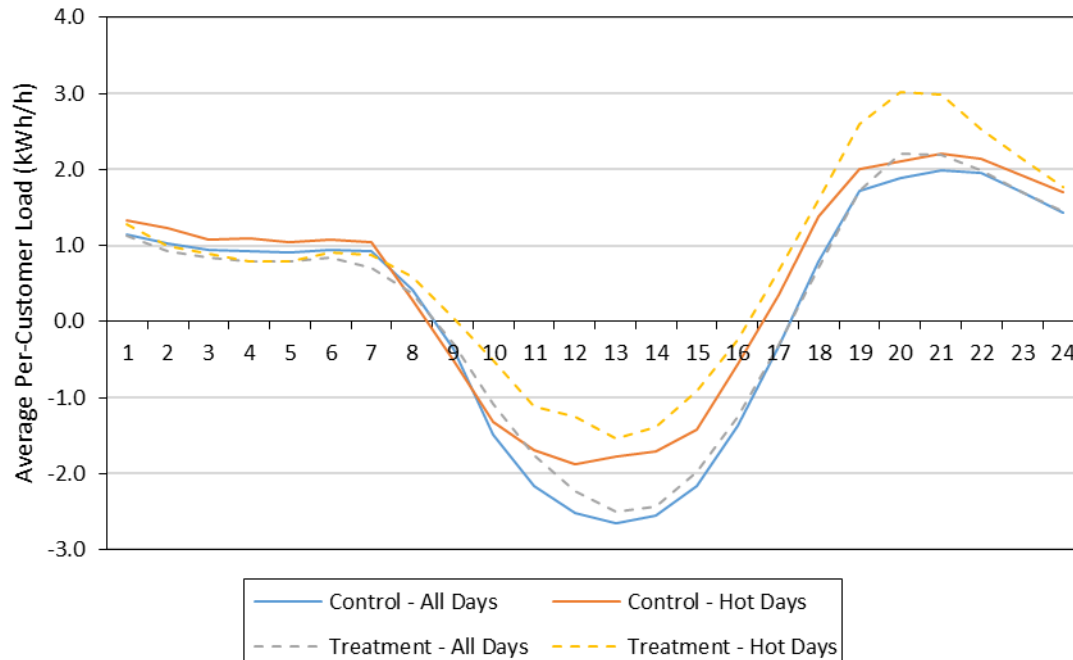
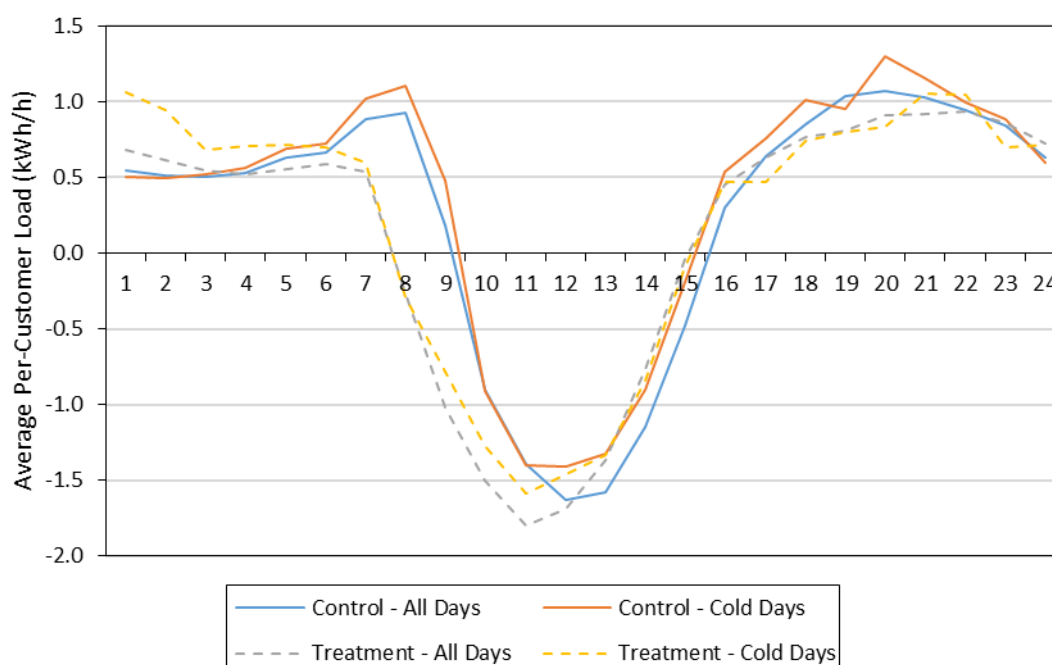


Figure 5.14: Grandfathered CPP and Matched Control Group Load Profiles – Winter



5.6 Ex-post TOU load impacts for Grandfathered customers

This sub-section shows ex-post TOU load impact results for Grandfathered customers (enrolled in GTOU-DR-P). Table 5.7 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 TOU load impacts are estimated using PY2017 incremental customers who have remained on the grandfathered TOU rate and have not had structural changes to their Net Energy Metering setups. Monthly enrollment numbers and reference loads are drawn from the October 2021 through July 2022 period as the grandfathered rate ended on July 31, 2022. The winter months are indicated by light blue shading. Customer enrollments range between 381 and 399.²⁷ Grandfathered customers increased usage by 0.99 kWh/h on average during peak hours in the summer season and a 0.38 kWh/h during peak hours in the winter season. Positive reference loads during the winter and negative reference loads during the summer occur because the grandfathered TOU peak-period in the summer occurs during the middle of the day, while the TOU peak-period in the winter occurs during the evening, after the sun has set. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

²⁷ 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, only nine incremental grandfathered customers were included in the regression analysis for the summer period, and one was used during the winter period. These are customers who remained unchanged since the pretreatment period in 2016. The aggregate TOU load impacts are then scaled to total enrollments during the PY2022 period.

