



**2023 Load Impact Evaluation of Voluntary
Residential Critical Peak Pricing (CPP) and
Time-of-Use (TOU) Rates
for
San Diego Gas & Electric**

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Corey Lott
Andi Romanovs-Malovrh
Michael Ty Clark

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800 University Bay Dr #400
Madison, WI 53705-2299

608.231.2266
www.CAEnergy.com

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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 2023. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015.

The TOU periods for the two rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. The analysis includes Net Energy Metered ("NEM") customers. Load impacts for these customers are 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.

Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. The CPP event window coincides with the resource adequacy window in all months except March, April, and May, when the RA window is 5 to 10 p.m. In 2023, SDG&E called one CPP event on August 29th.

The ex-post load impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that compare hourly usage of treatment customers and a quasi-experimental matched control group during the post treatment time period or event days and adjusts for usage differences on pre-treatment or non-event days. Control group customers are selected by matching each treatment customer to a sample of eligible non-treatment customers in relevant population segments (e.g., climate zone, NEM), based on the closest match of load profiles.

In 2023, the ex-post load impacts for the CPP event on August 29th indicate that, on average, customers reduced their usage by 0.06 kWh/hour for customers in the Coastal climate zone and 0.18 kWh/hour for the Inland climate zone. CPP enrollment on August 29th was 9,916 customers, with 67 percent of the customers residing in the Coastal climate zone. The aggregate event hour reference load was 15.44 MWh/hour for all climate zones with a load impact of 0.99 MWh/hour.

TOU customer¹ enrollment rose from 26,390 customers in October 2022 to 30,045 customers in September 2023. Per-customer seasonal load impacts were about 0.11 kWh/hour in summer and about 0.05 kWh/hour in winter. Overall, TOU customers reduced their energy consumption by an annual average of approximately 0.18 kWh/customer/hour, which is based on combining the TOU customer results across months and considering the effect of TOU on average *daily* usage.

Enrollment in CPP declined from 14,039 in October 2022 to 10,002 in September 2023. The main cause of de-enrollment in CPP is customers enrolling in community choice aggregators ("CCAs") between April and May 2023, which results in customers being shifted from a TOU-DR-P rate to a

¹ For the purposes of this report, unless specified otherwise, *TOU customers* refers to customers who are on a TOU-DR rate and does not include customers on a TOU-DR-P rate.

TOU-DR rate because CCA customers are ineligible for TOU-DR-P.² TOU load impacts are estimated for CPP customers by season. The results suggest that peak hour usage is reduced by about 0.06 kWh/hour during the summer months and 0.04 kWh/hour during the winter months. The overall daily effect from TOU for CPP customers was an average annual reduction of 0.15 kWh/customer/hour.

² TOU-DR-P is a commodity rate. When a customer joins a CCA, the CCA becomes responsible for procuring the commodity portion of the customer's rate.

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 2023. The two rates, referred to collectively as residential smart pricing project ("SPP") rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015.

ES.1 Resources Covered

The TOU periods for the two rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. The CPP event window coincides with the resource adequacy window in all months except March, April, and May (when the RA window is 5 to 10 p.m.). In 2023, SDG&E called one CPP event on August 29th.

ES.2 Evaluation Methodologies

The ex-post load impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that compare hourly usage of treatment customers and a quasi-experimental matched control group during the post treatment time period or event days and adjusts for usage differences on pre-treatment or non-event days. Control group customers are selected by matching each treatment customer to a sample of eligible non-treatment customers in relevant population segments (e.g., climate zone, NEM), based on the closest match of load profiles.

ES.3 Ex-Post Load Impacts

ES.3.1 Ex-Post CPP Event Load Impacts (TOU-DR-P)

Table ES.1 summarizes average event-hour reference loads and load impacts for residential CPP customers during the August 29, 2023, event.³ Results are shown by Coastal and Inland climate zones. The first two columns show the climate zone and number of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/hour. Note that here, and throughout the report, a positive load impact denotes a decrease in energy consumption. The next two columns show the average event hour results for the average customer, in kWh/hour. The last column shows the average temperature during the event window. Load impacts for events are not reported in percentage terms due to the large share of NEM customers in the sample.⁴ An asterisk included next to a load impact indicates that

³ CPP residential customers are those that voluntarily enrolled on rate TOU-DR-P.

⁴ Since NEM customers experience reference loads that become negative during daylight hours, the load impact divided by 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.

the result is statistically significant at the 10 percent level (or lower). All three geographic categories have load impacts which are statistically significant at the 10 percent level.

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

Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
		Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
Coastal	6,675	8.71	0.43*	1.31	0.06*	83
Inland	3,241	6.74	0.57*	2.08	0.18*	88
All	9,916	15.44	0.99*	1.56	0.10*	85

Program enrollment during the CPP event was 9,916 customers, of which about 67 percent were in the Coastal climate zone.⁵ The aggregate reference load was 15.44 MWh/hour, and the load impact was 0.99 MWh/hour. Per-customer load impacts averaged 0.06 kWh/hour for customers in the Coastal climate zone and 0.18 kWh/hour for customers in the Inland climate zone. Average temperatures during the event were somewhat cooler in the Coastal zone, at 83 degrees, compared to 88 degrees for the Inland zone.

ES.3.2 Ex-Post TOU Load Impacts – TOU Customers (TOU-DR)

Table ES.2 summarizes the average reference loads and load impacts on an aggregate and per-customer basis for customers on the TOU-DR rate during the TOU peak period (4 to 9 p.m.) for the average weekday in each month. The months are shown starting with the first month included in the analysis (October 2022). The winter months are indicated by light blue shading. TOU enrollments increased throughout the analysis period, with the numbers of enrolled customers rising from 26,390 in October 2022 to 30,045 in September 2023.⁶ The estimated seasonal load impacts were largest during the summer months, with the highest load impact occurring during August. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All but March and April results are statistically significant at the 10 percent level.

⁵ These enrollment numbers differ from the number of customers that were included in the regression models. In order to be included in the regression models, customers needed to have a sufficient load history that included all selected event-like days as well as the event day, along with other characteristics needed for the models.

⁶ The enrollment numbers shown differ from the number of customers used in the regression models. Treatment customers used for the TOU analysis are customers that switched from a non-TOU rate to TOU-DR during PY2023. Customer must also have sufficient load data history during both the pre-treatment period (PY2022) and the post-treatment period (PY2023). Specifically, there were 461 incremental TOU-DR customers with quality load data and sufficient history that were used in estimating the TOU load impacts for the winter model and 465 customers for the summer model. The aggregate TOU load impacts are obtained by scaling the per-customer load impacts for incremental customers to total TOU-DR enrollments.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2022	All	26,390	22.01	1.54*	0.83	0.06*	70
Nov-2022	All	26,433	23.03	1.39*	0.87	0.05*	59
Dec-2022	All	26,542	28.55	2.12*	1.08	0.08*	55
Jan-2023	All	26,738	26.56	2.03*	0.99	0.08*	56
Feb-2023	All	26,501	24.27	2.03*	0.92	0.08*	56
Mar-2023	All	26,394	17.02	0.66	0.64	0.02	56
Apr-2023	All	28,983	12.00	0.55	0.41	0.02	61
May-2023	All	29,535	12.80	1.36*	0.43	0.05*	62
Jun-2023	All	29,779	11.47	2.77*	0.39	0.09*	67
Jul-2023	All	29,787	26.82	3.94*	0.90	0.13*	75
Aug-2023	All	29,999	30.82	4.52*	1.03	0.15*	75
Sep-2023	All	30,045	26.25	3.69*	0.87	0.12*	71

Table ES.3 summarizes the results by season and climate zone. The Inland climate zone exhibits higher reference loads during the summer than during winter, while the Coastal climate zone has higher winter reference loads. Inland reference loads are higher than Coastal reference loads during both periods. Overall, TOU customers decrease loads during the peak period by 0.11 kWh/customer/hour on average during summer and 0.05 kWh/customer/hour during the winter. Inland customers have slightly higher load impacts compared to Coastal customers during both seasons. All results are statistically significant at the 10 percent 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		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	15,857	11.24	1.75*	0.71	0.11*	71
	Inland	13,343	12.28	1.59*	0.92	0.12*	72
	All	29,200	23.52	3.34*	0.81	0.11*	71
Winter	Coastal	15,805	11.69	0.82*	0.74	0.05*	58
	Inland	11,499	8.92	0.63*	0.78	0.06*	58
	All	27,304	20.61	1.45*	0.75	0.05*	58

Overall, TOU customers reduced their energy consumption by an annual average of approximately 0.18 kWh/customer/hour, which is based on combining the TOU results across months and considering the effect of TOU on average *daily* usage.

ES.3.3 Ex-Post TOU Load Impacts – CPP Customers (TOU-DR-P)

CPP customers experience TOU prices on all days that are not residential CPP event days. Table ES.4 summarizes the average reference loads and load impacts on an aggregate and per-customer basis for customers on the TOU-DR-P rate during the TOU peak period (4 to 9 p.m.) for the average weekday in each month. Enrollment in CPP declined from 14,039 in October 2022 to approximately 10,002 in September 2023. The estimated seasonal load impacts were largest during the summer months. Declining enrollments lead to aggregate load impacts during summer that are only slightly higher than the load impacts during some of the winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. The load impacts are not statistically significant in October, December, and June.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2022	All	14,039	12.31	0.21*	0.88	0.01	70
Nov-2022	All	14,345	12.78	0.49*	0.89	0.03*	58
Dec-2022	All	14,273	14.98	0.29	1.05	0.02	54
Jan-2023	All	14,209	13.59	0.33*	0.96	0.02*	55
Feb-2023	All	14,052	12.61	0.33*	0.90	0.02*	55
Mar-2023	All	14,072	10.95	0.67*	0.78	0.05*	56
Apr-2023	All	14,007	8.16	0.67*	0.58	0.05*	61
May-2023	All	11,365	5.98	0.49*	0.53	0.04*	63
Jun-2023	All	10,780	5.34	0.66	0.50	0.06	67
Jul-2023	All	10,354	10.38	0.69*	1.00	0.07*	76
Aug-2023	All	10,198	10.99	0.73*	1.08	0.07*	76
Sep-2023	All	10,002	8.85	0.67*	0.88	0.07*	72

Coastal customers had a lower load impact in the winter compared to the summer. On average, CPP customers decreased their load by 0.15 kWh/hour 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 percent level. Winter load impacts for the Coastal climate zone and both summer and winter for all climates are statistically significant at the 10 percent level.

Table ES.5 summarizes the results for CPP customers by season and climate zone. Both climate zones exhibit higher reference loads during the summer months, with higher reference loads for Inland customers. Overall, CPP customer decrease loads during the peak period by 0.06 kWh/customer/hour on average during summer and 0.04 kWh/customer/hour during the winter. Inland customers have lower load impacts compared to Coastal customers during both seasons. Only the overall results and the Coastal winter results are statistically significant at the 10 percent level. The overall daily effect from TOU for CPP customers was an average annual reduction of 0.14 kWh/customer/hour.

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		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	6,958	5.84	0.58	0.84	0.08	72
	Inland	4,117	3.84	0.11	0.93	0.03	73
	All	11,075	9.68	0.69*	0.87	0.06*	72
Winter	Coastal	7,460	5.95	0.34*	0.80	0.05*	58
	Inland	6,300	5.42	0.19	0.86	0.03	57
	All	13,760	11.37	0.53*	0.83	0.04*	57

ES.4 Ex-Ante Load Impacts

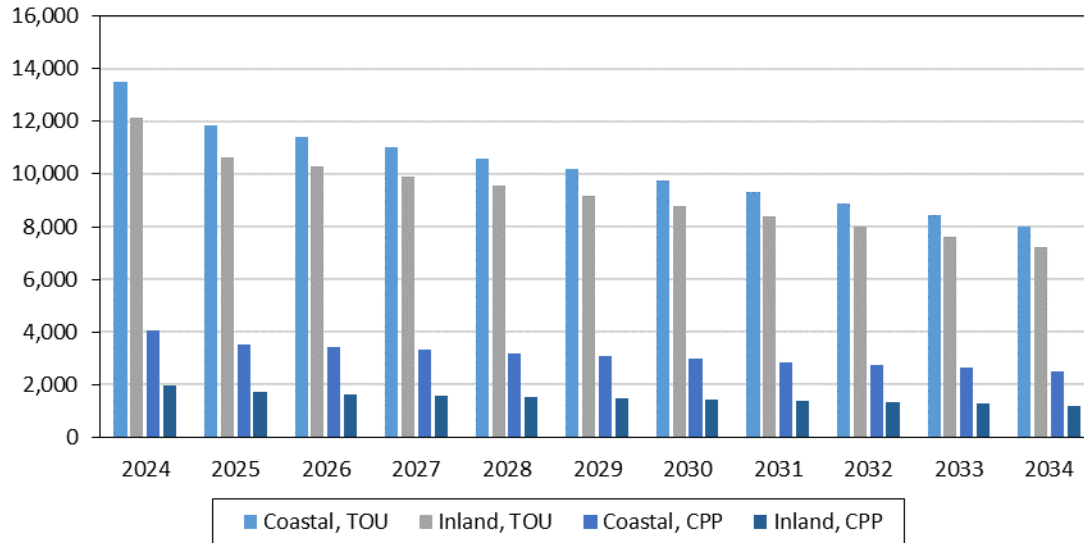
The ex-ante analysis for CPP events applies the PY2023 ex-post CPP event load impacts to reference loads calculated using PY2023 customer load data. Load impacts for different weather scenarios are developed by applying the estimated load impact from the ex-post analysis to weather-sensitive reference loads. The reference loads are estimated 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. Since June 1, 2022, the CPP event window coincides with the RA window (4 to 9 p.m.).

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 are developed as described above. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these 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 begin declining after 2024. Enrollment is expected to be greater in the Coastal climate zone than in the Inland climate zone for both TOU and CPP customers, however the differences are more pronounced for CPP customers. This mirrors the fact that the rates have different enrollment ratios in the two climate zones.

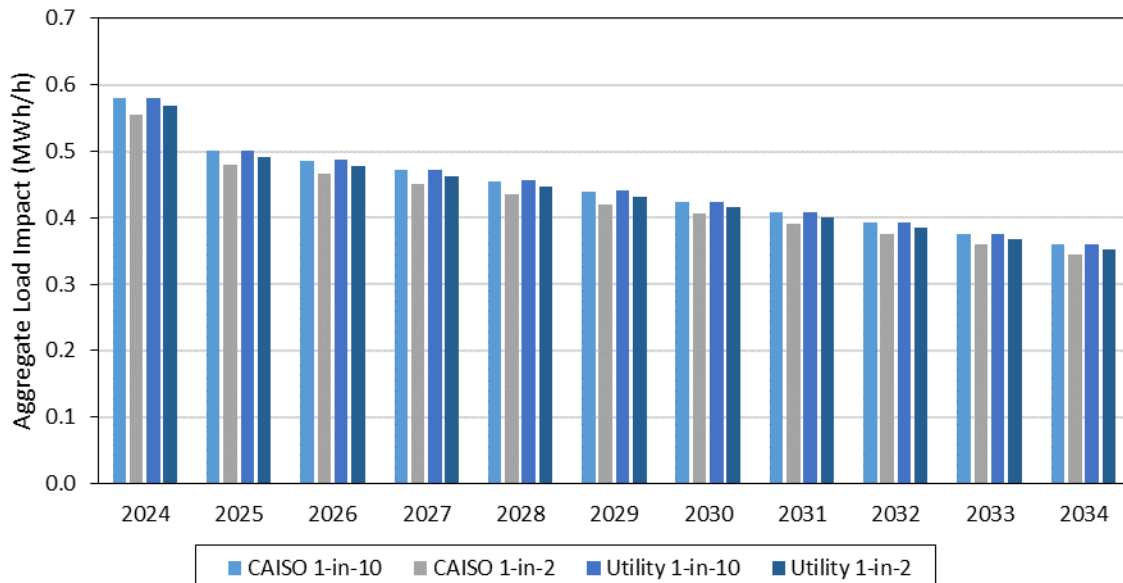
Figure ES.1: Enrollments in TOU and CPP Rates



ES.4.2 Ex-Ante CPP Event Load Impacts

Figure ES.2 illustrates the decline in forecasted aggregate CPP load impacts for the RA window over the forecast period for each weather scenario. Aggregate load impacts are forecasted to decline over time, commensurate with declining enrollments. The figure also shows relatively minor differences between the aggregate ex-ante load impacts by weather scenario. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to decrease from 0.57 MWh/hour in 2024 to 0.35 MWh/hour in 2034.

