



**2018 Load Impact Evaluation of  
San Diego Gas and Electric's  
Voluntary Residential Critical  
Peak Pricing (CPP) and Time-of-  
Use (TOU) Rates**

**CALMAC Study ID SDGE0314**

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*April 1, 2019*

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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 2018. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015.

Both summer and winter TOU periods in the two rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super off-peak period. During the months of March and April, a super off-peak period is carved into the off-peak period between 10 a.m. and 2 p.m. Weekend and holiday hours are all off-peak. This year, the analysis includes Net Energy Metered ("NEM") customers due to the growing proportion of residential solar customers on each rate. These customers were estimated separately but included in the results for each rate using a customer-weighted average.

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

CPP events may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year, whenever a Reduce Your Use (RYU) event is called. In 2018, SDG&E called six CPP events, July 6<sup>th</sup>, July 24<sup>th</sup>, July 25<sup>th</sup>, August 6<sup>th</sup>, August 7<sup>th</sup> and August 9<sup>th</sup>, all of which were weekdays.

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

In 2018, the *ex-post* CPP average weekday load impacts (*i.e.*, all events) indicate that, on average, customers reduced their usage by 0.17 kW for customers in the Coastal climate zone, representing 15 percent of their reference load, and 0.28 kW, or 17 percent, for the Inland climate zone. CPP enrollment averaged 6,796 customers on the six event

days, with a majority of customers in the Coastal climate zone. The aggregate reference load was 9.14 MW.

Among grandfathered customers, those in the Coastal climate zone reduced their usage by 0.13 kW, or 37 percent of their reference load, and those in the Inland climate zone reduced their usage by 0.33 kW, or 33 percent of their reference load. CPP enrollment among grandfathered customers averaged 426 customers during the event days. The aggregate reference load was 0.31 MW.

TOU enrollment rose from 1,019 customers in October 2017 to 2,869 in September 2018. The estimated seasonal percentage load impacts were approximately 9.4 percent in summer and 1.9 percent in winter. Summer peak load impacts were similar in percentage terms for the two climate zones. Combining results across months and considering the effect of TOU on average *daily* usage, we find that TOU customers *decreased* their energy consumption by an annual average of approximately 3 percent.

Similarly, we evaluated the TOU load impacts for CPP customers. Enrollment in CPP grew from 4,086 in October 2017 to approximately 8,048 in September 2018. Summer TOU peak load impacts varied across months, with load reductions in all months except October. Load impacts in winter months were smaller. Both summer and winter peak load impacts are similar between the Coastal and Inland climate zones, with Coastal percentage load impacts slightly larger in both summer and winter.

Among grandfathered customers, average enrollment in winter was 455 customers while average summer enrollment had dropped to 425 customers. The Coastal climate zone saw no TOU reduction during the summer season, while during the winter, Coastal customers *increased* usage by 7 percent. Inland customers reduced their load by similar amounts in both summer and winter, at 7 percent and 6 percent, respectively.

## **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 2018. The two rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both the TOU and CPP rates are voluntary rates that became active in February 2015. In addition, this report includes *ex-post* and *ex-ante* load impacts for grandfathered customers on the rate GTOU-DR-P. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions until July 31, 2027.

### ***ES.1 Resources Covered***

The TOU periods for the two non-grandfathered rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekend and holidays as well as during the months of March and April. The CPP rate may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year. SDG&E called six CPP events in 2018: 7/6, 7/24, 7/25, 8/6, 8/7, and 8/9.

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

### ***ES.2 Evaluation Methodologies***

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

## ES.3 Ex-Post Load Impacts

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

Table ES.1 summarizes average event-hour reference load and RYU/CPP load impact results for the RYU/CPP customers on the average weekday event in 2018.<sup>1</sup> Results are shown by Coastal and Inland climate zones. The first two columns show the climate zone and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MW. The next two columns show the same variables for the average customer, in units of kW. The last two columns show the load impacts as a percentage of the reference loads, and the average temperature during the event window.

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

Climate Zone	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
		Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
Coastal	4,105	4.72	0.69	1.15	0.17	15%	88
Inland	2,692	4.42	0.75	1.64	0.28	17%	94
<b>All</b>	<b>6,796</b>	<b>9.14</b>	<b>1.45</b>	<b>1.35</b>	<b>0.21</b>	<b>16%</b>	<b>91</b>

Program enrollment was 6,796 customers, skewed somewhat toward the Coastal climate zone.<sup>2</sup> The aggregate reference load was 9.14 MWh/h. Per-customer load impacts averaged 0.17 kWh/h for customers in the Coastal climate zone, representing 15 percent of their reference load, and 0.28 kWh/h, or 17 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 88 degrees, than the 94-degree temperature for the Inland zone.

Table ES.2 summarizes average event-hour reference load and CPP load impact results for the grandfathered CPP customers on the average weekday event in 2018. Program enrollment was 426 customers, with more customers in the Inland climate zone. The aggregate reference load was 0.31 MWh/h. Per-customer load impacts averaged 0.13 kWh/h for customers in the Coastal climate zone and 0.33 kWh/h for customers in the Inland climate zone.

<sup>1</sup> CPP residential customers are those that voluntarily enrolled on rate TOU-DR-P or are grandfathered on rate GTOU-DR-P.

<sup>2</sup> 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).

**Table ES.2: Average Grandfathered RYU/CPP Event-Hour Load Impacts  
– Average Weekday Event**

Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
		Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	181	0.06	0.02	0.35	0.13	88
Inland	246	0.25	0.08	1.01	0.33	95
<b>All</b>	<b>426</b>	<b>0.31</b>	<b>0.11</b>	<b>0.73</b>	<b>0.26</b>	<b>95</b>

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

Table ES.3 summarizes the average reference loads and load impacts for customers on the TOU-DR rate for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m. for all months), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with the first month included in the analysis (October 2017). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 1,019 in October 2017 to 2,869 in September 2018.<sup>3</sup> The estimated seasonal percentage load impacts were largest during the summer months. Only the month of March exhibited an *increase* in load usage during the TOU peak period.

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<sup>3</sup> The enrollment numbers shown differ from the number of customers used in the regression models, which use only those customers with sufficient program-year and pre-treatment period load data needed for matching to control groups and estimating load impacts. Specifically, there were 689 incremental customers on the TOU-DR rate with quality load data that were used in estimating the TOU load impacts. The aggregate TOU load impacts are then scaled to total enrollments.

**Table ES.3: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-17	All	1,019	1.13	0.07	1.11	0.07	6.0%	74
Nov-17	All	1,103	1.02	0.01	0.93	0.01	1.4%	66
Dec-17	All	1,233	1.26	0.02	1.02	0.01	1.4%	62
Jan-18	All	1,290	1.20	0.02	0.93	0.01	1.3%	62
Feb-18	All	1,290	1.15	0.01	0.89	0.01	1.2%	59
Mar-18	All	1,298	1.03	0.04	0.80	0.03	4.1%	63
Apr-18	All	1,335	0.99	0.04	0.74	0.03	3.6%	65
May-18	All	1,535	1.08	0.00	0.71	0.00	-0.4%	65
Jun-18	All	1,729	1.52	0.18	0.88	0.10	11.6%	70
Jul-18	All	1,917	2.91	0.27	1.52	0.14	9.3%	78
Aug-18	All	2,456	3.96	0.38	1.61	0.16	9.7%	79
Sep-18	All	2,869	3.31	0.44	1.15	0.16	13.5%	73

Table ES.4 shows peak load impact results by season and climate zone. The coastal climate had at least one and a half times larger level and percentage load impacts for each season.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	1,102	1.28	0.16	1.17	0.14	12.1%	74
	Inland	896	1.25	0.08	1.40	0.09	6.6%	76
	<b>All</b>	<b>1,998</b>	<b>2.54</b>	<b>0.24</b>	<b>1.27</b>	<b>0.12</b>	<b>9.4%</b>	<b>75</b>
Winter	Coastal	742	0.61	0.02	0.82	0.02	2.5%	63
	Inland	556	0.50	0.01	0.89	0.01	1.1%	63
	<b>All</b>	<b>1,298</b>	<b>1.11</b>	<b>0.02</b>	<b>0.85</b>	<b>0.02</b>	<b>1.9%</b>	<b>63</b>

Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy finds that TOU customers *decreased* their energy consumption by an annual average of approximately 3 percent.

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

Since TOU-DR-P customers experience TOU prices on all weekdays that are not RYU/CPP event days, it is of interest to examine their average usage changes on non-event days,

similar to TOU-only customers. Table ES.5 shows load and load impacts for the average summer (October 2017, and June through September 2018) and winter (November 2017 through May 2018) weekdays, by month. Enrollment in CPP grew from 4,086 in October 2017 to approximately 8,048 in September 2018.<sup>4</sup> Peak load impacts varied across months, with estimated load reductions in all months except for near-zero amounts in October, November, December, and February.