Table 5.7: TOU Peak Load Impacts for Grandfathered Customers – Average Weekday by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Oct-21	All	381	-0.55	-0.15	-1.44	-0.38	72
Nov-21	All	384	0.16	-0.38*	0.42	-0.99	63
Dec-21	All	387	0.27	-0.38*	0.70	-0.99	55
Jan-22	All	390	0.20	-0.39*	0.50	-0.99	58
Feb-22	All	395	0.17	-0.39*	0.43	-0.99	59
Mar-22	All	396	0.00	-0.39*	-0.01	-0.99	64
Apr-22	All	397	-0.12	-0.39*	-0.31	-0.99	67
May-22	All	399	-0.17	-0.40*	-0.43	-0.99	66
Jun-22	All	399	-0.91	-0.15	-2.27	-0.38	77
Jul-22	All	387	-0.80	-0.15	-2.07	-0.38	76

Table 5.8 summarizes results by season and climate zone. Because of data limitations arising from a small number of treatment customers, TOU regressions by climate zone were not estimated. Instead, the analysis estimates TOU impacts across a combined group of customers, which gives rise to load impacts that are assumed to be equal between climate zones. These load impacts were applied to climate zone-specific reference loads. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

Table 5.8: TOU Peak Load Impacts for Grandfathered Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave Peak Temp
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	180	-0.37	-0.07	-2.04	-0.38	74
	Inland	209	-0.38	-0.08	-1.83	-0.38	76
	All	389	-0.75	-0.15	-1.93	-0.38	75
Winter	Coastal	183	0.04	-0.18	0.20	-0.99	62
	Inland	210	0.04	-0.21	0.17	-0.99	62
	All	393	0.07	-0.39	0.18	-0.99	62

Table 5.9 shows the TOU effect on average daily usage by month. Grandfathered customers *decreased* overall usage during winter months but *increased* overall usage during summer months. The overall effect is an average annual *increase* of about 1.99 kWh/h per customer. An asterisk next to a load impact indicates that the result is statistically significant at the 10% level. No results are statistically significant at the 10% level.

Table 5.9: TOU Average Daily Load Impacts for Grandfathered Customers, by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-21	All	381	0.06	-2.16	0.15	-5.67	63
Nov-21	All	384	-1.60	-4.57	-4.18	-11.91	61
Dec-21	All	387	2.94	-4.61	7.59	-11.91	54
Jan-22	All	390	-0.33	-4.64	-0.85	-11.91	55
Feb-22	All	395	-2.71	-4.70	-6.85	-11.91	55
Mar-22	All	396	-5.59	-4.72	-14.12	-11.91	59
Apr-22	All	397	-7.82	-4.73	-19.69	-11.91	62
May-22	All	399	-7.93	-4.75	-19.89	-11.91	62
Jun-22	All	399	-2.76	-2.26	-6.91	-5.67	69
Jul-22	All	387	-1.55	-2.19	-4.00	-5.67	70

Figure 5.15 and Figure 5.16 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. During the summer period, customers increased usage during all hours. The winter load profile illustrates a reduction in usage during peak hours.

Figure 5.15: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) - Grandfathered Customers (Average Weekday, July 2022)

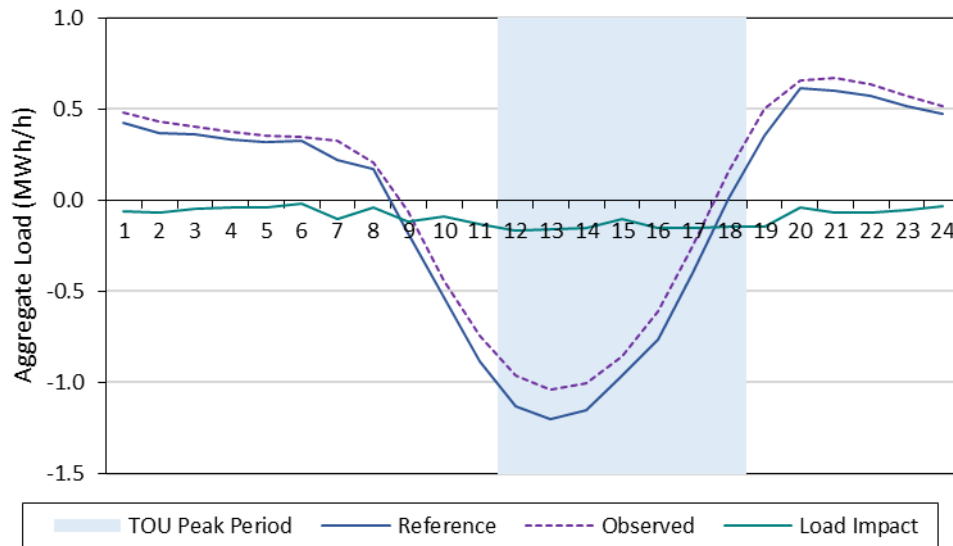
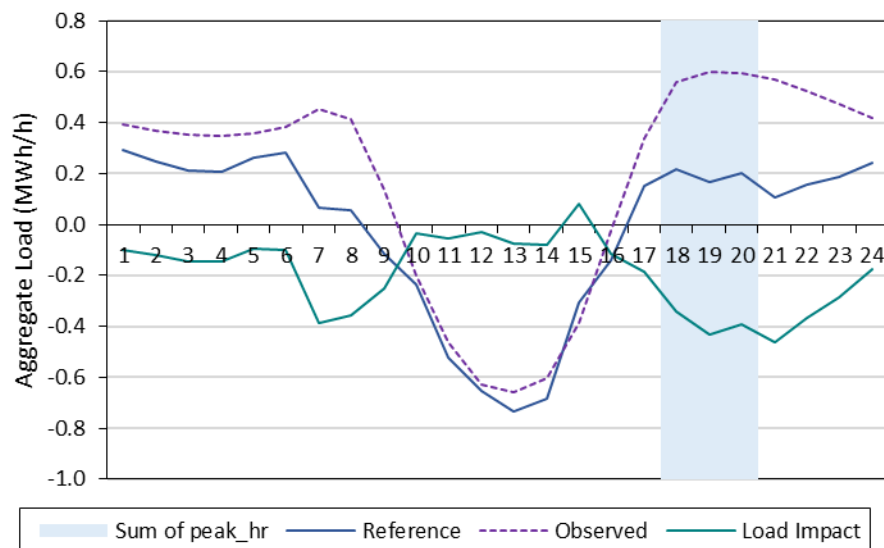


Figure 5.16: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) - Grandfathered Customers (Average Weekday, January 2022)



6 EX-ANTE EVALUATION METHODOLOGY

This section describes the methodology for developing ex-ante load impact forecasts for the CPP and TOU rates. Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on analyses of per-customer load impact findings from ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments. The ex-ante analysis for CPP events applies CPP event load impacts from the ex-post analysis to simulated reference loads using PY2022 customer load data.