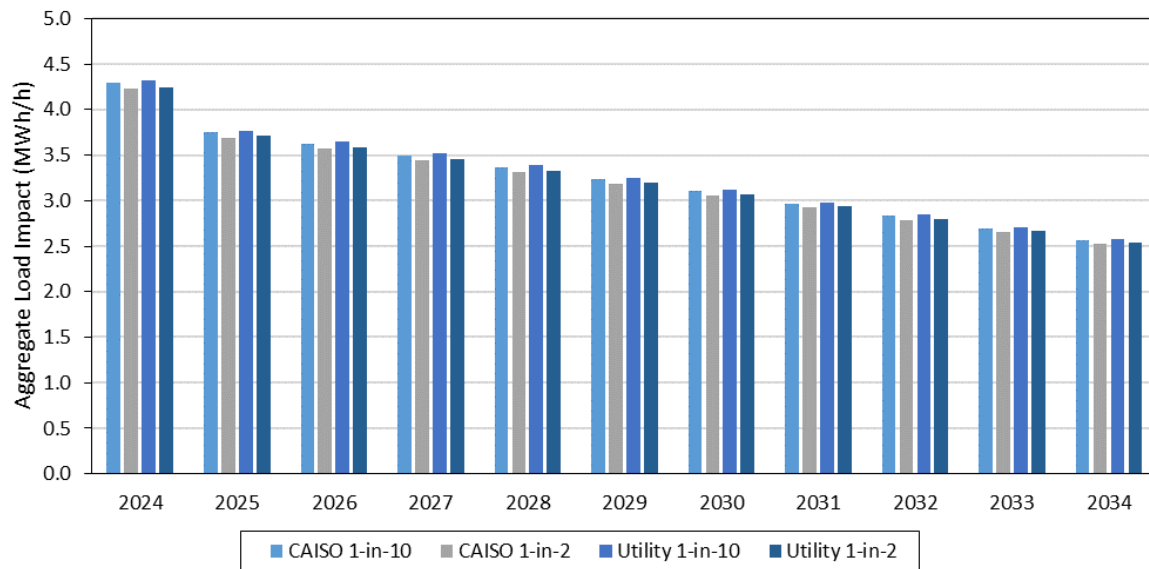
Figure ES.2: Aggregate CPP Load Impacts (MWh/hour), by Year and Weather Scenario (August Peak Day, RA Window)



ES.4.3 Ex-Ante TOU Load Impacts

Aggregate load impacts for TOU customers during the average peak hour are forecast to decline after 2024, commensurate with declining enrollments. 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. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to decrease from 4.24 MWh/hour in 2024 to 2.54 MWh/hour in 2034.

Figure ES.3: Aggregate TOU Load Impacts (MWh/hour) – 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 the 2023 program year ("PY"). 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).⁷ Both rates are voluntary and became active in February 2015. TOU load impacts are estimated for customers enrolled in both rates, since the TOU-DR-P customers experience TOU rates on days that are not CPP event days, while CPP load impacts are estimated only for residential TOU-DR-P customers.⁸ 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 for the two rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year.

Table 1.1 provides monthly enrollments for each rate by net energy metered ("NEM") status. NEM customers constitute a significant proportion of residential TOU customers⁹. Some CPP customers transitioned to a community choice aggregator ("CCA") between April and May 2023. CCA customers cannot be enrolled in the CPP program and thus were migrated from a TOU-DR-P rate to TOU-DR rate because of their CCA enrollment.¹⁰ This explains the pattern of declining CPP customer enrollment and increasing TOU customer enrollment during PY2023.¹¹ 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 percent for TOU customers and 30 percent for CPP customers.

⁷ Results are also reported for a subset of CPP customers who participate in the Technology Deployment ("TD") program.

⁸ TOU ex-post load impacts are estimated only for customers who enrolled in either SPP rate during PY2023 (October 2022 to September 2023), also referred to as incremental TOU customers. The estimated TOU load impacts of incremental customers are applied to all customers on SPP rates (TOU-DR and TOU-DR-P).

⁹ For the purposes of this report, unless specified otherwise, *TOU customers* refers to customers who are on a TOU-DR rate and does not include customers on a TOU-DR-P rate.

¹⁰ TOU-DR-P is a commodity rate. When a customer joins a CCA, the CCA becomes responsible for procuring the commodity portion of the customer's rate.

¹¹ Customers who are both TOU-DR and TOU-DR-P in a given month are counted as enrolled in both rates. Therefore, counting customers that switched rates in April 2023 causes increased enrollments in TOU before enrollments decline in CPP.

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-2022	15,199	11,191	26,390	9,768	4,271	14,039
Nov-2022	14,941	11,492	26,433	10,186	4,159	14,345
Dec-2022	14,659	11,883	26,542	10,243	4,030	14,273
Jan-2023	14,529	12,209	26,738	10,309	3,900	14,209
Feb-2023	14,206	12,295	26,501	10,281	3,771	14,052
Mar-2023	13,993	12,401	26,394	10,237	3,835	14,072
Apr-2023	16,324	12,659	28,983	10,130	3,877	14,007
May-2023	16,547	12,988	29,535	7,602	3,763	11,365
Jun-2023	16,302	13,477	29,779	7,157	3,623	10,780
Jul-2023	15,976	13,811	29,787	6,988	3,366	10,354
Aug-2023	15,771	14,228	29,999	6,967	3,231	10,198
Sep-2023	15,558	14,487	30,045	6,911	3,091	10,002

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 TOU periods for the two rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m.

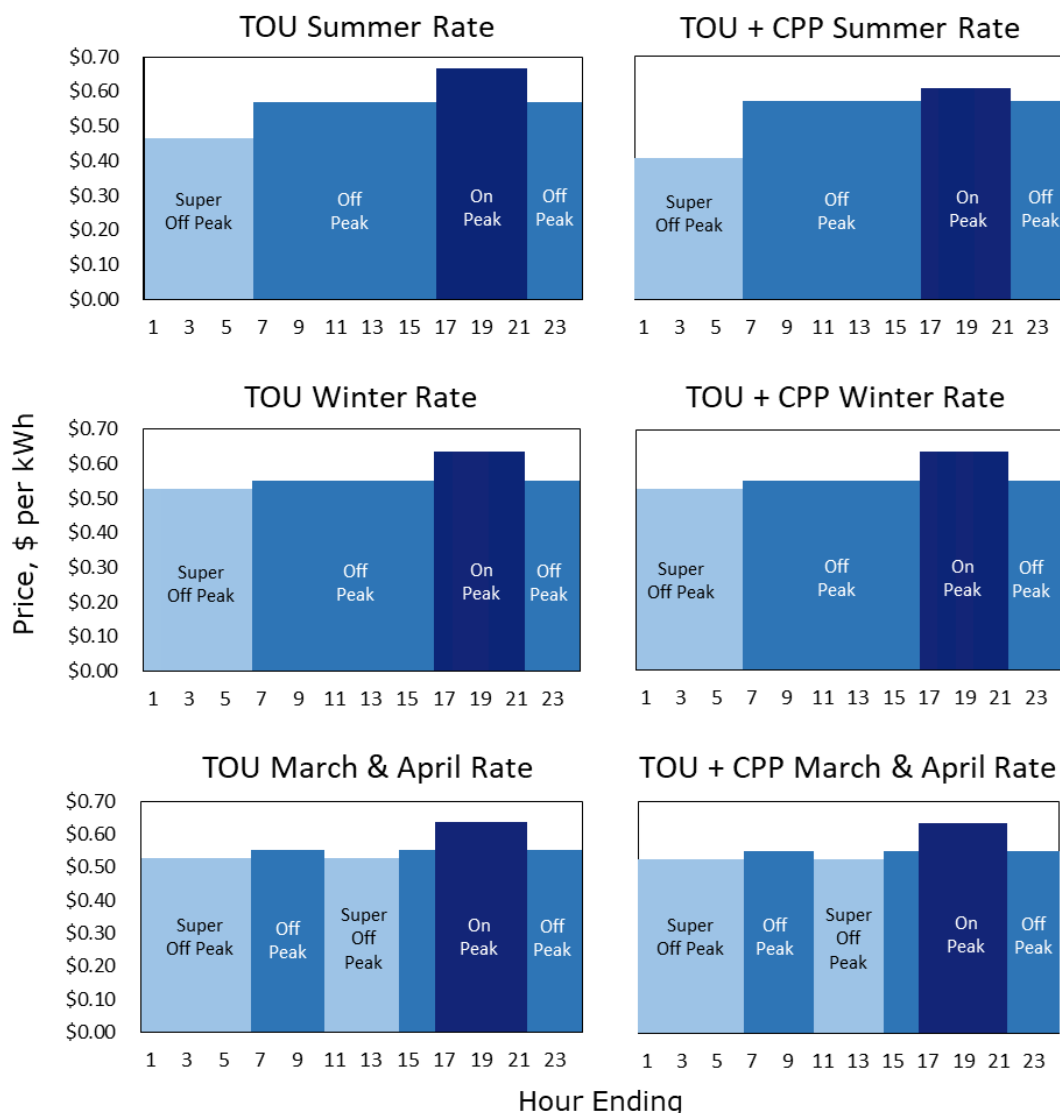
The total TOU rate charges as of January 1, 2023, for TOU customers during summer months (June 1st through October 31st) are \$0.666, \$0.569, and \$0.465 per kWh for the on-peak, off-peak, and super-peak periods, respectively.^{12, 13} Thus, the peak to super-off-peak price ratio is

¹² See Schedule TOU-DR and TOU-DR-P for current rates and Residential Time-of-Use periods: Residential TOU-DR and TOU-DR-P for TOU periods at <https://www.sdge.com/total-electric-rates>.

¹³ Customers with CARE status are charged lower rates across all hours but have a similar peak-to-off peak ratio to Non-CARE customers, providing a similar incentive to reduce usage during peak hours. As the proportion of CARE customers is less than 18 percent of all customers included in the analysis, the rates shown in Figure 2.1 only reflect prices charged to Non-CARE customers.

1.43-to-1. Summer TOU charges for CPP customers are somewhat lower, at \$0.609, \$0.571, and \$0.407 per kWh, implying a peak to off-peak price ratio of 1.50-to-1. In addition, a CPP event-period adder of \$1.16 per kWh applies during event hours on CPP event days for these customers, implying a peak to off-peak price ratio of 4.35-to-1. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.¹⁴ Rates differ by season for each time period, but the time periods are the same (with the exception of the super off-peak period in March and April).

Figure 2.1: Time-of-Use Periods and Prices by Rate¹⁵



¹⁴ The weekend and non-holiday weekday time-of-use periods and prices are not included in Figure 2.1. The same prices apply to weekends and non-holiday weekdays, but the time periods differ somewhat. For weekends and non-holiday weekdays, the super-off-peak hours extend until 2 p.m. in both winter and summer.

¹⁵ See Schedule TOU-DR and TOU-DR-P for current rates and Residential Time-of-Use periods: Residential TOU-DR and TOU-DR-P for TOU periods at <https://www.sdge.com/total-electric-rates>.

Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. 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. During PY2023, SDG&E called one CPP event on Tuesday, August 29, 2023.

3. EX-POST EVALUATION METHODOLOGY

The primary objectives of the ex-post load impact evaluation were described in Section 1. This section describes the data and methods that are used to produce the ex-post load impact estimates for this study.

3.1 Data

To address each of the load impact objectives listed in Section 1, the following data is required:

- *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 2021 through September 2023;
- *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. Using hourly load data for TOU and CPP enrollees and potential control group customers for the current year and the previous year (pre-enrollment year for new enrollees), matched control group customers are selected for the TOU and CPP enrollees based on average customer load profiles. For the TOU evaluation, matching is performed on average load profiles during the pre-enrollment period. For the CPP evaluation, matching is based on event-like, non-event days in PY2023. Following matching, fixed-effects panel regression models are estimated on treatment and matched control customers, 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

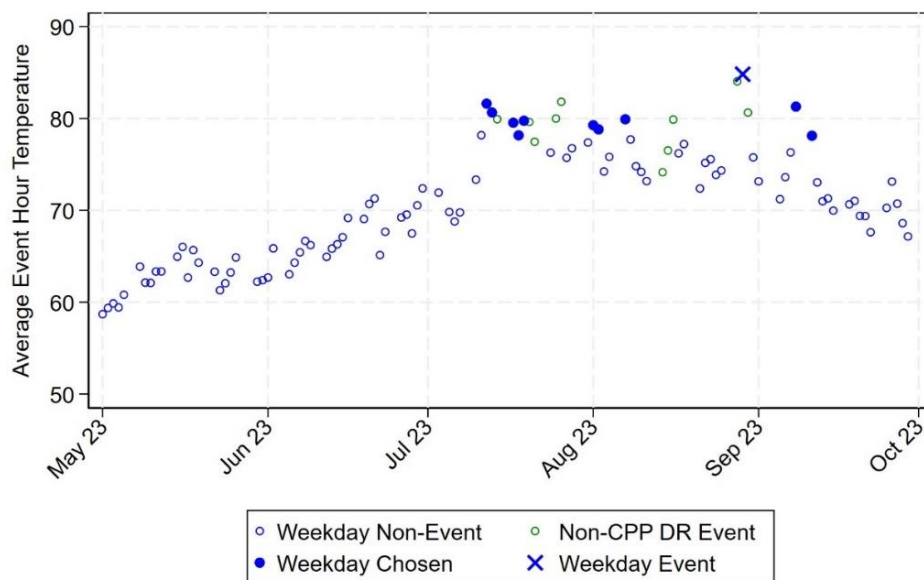
Difference-in-differences is a quasi-experimental approach that compares the usage of treatment and matched control group customers during the post treatment period, or event days, and

adjusts for usage differences during the pre-treatment period, or non-event days. The control groups are 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), based on the closest match of load profiles. The matched control group customers are drawn from an eligible population of SDG&E residential customers. For analyzing the TOU impacts, the eligible population consists of customers that were retained as control customers for the default TOU pilot program. These are customers that are not on a TOU rate for the entire two-year period between October 2021 and September 2023. For analyzing the CPP impacts, the population used to analyze TOU impacts is expanded to include customers that are TOU (TOU-DR) on all CPP event days.

The matching process differs for customers on the two rates. Since the CPP (TOU-DR-P) customers experience TOU rates on all non-event days, and the CPP rate on event days, those customers are treated as CPP customers when evaluating CPP load impacts and as TOU customers when evaluating TOU impacts. As a result, TOU load impacts are provided for both the TOU customers (TOU-DR) and CPP customers (TOU-DR-P).

For the CPP load impacts analysis, CPP customers are matched to potential control group customers using loads on selected event-like non-event days (i.e., days with temperatures that are closest to event day temperatures). Figure 3.1 displays the average event-hour temperature for all weekdays between May and September 2023. The blue X marker represents the PY2023 weekday event on August 29th. Blue circles indicate weekday non-event days. The event day in 2023 was among the hottest weekdays during 2023. The filled in blue circles represent weekday event-like non-event days that were chosen.¹⁶ Green circles are weekdays on which other demand response ("DR") events (e.g., AC Saver Day-Ahead or AC Saver Day-Of) were called in 2023 and were thus excluded as potential event-like non-event days.

Figure 3.1: Average Event-Hour Temperatures



Note: Averaged over event hours HE 17-21

¹⁶ The event-like days used in the 2023 CPP analysis are 7/12, 7/13, 7/17, 7/18, 7/19, 8/1, 8/2, 8/7, 9/8, and 9/11.