**Table ES.5: TOU Peak Load Impacts for RYU/CPP Customers –  
Average Weekday by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-17	All	4,086	5.01	0.00	1.23	0.00	0.0%	75
Nov-17	All	4,280	3.90	0.02	0.91	0.00	0.4%	66
Dec-17	All	4,528	4.49	0.00	0.99	0.00	0.0%	62
Jan-18	All	4,807	4.42	0.05	0.92	0.01	1.1%	62
Feb-18	All	5,433	4.67	0.02	0.86	0.00	0.4%	59
Mar-18	All	6,032	4.56	0.10	0.76	0.02	2.2%	63
Apr-18	All	6,227	4.54	0.17	0.73	0.03	3.7%	64
May-18	All	6,364	4.63	0.19	0.73	0.03	4.1%	64
Jun-18	All	6,542	5.40	0.31	0.83	0.05	5.7%	70
Jul-18	All	6,817	8.62	0.70	1.27	0.10	8.2%	78
Aug-18	All	7,488	9.90	0.79	1.32	0.11	8.0%	79
Sep-18	All	8,048	8.12	0.59	1.01	0.07	7.2%	73

Table ES.6 summarizes TOU load impact for results for RYU/CPP customers by season and climate zone. Summer load impacts are similar between the Coastal and Inland climate zones; while winter load impacts are larger for the coastal climate zone.

<sup>4</sup> The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days in 2018 were required for measuring CPP load impacts.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	3,945	4.11	0.27	1.04	0.07	6.6%	74
	Inland	2,651	3.34	0.21	1.26	0.08	6.3%	76
	<b>All</b>	<b>6,596</b>	<b>7.45</b>	<b>0.48</b>	<b>1.13</b>	<b>0.07</b>	<b>6.5%</b>	<b>75</b>
Winter	Coastal	3,247	2.64	0.07	0.81	0.02	2.7%	63
	Inland	2,134	1.82	0.01	0.85	0.00	0.3%	63
	<b>All</b>	<b>5,382</b>	<b>4.46</b>	<b>0.08</b>	<b>0.83</b>	<b>0.01</b>	<b>1.7%</b>	<b>63</b>

In contrast to the TOU customers, CPP customers *increased* their average daily usage during October through April, and then *decreased* usage in the subsequent months. However, the overall annual effect is similar, with an average annual *decrease* of about 0.4 percent.

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

Table ES.7 summarizes TOU peak-period load impact results for grandfathered customers by season and climate zone. Monthly results are similar within each season because seasonal level load impacts were estimated by climate zone. The coastal climate had no load impact in the summer period and an *increase* in usage during the winter period. Whereas the inland climate zone exhibited similar TOU peak-period load impacts each season. The overall effect of *daily* usage is an average annual *decrease* of about 0.47 kWh/h per customer.

**Table ES.7: TOU Peak Load Impacts for Grandfathered RYU/CPP Customers – Average Weekday by Season & Climate Zone**

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	182	-0.24	0.00	-1.32	0.00	77
	Inland	243	-0.26	0.02	-1.07	0.07	80
	<b>All</b>	<b>425</b>	<b>-0.50</b>	<b>0.02</b>	<b>-1.17</b>	<b>0.04</b>	<b>78</b>
Winter	Coastal	201	0.24	-0.02	1.21	-0.08	63
	Inland	255	0.33	0.02	1.31	0.08	63
	<b>All</b>	<b>455</b>	<b>0.58</b>	<b>0.01</b>	<b>1.27</b>	<b>0.01</b>	<b>63</b>

## ES.4 Ex-Ante Load Impacts

SDG&E called six RYU/CPP events in 2018, all on weekdays. Load impacts for different weather scenarios were developed by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads. Those were developed using regression models similar to those used in the *ex-post* analysis, and then simulating loads under the four alternative weather scenarios.

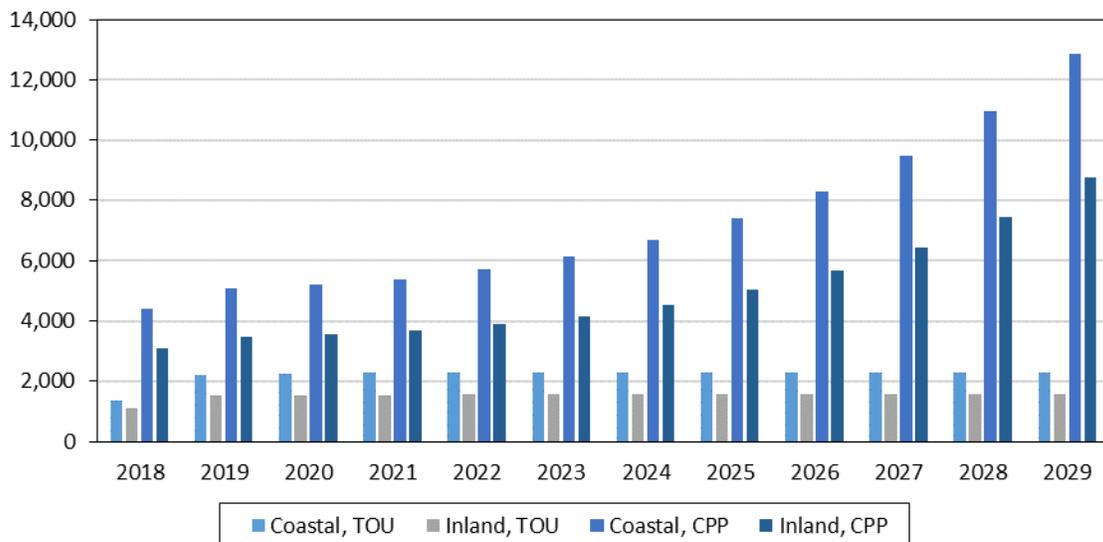
An issue in producing the *ex-ante* load impact forecasts for CPP is that the Protocols call for estimating load impacts for the Resource Adequacy (RA) hours of 4 to 9 p.m. for all months, while the CPP events are called during the program hours of 2 to 6 p.m. year-round. The load impacts were simulated using the event hours that are indicated by the tariff but are summarized across the RA window as required.

For the TOU rate and the TOU portion of the CPP rate, hourly percentage load impacts from the *ex-post* analysis (developed from monthly values for CPP and seasonal values for TOU) are applied to weather-sensitive reference loads that were developed as described above.

### ES.4.1 Enrollment forecast

Figure ES.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU after 2019, while enrollment in CPP is forecasted to nearly triple by the end of the forecast period. Enrollment is expected to be somewhat greater in the Coastal climate zone than in the Inland for both rates. Enrollment for grandfathered customers (GDRTOPH) is assumed to remain constant at 418 customers until the grandfathering term expires on July 31, 2027.

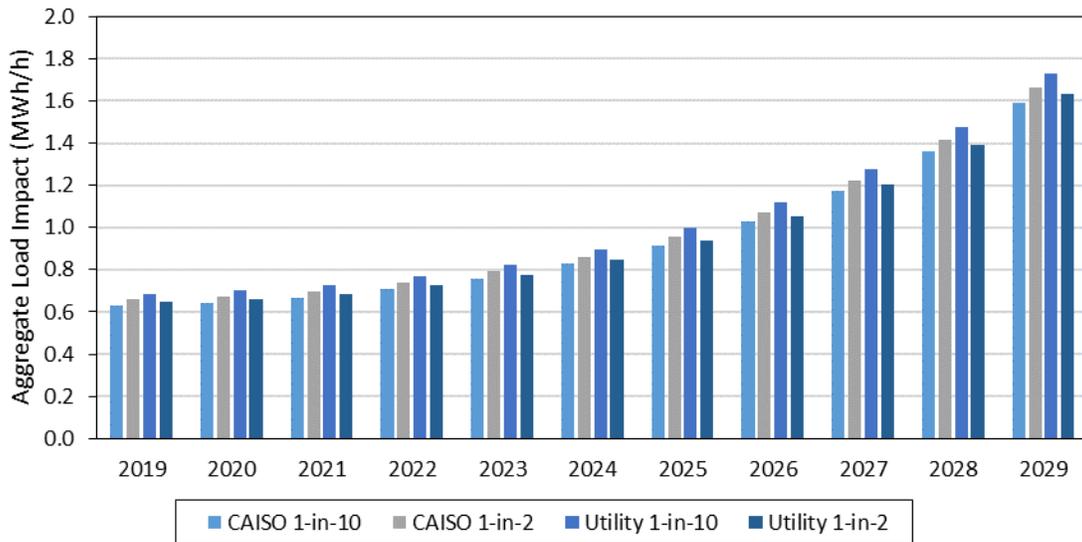
Figure ES.1: Enrollments in TOU and CPP Rates



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

Figure ES.2 illustrates the growth in forecast CPP load impacts over the forecast period, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to grow from just less than 0.65 MWh/h in 2019 to over 1.63 MWh/h in 2029.