6.1 Per-customer load impacts

CPP events are usually called during extreme weather scenarios. We develop a relationship between event-day ex-post load impacts and weather conditions. That relationship is used to produce weather-sensitive ex-ante load impacts for the relevant weather scenarios. SDG&E called five CPP events in 2022. The ex-ante analysis uses load impacts from the two weekday non-holiday events as a basis for PY2022 ex-ante forecasts. The average weekday event percentage load impact calculated in the ex-post analysis is used to simulate the ex-ante CPP load impact. CPP load impacts for different weather scenarios are developed by applying the estimated percentage ex-post load impact, in the case of non-NEM customers, or level load impacts for NEM customers, to simulated weather-sensitive reference loads. Different ex-post percentage load impacts are applied to reference loads by climate zone, NEM status, and dual enrollment in either ACSDA or ELRP.

Portfolio-level load impacts are reported for instances when a CPP event is called on the same day as an AC Saver Day-Of (ACSDO) event. For such days, it is assumed that ACSDO customers do not provide a load impact that can be attributable to CPP. Therefore, dually enrolled customers are removed from the reference load and load impacts for portfolio-level estimates. The proportion of ACSDO customers is assumed to be equivalent to ex-post enrollment numbers and is held constant throughout the ex-ante forecast.

For TOU load impacts (TOU-DR and TOU-DR-P customers), percentage peak load impacts from the ex-post analysis (monthly values for CPP and seasonal values for TOU) 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 within each rate is assumed to remain constant throughout the forecast period. Non-NEM and NEM results are customer weighted to produce program TOU and CPP outcomes.

6.2 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 CPP and TOU customers. Customers are first sorted as weather sensitive or not.²⁸

²⁸ 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:

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

where Q_t represents the average customer usage during event hours on day t in the summer months of June through September. Event days were removed from the dataset. $MONTH_{i,t}$ represents each month. The variable of importance is $Weather_t$, which is defined as CDD65 for summer weather sensitivity or HDD65 for

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, CDH65, and HDH60);²⁹
- Data for all months were included, rather than estimating separate models by season; and
- Month-year indicator variables were added to account for monthly and yearly differences in usage patterns.

The resulting equations allow the simulation of “observed” (*i.e.*, post TOU load impacts) loads under the four different weather scenarios. Reference loads for the alternative scenarios were then obtained by adjusting the above observed loads by the relevant estimated percentage TOU load impacts from the ex-post analysis (seasonal values for TOU, and monthly values for CPP).³⁰ 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.³¹

6.3 Enrollment Forecast

Figure 6.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be declining for TOU. The spatial composition of TOU and TOU+CPP customers is different with CPP customers being approximately evenly distributed while TOU customers have 1.5 times higher enrollment in the Coastal climate zone compared to the Inland climate zone.

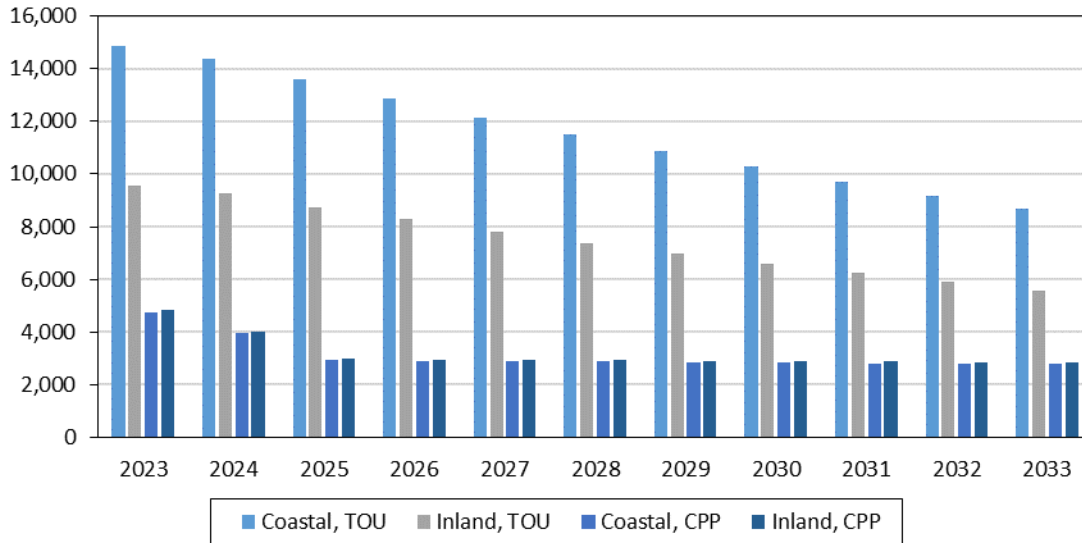
winter weather sensitivity, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant.

²⁹ Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree hours (CDH) for each hour of the day are defined as: $CDH65 = \max(0, \text{Temperature in } ^\circ\text{F} - 65)$. Likewise, heating degree hours (HDH) for each hour of the day are defined as: $HDH60 = \max(0, 60 - \text{Temperature in } ^\circ\text{F})$.

³⁰ The adjustment takes the form of $\text{Reference} = \text{Observed} / (1 - \% \text{TOULoadImpact})$. 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.

³¹ 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 be 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 may 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 6.1: Enrollments in TOU and CPP Rates



7 EX-ANTE LOAD IMPACT STUDY FINDINGS

This section presents the ex-ante TOU load impacts for rates TOU-DR and TOU-DR-P.