For the TOU load impact analysis, which includes both CPP and TOU customers, only incremental treatment customers are included in the analysis. Incremental customers are customers that were on a non-TOU rate during PY2022 and switched to TOU-DR or TOU-DR-P at some point during PY2023. The matching is performed based on loads during the pre-treatment period (October 2021 through September 2022). To be included in the analysis, customers must have sufficient pre-treatment data history to provide a quality difference-in-difference analysis.¹⁷ The matching and regression analysis are performed separately by season, thus allowing different threshold dates that define incremental customers. The incremental customers are 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. This ensures that customers are matched based on the sensitivity of their energy usage to weather conditions. Matching for the *winter* season uses data for November 2021 through May 2022, while matching for the *summer* season used data for October 2021 and June through September 2022.

Matching is based on Euclidean distance minimization between treatment and potential control group customer loads based on the metric 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* and *C* variables represent the value of the treatment and control customers' characteristics (e.g., average load during a given hour of the day). For the TOU analysis, the relevant customer characteristics include the average hourly usage over three time periods across all weekdays, average usage on weekdays with extreme temperatures (i.e., the hottest or coldest weekdays in summer or winter, respectively), and customer characteristics that include CARE status and solar photovoltaic generation capacity size for NEM customers.¹⁸ The hourly time period averages used for matching are 1 to 6 a.m., 10 a.m. to 2 p.m., and 4 to 9 p.m. Treatment and potential control customers are also segmented by climate zone and NEM status to ensure the treatment and control customer have the same value of these characteristics.¹⁹

Each treatment customer in the analysis is matched with the control customer in their segment associated with the smallest value of the above distance measure. Potential control group customers are matched with replacement (i.e., may be matched with multiple treatment customers).

While NEM customers are matched similarly, there are additional considerations made for such customers. Only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included in the treatment or eligible control group.²⁰ Customers with large changes in net load profiles between periods are not used in the analysis

¹⁷ Customers must also be on a non-TOU rate (i.e., DR) throughout the pre-treatment period to be a valid incremental customer. Customers that switch from other TOU rates such as TOU-DR1, TOU-DR2, and TOU-ELEC are not eligible to be incremental customers.

¹⁸ 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.

¹⁹ Only customers that have not made changes to their NEM status for the duration of the entire analysis period are included in the analysis.

²⁰ Treatment or control customers with large changes in their PV system during the analysis period are not included in the regressions.

because the differences are more likely caused by unobserved structural changes to a customer's solar PV system. The methodology for identifying large changes in usage is explained in more detail in Appendix C. These requirements help prevent estimating load impacts that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to the behavioral response to the TOU or CPP rates that this evaluation seeks to estimate.²¹

3.2.2 Fixed-Effects Panel Regression Models

The ex-post load impact estimates are based on fixed-effects panel regression models. These panel data models are appropriate when observed data are available for many individual customers (cross section) over a long time frame of days or months (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 is used to estimate residential CPP event-day hourly load impacts. Weekend CPP event load impacts are estimated separately from weekday event impacts since load patterns may vary between weekdays and weekend days. However, there were no weekend events called in PY2023. The second version is used to estimate TOU load impacts, which are separately estimated for TOU-DR and TOU-DR-P customers and separately for NEM customers within each rate class.

3.2.3 Ex-Post Regression Model for Estimating CPP Load Impacts

The load impact estimation model for CPP estimates the CPP load impact as the difference between CPP and control-group customer loads on event days less the difference on non-event days. The following model is estimated for each hour of the day:

$$kWh_{c,d} = \beta_0 + \sum_{Evs(i)} (\beta_{1,i} \times NonDual_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{2,i} \times Dual_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{3,i} \times NonDual\ Control_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{4,i} \times Dual\ Control_{c,d} \times Evt_{i,d}) + \beta_5 \times CPP_{c,d} + \beta_6 \times ACSDO_Evt_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

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

²¹ For example, a high usage treatment customer with a large solar generation system may be matched to a low usage control customer with a small solar generation system based on similar net load profiles. If weather conditions during the post-treatment period cause increased solar generation relative to the pre-treatment period, then net load profiles comparisons in the pre- and post-treatment periods will measure the differences between solar installation sizes of the treatment and control customers, indicating a load reduction, rather than measuring load changes that are a result of a behavioral response to the TOU rate.

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
$NonDual_{c,d}$	Variable indicating whether customer c is a non-dual <i>CPP</i> customer on date d (1 = yes, 0 if not)
$Dual_{c,d}$	Variable indicating whether customer c is a dually enrolled <i>CPP</i> customer on date d (1 = yes, 0 if not)
$NonDual_Control_{c,d}$	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)
$Dual_Control_{c,d}$	Variable indicating whether customer c is a control customer matched to a dually enrolled <i>CPP</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)
$ACSDO_Evt_{c,d}$	Variable indicating that date d is an <i>AC Saver Day-Of</i> ("ACSDO") event day (1=event, 0 if not) for customer c
C_c	Customer Fixed Effects
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
$\beta_{1,i}$	Estimated load impact for event i for non-dual <i>CPP</i> customers
$\beta_{2,i}$	Estimated load impact for event i for dually enrolled <i>CPP</i> customers
$\beta_{3,i}$	Estimated load impact for event i for control customers matched to non-dual <i>CPP</i> customers
$\beta_{4,i}$	Estimated load impact for event i for control customers matched to dually enrolled <i>CPP</i> customers
β_5	Estimated non-event day response for incremental <i>CPP</i> customers
β_6	Estimated average ACSDO event load impact

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time (e.g., weather conditions and day-type factors) and time-invariant customer characteristics (e.g., home size). The $\beta_{1,i}$ coefficients represent the estimated average load impacts for each hour of every event day for *CPP* customers who are not dually enrolled. The $\beta_{2,i}$ coefficients separately estimate load impacts for customers dually enrolled in *CPP* and a dual group of interest. We apply this interacted model to produce separate estimates for customers dually enrolled in the technology deployment ("TD") program or emergency load reduction program ("ELRP"). This model is also estimated for customers who receive notifications and customer who do not receive notifications.

Results are scaled to enrollment numbers because a portion of residential CPP customers are removed from the analysis based upon insufficient load quality and NEM customer restrictions (see Appendix C). To produce load impact estimates for specific customer segments (e.g., by climate zone, NEM), the model is estimated for the subset of customers in each segment.

3.2.4 Ex-Post Regression Model for Estimating TOU Load Impacts

The load impact estimation model for TOU estimates the TOU load impact as the difference between TOU and non-TOU (DR) control-group customer loads during the post-TOU enrollment period less the difference during the pre-enrollment period. The following model is estimated for each season²² and hour of the day:

$$kWh_{c,d} = \beta_0 + \beta_1 \times TOU_c \times Post_{c,d} + \beta_2 \times Post_{c,d} + \beta_3 \times Weather_{c,d} + \beta_4 \times TOU_c \times Weather_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.2.

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 in TOU (1) or Control (0) customer
$Post_{c,d}$	Variable indicating that date d is in the post-enrollment period for customer c
$Weather_{c,d}$	Weather conditions on day d for customer c
C_c	Customer Fixed Effects
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
β_1	Estimated load impact for TOU
β_2	Estimated load impact for control customers during post-enrollment period
β_3	Estimated coefficient for weather variable
β_4	Estimated load impact of TOU interacted with weather

The model is estimated for each TOU season. Interactions between the treatment effect and weather allow the load impact to vary based on weather conditions in a given month or on a

²² The model is estimated for the three TOU seasons: summer, winter, and March through April. The summer season includes June, July, August, September, and October, while the winter season includes January, February, May, November, and December.

given peak day within a month. The β_1 coefficient is the estimated average TOU load impact for each season and hour. The β_4 coefficient is the incremental load impact associated with a change in weather conditions. The estimated load impact for a given month is obtained by the following formula:

$$Load\ Impact_{month\ m} = \hat{\beta}_1 + \hat{\beta}_4 \times \overline{Weather}_{month\ m}$$

The second term multiplies the average weather conditions during month m by the estimated coefficient for the interaction term between the treatment effect and weather. The same formula is applied using weather conditions for each monthly peak day to produce TOU load impacts for monthly system peak days.

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time (e.g., day-type factors) and time-invariant customer characteristics (e.g., home size). Incremental customers along with their matched control group are used to estimate the TOU load impacts in each regression. Event days are removed from the dataset when estimating TOU load impacts. Results are then scaled to the program level of enrollments. To produce load impact estimates for specific customer segments (e.g., TOU vs. CPP rate, climate zone, NEM), the model is estimated for the subset of customers in each segment.

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 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 analysis) or during event-like non-event days (CPP analysis). 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. 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 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.

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, the 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 match quality for non-NEM residential CPP (TOU-DR-P) customers. The figure shows the average CPP customer load profile compared to the load profile of matched control-group customers across the selected event-like non-event days. Eligible control group customers for this analysis include non-NEM customers on a DR or TOU-DR rate that reside in the same climate zone as the treatment customers. 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 1.4 percent. For the CPP event window (4 to 9 p.m.), the MPE and MAPE are 0.9 percent.

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

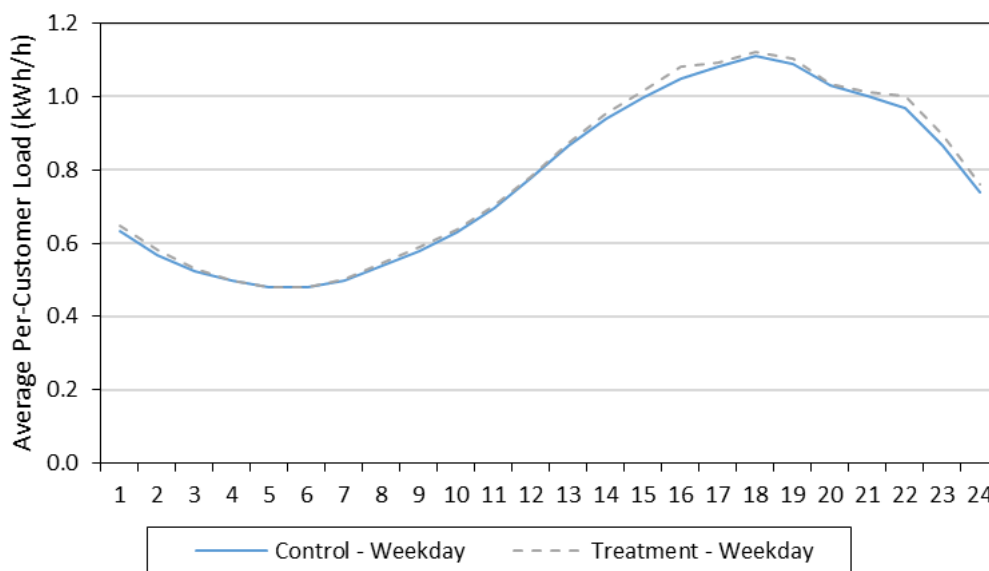
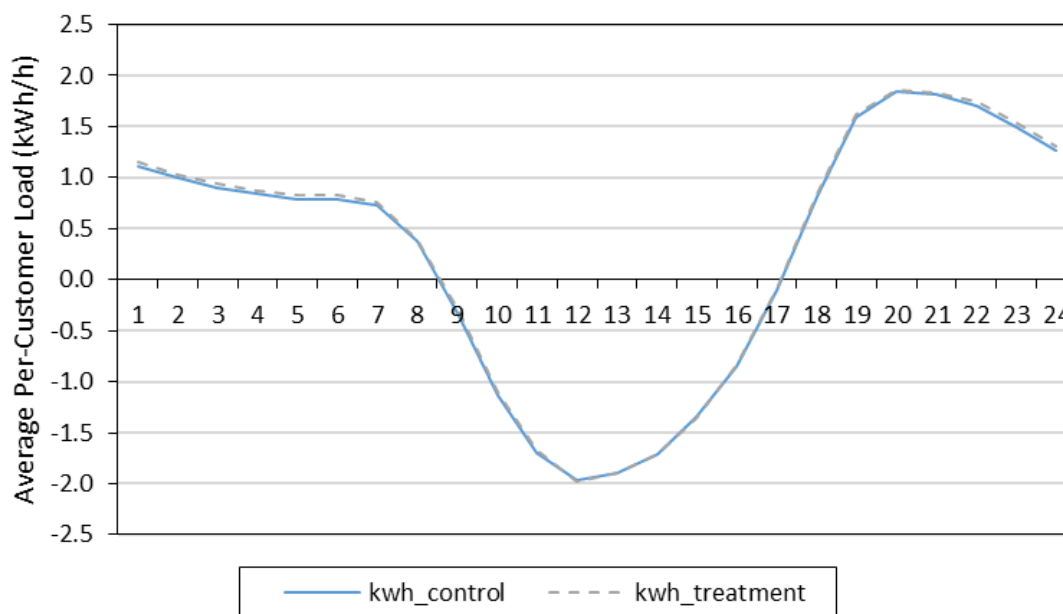


Figure 4.2 similarly illustrates the match quality for NEM residential CPP customers. Eligible control group customers for this analysis include non-NEM customers on a DR or TOU-DR rate that reside in the same climate zone as the treatment customers. Across all 24 hours, the mean error (ME) and mean absolute error (MAE) of the CPP profile compared to the control-group profile are 0.03 kWh/hour. For the CPP event window (4 to 9 p.m.), the ME and MAE are 0.02 kWh/hour.²³

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



4.2 CPP Load Impacts

This section summarizes average event-hour reference loads²⁴ and load impacts, at an aggregate and per-customer basis, for the one 2023 CPP event called on August 29th. The CPP event window is from 4 to 9 p.m. (HE 17-21).

Table 4.1 summarizes average event hour reference loads and CPP load impacts for all CPP customers, by climate zone.²⁵ The first two columns show the climate zone and number of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/hour. The next two columns show the same variables for the average customer, in kWh/hour. The last column summarizes the average

²³ The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which distorts percentage values so that large percentages can result from relatively small magnitude differences.

²⁴ 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.

²⁵ Technology Deployment customers are included in these results.

temperature during the event window. An asterisk is included next to load impacts that are statistically significant at the 10 percent level. All results are statistically significant at the 10 percent level.

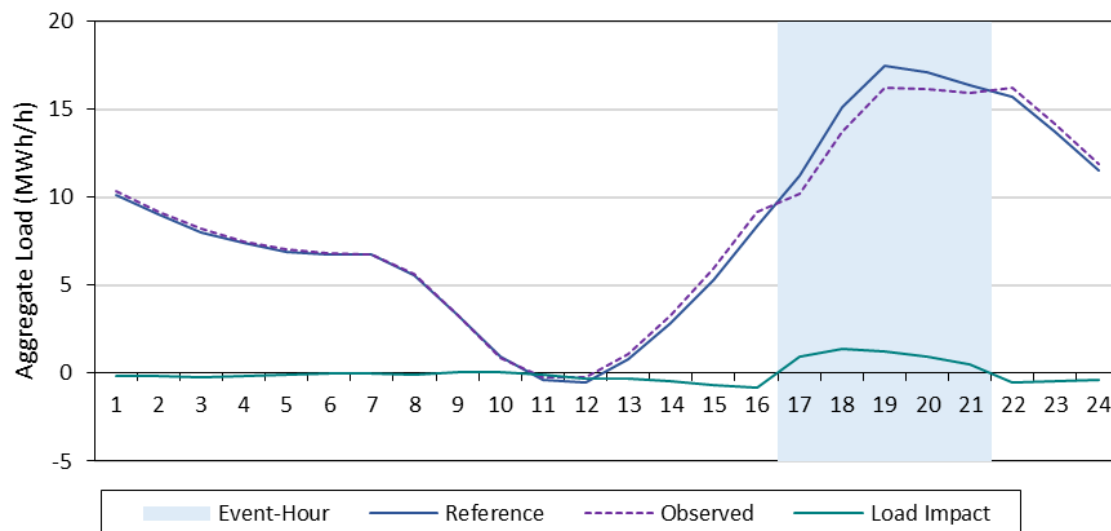
Table 4.1: Average CPP Event-Hour Load Impacts

Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
		Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
Coastal	6,675	8.71	0.43*	1.31	0.06*	83
Inland	3,241	6.74	0.57*	2.08	0.18*	88
All	9,916	15.44	0.99*	1.56	0.10*	85

Program enrollment was 9,916 customers, of which 67 percent of customers were in the Coastal climate zone.²⁶ On the August 29th event, the per-customer reference load during event hours for all customers was 1.56 kWh/hour with a per-customer load impact of 0.10 kWh/hour. Per-customer load impacts averaged 0.06 kWh/hour for customers in the Coastal climate zone and 0.18 kWh/hour for the Inland climate zone. Average event temperatures were somewhat cooler in the Coastal climate zone at 83 degrees, compared to 88-degrees for the Inland climate zone.