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



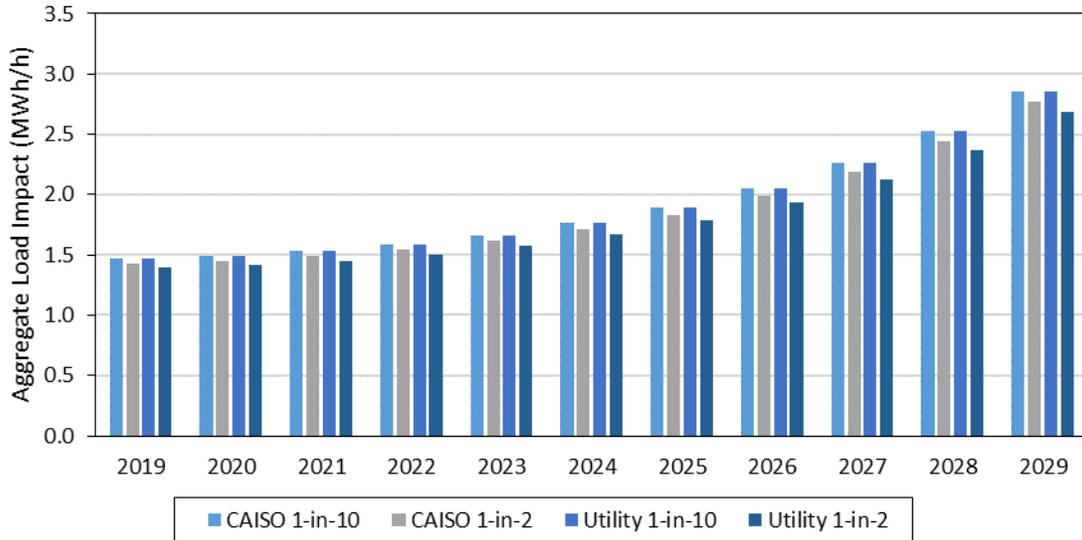
The *ex-ante* CPP load impact forecasts for grandfathered customers is assumed to remain constant at 0.23 MWh/h during the RA window for each weather scenario and year up to the grandfathered term expiration on July 31, 2027.

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

Aggregate peak load impacts for TOU customers are forecast to remain constant after 2019, given the flat enrollment forecast. Figure ES.3 shows differences in the aggregate peak 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 the two 1-in-10 scenarios are identical, rising to 2.9 MWh/h in the final year. Load impacts in the SDG&E 1-in-2 scenario are nearly identical to the CAISO 1-in-2 scenario as well, rising to just over 2.7 MWh/h in 2029.<sup>5</sup>

<sup>5</sup> SDG&E expects to move to default TOU pricing for its residential customers in 2019, which is not modeled in this report.

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



The *ex-ante* TOU load impact forecasts for grandfathered customers is assumed to remain constant at 0.014 MWh/h during summer months, June through October, and 0.008 MWh/h during winter months. Similar to the CPP load impact forecast for grandfathered customers, the TOU load impact does not vary by weather scenario and year. Therefore, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2027.

# 1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company's ("SDG&E") voluntary residential time of use (TOU) and critical peak pricing (CPP) rates for 2018. 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).<sup>6</sup> Both rates are voluntary and became active in February 2015. Since the TOU/CPP customers experience TOU rates on days that are not CPP event days, TOU load impacts are estimated for customers enrolled in both rates, while CPP load impacts are estimated only for CPP customers.<sup>7</sup> The evaluation also develops *ex-ante* load impacts for both rates, with the evaluations conforming to the Load Impact Protocols adopted by the CPUC in D-08-04-050.

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

Given a rapid increase in NEM enrollments in 2018, NEM customers now constitute a significant proportion of residential TOU customers, as shown in the Table 1.1 below. The increased proportion of NEM customers is much more dramatic for the TOU-only rate (TOU-DR). Unlike prior years, Net Energy Metered (NEM) customers were included in this year's analysis.

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<sup>6</sup> Results are also reported for a subset of CPP customers who also participated in the Technology Deployment (TD) program.

<sup>7</sup> CPP *ex-post* load impacts are estimated for *all* customers enrolled in CPP (TOU-DR-P) during the 2018 program year. TOU load impacts are estimated for only those customers who enrolled in either of the rates during the October 2017 to September 2018 period, also referred to as *incremental* TOU customers. The *incremental* TOU load impacts apply to all customers on SPP rates (TOU-DR and TOU-DR-P).

**Table 1.1: NEM and Non-NEM Customer Enrollments**

Date	TOU			TOU + CPP		
	Regular Enrollments	NEM Enrollments	NEM Share of Enrollments	Regular Enrollments	NEM Enrollments	NEM Share of Enrollments
Oct-17	950	69	6.8%	3,902	184	4.5%
Nov-17	1,032	71	6.4%	4,096	184	4.3%
Dec-17	1,152	81	6.6%	4,331	197	4.4%
Jan-18	1,203	87	6.7%	4,596	211	4.4%
Feb-18	1,197	93	7.2%	5,212	221	4.1%
Mar-18	1,192	106	8.2%	5,794	238	3.9%
Apr-18	1,187	148	11.1%	5,956	271	4.4%
May-18	1,310	225	14.7%	6,046	318	5.0%
Jun-18	1,338	391	22.6%	6,174	368	5.6%
Jul-18	1,323	594	31.0%	6,398	419	6.1%
Aug-18	1,553	903	36.8%	7,006	482	6.4%
Sep-18	1,692	1,177	41.0%	7,541	507	6.3%

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

The SPP rates are voluntary TOU rates, as part of the Residential Rate Reform decision, the CPUC ruled that the California Investment Owned Utilities were to implement default TOU rates. In 2016 SDG&E began conducting its Opt-In TOU pilot, and in 2018 its Default TOU pilot which was considered phase 1 of the full TOU rollout which begins in March of 2019. SDG&E plans to default more than 750,000 residential customers in 2019 to 2020.

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

## 2. Description of SPP Rates

As noted in the introduction, the current TOU on-peak period in summer is 4 p.m. to 9 p.m. on non-holiday weekdays, with morning and evening off-peak periods before and after, and an overnight super-off-peak period. The super-off-peak hours are longer for weekend and holidays as well as during the months of March and April. CPP events are called in conjunction with SDG&E's Reduce Your Use (RYU) program, a peak time rebate program. Up to 18 RYU events can be triggered per year, on any day of the week, at any time during the year. Six CPP events were called in 2018, 7/6, 7/24, 7/25, 8/6, 8/7, and 8/9.

TOU prices apply only to SDG&E's commodity energy charges, which are \$0.230, \$0.172, and \$0.115 per kWh for the summer on-peak, off-peak, and super-peak periods respectively. Thus, the peak to super-off-peak price ratio is approximately two-to-one.<sup>8</sup> Summer TOU commodity prices for CPP (TOU-DR-P) customers are somewhat lower, at \$0.179, \$0.171, and \$0.074 per kWh, implying a peak to off-peak price ratio of approximately 2.4 to one. Summer commodity prices for grandfathered CPP (GTOU-DR-P) customers are \$0.229, \$0.171, and \$0.095 for summer on-peak, semi-peak, and off-peak periods, respectively. In addition, a CPP event-period adder of \$1.16/kWh applies on event days for both CPP and grandfathered CPP customers. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.<sup>9</sup>