7.1 Ex-Ante load impacts – Residential CPP

This subsection summarizes the ex-ante load impact forecasts for future CPP event days, for customers anticipated to be enrolled in CPP. Figure 7.1 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2023 for the SDG&E 1-in-2 weather scenario. The average event-period load impact is 1.25 MWh/h.

Figure 7.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) – (August 2023 SDG&E 1-in-2 Peak Day)

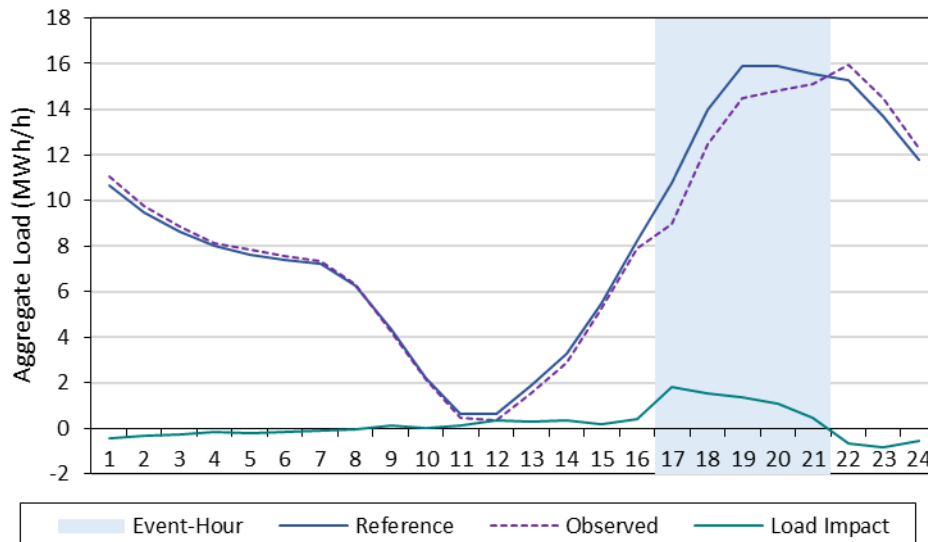


Figure 7.2 shows the monthly pattern of aggregate average ex-ante load impacts (RA window) in 2023 for the SDG&E 1-in-2 peak day. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March and April, when it is 5 to 10 p.m. (HE 18-22). Load impacts are greatest in the summer months, reaching a maximum in August. The difference in load impacts between months also indicates the seasonal pattern in customer reference loads. The lower load impacts in March and April are driven by differences between the CPP event and RA window during these months.

Figure 7.2: Aggregate CPP Load Impacts (MWh/h), by Month – (2023 SDG&E 1-in-2 Peak Day, RA Window)

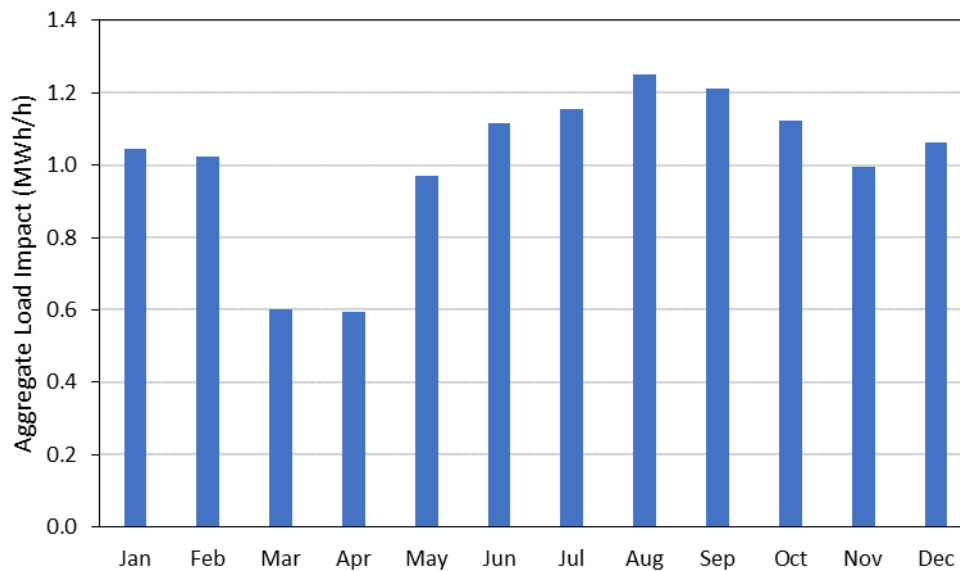
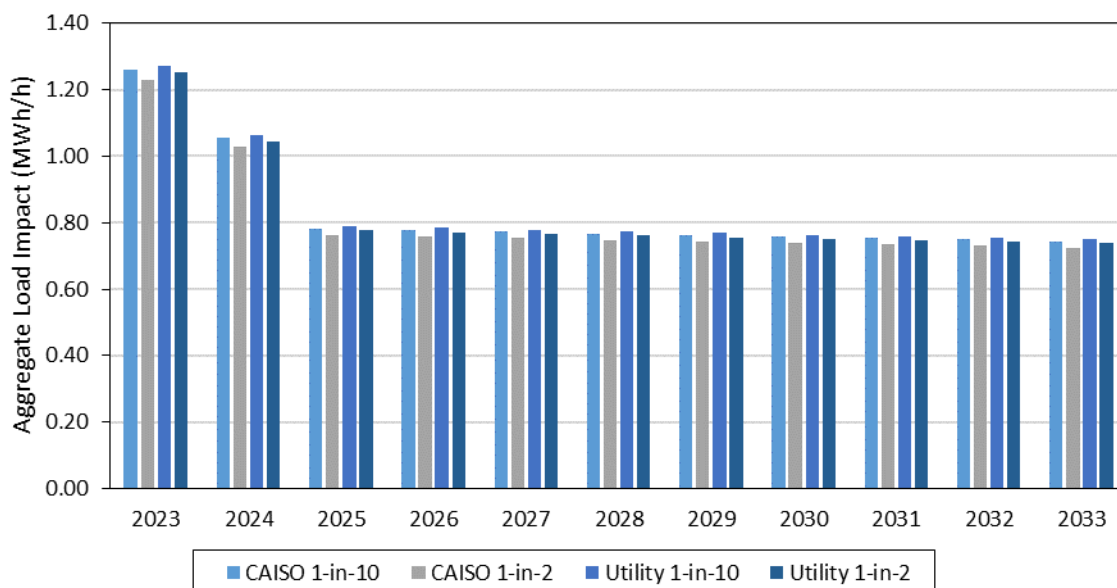