Figure 4.3 shows aggregate hourly loads and load impacts for the August 29th event. The largest hourly load impact was 1.36 MWh/hour in hour-ending 18 (5 to 6 p.m.).

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



²⁶ 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 8,155. The CPP load impacts are scaled up to total program enrollments.

4.3 Technology Deployment Load Impacts

This section compares the CPP load impact estimates for customers who were dually enrolled in CPP and the Technology Deployment ("TD") program, also known as AC Saver Day-Ahead ("ACSDA"), during 2023. Customers dually enrolled in TD and CPP experience the same CPP events. TD customers have automated demand response during CPP events via thermostat enabled technology, which typically leads to higher load impacts.

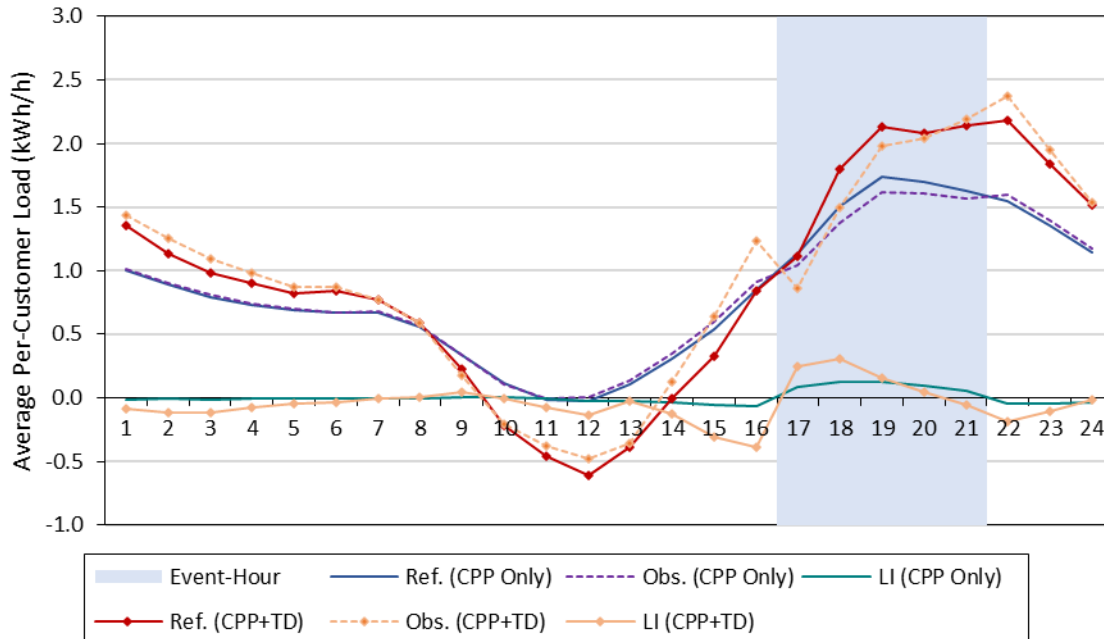
Table 4.2 summarizes reference loads and load impacts for customers enrolled in CPP ("CPP Only") and customers dually enrolled in CPP and TD ("CPP+TD"). An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All results are statistically significant at the 10 percent level. The number of dually enrolled customers for the August 29th event was 555, about 5.6 percent of CPP customers. On average, customers dually enrolled in TD have larger reference loads and load impacts. The average per-customer reference load and load impact for dually enrolled customers was 1.85 kWh/hour and 0.14 kWh/hour, respectively. The average per-customer event reference load and load impact for non-dually enrolled customers was 1.54 kWh/hour and 0.10 kWh/hour, respectively.

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

Type	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
		Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
CPP Only	9,361	14.41	0.91*	1.54	0.10*	85
CPP + TD	555	1.03	0.08*	1.85	0.14*	85

Figure 4.4 shows average per-customer hourly loads and load impacts for CPP-only customers and those dually enrolled in CPP and TD for the August 29th CPP event. The event hours from 4 to 9 p.m. are shaded. The observed loads of dually enrolled customers ("Obs. (CPP+TD)") illustrate that TD customers have significant pre-cooling in the hours before the event begins and a snapback effect in the hours after the event. While CPP-only customers have a similar pattern in observed loads, the magnitude of pre-cooling and snapback is much smaller. The largest hourly TD load impact was 0.3 kWh/customer/hour in the second hour of the event (5 to 6 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 to load impacts for customers that did not receive notifications. Customers who were not notified may not have known that a CPP event was occurring.

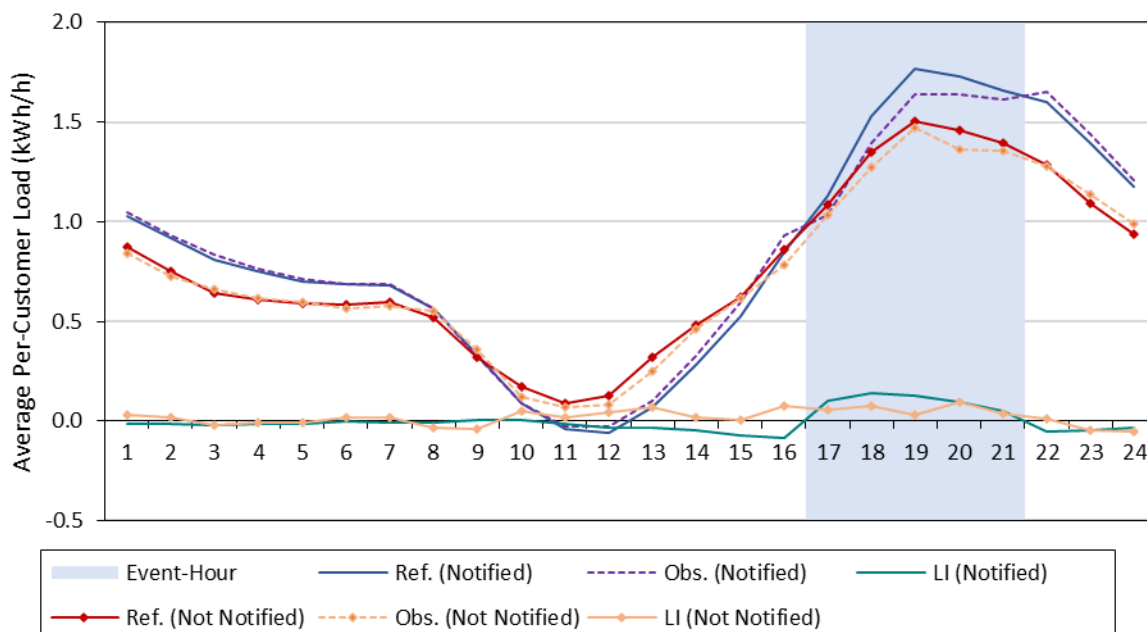
Table 4.3 summarizes reference loads and load impacts for customers that were notified of an event and those that did not receive notifications. The number of non-notified customers for the August 29th event was 347 (which is about 3.6 percent of CPP customers). Customers who were not notified had smaller average reference loads and load impacts that are not statistically significant, which is consistent with customers having a load response that is not distinguishable from zero. The average event reference load and load impact for non-notified customers was 1.36 kWh/hour and 0.06 kWh/hour, respectively. The average event reference load and load impact for notified customers was 1.56 kWh/hour and 0.10 kWh/hour, respectively. The load impacts for notified customers are statistically significant at the 10 percent level.

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

Type	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
		Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
Notified	9,559	14.95	0.97*	1.56	0.10*	85
Non-Notified	357	0.49	0.02	1.36	0.06	84

Figure 4.5 shows average per-customer hourly loads and load impacts for CPP customers who were notified compared to customers who were not notified for the August 29th event. The event hours from 4 to 9 p.m. are shaded. Non-notified customers do not show evidence of a noticeable load impact during event hours, unlike the notified customers. The only event hour with a load impact that is statistically significant at the 10 percent level occurs during HE 20 (7-8 p.m.). Notified customers have statistically significant load impacts during each event hour as well as statistically significant pre-cooling and post-event snapback.

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) and CPP (TOU-DR-P) customers.

5.1 TOU Control Group Matching Results for TOU Customers

Figure 5.1 and Figure 5.2 illustrate the match quality 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. Eligible control group customers for this analysis include non-NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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 over the 24-hour period is 1.2 percent, while the mean absolute percentage error (MAPE) is 2.8 percent. During the summer peak hours (4 p.m. to 9 p.m.) the MPE and MAPE is 2.5 percent. In the winter months, over the 24-hour period, the MPE is 2.8 percent and the MAPE is 3.0 percent. Over the winter peak hours, the MPE and MAPE is 1.9 percent.

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

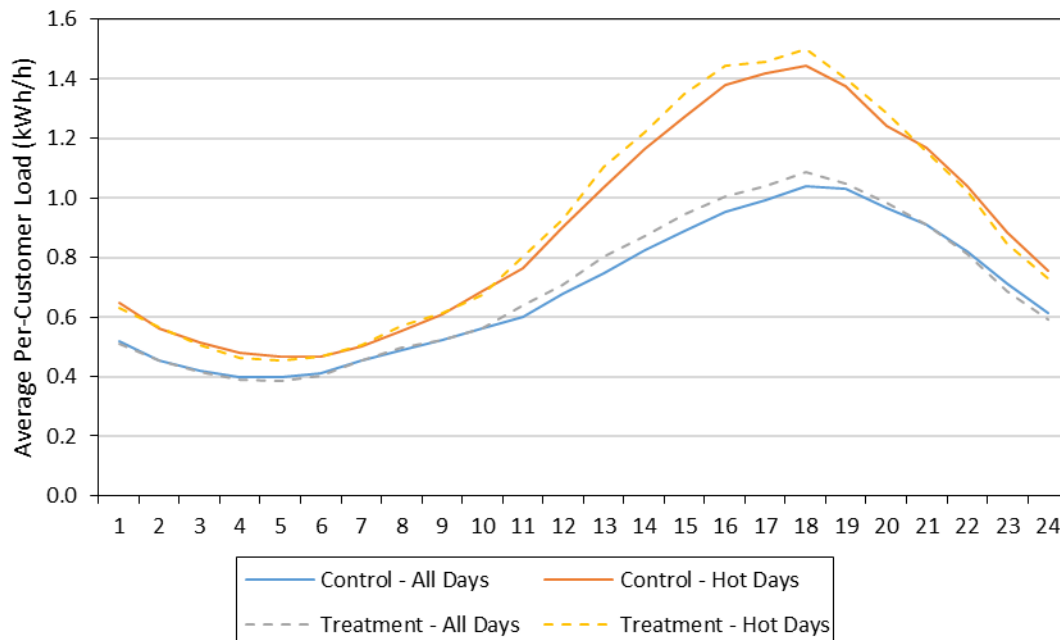


Figure 5.2: Non-NEM TOU and Matched Control Group Load Profiles – Winter

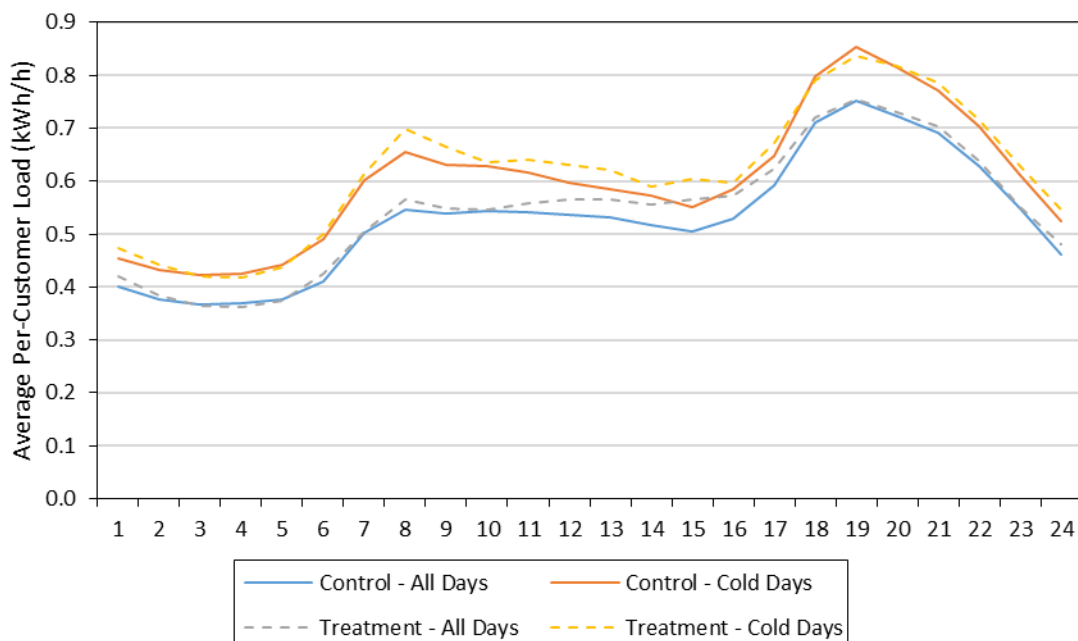


Figure 5.3 and Figure 5.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, similar to the above figures. Eligible control group customers for this analysis include NEM customers on a DR rate that reside in the same climate zone as the treatment customers. In the summer months, the mean error (ME) of the TOU profile compared to the control-group

profile over the 24-hour period is 0.00 kWh/hour, while the mean absolute error (MAE) is 0.06 kWh/hour. Over the peak-hour period the ME is 0.07 kWh/hour and the MAE is 0.08 kWh/hour. In the winter months, over the 24-hour period, the ME is -0.01 kWh/hour and the MAE is 0.03 kWh/hour. Over the winter peak-hour period both ME and MAE is 0.03 kWh/hour.