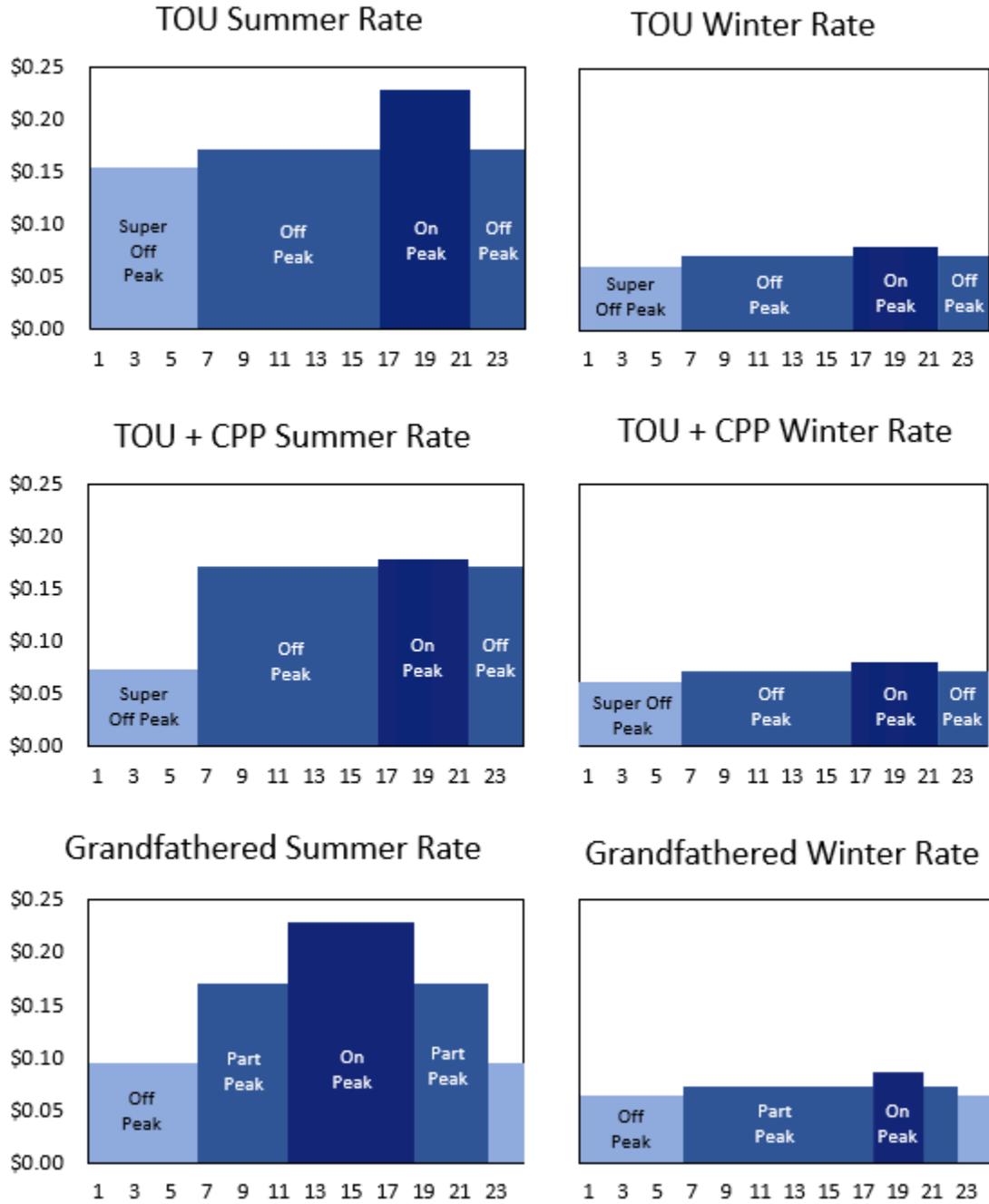
CPP participants are generally notified of events by 3 p.m. on the business day prior to the event, and several notification options are available, including email and text. For the first full season following their enrollment, CPP participants are eligible for *bill protection*, which guarantees that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

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<sup>8</sup> Non-commodity prices of approximately \$0.297 per kWh in the summer are not time-differentiated, implying that the total peak-to-super-off-peak price ratio is less than two-to-one.

<sup>9</sup> The super-off-peak period includes 10 a.m. to 2 p.m. in March and April for non-grandfathered customers, which is not represented by the winter rates in Figure 2.1.

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



### 3. *Ex-Post* Evaluation Methodology

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

### **3.1 Data**

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

- *Customer* information for the residential TOU and CPP enrollees and potential control group customers (*e.g.*, location indicator for matching to climate zone, CARE status);
- Billing-based *interval load data* (*i.e.*, hourly loads for each TOU and CPP enrollee, and potential control group customers), for October 2016 through September 2018;
- *Weather data* (*i.e.*, hourly temperatures and other variables for the relevant time period, for both climate zones—coastal and inland);
- *Program event data* (*i.e.*, dates and hours of CPP events, and event triggers).

### **3.2 Analysis Methods**

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

#### **3.2.1 Evaluation design and control group matching**

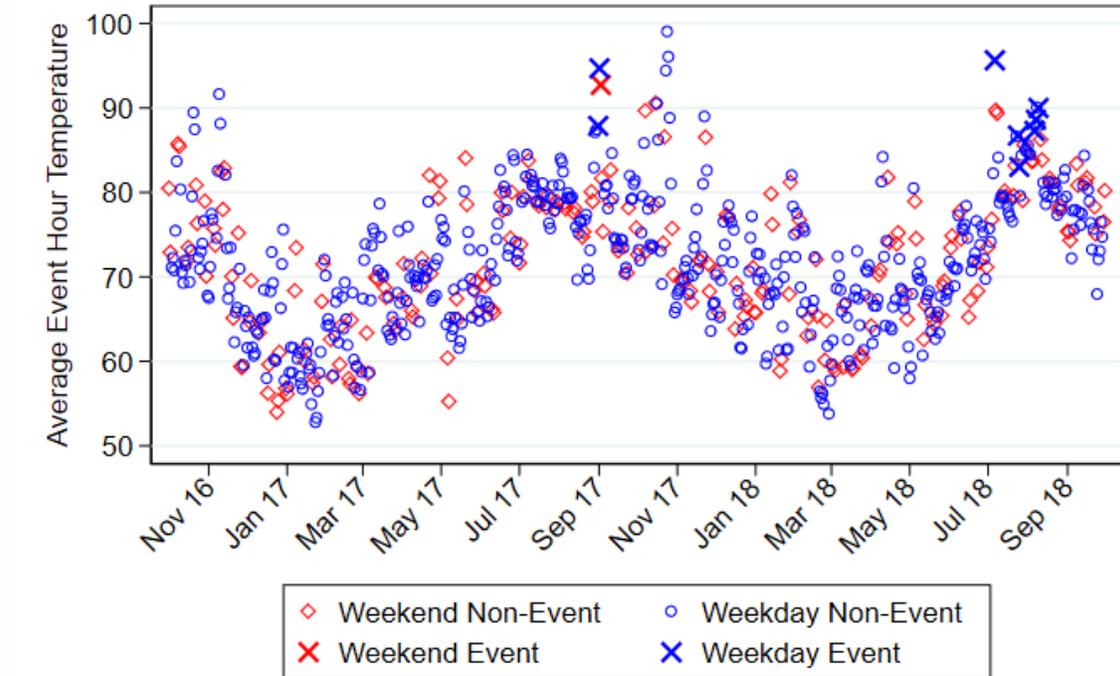
The difference-in-differences evaluation is a quasi-experimental approach that compares the usage of treatment and matched control group customers on relevant days or time periods, adjusted by their usage differences on pre-treatment or non-event days. The control groups were selected by matching each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

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

For analyzing CPP impacts, the CPP customers were matched to potential control group customers using loads on selected event-like non-event days (*e.g.*, days with

temperatures most like those on the event days). Figure 3.1 displays the average event-hour temperature for all weekday and weekends between October 2016 and November 2018. Red diamond markers indicate weekend non-event days while blue circles indicate weekday non-event days. The red and blue X represent weekend and weekday event days, respectively. The event days in 2018 were among the hottest days during 2018. With enough non-event hot days to choose from in 2018, the selected set of event-like non-event days is 7/9, 7/23, 7/27, 8/1, 8/2, 8/3, 8/13, 8/14, 8/30, and 9/14.

**Figure 3.1: Average Event-Hour Temperatures**



For analyzing TOU impacts, for both CPP and TOU customers, only incremental treatment customers were used in the analysis and matched based on loads in the pre-treatment period (October 2016 through September 2017). Only incremental customers are used in the TOU load impact study because these customers have enough pre-treatment data to provide a quality difference-in-difference analysis. The matching and regression analysis are separated by season, thus allowing different threshold dates that define incremental customers.<sup>10</sup> Specifically, incremental customers for the winter analysis are those that enrolled after June 1, 2017 while incremental customers for the summer analysis are those that enrolled after October 1, 2017. The incremental TOU customers were matched based on two pairs of hourly loads for each season – one for all weekdays, and one for a subset of the hottest (or coldest) weekdays. Matching for

<sup>10</sup> The seasons defined for matching are summer (June through October) and winter (November through May).

the *winter* season used data for November 2016 through May 2017, while that for the *summer* season used data for October 2016 and June through September of 2017.

The grandfathered rate prevents new customers from joining the rate. As a result, all grandfathered customers are already treated during the pre-treatment matching periods mentioned above. To estimate TOU load impacts for these customers, PY2017 TOU load impacts are estimated using PY2017 incremental customers that are now grandfathered customers. The PY2017 pre- and post-treatment analysis periods cover October 2015 through September 2017. Current grandfathered customers that enrolled in either TOU-DR or TOU-DR-P after May 1, 2016 are incremental customers for the grandfathered winter analysis and those that enrolled after September 1, 2016 are incremental customers for the grandfathered summer analysis.

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

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

In this equation, the *T* variables represent treatment customer characteristics and the *C* variables represent the corresponding eligible control group customer characteristics. As described, separate matches and therefore sets of variables are used for the for the CPP and TOU analyses. For matching in the CPP analysis, the customer characteristics include the average hourly usage on event-like non-event weekdays (24 variables). For the TOU analysis, the customer characteristics include the average hourly usage on weekdays and hot/cold days for the summer/winter match (48 variables).<sup>11</sup> Treatment and potential control customers are also segmented by climate zone, CARE status, and enrollment in PTR-RYU. Each enrolled customer is compared to each potential control group customer within their segment, using the distance measure. When the minimum distance statistic is found, the potential control group customer associated with that value is selected as the match for that TOU customer. Potential control group customers were allowed to be matched with replacement (*i.e.*, matched to multiple enrolled customers).