Figure 7.3 illustrates a decrease in aggregate load impact over time as enrollment decreases. The differences are relatively minor between the aggregate ex-ante load impacts for the alternative weather scenarios over the forecast period. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

Figure 7.3: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario - (August Peak Day, RA Window)



7.2 Ex-Ante load impacts – Residential TOU

This subsection summarizes the ex-ante TOU peak load impact forecasts for customers anticipated to be enrolled in both the TOU and CPP rates (TOU-DR and TOU-DR-P). Figure 7.4 shows aggregate loads and load impacts for TOU and CPP customers, in 2023 for an August SDG&E 1-in-2 average weekday. The average peak load impact is 1.99 MWh/h.

Figure 7.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, (August 2023 SDG&E 1-in-2 Average Weekday)

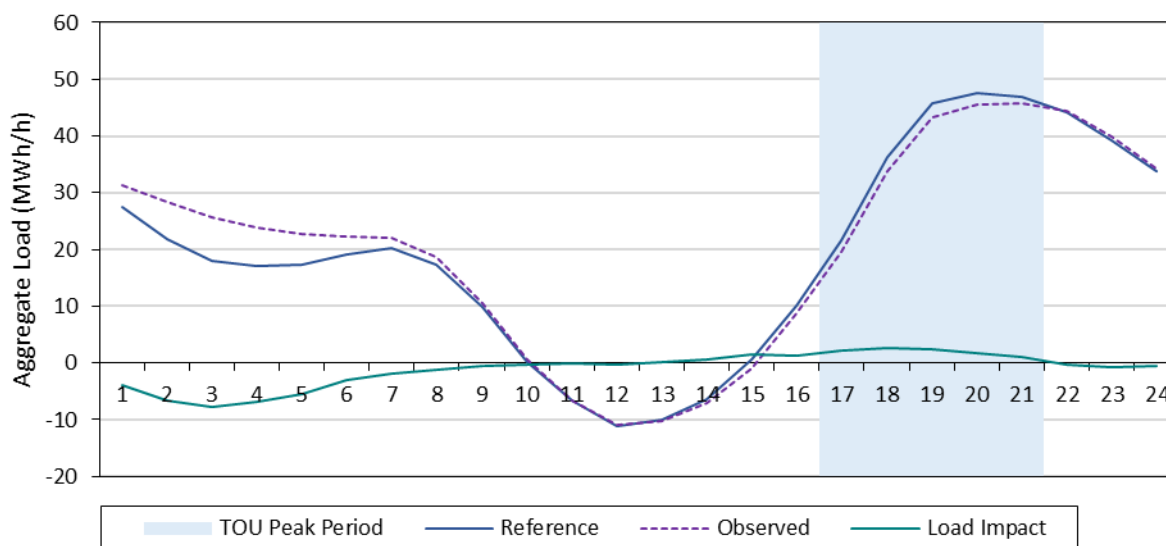


Figure 7.5 shows the monthly distributions of the peak-period TOU load impacts for TOU and CPP customers. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March and April, when

it is 5 to 10 p.m. (HE 18-22); however, the peak period is 4 to 9 p.m. (HE 17 – 21) in all months. Load impacts are slightly larger in the spring months, March and April, compared to the summer months.³²

Figure 7.5: Aggregate TOU Load Impacts (MWh/h) by Month – TOU-DR and TOU-DR-P Customers, (2023 SDG&E 1-in-2 Average Weekday, RA Window)

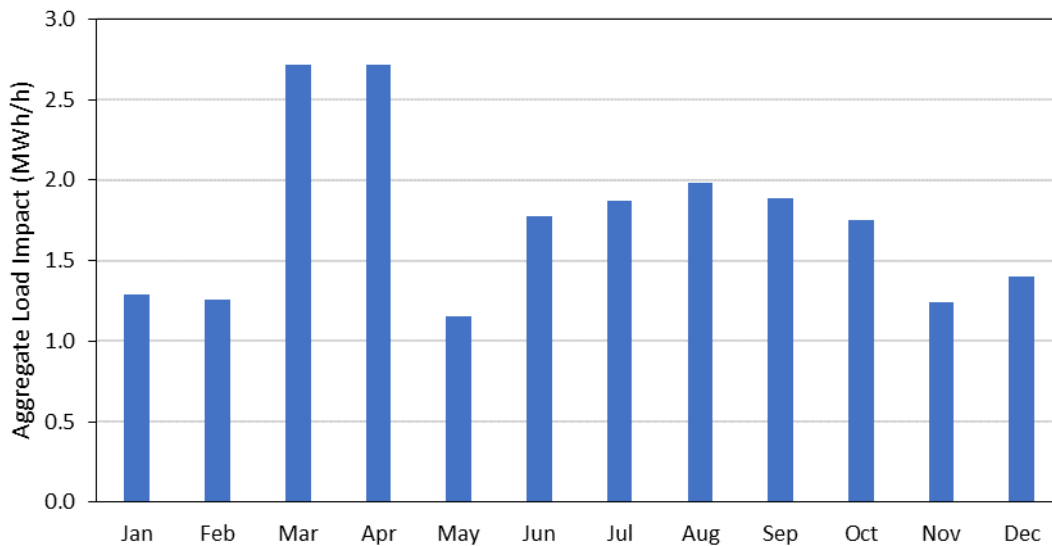
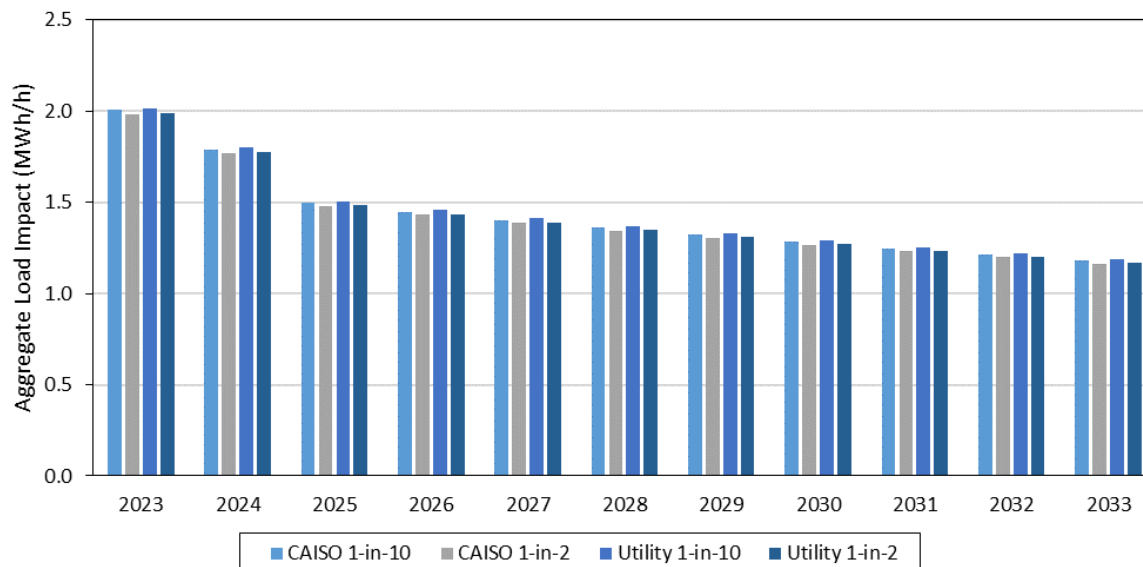