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

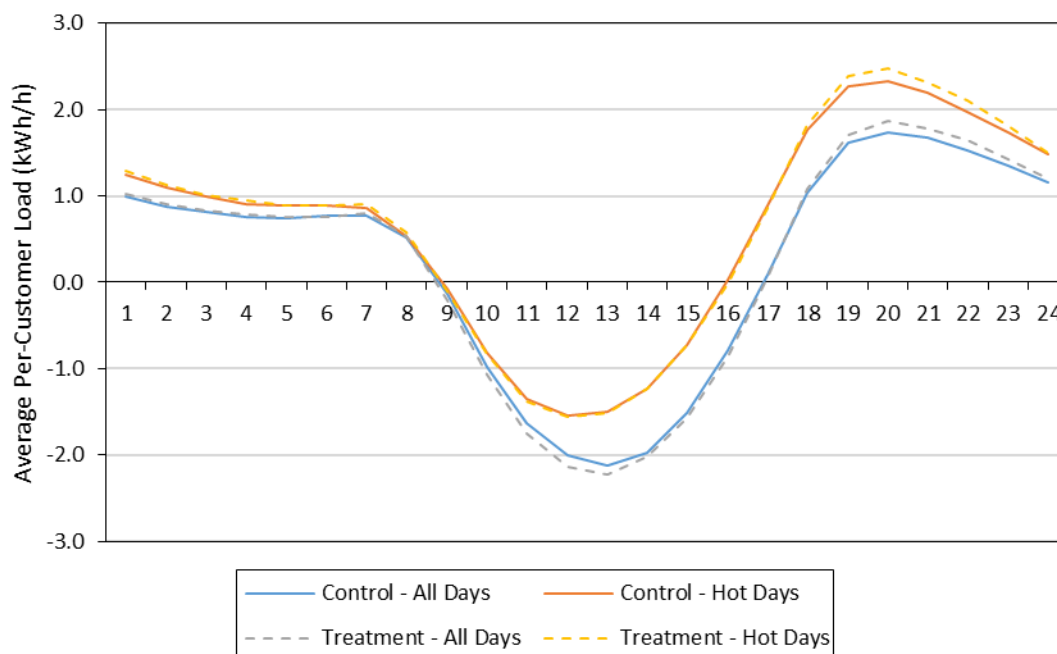
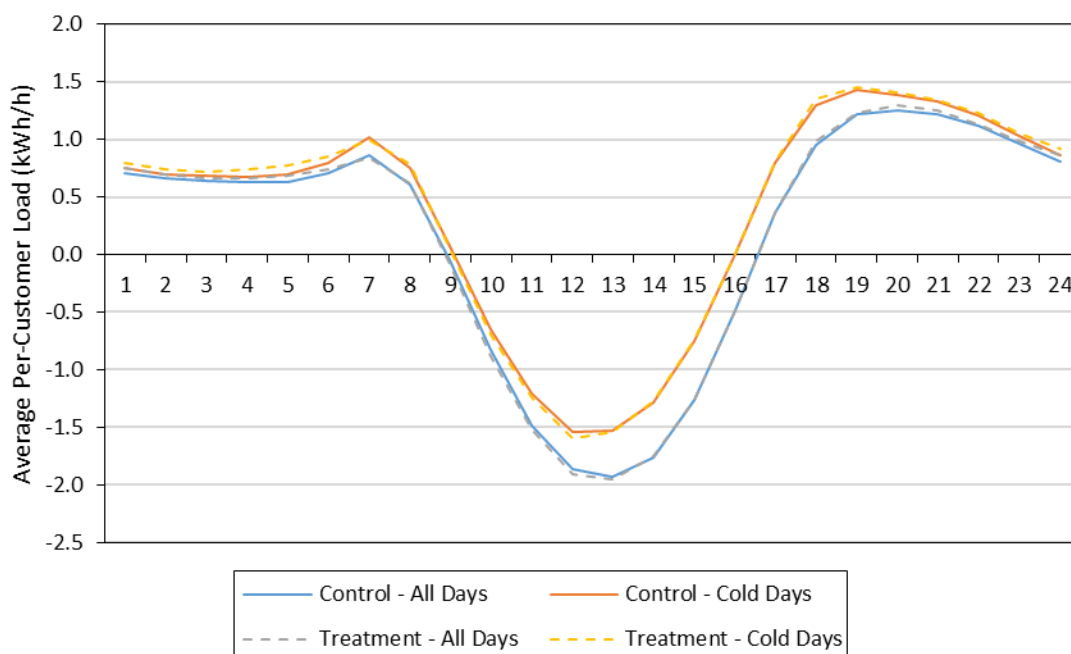


Figure 5.4: NEM TOU and Matched Control Group Load Profiles – Winter



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 (4 to 9 p.m.) for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown chronologically starting with the first month included in the analysis (October 2022). The winter months are indicated by light blue shading. Enrollments increased throughout the period, with the number of enrolled customers increasing from 26,390 in October 2022 to 30,045 in September 2023.²⁷ As described in Section 3.2.4, the TOU methodology estimates load impacts using seasonal models that interact the estimated load impacts with weather conditions to produce monthly TOU load impacts based on differences in average monthly weather. The per-customer load impacts are higher during the summer months at approximately 0.11 kWh/hour compared to 0.06 kWh/hour during winter months. The lowest load impacts occur during March and April when peak usage decreases by 0.02 kWh/customer/hour. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All results are statistically significant except March and April.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2022	All	26,390	22.01	1.54*	0.83	0.06*	70
Nov-2022	All	26,433	23.03	1.39*	0.87	0.05*	59
Dec-2022	All	26,542	28.55	2.12*	1.08	0.08*	55
Jan-2023	All	26,738	26.56	2.03*	0.99	0.08*	56
Feb-2023	All	26,501	24.27	2.03*	0.92	0.08*	56
Mar-2023	All	26,394	17.02	0.66	0.64	0.02	56
Apr-2023	All	28,983	12.00	0.55	0.41	0.02	61
May-2023	All	29,535	12.80	1.36*	0.43	0.05*	62
Jun-2023	All	29,779	11.47	2.77*	0.39	0.09*	67
Jul-2023	All	29,787	26.82	3.94*	0.90	0.13*	75
Aug-2023	All	29,999	30.82	4.52*	1.03	0.15*	75
Sep-2023	All	30,045	26.25	3.69*	0.87	0.12*	71

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, there were 559 incremental non-NEM customers who switched to the TOU-DR rate with quality load data sufficient for estimating the TOU load impacts. Many NEM customers could not be used in the analysis because of a change in NEM status or PV installation size during the two-year study period. Specifically, only 218 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. The Inland climate zone exhibits higher reference loads during the summer than during winter, while the Coastal climate zone has higher winter reference loads. Inland reference loads are higher than Coastal reference loads during both periods. While customers in both climate zones decrease loads by 0.11 kWh/customer/hour on average during the peak period in summer months, Inland customers have a slightly higher load impact of 0.12 kWh/customer/hour. Inland customers also have a higher load impact during winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All results are statistically significant at the 10 percent 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		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	15,857	11.24	1.75*	0.71	0.11*	71
	Inland	13,343	12.28	1.59*	0.92	0.12*	72
	All	29,200	23.52	3.34*	0.81	0.11*	71
Winter	Coastal	15,805	11.69	0.82*	0.74	0.05*	58
	Inland	11,499	8.92	0.63*	0.78	0.06*	58
	All	27,304	20.61	1.45*	0.75	0.05*	58

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their daily energy consumption in October, December, January, February, and June through September and increased their usage in November March, April, and May. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. Results in July, August and September are statistically significant.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Daily Temp.
			Daily Ref. Load (MWh/hr)	Daily Load Impact (MWh/hr)	Daily Ref. Load (kWh/hr)	Daily Load Impact (kWh/hr)	
Oct-2022	All	26,390	234.45	5.97	8.88	0.23	67
Nov-2022	All	26,433	230.12	-1.20	8.71	-0.05	57
Dec-2022	All	26,542	341.68	1.49	12.87	0.06	53
Jan-2023	All	26,738	310.83	0.77	11.62	0.03	54
Feb-2023	All	26,501	226.30	3.60	8.54	0.14	53
Mar-2023	All	26,394	164.63	-16.38	6.24	-0.62	54
Apr-2023	All	28,983	79.73	-13.64	2.75	-0.47	58
May-2023	All	29,535	141.79	-0.45	4.80	-0.02	60
Jun-2023	All	29,779	89.65	8.94	3.01	0.30	64
Jul-2023	All	29,787	239.96	23.17*	8.06	0.78*	71
Aug-2023	All	29,999	300.72	29.87*	10.02	1.00*	71
Sep-2023	All	30,045	261.69	18.60*	8.71	0.62*	68

Figure 5.5 shows aggregate (NEM and non-NEM combined) hourly observed and estimated reference loads and 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 statistically significant reduction in usage during the peak hours. The TOU load impacts during the winter are also positive and statistically significant for the peak hours. For both winter and summer 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 ("HE") 1 through 7.²⁸

²⁸ In August, only hours ending 1 through 6 show a statistically significant result at the 10 percent significance level.

Figure 5.5: Aggregate Hourly Loads and TOU Load Impacts(MWh/hour) – TOU Customers (Average Weekday, August 2023)

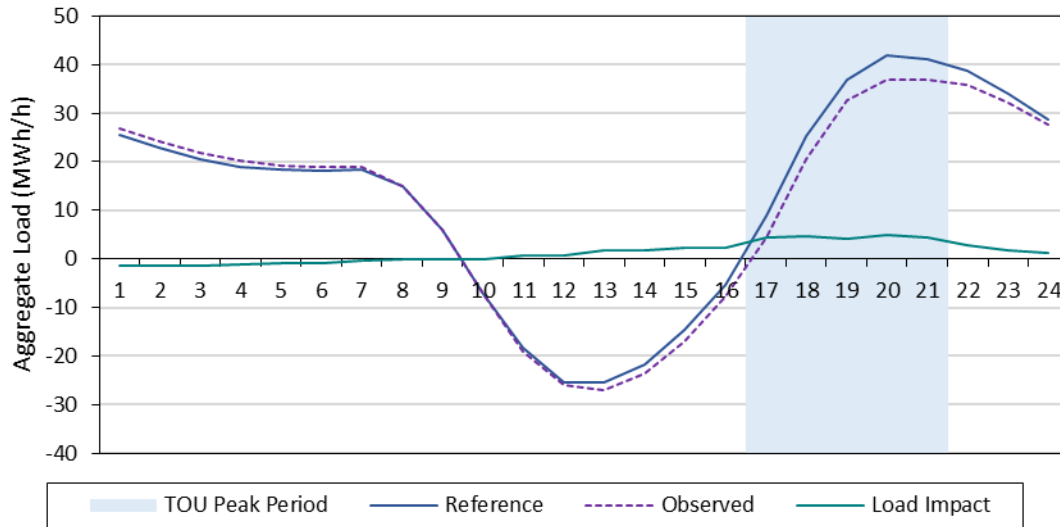
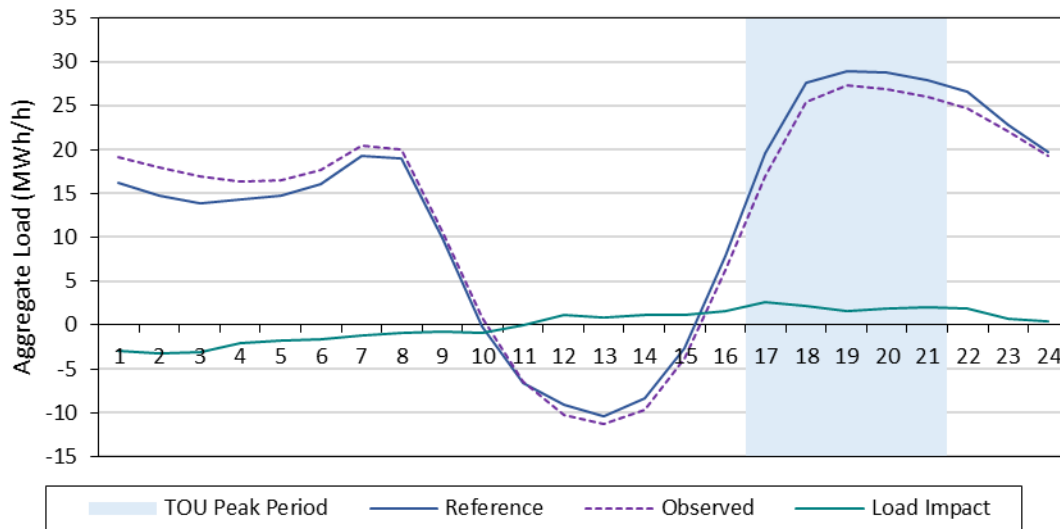


Figure 5.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU Customers (Average Weekday, January 2023)



5.3 TOU Control Group Matching Results for CPP Customers

Figure 5.7 and Figure 5.8 illustrate the match quality for the non-NEM residential CPP (TOU-DR-P) customers on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Eligible control group customers for this analysis include non-NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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 over the 24-hour period is 0.05 percent, while the mean absolute percentage error (MAPE) is 1.5 percent. During the summer

peak hours (4 p.m. to 9 p.m.) the MPE is -0.9 percent and the MAPE is 0.9 percent. In the winter months, over the 24-hour period, the MPE is 1.4 percent and the MAPE is 2.3 percent. Over the winter peak hours, the MPE is 0.7 percent and the MAPE is 2.1 percent.

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

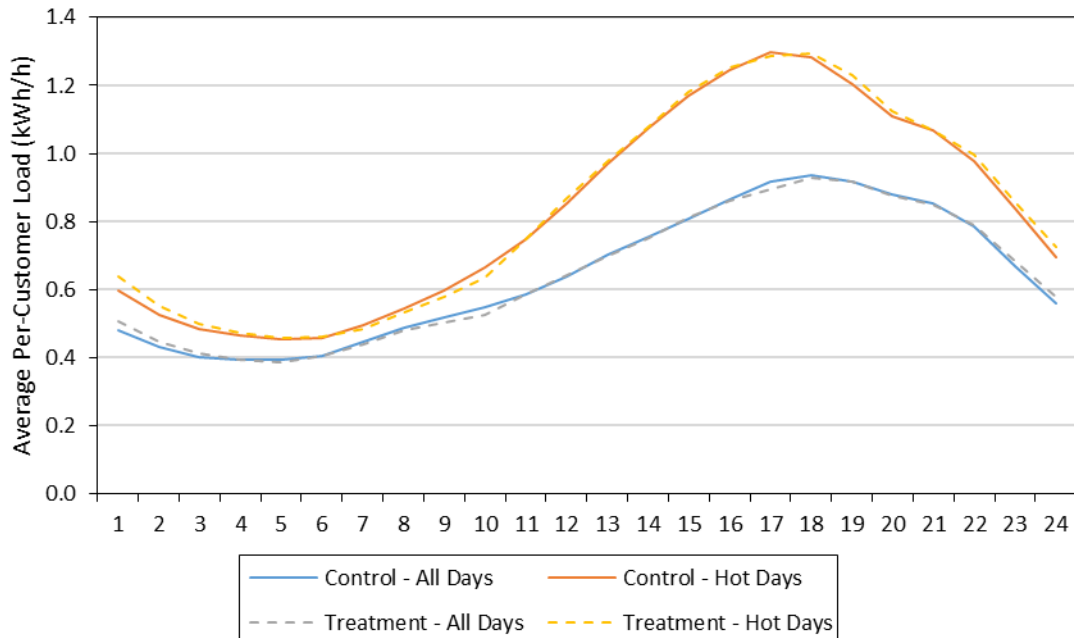


Figure 5.8: Non-NEM CPP and Matched Control Group Load Profiles – Winter

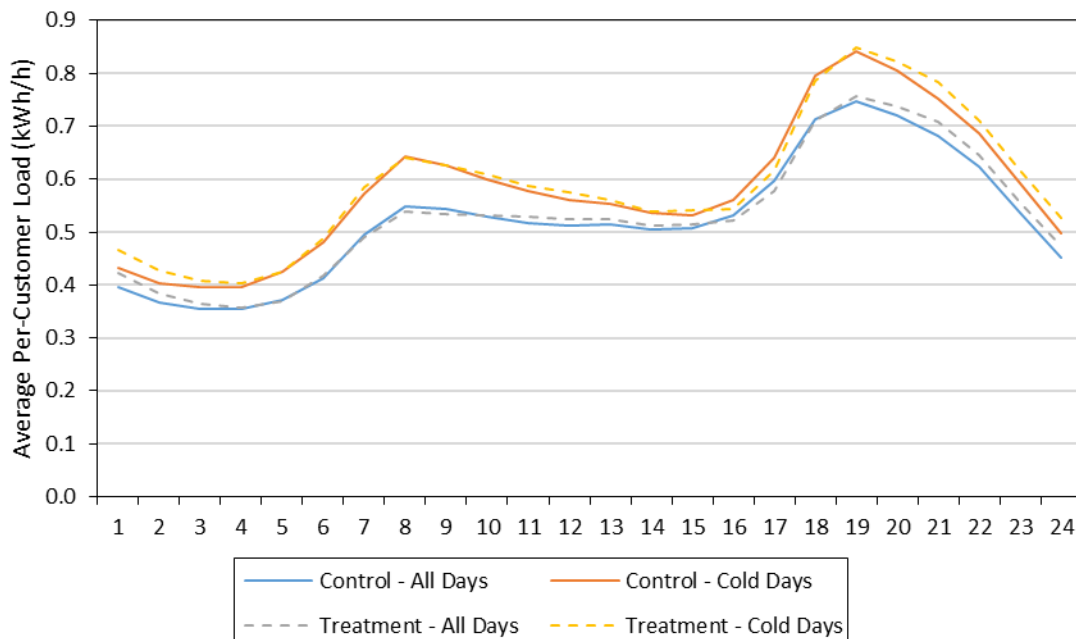


Figure 5.9 and Figure 5.10 illustrate the match quality for the NEM residential CPP (TOU-DR-P) customers on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Eligible control group customers for this analysis include NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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 over the 24-hour period is 0.05 kWh/hour, while the mean absolute error (MAE) is 0.07 kWh/hour. Over the peak-hour period the ME is 0.05 kWh/hour, and the MAE is 0.06 kWh/hour. In the winter months, over the 24-hour period the ME is 0.01 kWh/hour, and the MAE is 0.03 kWh/hour. Over the winter peak-hour period the ME is -0.01 kWh/hour, and the MAE is 0.02 kWh/hour.