NEM customers are matched similarly, with three major distinctions. First, only customers that are NEM for the entire analysis period are included. Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.<sup>12</sup> Third, customers with large changes in net profiles between periods are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system.

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

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

The methodology and thresholds used for identifying NEM customers with large changes in usage and subsequently removed from the analysis is explained in more detail in Appendix C. Each of these requirements helps prevent estimating load impacts (TOU or RYU/ CPP) that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to only a behavioral response to TOU rates or CPP events.<sup>13</sup>

### 3.2.2 Fixed-effects panel regression models

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

Two versions of fixed-effects models were estimated. The first version was used to estimate CPP event-day hourly load impacts (estimated separately for TOU-DR-P and GTOU-DR-P customers). The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR, TOU-DR-P, and GTOU-DR-P customers). In addition to estimating each load impact type separately by rate, the load impacts were estimated separately for NEM customers within each rate.

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

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

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

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<sup>13</sup> For example, a high premise usage treatment customer with a larger solar generation system may be matched to a lower premise usage control customer with a smaller solar generation system based on similar net load profiles. If conditions are met so that solar generation is larger in the post-period, then any analysis based on net load profiles will exhibit that the treatment customer reduced their usage, relative to their own pre-treatment usage as well as relative to the control customer's usage.

below, where the equation is estimated separately for each of the 24 hours. This model produces load impact estimates for each hour of every event:

$$kWh_{c,d} = \beta_0 + \sum_{Evs(i)} (\beta_{1,i} \times CPP_{c,d} \times Evt_{i,d}) + \beta_2 \times CPP_{c,d} + \sum_{Evs(i)} (\beta_{3,i} \times TD_{c,d} \times Evt_{i,d}) + \sum_{Cust} (\beta_{4,Cust} \times C_c) + \sum_{date} (\beta_{5,date} \times D_{date,d}) + \beta_6 \times SS\_Evt_{c,d} + \epsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.1. Results are then scaled to enrollment numbers because a portion CPP customers are removed from the analysis based upon load quality and NEM customer restrictions (see Appendix C).

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer $c$ on date $d$
$CPP_{c,d}$	Variable indicating whether customer $c$ is only a <i>CPP</i> customer ( <i>i.e.</i> , not also dually enrolled in <i>TD</i> ) on date $d$ (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date $d$ is the $i^{th}$ event day (1= $i^{th}$ event, 0 if not)
$TD_{c,d}$	Variable indicating whether customer $c$ is a dually enrolled <i>CPP</i> and <i>TD</i> customer on date $d$ (1 = yes, 0 if not)
$SS\_Evt_{c,d}$	Variable indicating that date $d$ is a <i>Summer Saver</i> event day (1=event, 0 if not) for customer $c$
$\beta_0$	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event $d$ for <i>CPP</i> only customers
$\beta_2$	Estimated non-event day response for incremental <i>CPP</i> customers
$\beta_{3,d}$	Estimated load impact for event $d$ for dually enrolled <i>CPP</i> and <i>TD</i> customers
$\beta_{4,Cust}$ and $\beta_{5,date}$	Customer and date fixed effects
$\beta_6$	Estimated average <i>Summer Saver</i> load impact
$C_c$	Variable indicating that the observation is for customer $c$
$D_{date,d}$	Date indicator variable (1 = date $d$ equals date $day$ )
$\epsilon_{c,d}$	Error term

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

To obtain TOU load impacts (for TOU-DR, TOU-DR-P, and GTOU-DR-P customers), a distinct model is estimated for each required result. For example, to obtain the average TOU load impacts on August non-holiday weekdays, a model is estimated that includes

only days of that day type.<sup>14</sup> In this case, the model is simplified to include customer and date fixed effects, plus a variable to estimate the load impact (*i.e.*, the coefficient  $\beta_1$ ). Separate models are estimated by rate (*e.g.*, TOU-DR, TOU-DR-P, GTOU-DR-P), hour, month, day-type (*i.e.*, average weekday versus peak month day), applicable customer groups (*e.g.*, climate zone, NEM), where the customer-level fixed-effects models are of the following form:<sup>15</sup>

$$kW_{c,d} = \beta_0 + \beta_1 \times (TOU_c \times Post_{c,d}) + \sum_{Cust} (\beta_{2,Cust} \times C_c) + \sum_{dates} (\beta_{3,dates} \times D_{dates}) \\ + \beta_4 \times Evt_{c,d} + \beta_5 \times SS\_Evt_{c,d} + \beta_6 \times TD\_Evt_{c,d} + \epsilon_{c,d}$$

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

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<sup>14</sup> In cases where insufficient numbers of observations were available, the approach was modified by combining day-types into seasons that correspond to TOU periods (*i.e.*, summer is June through October, winter is November through February and May, and a separate core winter season for March and April). Specifically, observations were combined for all season-specific weekdays to estimate a constant season percentage load impact (*i.e.*,  $PctLI_{Season} = LI_{Season} / (Obs_{Season} + LI_{Season})$ ). The season-specific percentage load impacts are then used to calculate monthly average weekday or system peak day reference loads (*i.e.*,  $Ref_{Daytype} = Obs_{Daytype} / (1 - PctLI_{Season})$ ) and level load impacts (*i.e.*,  $LI_{Daytype} = Ref_{Daytype} * PctLI_{Season}$ ). This method was used for each season for TOU-DR, GTOU-DR-P, and NEM customers.

<sup>15</sup> Note that the customer and date fixed effects remove the need for us to include stand-alone  $TOU_c$  and  $Post_{c,d}$  variables. The former is perfectly collinear with the customer's fixed effect and the latter is perfectly collinear with a combination of date fixed effects.

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

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer $c$ on date $d$
$TOU_c$	Variable indicating whether customer $c$ is a TOU or CPP (1) or Control (0) customer
$Evt_{c,d}$	Variable indicating whether date $d$ is an event day for customer $c$ <sup>16</sup>
$Post_{c,d}$	Variable indicating that date $d$ is in the post-enrollment period for customer $c$
$TD\_Evt_{c,d}$	Variable indicating that date $d$ is a $TD$ event day (1= event, 0 if not) for customer $c$
$SS\_Evt_{c,d}$	Variable indicating that date $d$ is a Summer Saver event day (1=event, 0 if not) for customer $c$
$\beta_0$	Estimated constant coefficient
$\beta_1$	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
$\beta_4$	Estimate of average event-day load impact
$\beta_5$ and $\beta_6$	Estimated average $TD$ and $SS$ event event-day load impacts
$C_c$	Variable indicating that the observation is associated with customer $c$
$D_{date}$	Variable indicating that the observation is for date $d$
$\epsilon_{c,d}$	Error term

### 3.2.5 Calculating uncertainty-adjusted load impacts

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

The uncertainty-adjusted scenarios are then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum

<sup>16</sup> For CPP customers, the *Evt* variable indicates that a day is a CPP event day. For TOU customers who are also enrolled to receive PTR-RYU alerts, that variable indicates that a day is a PTR-RYU event day.

of the variances of the errors around the estimates of the load impacts. Results for the 10<sup>th</sup>, 30<sup>th</sup>, 70<sup>th</sup>, and 90<sup>th</sup> percentile scenarios are generated from these distributions.

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

### **3.2.6 Validity assessment**

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

## **4. 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 and GTOU-DR-P rates. 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 four-hour event window from 2 p.m. to 6 p.m.), in aggregate and per-customer, for each event day. Results of the analysis of the TOU portion of each rate (*i.e.*, peak load impacts on non-event days) are presented in Section 5, along with results for the TOU-DR rate.

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

### **4.1 Control group matching results**

Figure 4.1 illustrates the quality of the matches for the CPP (TOU-DR-P) customers in the context of estimating load impacts on the CPP event day. The figure shows the average CPP and matched control-group customer load profiles for the selected event-like non-event days. Across all 24 hours, the mean percentage error (MPE) of the CPP profile compared to the control-group profile is 1.5 percent, while the mean absolute percentage error (MAPE) is 1.6 percent. For the CPP event window (2 p.m. to 6:00 p.m.), the MPE is 0.3 percent while the MAPE is 0.5 percent.