Figure 7.6 shows the aggregate average August weekday TOU load impacts over the forecast period, differentiated by weather scenario. The load impacts are largest for the CAISO and Utility 1-in-10 scenarios, which have equivalent temperatures for the average August weekday. (TOU load impacts are largest for the Utility 1-in-10 scenarios on monthly peak days.) In 2022, a substantial number of residential CPP customers are forecasted to de-enroll as they transition to Community Choice Aggregator programs. The relatively level forecast reflects the enrollment forecast for TOU-DR customers remaining constant between 2022 and 2033, whereas any decay in aggregate load impact is due to decreasing enrollments of TOU-DR-P customers.

³² March and April are estimated separately because the TOU period during these months incorporates midday off-peak hours that differ from all other months.

Figure 7.6: Aggregate TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, by Year and Weather Scenario (Average August Weekday, RA Window)



8 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.
- Previous CPP ex-post and ex-ante load impacts.

In the above list, “current study” refers to this report, which is based on findings from the 2022 program year; and “previous study” refers to the report that was developed following the 2021 program year.

8.1 Residential CPP

8.1.1 Previous versus current ex-post

Table 8.1 shows the average event-hour reference loads and CPP load impacts for the average weekday event during the current and previous program years, using PY2020 as the previous year comparison since there were no residential CPP events called in PY2021. The event hours were 2 p.m. to 6 p.m. in PY2020 and 4 p.m. to 9 p.m. in PY2022. The aggregate enrollments are comparable between the two years while the reference loads have disproportionately increased. The per-customer reference load in the PY2022 study is larger while the per-customer load impact is smaller. However, the ratio of NEM to Non-NEM customers nearly doubled in this time for CPP customers.

Table 8.1: Comparison of PY2020 Ex-Post and Current 2022 Ex-Post Load Impacts, Residential CPP Weekday Event

Result	<i>Ex-post for 2020 Event Day from PY2020 Study</i>	<i>Ex-post for 2022 Event Day from PY2022 Study</i>
# Enrolled	15,384	15,862
Reference (MWh/h)	19.28	30.29
Load Impact (MWh/h)	2.57	2.27
Per-customer reference (kWh/h)	1.25	1.91
Per-customer load impact (kWh/h)	0.17	0.14
Temperature	89.3	86.7
% NEM	17.4%	33.1%

8.1.2 Previous versus current ex-ante

In this sub-section, the ex-ante forecast prepared in PY2021 is compared to the ex-ante forecast contained in this study. Table 8.2 reports the average event-hour load impacts for the August 2023 system peak day under utility-specific 1-in-2 weather conditions. While per-customer reference loads are higher in the current study due to hotter temperatures, the current study ex-ante forecast has slightly lower load impacts. Aggregate reference loads and load impacts are larger in the PY2022 ex-ante analysis due to an updated enrollment forecast having higher overall enrollments.

Table 8.2: Comparison of PY2021 Ex-Ante 2023 Forecast and Current Ex-Ante 2023 Forecast Load Impacts, CPP Event

Result	<i>Ex-ante for 2023 System Peak Day from PY2021 Study</i>	<i>Ex-ante for 2023 System Peak Day from PY2022 Study</i>
# Enrolled	3,852	9,510
Reference (MWh/h)	5.04	14.42
Load Impact (MWh/h)	0.58	1.25
Per-customer reference (kWh/h)	1.31	1.52
Per-customer load impact (kWh/h)	0.15	0.13
Temperature	82.9	84.7
% NEM	20.9%	33.6%

8.1.3 Previous ex-ante versus current ex-post

Table 8.3 provides a comparison of the ex-ante forecast of 2022 load impacts prepared in PY2021 and the PY2022 load impacts estimated as part of this study, averaged over the CPP

event-window. The ex-ante forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The increase in aggregate reference loads is due to an increase in enrollment. The per-customer load impact is 0.01 kWh/h lower in ex-post than ex-ante. This may be due to the percentage NEM composition between ex-ante and ex-post.