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

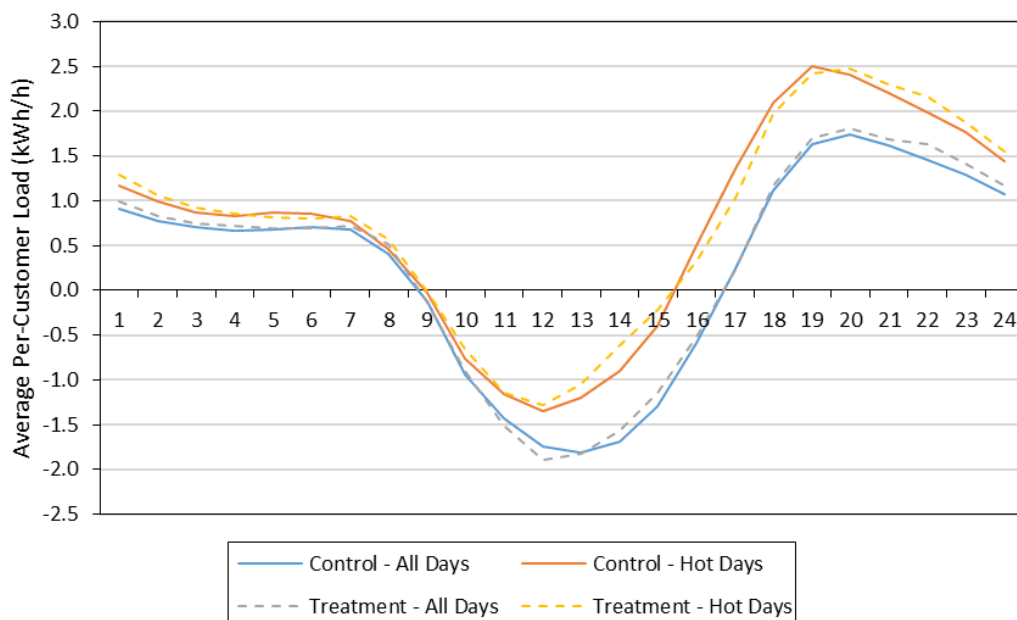
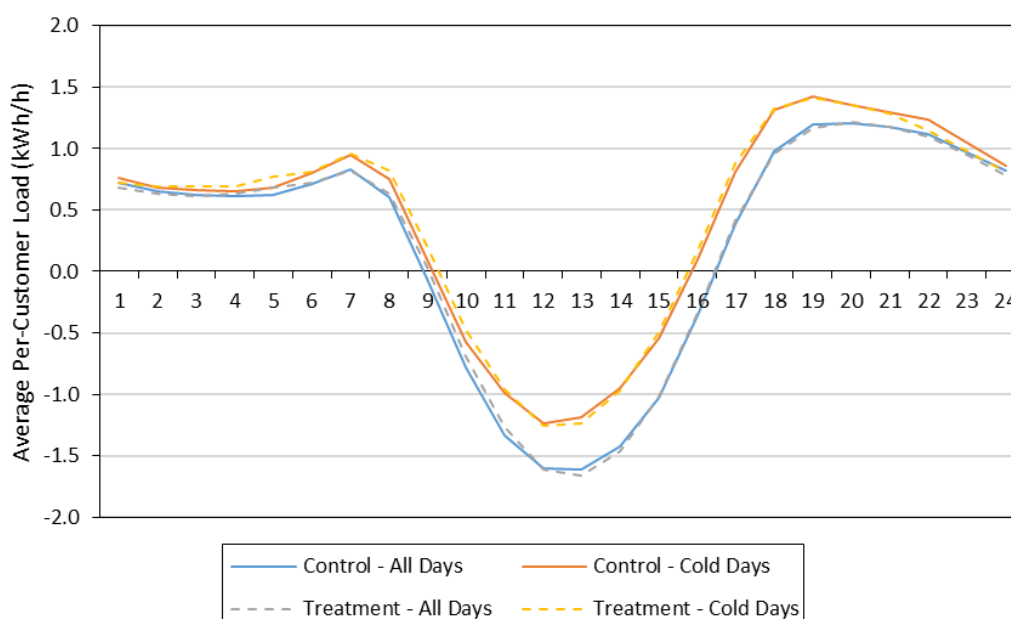


Figure 5.10: NEM CPP and Matched Control Group Load Profiles – Winter



5.4 Ex-Post TOU Load Impacts for CPP Customers

Since TOU-DR-P customers experience TOU prices on days that are not residential CPP event days, it is of interest to examine the impact of TOU prices on non-event day usage for these customers. This sub-section reports ex-post TOU load impact results for customers on the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average summer (October 2022, and June through September 2023) and winter (November 2022 through May 2023) weekdays, by month. Reported enrollment in CPP fell from 14,039 in October 2022 to 10,002 in September 2023.²⁹ A majority of the enrollment decreased between April and May was because of customers that transitioned to a CCA and were no longer eligible to be on the CPP rate. Peak load impacts varied between seasons, with estimated load reductions of 0.06 kWh/hour in all summer months and 0.04 kWh/hour in all winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level.

²⁹ The number of CPP customers included in the regressions is substantially smaller than the number used for CPP load impact regressions. This difference is due to the data requirements for the TOU analysis, including load histories for both the program year and the pre-treatment period, which served as the basis for control group matching. Moreover, TOU load impacts are based on incremental customers, which make up a small share of total customers on each rate. There were 490 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 60 NEM TOU-DR-P customers were used to estimate the NEM regressions.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2022	All	14,039	12.31	0.21*	0.88	0.01	70
Nov-2022	All	14,345	12.78	0.49*	0.89	0.03*	58
Dec-2022	All	14,273	14.98	0.29	1.05	0.02	54
Jan-2023	All	14,209	13.59	0.33*	0.96	0.02*	55
Feb-2023	All	14,052	12.61	0.33*	0.90	0.02*	55
Mar-2023	All	14,072	10.95	0.67*	0.78	0.05*	56
Apr-2023	All	14,007	8.16	0.67*	0.58	0.05*	61
May-2023	All	11,365	5.98	0.49*	0.53	0.04*	63
Jun-2023	All	10,780	5.34	0.66	0.50	0.06	67
Jul-2023	All	10,354	10.38	0.69*	1.00	0.07*	76
Aug-2023	All	10,198	10.99	0.73*	1.08	0.07*	76
Sep-2023	All	10,002	8.85	0.67*	0.88	0.07*	72

Table 5.5 summarizes results by season and climate zone. The Inland climate zone has a decrease in average peak-hour loads of 0.03 kWh/hour in both seasons compared to 0.08 kWh/hour in the Coastal climate zone during summer and 0.05 kWh/hour during winter. Load impacts in the Coastal climate zone are lower in winter. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. Winter load impacts for the Coastal climate zone and both summer and winter for all climates are statistically significant at the 10 percent level.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	6,958	5.84	0.58	0.84	0.08	72
	Inland	4,117	3.84	0.11	0.93	0.03	73
	All	11,075	9.68	0.69*	0.87	0.06*	72
Winter	Coastal	7,460	5.95	0.34*	0.80	0.05*	58
	Inland	6,300	5.42	0.19	0.86	0.03	57
	All	13,760	11.37	0.53*	0.83	0.04*	57

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers increased their average daily usage during the core winter months December through February and decreased their usage in spring and summer months. There is an overall annual load decrease of approximately 0.15 kWh/hour relative to the reference load. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. No results are statistically significant at the 10 percent level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Daily Temp.
			Daily Ref. Load (MWh/hr)	Daily Load Impact (MWh/hr)	Daily Ref. Load (kWh/hr)	Daily Load Impact (kWh/hr)	
Oct-2022	All	14,039	176.40	-0.94	12.56	-0.07	67
Nov-2022	All	14,345	181.62	0.13	12.66	0.01	56
Dec-2022	All	14,273	228.93	-3.68	16.04	-0.26	52
Jan-2023	All	14,209	211.90	-2.97	14.91	-0.21	52
Feb-2023	All	14,052	184.75	-2.24	13.15	-0.16	51
Mar-2023	All	14,072	170.32	0.30	12.10	0.02	53
Apr-2023	All	14,007	116.26	1.65	8.30	0.12	57
May-2023	All	11,365	88.62	2.03	7.80	0.18	60
Jun-2023	All	10,780	76.21	6.31	7.07	0.59	64
Jul-2023	All	10,354	135.16	7.20	13.05	0.70	71
Aug-2023	All	10,198	148.09	7.69	14.52	0.75	72
Sep-2023	All	10,002	124.51	6.55	12.45	0.66	69

Figure 5.11 shows aggregate hourly observed and estimated reference loads and load impacts for residential CPP customers (both non-NEM and NEM) for the weekday in August. Figure 5.12 shows the same information for the average weekday in January. The January average loads exhibit slight load shifting (load increases) during some of the super off-peak hours and decreases in loads in four out of five peak hours. The August loads have significant decreases during all peak hours, but no significant load shifting to other hours.

Figure 5.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – CPP Customers (Average Weekday, August 2023)

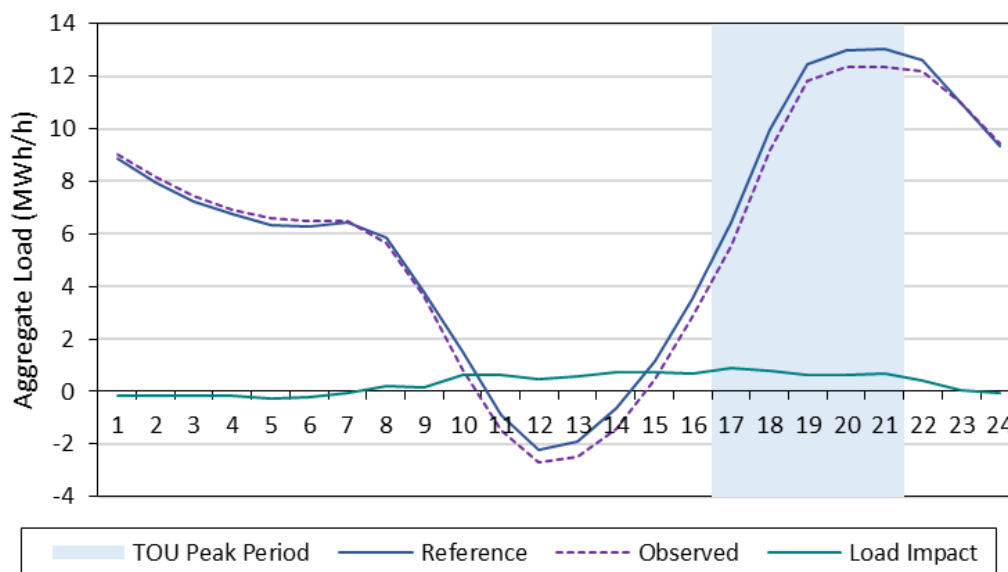
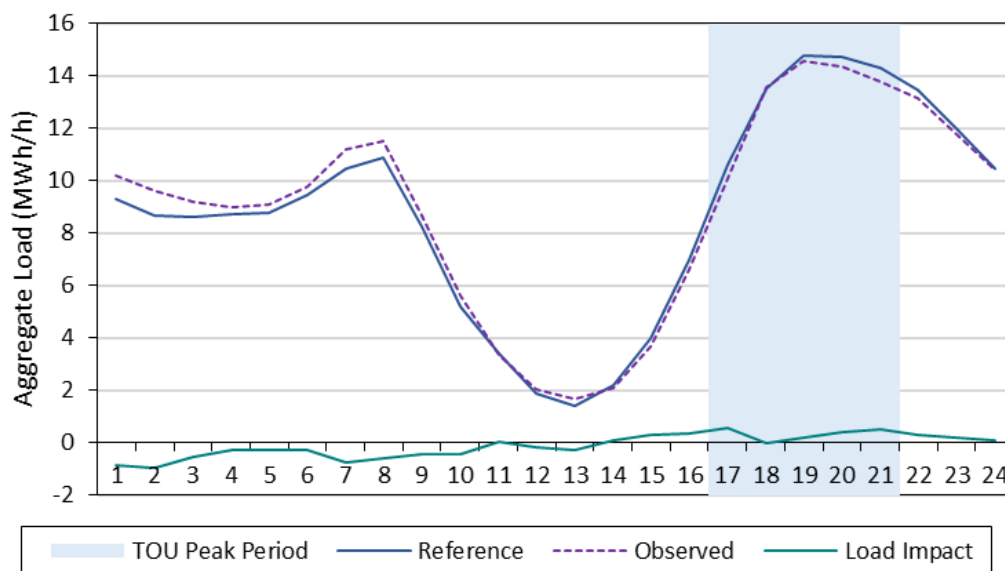


Figure 5.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – CPP Customers (Average Weekday, January 2023)



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 per-customer load impacts from the ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

6.1 Per-Customer Load Impacts

CPP events are usually called during extreme weather scenarios. Weather-sensitive ex-ante load impacts for the relevant weather scenarios are constructed by applying percentage load impacts from ex-post to simulated weather-sensitive reference loads. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these customers. SDG&E called one CPP event in 2023. The ex-ante analysis uses load impacts from this event as a basis for PY2023 ex-ante forecasts. Different ex-post percentage load impacts (or level load impacts in the case of NEM customers) by climate zone, dual enrollment in either ACSDO or ELRP, and for customers who receive notifications are applied to simulated reference loads.

Portfolio-level load impacts are reported for instances when a CPP event is called on the same day as an 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 ex-ante load impacts (TOU-DR and TOU-DR-P customers), percentage load impacts from the ex-post analysis are applied to weather-sensitive observed loads that are developed as described in the following sub-section. NEM customer observed loads and level load impacts are used to avoid issues with percentage load impacts for these customers.

6.2 Per-Customer Reference Loads

Weather-sensitive reference loads for the average customer in each of the two climate zones are developed through a regression analysis of hourly load data for weekday non-event days in PY2023 for CPP and TOU customers. Customers are first sorted as weather sensitive or not.³⁰

³⁰ Customer-specific regressions are implemented to categorize customers as weather sensitive or not, by season. Weather sensitive customers have hourly loads that change 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 . Event days are 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 winter weather sensitivity. The regression is

Regression models are estimated separately for each hour of the day, by weather sensitivity, using daily observations for weekdays, and a regression equation 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 includes only the treatment customer loads during PY2023;
- Weather variables are included (e.g., Mean17, CDH, CDD, HDH and HDD);³¹ and
- Month specific variables are included in the models that are estimated by season to account for monthly differences in usage patterns.

The resulting equations are used to simulate “observed” loads under the four different weather scenarios. Simulated reference loads for the alternative scenarios are obtained by scaling up the simulated observed loads by the relevant estimated percentage TOU load impacts from the ex-post analysis.³² NEM customer observed loads and load impacts are estimated separately from non-NEM customers. For NEM customers, reference loads are calculated by adding the level load impacts from ex-post to the observed loads. The process for obtaining simulated reference and observed loads is completed separately for each reporting category.³³

6.3 Enrollment Forecast

Figure 6.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment for TOU is anticipated to begin declining after 2024. Enrollment is expected to be greater in the Coastal climate zone than in the Inland climate zone for both TOU-DR and TOU-DR-P customers, however the differences are more pronounced for TOU-DR-P customers. This mirrors the fact that the rates have different enrollment ratios in the two climate zones.