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

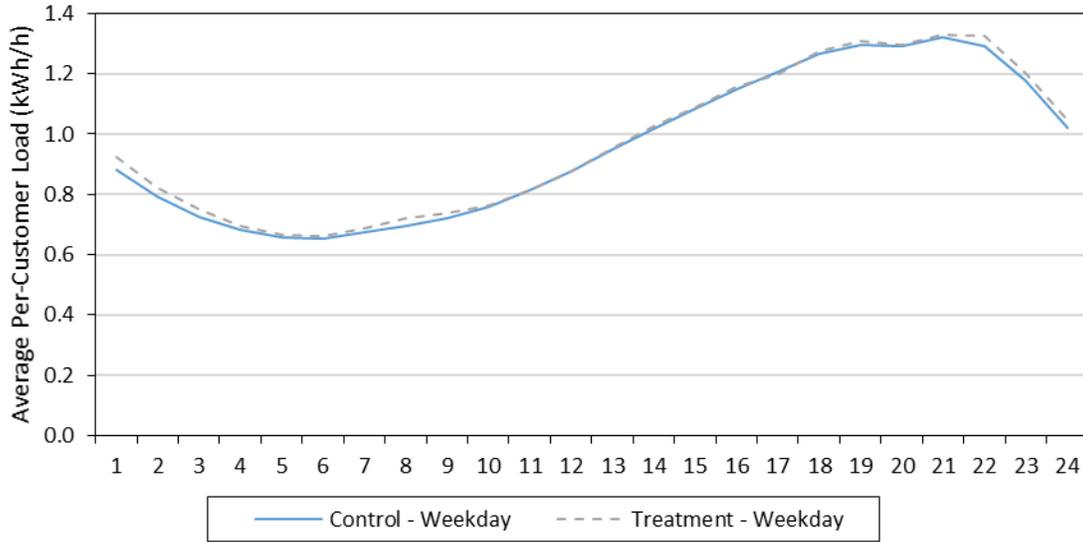
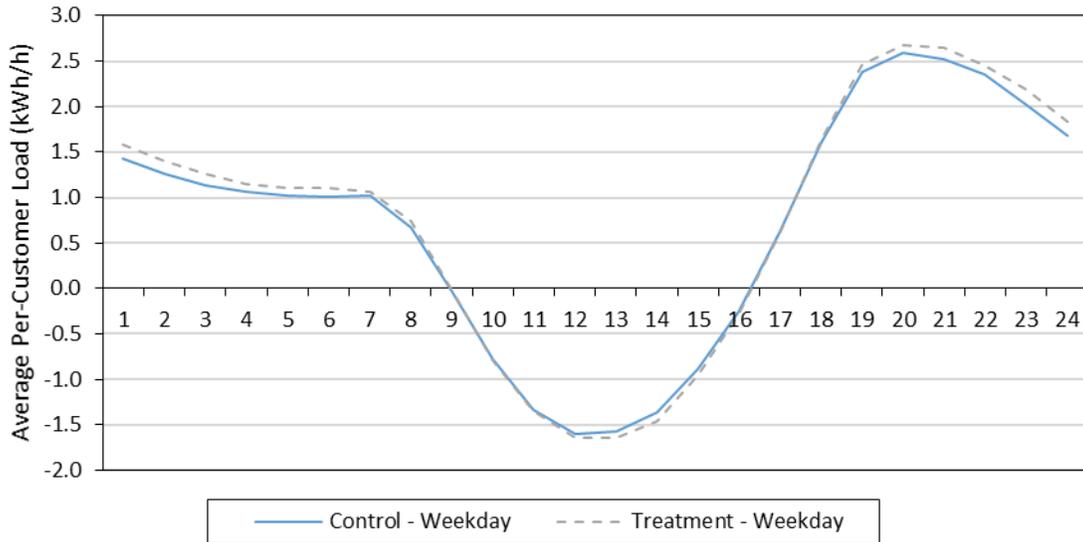


Figure 4.2 similarly illustrates the match quality for grandfathered CPP customers (GTOU-DR-P). Across all 24 hours, the mean error (ME) of the CPP profile compared to the control-group profile is 0.05 kWh/h, while the mean absolute error (MAE) is 0.08 kWh/h. For the CPP event window (2 p.m. to 6:00 p.m.), the ME is -0.02 kWh/h while the MAE is 0.03 kWh/h.<sup>17</sup>

**Figure 4.2: Grandfathered CPP and Matched Control Group Load Profile – Average Event-Like Day**



<sup>17</sup> The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which disproportionately distort percentage values.

## 4.2 CPP load impacts

This section summarizes average event-hour reference loads<sup>18</sup> and load impacts, at an aggregate and per-customer basis, for the six 2018 CPP events called on July 6, July 24, July 25, August 6, August 7, and August 9. Each event had an event-window of 2 p.m. to 6 p.m. (HE 15-18). This section contains only the results for CPP customers; CPP load impacts for Grandfathered CPP customers are reported in Section 4.3.

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

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<sup>18</sup> 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.

**Table 4.1: Average CPP Event-Hour Load Impacts**

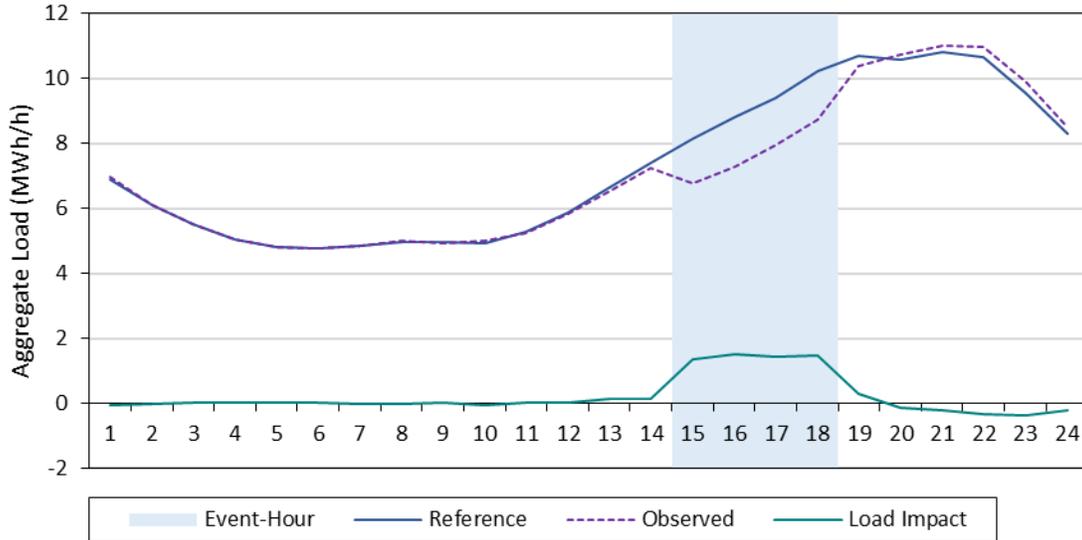
Climate Zone	Date	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
Coastal	Jul 6, 2018	3,981	4.89	0.68	1.23	0.17	14%	96
	Jul 24, 2018	4,051	4.47	0.64	1.10	0.16	14%	85
	Jul 25, 2018	4,063	4.15	0.52	1.02	0.13	13%	82
	Aug 6, 2018	4,166	4.67	0.74	1.12	0.18	16%	87
	Aug 7, 2018	4,175	4.81	0.62	1.15	0.15	13%	90
	Aug 9, 2018	4,193	5.35	0.94	1.28	0.22	17%	89
	<b>Typical Event Day</b>	<b>4,105</b>	<b>4.72</b>	<b>0.69</b>	<b>1.15</b>	<b>0.17</b>	<b>15%</b>	<b>88</b>
Inland	Jul 6, 2018	2,600	4.64	0.66	1.78	0.25	14%	103
	Jul 24, 2018	2,649	4.32	0.75	1.63	0.28	17%	92
	Jul 25, 2018	2,655	3.94	0.58	1.48	0.22	15%	89
	Aug 6, 2018	2,728	4.41	0.91	1.61	0.33	21%	93
	Aug 7, 2018	2,743	4.50	0.76	1.64	0.28	17%	94
	Aug 9, 2018	2,774	4.70	0.81	1.70	0.29	17%	91
	<b>Typical Event Day</b>	<b>2,692</b>	<b>4.42</b>	<b>0.75</b>	<b>1.64</b>	<b>0.28</b>	<b>17%</b>	<b>94</b>
All	Jul 6, 2018	6,581	10.13	1.36	1.54	0.21	13%	99
	Jul 24, 2018	6,700	9.46	1.42	1.41	0.21	15%	89
	Jul 25, 2018	6,718	8.61	1.12	1.28	0.17	13%	86
	Aug 6, 2018	6,894	9.84	1.67	1.43	0.24	17%	90
	Aug 7, 2018	6,918	9.93	1.40	1.44	0.20	14%	92
	Aug 9, 2018	6,967	10.82	1.76	1.55	0.25	16%	90
	<b>Typical Event Day</b>	<b>6,796</b>	<b>9.14</b>	<b>1.45</b>	<b>1.35</b>	<b>0.21</b>	<b>16%</b>	<b>91</b>

Program enrollment was 6,581 customers for the first event, skewed somewhat toward the Coastal climate zone.<sup>19</sup> On a Typical Event Day (*i.e.*, the average event), the per-customer reference load during event hours for all customers was 1.35 kWh/h. Per-customer load impacts averaged 0.17 kWh/h for customers in the Coastal climate zone, representing 15 percent of their reference load, and 0.28 kW, or 17 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 88 degrees, than the 94-degree temperature for the Inland zone. Both customer groups, inland and coastal, respond similarly in percentage terms to the average weekday event. The first event-day, July 6, had the hottest event-window temperature but not the largest per-customer load impact.