Table 8.3: Comparison of PY2021 Ex-Ante 2022 Forecast and Current Ex-Post Load Impacts, Residential CPP Event

Result	<i>Ex-ante for 2022 System Peak Day from PY2021 Study</i>	<i>Ex-post for 2022 Event Day from PY2022 Study</i>
# Enrolled	9,240	15,862
Reference (MWh/h)	12.09	30.29
Load Impact (MWh/h)	1.40	2.27
Per-customer reference (kWh/h)	1.31	1.91
Per-customer load impact (kWh/h)	0.15	0.14
Temperature	82.9	86.7
% NEM	20.9%	33.1%

8.1.4 Current ex-post versus current ex-ante

Table 8.4 compares the CPP ex-post load impacts for the average weekday event against the ex-ante load impacts for 2023 (of the SDG&E 1-in-2 August peak day), from this study. The current ex-ante study forecasts lower enrollments, resulting in a lower aggregate reference load. Per-customer reference loads are lower in ex-ante because of cooler temperatures compared to ex-post (93.0 vs 84.7 degrees). The smaller reference loads results in smaller ex-ante load impacts.

Table 8.4: Comparison of Current Ex-Post and Ex-Ante Load Impacts, Residential CPP Event

Result	<i>Ex-post for 2022 Event Day from PY2022 Study</i>	<i>Ex-ante for 2023 System Peak Day from PY2022 Study</i>
# Enrolled	15,862	9,510
Reference (MWh/h)	30.29	14.42
Load Impact (MWh/h)	2.27	1.25
Per-customer reference (kWh/h)	1.91	1.52
Per-customer load impact (kWh/h)	0.14	0.13
Temperature	86.7	84.7
% NEM	33.1%	33.6%

Table 8.5 compares the key components of the two analyses. As the table describes, the three largest sources of differences between the ex-post and ex-ante load impacts are the effect of Covid-19, the enrollment level, and the summary over the RA window for ex-ante versus the actual event hours for the ex-post impacts.

Table 8.5: Ex-Post versus Ex-Ante Factors, CPP Event

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	86.7 degrees Fahrenheit during HE 17-21.	84.7 degrees Fahrenheit during HE 17-21 of a utility-specific 1-in-2 August peak day.	Cooler ex-ante weather decreases the reference load and load impact.
% of resource dispatched	The entire program was dispatched on each of the days that comprise the average weekday event.	Assume all customers are called.	None. The ex-ante method assumes that all enrolled customers are dispatched.
Enrollment	15,862 customers enrolled.	9,510 customers.	The decrease in ex-ante enrollments decreases the total load impact proportionately relative to ex-post.
Methodology	Climate-zone-specific regressions using a matched control-group and difference-in-differences analysis on event and event-like non-event days.	Treatment only customer regressions to estimate observed loads using PY2022 data.	No effect to percentage load impacts. The ex-post percentage load impacts are applied to reference loads of the various scenarios in the ex-ante study.

8.2 Residential TOU

8.2.1 Previous versus current ex-post

Table 8.6 shows the reference loads and load impacts for the average August and January weekday during the current and previous program years, averaged over the RA window, which corresponds to the TOU peak period. Enrollment numbers have increased resulting in higher aggregate reference loads and load impacts. Per-customer load impacts decreased in the summer period but increased in the winter period. The 2022 summer per-customer impact of 0.06 kWh/h is similar to the 2021 per-customer load impact as well as the pre-covid load impacts.

Table 8.6: Comparison of PY2021 Ex-Post and PY2022 Ex-Post TOU Load Impacts

Season	Result	Ex-post for 2021 Avg. Weekday PY2021 Study	Ex-post for 2022 Avg. Weekday PY2022 Study
Summer (August)	# Enrolled	33,742	43,147
	Reference (MWh/h)	37.71	52.70
	Load Impact (MWh/h)	2.60	2.70
	Per-customer reference (kWh/h)	1.12	1.22
	Per-customer load impact (kWh/h)	0.08	0.06
	Temperature	75.5	77.4
	% NEM	36.6%	36.9%
Winter (January)	# Enrolled	24,736	38,101
	Reference (MWh/h)	26.50	34.87
	Load Impact (MWh/h)	0.25	1.19
	Per-customer reference (kWh/h)	1.07	0.92
	Per-customer load impact (kWh/h)	0.01	0.03
	Temperature	57.7	58.4
	% NEM	31.0%	31.2%

8.2.2 Previous versus current ex-ante

Table 8.7 reports the average RA-window load impacts for the August and January 2023 average weekday under utility-specific 1-in-2 weather conditions. The TOU RA window and peak-period remains the same in both forecasts. The current study has a higher forecast enrollment, which is associated with an increase in aggregate reference loads. Per-customer reference loads and load impacts in the present analysis are slightly smaller compared to the previous study.

Table 8.7: Comparison of PY2021 and PY2022 Ex-Ante 2023 Forecast TOU Load Impacts

Season	Result	Ex-ante for 2023 Avg. Weekday PY2021 Study	Ex-ante for 2023 Avg. Weekday PY2022 Study
Summer (August)	# Enrolled	16,142	34,035
	Reference (MWh/h)	20.64	39.62
	Load Impact (MWh/h)	2.15	1.99
	Per-customer reference (kWh/h)	1.28	1.16
	Per-customer load impact (kWh/h)	0.13	0.06
	Temperature	75.9	76.3
	% NEM	51.6%	37.7%
Winter (January)	# Enrolled	16,142	34,035
	Reference (MWh/h)	17.91	31.50
	Load Impact (MWh/h)	1.08	1.29
	Per-customer reference (kWh/h)	1.11	0.93
	Per-customer load impact (kWh/h)	0.07	0.04
	Temperature	61.1	60.8
	% NEM	51.6%	37.7%

8.2.3 Previous ex-ante versus current ex-post

Table 8.8 provides a comparison of the ex-ante forecast of 2022 TOU load impacts prepared in the previous study and the PY2022 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 reference loads in both periods. The per-customer load impacts are smaller than the predicted ex-ante load-impacts. The difference in ex-ante results shown here corresponds to the difference in ex-post results seen in Table 8.6.