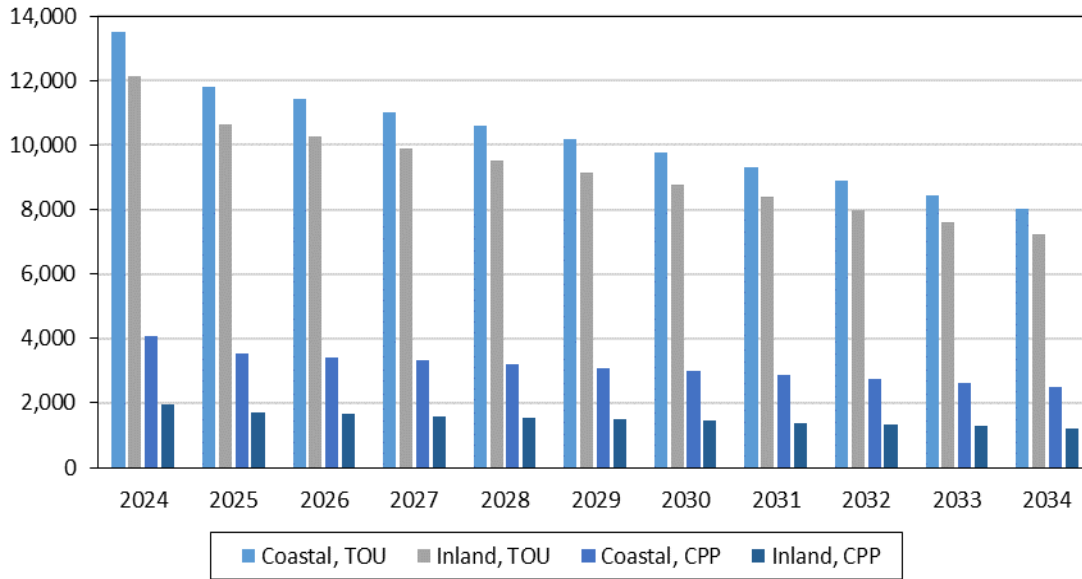
estimated for each customer and season specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant.

³¹ 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: $CDH_{65} = \max(0, \text{temperature in } ^\circ\text{F} - \text{chosen temperature threshold})$. Likewise, heating degree hours (HDH) for each hour of the day are defined as: $HDH_{60} = \max(0, \text{chosen temperature threshold} - \text{temperature in } ^\circ\text{F})$. Cooling degree days (CDD) for each day are defined as $\max(0, (\text{maximum daily temperature} - \text{minimum daily temperature})/2 - \text{chosen temperature threshold})$. Likewise, heating degree days (HDD) for each day are defined as $\max(0, \text{chosen temperature threshold} - (\text{maximum daily temperature} - \text{minimum daily temperature})/2)$. Commonly used temperature thresholds for the calculation of CDH, CDD, HDH and HDD are 60, 65 and 70.

³² The adjustment takes the form of $\text{Reference} = \text{Observed} / (1 - \% \text{TOULoadImpact})$. Several alternative approaches were considered to develop 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 sensitive to the data and approach used, although the selected approach produced more accurate loads during the swing months.

³³ 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 non-NEM and NEM customers and TOU and CPP customers, separate panel regressions including only the customers in each group are estimated to simulate reference and observed loads for that group of customers.

Figure 6.1: Enrollments in TOU and CPP Rates



7. EX-ANTE LOAD IMPACT STUDY FINDINGS

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

7.1 Ex-Ante CPP Event Load Impacts

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 estimated aggregate reference loads, observed loads, and load impacts for an August peak day in 2024 for the SDG&E 1-in-2 weather scenario. The average event-period load impact is 0.57 MWh/hour.

Figure 7.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/hour) – (August 2024 SDG&E 1-in-2 Peak Day)

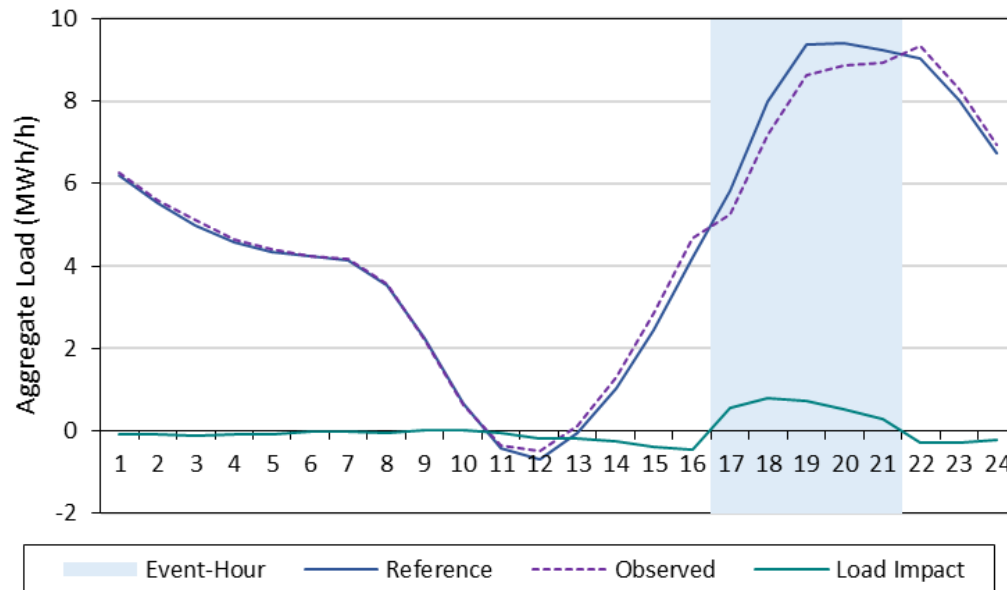


Figure 7.2 shows the monthly pattern of aggregate ex-ante load impacts for the average hour in the RA window (blue) and event window (gray) in 2024 for the SDG&E 1-in-2 peak day. Table 7.1 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as forecasted customer enrollment in each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March, April, and May when it is 5 to 10 p.m. (HE 18-22). The event hours in all months are from 4 to 9 p.m. (HE 17-21). The lower RA window load impacts in March, April and May are driven by differences between the CPP event and RA window during these months as can be seen by contrasting RA window and event-hour aggregate load impacts in Figure 7.2. While per-customer load impacts are higher during summer months due to higher reference loads, the aggregate load impacts in 2024 are highest in January and February due to an anticipated drop in enrollments in April 2024 of 2,225 customers. Enrollments are forecasted to be almost 3,000 customers less in December of 2024 compared to January.

Figure 7.2: Aggregate CPP Load Impacts (MWh/hour), by Month – (2024 SDG&E 1-in-2 Peak Day, RA Window and Event Hours)

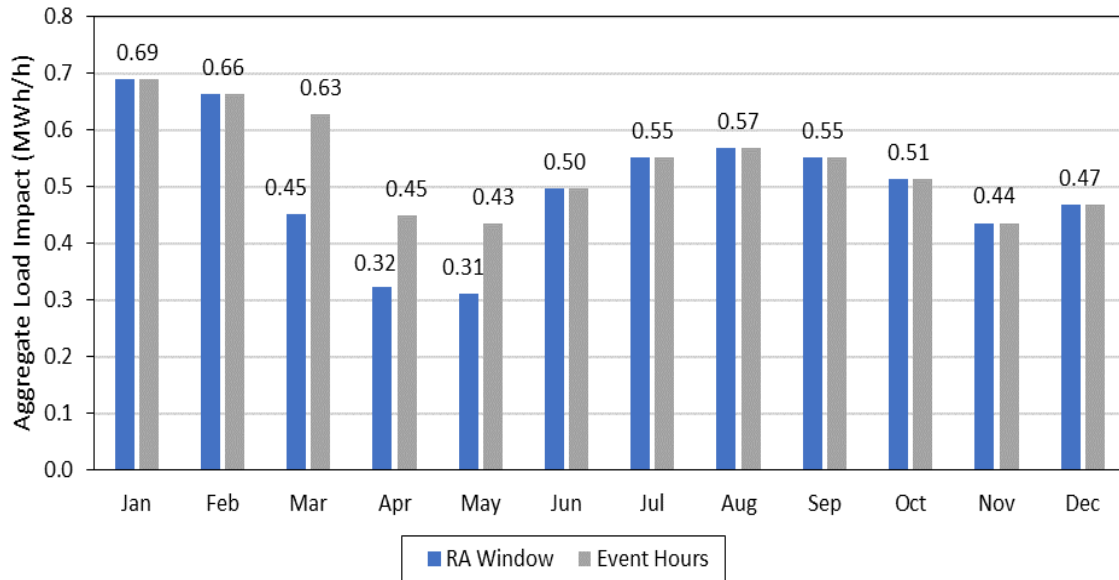
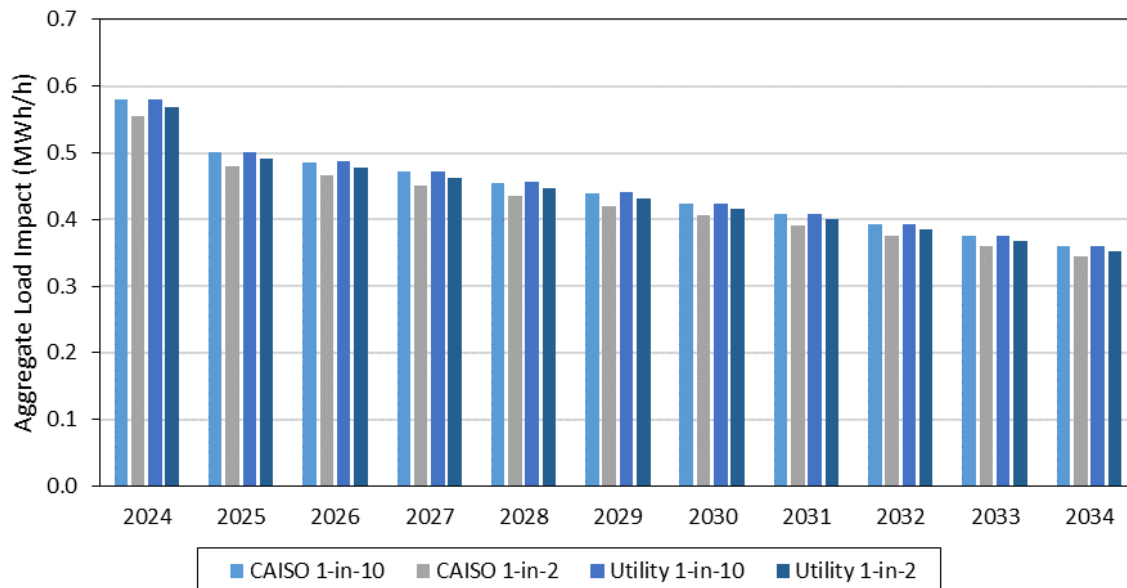


Table 7.1 Aggregate (MWh/hour) and Per-Customer (kWh/hour) CPP Load Impacts, by Month – (2024 SDG&E 1-in-2 Peak Day, RA Window)

Month	Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hr)	Event Load Impact (MWh/hr)	Event Ref. Load (kWh/hr)	Event Load Impact (kWh/hr)
January	8,770	8.21	0.69	0.94	0.08
February	8,651	7.47	0.66	0.86	0.08
March	8,510	6.91	0.45	0.81	0.05
April	6,285	4.28	0.32	0.68	0.05
May	6,225	3.91	0.31	0.63	0.05
June	6,177	4.55	0.50	0.74	0.08
July	6,122	6.92	0.55	1.13	0.09
August	6,061	7.80	0.57	1.29	0.09
September	6,008	7.77	0.55	1.29	0.09
October	5,960	6.86	0.51	1.15	0.09
November	5,930	4.71	0.44	0.80	0.07
December	5,828	5.91	0.47	1.01	0.08

Figure 7.3 illustrates the forecasted aggregate event load impacts for CPP by weather scenario. Load impacts decrease over time as enrollments decrease, with the largest drop occurring from 2024 to 2025. 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/hour), by Year and Weather Scenario - (August Peak Day, RA Window)



7.2 Ex-Ante TOU Load Impacts

This subsection summarizes the ex-ante TOU peak load impact forecasts for customers anticipated to be enrolled in either the TOU (TOU-DR) or CPP (TOU-DR-P) rate. Figure 7.4 shows aggregate reference loads, observed loads, and load impacts for TOU and CPP customers, in 2024 for an SDG&E 1-in-2 average weekday in August. The average peak load impact is 4.24 MWh/hour.

Figure 7.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU and CPP Customers, (August 2024 SDG&E 1-in-2 Average Weekday)

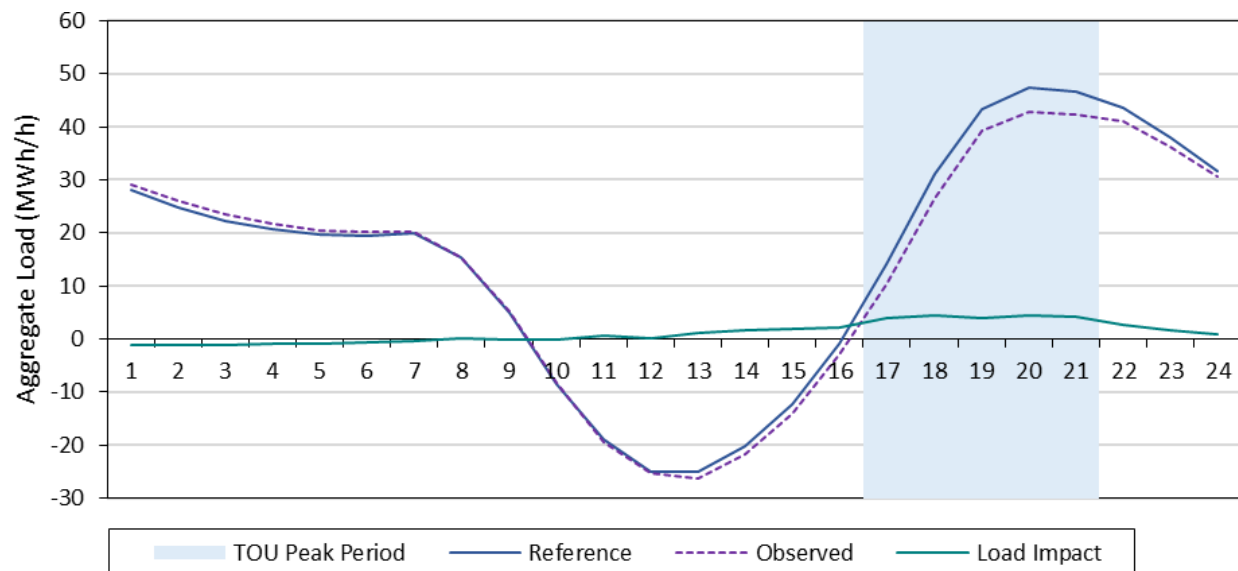
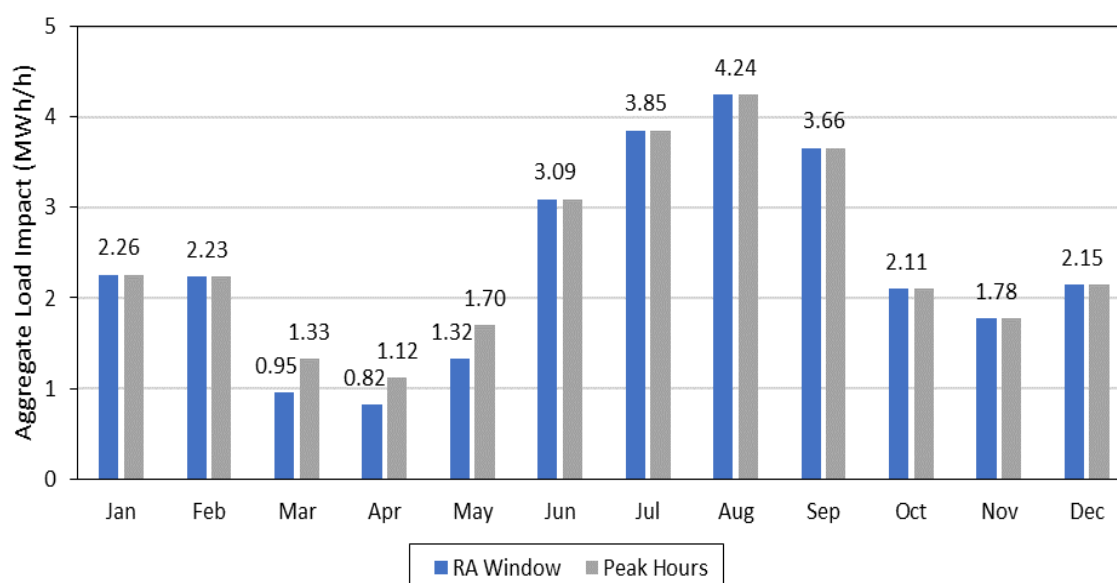


Figure 7.5 shows the seasonality of aggregate ex-ante TOU load impacts for TOU and CPP customers for the average hour in the RA window (blue) and the peak hours. Table 7.2 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as customer forecasted enrollment in each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March, April, and May, when it is 5 to 10 p.m. (HE 18-22). The peak period is 4 to 9 p.m. (HE 17-21) in all months. Aggregate and per-customer load impacts are the highest during summer months and the lowest in March, April, and May.³⁴ The difference between the RA window and the peak hours during March, April, and May lead to lower load impacts during the RA window relative to the peak hour load impacts. Load impacts are driven by seasonal differences in reference loads, with lower reference loads occurring during spring and autumn months.³⁵ Table 7.2 also shows that TOU and CPP enrollments are forecasted to decline throughout 2024 by over 4,000 customers between January and December.