Figure 4.3 shows aggregate hourly loads and load impacts for the average weekday event. The largest hourly load impact was 1.53 MWh/h in hour-ending 16 (3 to 4 p.m.).

<sup>19</sup> 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 6,261. The CPP load impacts are scaled up to total program enrollments.

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



### 4.3 Grandfathered CPP load impacts

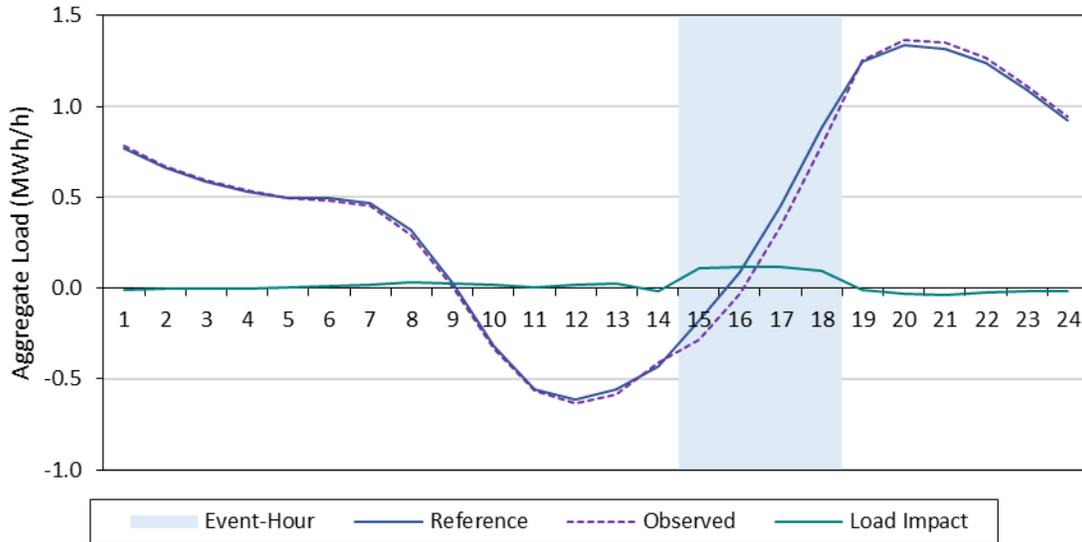
This section summarizes average event-hour reference loads and load impacts, at an aggregate and per-customer basis, for the six 2018 CPP events for the Grandfathered CPP customers. Table 4.1 summarizes reference load and CPP load impact results for Grandfathered CPP customers, by climate zone. Program enrollment remained fairly constant between events. The average per-customer load impact is larger for customers in the inland climate zone. Percentage load impacts are not presented because all grandfathered customers are NEM customers that can have near zero reference loads, resulting in misleading percentage load impacts. Customers in the coastal climate exhibited an average *increase* in usage for the second event, July 24, 2018. For the average weekday event, the per-customer level load impact of grandfathered customers is larger than non-grandfathered CPP customers.

**Table 4.2: Average Grandfathered CPP Event-Hour Load Impacts**

Climate Zone	Date	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	Jul 6, 2018	181	0.09	0.01	0.51	0.05	96
	Jul 24, 2018	181	-0.01	0.00	-0.04	-0.01	85
	Jul 25, 2018	181	-0.03	0.01	-0.14	0.03	82
	Aug 6, 2018	181	0.03	0.05	0.15	0.29	86
	Aug 7, 2018	181	0.07	0.04	0.36	0.24	89
	Aug 9, 2018	180	0.22	0.04	1.25	0.20	89
	<b>Typical Event Day</b>	<b>181</b>	<b>0.06</b>	<b>0.02</b>	<b>0.35</b>	<b>0.13</b>	<b>88</b>
Inland	Jul 6, 2018	246	0.36	0.10	1.46	0.42	106
	Jul 24, 2018	246	0.19	0.07	0.79	0.29	94
	Jul 25, 2018	246	0.14	0.06	0.58	0.26	91
	Aug 6, 2018	245	0.19	0.09	0.78	0.37	95
	Aug 7, 2018	245	0.18	0.06	0.75	0.23	96
	Aug 9, 2018	245	0.41	0.11	1.68	0.44	92
	<b>Typical Event Day</b>	<b>246</b>	<b>0.25</b>	<b>0.08</b>	<b>1.01</b>	<b>0.33</b>	<b>95</b>
All	Jul 6, 2018	427	0.45	0.12	1.07	0.28	106
	Jul 24, 2018	427	0.19	0.07	0.45	0.18	94
	Jul 25, 2018	427	0.12	0.07	0.28	0.17	91
	Aug 6, 2018	426	0.22	0.15	0.52	0.35	95
	Aug 7, 2018	426	0.25	0.10	0.58	0.23	96
	Aug 9, 2018	425	0.64	0.14	1.50	0.34	92
	<b>Typical Event Day</b>	<b>426</b>	<b>0.31</b>	<b>0.11</b>	<b>0.73</b>	<b>0.26</b>	<b>95</b>

Figure 4.4 shows aggregate hourly loads and load impacts for the average weekday event for Grandfathered CPP customers. The largest hourly load impact was 0.12 MWh/h in hours-ending 16 and 17 (3 to 5 p.m.).

**Figure 4.4 Aggregate Grandfathered CPP Hourly Loads and Load Impacts  
– Average Weekday Event**



#### **4.4 Technology Deployment load impacts**

This section compares the CPP load impact estimates for customers that were dually enrolled in CPP and the Technology Deployment (“TD”) program during 2018. Customers dually enrolled in TD and CPP experienced the same CPP events and event-window (July 6, July 24, July 25, August 6, August 7, and August 9; 2 p.m. to 6 p.m.).

Table 4.3 summarizes reference loads and load impacts for customers by enrollment status during the event-hour window, bifurcating results for customers enrolled solely in CPP (“CPP Only”) and customers dually enrolled in CPP and TD (“Dually Enrolled CPP+TD”). The number of dually enrolled customers by the last event date was 1,192 (which is about 9% of all CPP customers). On average, customers dually enrolled in TD have larger reference loads and load impacts. For example, the average weekday event reference load and load impact for dually enrolled customers was 1.60 kWh/h and 0.59 kWh/h, respectively. While the average weekday event reference load and load impact for non-dually enrolled customers was 1.33 kWh/h and 0.19 kWh/h, respectively. The load impact percentage of dually enrolled customers is more than double that of non-dually enrolled customers for each event.

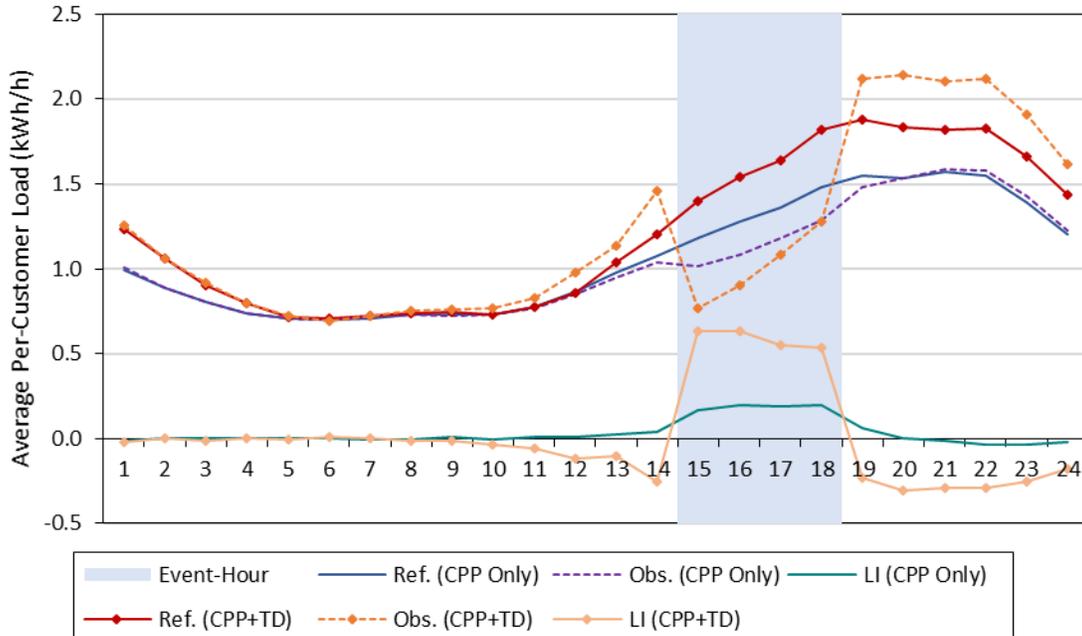
The lowest dually enrolled customer load impact of 0.54 kWh/h occurred on July 25<sup>th</sup>, the event with the lowest average event-hour temperature.