Table 8.8: Comparison of PY2021 Ex-Ante 2022 Forecast and PY2022 Ex-Post TOU Load Impacts

Season	Result	<i>Ex-ante for 2022 Avg. Weekday PY2021 Study</i>	<i>Ex-post for 2022 Avg. Weekday PY2022 Study</i>
Summer (August)	# Enrolled	21,570	43,147
	Reference (MWh/h)	26.03	52.70
	Load Impact (MWh/h)	2.36	2.70
	Per-customer reference (kWh/h)	1.21	1.22
	Per-customer load impact (kWh/h)	0.11	0.06
	Temperature	76.1	77.4
	% NEM	43.8%	36.9%
Winter (January)	# Enrolled	21,937	38,101
	Reference (MWh/h)	23.42	34.87
	Load Impact (MWh/h)	1.07	1.19
	Per-customer reference (kWh/h)	1.07	0.92
	Per-customer load impact (kWh/h)	0.05	0.03
	Temperature	61.1	58.4
	% NEM	43.8%	31.2%

8.2.4 Current ex-post versus current ex-ante

Table 8.9 compares the PY2022 ex-post TOU load impacts for the August average weekday with the corresponding ex-ante forecast for 2023 (of the utility-specific 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, which perfectly overlaps with the TOU peak period. The per-customer reference loads and load-impacts are nearly identical between the two scenarios.

Table 8.9: Comparison of Current Ex-Post and Ex-Ante TOU Load Impacts

Season	Result	<i>Ex-post for 2022 Avg. Weekday from PY2022 Study</i>	<i>Ex-ante for 2023 Avg. Weekday from PY2022 Study</i>
Summer (August)	# Enrolled	43,147	34,035
	Reference (MWh/h)	52.70	39.62
	Load Impact (MWh/h)	2.70	1.99
	Per-customer reference (kWh/h)	1.22	1.16
	Per-customer load impact (kWh/h)	0.06	0.06
	% Load Impact	5.1%	5.0%
	Temperature	77.4	76.3
	% NEM	36.9%	37.7%
Winter (January)	# Enrolled	38,101	34,035
	Reference (MWh/h)	34.87	31.50
	Load Impact (MWh/h)	1.19	1.29
	Per-customer reference (kWh/h)	0.92	0.93
	Per-customer load impact (kWh/h)	0.03	0.04
	% Load Impact	3.4%	4.1%
	Temperature	58.4	60.77
	% NEM	31.2%	37.7%

8.3 Grandfathered Customers – Residential CPP

There were no grandfathered customers on a grandfathered rate when the CPP events were called.

8.4 Grandfathered Customers – Residential TOU

8.4.1 Previous versus current ex-post

Table 8.10 shows the average reference loads and load impacts for the average July and January weekday during the current and previous program years, averaged over the RA window. The RA window does not overlap with the summer peak period for grandfathered customers. The RA window is 4 to 9 p.m. while the peak period is 11 a.m. to 6 p.m. The load impacts were several times the reference loads for all but 2021 winter. This can occur because grandfathered customers are NEM customers. Customers reduced usage during the 2021 winter peak period, in comparison to increased usage during the 2022 winter peak period.

**Table 8.10: Comparison of PY2021 Ex-Post and PY2022 Ex-Post TOU Load Impacts
– for Grandfathered Customers**

Season	Result	<i>Ex-post for 2021 Avg. Weekday PY2021 Study</i>	<i>Ex-post for 2022 Avg. Weekday PY2022 Study</i>
Summer (July)	# Enrolled	369	387
	Reference (MWh/h)	0.25	0.24
	Load Impact (MWh/h)	-0.20	-0.11
	Per-customer reference (kWh/h)	0.67	0.61
	Per-customer load impact (kWh/h)	-0.55	-0.28
	Temperature	75.5	72.9
Winter (January)	# Enrolled	373	390
	Reference (MWh/h)	0.57	0.17
	Load Impact (MWh/h)	0.03	-0.36
	Per-customer reference (kWh/h)	1.54	0.44
	Per-customer load impact (kWh/h)	0.08	-0.93
	Temperature	57.4	58.4

8.4.2 Previous ex-ante versus current ex-post

Table 8.11 provides a comparison of the ex-ante forecast of 2022 TOU load impacts prepared in the previous study and the PY2022 ex-post TOU load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the January average weekday during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on January weekdays. Per-customer reference loads were lower than predicted in the winter while the corresponding load impact was much higher than predicted, and wrong signed. The 2022 ex-post July reference loads are also lower than the ex-ante reference loads; however, the ex-post load impact is smaller in magnitude than ex-ante, unlike in January.

Table 8.11: Comparison of PY2021 Ex-Ante 2022 Forecast and PY2022 Ex-Post TOU Load Impacts for Grandfathered Customers

Season	Result	<i>Ex-ante for 2022 Avg. Weekday PY2021 Study</i>	<i>Ex-post for 2022 Avg. Weekday PY2022 Study</i>
Summer (July)	# Enrolled	367	387
	Reference (MWh/h)	0.44	0.24
	Load Impact (MWh/h)	-0.20	-0.11
	Per-customer reference (kWh/h)	1.19	0.61
	Per-customer load impact (kWh/h)	-0.55	-0.28
	Temperature	74.7	72.9
Winter (January)	# Enrolled	367	390
	Reference (MWh/h)	0.50	0.17
	Load Impact (MWh/h)	0.03	-0.36
	Per-customer reference (kWh/h)	1.35	0.44
	Per-customer load impact (kWh/h)	0.08	-0.93
	Temperature	61.8	58.4

9 RECOMMENDATIONS

The treatment group among CPP customers will decrease in enrollment as customers migrate to Community Choice Aggregator programs. As a result, finding valid incremental treatment customers will become more difficult in future years. The reduction of incremental customers limits the experimental leverage of estimating TOU load impacts for future program years.

Five CPP events were called during the September heat wave, including weekends and a holiday. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures and months.

10 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 results if changes occur to their solar PV generation that is not accounted for. We address this potential bias this by 1) including only NEM customers that are NEM for the entire analysis period, 2) including only customers whose PV system did not change size for the analysis period, 3) matching NEM customers to other NEM customer with similar size solar PV generation, and 4) removing customers that have large changes in usage between the pre- and post-period.

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). For each customer, we calculate the average usage differences between the pre-treatment period and the treatment period. Customers with usage differences below the chosen threshold are kept in the analysis. The raw difference-in-difference assessment covers the mid-day period, HE 11–15, and the TOU peak/event period, HE 17–21. Customers who were part of a treatment-control pair with a difference-in-difference in either period that was larger than 1 kWh/h were excluded from regression estimation.