Figure 7.5: Aggregate TOU Load Impacts (MWh/hour) by Month – TOU and CPP Customers, (2024 SDG&E 1-in-2 Average Weekday, RA Window and Peak Hours)



³⁴ March and April are estimated separately because the midday off-peak hours differ from other months.

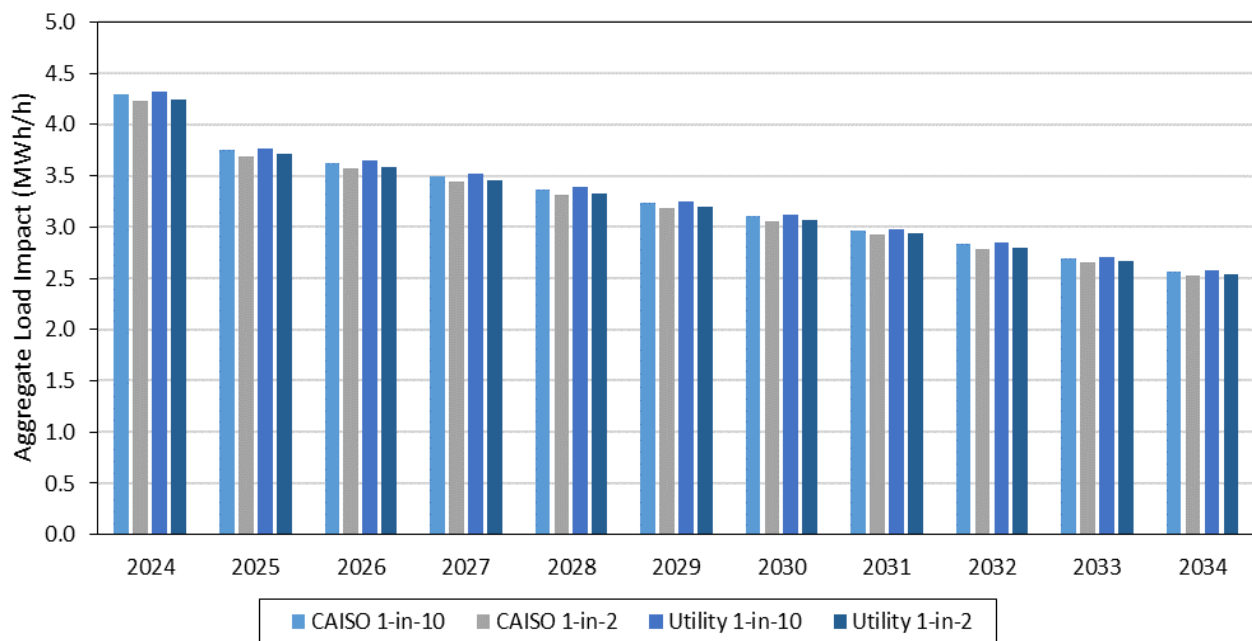
³⁵ The lowest aggregate and per-customer reference loads are in June, which is driven by PV generation by NEM customers and daylight hours that extend over the first several hours of the RA window.

Table 7.2 Aggregate (MWh/hour) and Per-Customer (kWh/hour) TOU Load Impacts by Month - TOU and CPP Customers, (2024 SDG&E 1-in-2 Average Weekday, RA Window)

Month	Enrolled	Aggregate		Per-Customer	
		Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)
January	35,241	33.97	2.26	0.96	0.06
February	34,963	31.21	2.23	0.89	0.06
March	34,689	28.93	0.95	0.83	0.03
April	32,183	22.21	0.82	0.69	0.03
May	32,082	20.72	1.32	0.65	0.04
June	31,973	15.98	3.09	0.50	0.10
July	31,855	28.45	3.85	0.89	0.12
August	31,728	34.29	4.24	1.08	0.13
September	31,590	31.60	3.66	1.00	0.12
October	31,480	27.70	2.11	0.88	0.07
November	31,393	27.79	1.78	0.89	0.06
December	31,161	33.62	2.15	1.08	0.07

Figure 7.6 shows the forecasted TOU aggregate load impacts for an August weekday over the forecast period 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.

Figure 7.6: Aggregate TOU Load Impacts (MWh/hour) – TOU and CPP 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.

In the above list, “current study” refers to this report, which is based on findings from the 2023 program year; and “previous study” refers to the report that was developed following the 2022 program year. The comparison of results is provided for the CPP analysis as well as TOU analysis.

8.1 CPP Load Impacts

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 year.³⁶ The event hours were 4 to 9 p.m. in both program years. The aggregate enrollments are significantly higher in 2022 than in 2023 which is primarily due to CCA enrollments of CPP customers in 2023. This drives the large decline in aggregate load impacts and reference loads between 2022 and 2023. The per-customer reference loads and load impacts are also lower in 2023 as are event hour temperatures.

Table 8.1: Previous vs. Current Ex-Post CPP Event Load Impacts

Result	Ex-post 2022 Event Day PY2022 Study	Ex-post 2023 Event Day PY2023 Study
# Enrolled	15,862	9,916
Reference (MWh/hour)	30.29	15.44
Load Impact (MWh/hour)	2.27	0.99
Per-customer reference (kWh/hour)	1.91	1.56
Per-customer load impact (kWh/hour)	0.14	0.10
Temperature	86.7	84.8
% NEM	33.6%	30.9%

8.1.2 Previous versus current ex-ante

In this sub-section, the ex-ante forecast prepared in PY2022 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 SGD&E 1-in-2 weather conditions. The per-customer reference

³⁶ As the event on August 29th was the only CPP event in 2023, the average weekday event in 2023 refers to the August 29th event.

loads and load impacts are higher in the previous study. Aggregate reference loads and load impacts are smaller in the PY2023 ex-ante analysis due to an updated enrollment forecast that predicts lower enrollments in 2024 compared to the previous forecast.

Table 8.2: Previous vs. Current Ex-Ante CPP Event Load Impacts

Result	Ex-ante 2024 Peak Day PY2022 Study	Ex-ante 2024 Peak Day PY2023 Study
# Enrolled	7,932	6,061
Reference (MWh/hour)	12.05	7.80
Load Impact (MWh/hour)	1.05	0.57
Per-customer reference (kWh/hour)	1.52	1.29
Per-customer load impact (kWh/hour)	0.13	0.09
Temperature	84.7	83.8
% NEM	33.6%	31.7%

8.1.3 Previous ex-ante versus current ex-post

Table 8.3 provides a comparison of the ex-ante forecast of 2023 load impacts prepared in PY2022 and the PY2023 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 an SDG&E 1-in-2 weather year. The increase in aggregate reference loads is due to a slight increase in enrollments compared to the forecast and per-customer references loads. The per-customer load impact is 0.03 kWh/hour lower in ex-post than ex-ante, which drives the decline in aggregate load impacts.

Table 8.3: Previous Ex-Ante vs. Current Ex-Post CPP Event Load Impacts

Result	Ex-ante 2023 Peak Day PY2022 Study	Ex-post 2023 Event Day PY2023 Study
# Enrolled	9,510	9,916
Reference (MWh/hour)	14.42	15.44
Load Impact (MWh/hour)	1.25	0.99
Per-customer reference (kWh/hour)	1.52	1.56
Per-customer load impact (kWh/hour)	0.13	0.10
Temperature	84.7	84.8
% NEM	33.6%	30.9%

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 2024 for the SDG&E 1-in-2 August peak day from this study. The current

ex-ante study forecasts lower enrollments, resulting in lower aggregate reference loads. Per-customer reference loads and load impacts are lower in ex-ante.

Table 8.4: Current Ex-Post vs. Current Ex-Ante CPP Event Load Impacts

Result	Ex-post 2023 Event Day PY2023 Study	Ex-ante 2024 Peak Day PY2023 Study
# Enrolled	9,916	6,061
Reference (MWh/hour)	15.44	7.80
Load Impact (MWh/hour)	0.99	0.57
Per-customer reference (kWh/hour)	1.56	1.29
Per-customer load impact (kWh/hour)	0.10	0.09
Temperature	84.8	83.8
% NEM	30.9%	31.7%

Table 8.5 compares the key components of the two analyses. As the table describes, the main source of difference between the analyses is the enrollment count differences between ex-post and ex-ante.

Table 8.5: Comparison of Ex-Post and Ex-Ante Factors, CPP Event

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	84.8 degrees Fahrenheit during HE 17-21.	83.8 degrees Fahrenheit during HE 17-21 of an SDG&E 1-in-2 August peak day.	None. The weather conditions are similar
% of resource dispatched	The entire program was dispatched on August 29 th .	Assume all customers are called.	None. The ex-ante method assumes that all enrolled customers are dispatched.
Enrollment	9,916 customers enrolled.	6,061 customers.	The decrease in ex-ante enrollments decreases the aggregate 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 PY2023 data.	No effect on 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 TOU Load Impacts

This section compares TOU load impacts over the RA window. All comparisons include both TOU and CPP customers.

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 increased in winter but were lower in during summer. Per-customer load impacts increased during both seasons, which drives the increase in aggregate load impacts. The 2023 summer per-customer impact of 0.13 kWh/hour and the winter per-customer load impact of 0.06 kWh/hour are double the 2022 per-customer load impacts in summer and winter, respectively. Per-customer reference loads increase during winter and decrease in the summer period, which leads to increased aggregate reference loads during winter and decreased aggregate reference loads during summer.

Table 8.6: Previous vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-post 2022 Avg. Weekday PY2022 Study	Ex-post 2023 Avg. Weekday PY2023 Study
Summer (August)	# Enrolled	43,147	40,197
	Reference (MWh/hour)	52.70	41.81
	Load Impact (MWh/hour)	2.70	5.24
	Per-customer reference (kWh/hour)	1.22	1.04
	Per-customer load impact (kWh/hour)	0.06	0.13
	Temperature	77.4	75.3
	% NEM	36.9%	43.4%
Winter (January)	# Enrolled	38,101	40,947
	Reference (MWh/hour)	34.87	40.15
	Load Impact (MWh/hour)	1.19	2.36
	Per-customer reference (kWh/hour)	0.92	0.98
	Per-customer load impact (kWh/hour)	0.03	0.06
	Temperature	58.4	55.3
	% NEM	31.2%	39.3%

8.2.2 Previous versus current ex-ante

Table 8.7 reports the average RA-window load impacts for the August and January 2024 average weekday under SDG&E 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 in the winter period and comparable summer enrollments. The per-customer load impacts are much higher in

the current forecast during summer months and slightly higher during winter months. Combined with enrollment increases, this leads to a large increase in aggregate load impacts in each season. Aggregate reference loads are also higher during winter in the 2023 forecast as a result of higher per-customer reference loads and forecasted enrollments.

Table 8.7: Previous vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-ante 2024 Avg. Weekday PY2022 Study	Ex-ante 2024 Avg. Weekday PY2023 Study
Summer (August)	# Enrolled	31,652	31,728
	Reference (MWh/hour)	36.59	34.29
	Load Impact (MWh/hour)	1.77	4.24
	Per-customer reference (kWh/hour)	1.16	1.08
	Per-customer load impact (kWh/hour)	0.06	0.13
	Temperature	76.3	76.5
	% NEM	37.8%	44.9%
Winter (January)	# Enrolled	31,652	35,241
	Reference (MWh/hour)	29.31	33.97
	Load Impact (MWh/hour)	1.22	2.26
	Per-customer reference (kWh/hour)	0.93	0.96
	Per-customer load impact (kWh/hour)	0.04	0.06
	Temperature	60.8	60.8
	% NEM	37.8%	43.9%

8.2.3 Previous ex-ante versus current ex-post

Table 8.8 provides a comparison of the ex-ante forecast of 2023 TOU load impacts prepared in the previous study and the PY2023 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 an SDG&E 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 seasons. The per-customer load impacts are notably higher 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, with the exception of increasing enrollments during summer compared to forecasted enrollments. This leads to increased aggregate reference loads in summer months compared to the forecast from 2022.

Table 8.8: Previous Ex-Ante vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-ante 2023 Avg. Weekday PY2022 Study	Ex-post 2023 Avg. Weekday PY2023 Study
Summer (August)	# Enrolled	34,035	40,197
	Reference (MWh/hour)	39.62	41.81
	Load Impact (MWh/hour)	1.99	5.24
	Per-customer reference (kWh/hour)	1.16	1.04
	Per-customer load impact (kWh/hour)	0.06	0.13
	Temperature	76.3	75.3
	% NEM	37.7%	43.4%
Winter (January)	# Enrolled	34,035	40,947
	Reference (MWh/hour)	31.50	40.15
	Load Impact (MWh/hour)	1.29	2.36
	Per-customer reference (kWh/hour)	0.93	0.98
	Per-customer load impact (kWh/hour)	0.04	0.06
	Temperature	60.8	55.3
	% NEM	37.7%	39.3%

8.2.4 Current ex-post versus current ex-ante

Table 8.9 compares the PY2023 ex-post TOU load impacts for the August average weekday with the corresponding ex-ante forecast for 2024 (of the SDG&E 1-in-2 August average weekday) produced in this study. The TOU load impacts are presented for all TOU customers and are averaged over the RA window, which perfectly overlaps with the TOU peak period. The per-customer reference loads and load-impacts are similar between the two scenarios, with the slight differences likely explained by temperature differences between the ex-ante scenarios and the ex-post weather conditions. Lower enrollments in 2024 compared to 2023 drive lower aggregate reference loads and load impacts.

Table 8.9: Current Ex-Post vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-post 2023 Avg. Weekday PY2023 Study	Ex-ante 2024 Avg. Weekday PY2023 Study
Summer (August)	# Enrolled	40,197	31,728
	Reference (MWh/hour)	41.81	36.53
	Load Impact (MWh/hour)	5.24	4.29
	Per-customer reference (kWh/hour)	1.04	1.15
	Per-customer load impact (kWh/hour)	0.13	0.14
	% Load Impact	12.5%	11.7%
	Temperature	75.3	76.6
	% NEM	43.4%	44.9%
Winter (January)	# Enrolled	40,947	35,241
	Reference (MWh/hour)	40.15	33.97
	Load Impact (MWh/hour)	2.36	2.26
	Per-customer reference (kWh/hour)	0.98	0.96
	Per-customer load impact (kWh/hour)	0.06	0.06
	% Load Impact	5.9%	6.6%
	Temperature	55.3	60.8
	% NEM	39.3%	43.9%

9. RECOMMENDATIONS

One CPP event was called August 29th, which was a weekday event. We suggest calling more events to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures, months, and days of week.

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) including solar size PV as an additional characteristic in the matching process for NEM customers, 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 1.5 kWh/hour were excluded from the regression sample.