**Table 4.3: Comparison of Average CPP Event-Hour Load Impacts  
for TD and CPP Enrollment Type**

Enrollment Type	Date	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
CPP Only	Jul 6, 2018	6,004	9.17	1.08	1.53	0.18	12%	99
	Jul 24, 2018	6,111	8.57	1.14	1.40	0.19	13%	89
	Jul 25, 2018	6,128	7.78	0.86	1.27	0.14	11%	86
	Aug 6, 2018	6,292	8.91	1.35	1.42	0.21	15%	90
	Aug 7, 2018	6,312	9.00	1.11	1.43	0.18	12%	92
	Aug 9, 2018	6,356	9.81	1.43	1.54	0.22	15%	90
	<b>Typical Event Day</b>	<b>6,201</b>	<b>8.23</b>	<b>1.16</b>	<b>1.33</b>	<b>0.19</b>	<b>14%</b>	<b>91</b>
Dually Enrolled CPP + TD	Jul 6, 2018	577	0.98	0.33	1.70	0.58	34%	100
	Jul 24, 2018	589	0.93	0.34	1.58	0.57	36%	89
	Jul 25, 2018	590	0.86	0.32	1.46	0.54	37%	86
	Aug 6, 2018	602	0.96	0.39	1.59	0.64	40%	90
	Aug 7, 2018	606	0.95	0.34	1.58	0.56	36%	92
	Aug 9, 2018	611	1.03	0.39	1.68	0.63	38%	90
	<b>Typical Event Day</b>	<b>596</b>	<b>0.95</b>	<b>0.35</b>	<b>1.60</b>	<b>0.59</b>	<b>37%</b>	<b>91</b>

Figure 4.5 shows average per-customer hourly loads and load impacts for customers dually enrolled and not dually-enrolled in CPP and TD for the 2018 average weekday event. The shaded hours indicate the event-hours (2 to 6 p.m.). The observed load of dually enrolled customers (“Obs. (CPP+TD)”) illustrates that TD customers have pre-cooling in the hours before the event begins and a snapback effect in the hours after the event, whereas non-dually enrolled customers do not have this pattern surrounding the event hours. The largest hourly TD load impact was 0.63 kWh/h in the second SCTD event-hour (3 to 4 p.m.).

**Figure 4.5: CPP+TD Hourly Loads and Load Impacts for Dually Enrolled Customers – Average Weekday Event**



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

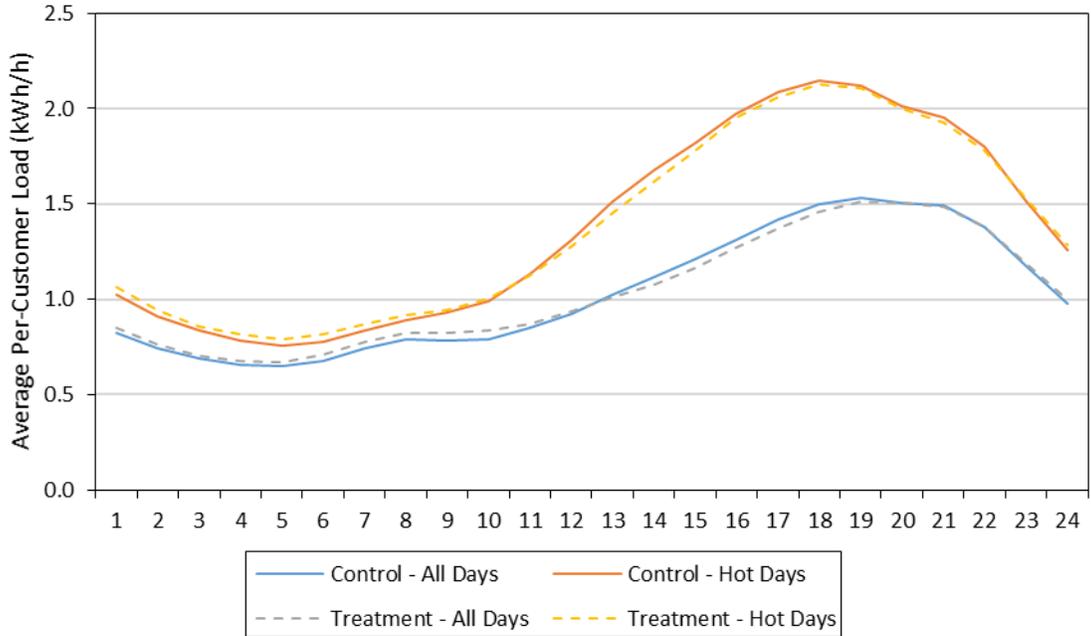
This section presents the match quality and estimates of monthly peak TOU load impacts for the TOU (TOU-DR), CPP (TOU-DR-P), and grandfathered (GTOU-DR-P) customers.

### 5.1 TOU control group matching results for TOU customers

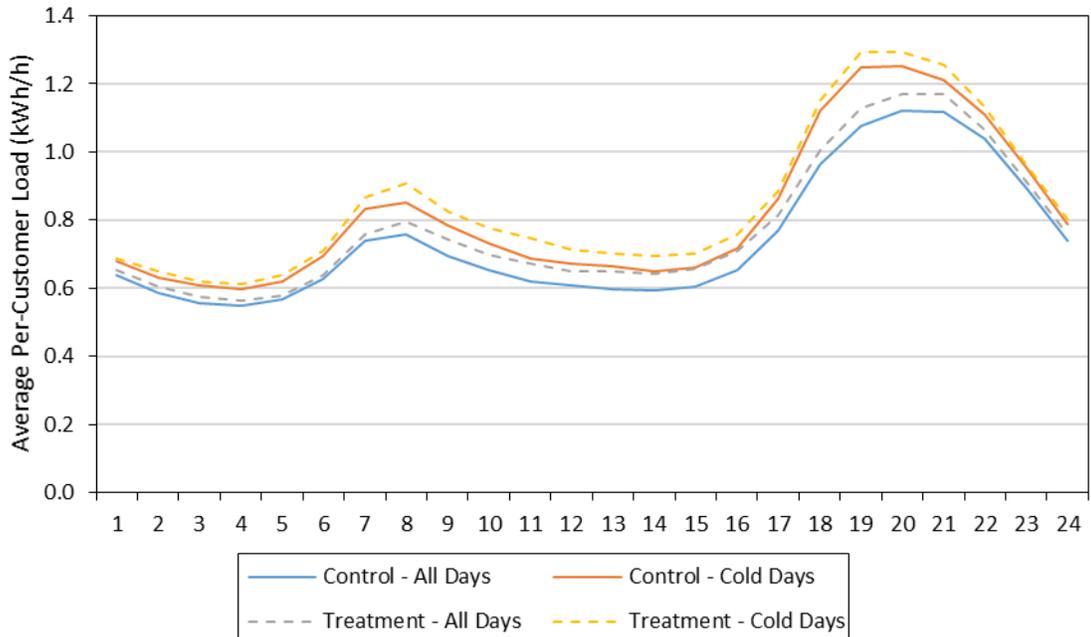
Figures 5.1 and 5.2 illustrate the quality of the matches for the TOU (TOU-DR) customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is 0.8 percent, while the mean absolute percentage error (MAPE) is 2.5 percent. In the winter months, the MPE is 4.2 percent and the MAPE is 4.2 percent.<sup>20</sup>

<sup>20</sup> The MPE and MAPE statistics for the TOU matches are calculated over the two 24-hour load profiles, all days and hot/cold days.

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



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



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

This sub-section shows *ex-post* TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m.), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with the first month included in the analysis (October 2017). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 1,019 in October 2017 to 2,869 in September 2018.<sup>21</sup> The estimation methodology for TOU non-NEM customers included applying seasonal (March and April as a separate season) percentage load impacts to monthly reference loads. The seasonal level load impacts are similarly used for NEM customers. Therefore, differences in percentage load impacts across seasons is driven by load impacts of NEM customers. The per-customer load impacts are largest during the summer months, followed by the March and April season, and lowest for the remaining winter period. The largest per-customer load impact of 0.156 kWh/h occurs in August, which also has the largest average event-hour temperature.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-17	All	1,019	1.13	0.07	1.11	0.07	6.0%	74
Nov-17	All	1,103	1.02	0.01	0.93	0.01	1.4%	66
Dec-17	All	1,233	1.26	0.02	1.02	0.01	1.4%	62
Jan-18	All	1,290	1.20	0.02	0.93	0.01	1.3%	62
Feb-18	All	1,290	1.15	0.01	0.89	0.01	1.2%	59
Mar-18	All	1,298	1.03	0.04	0.80	0.03	4.1%	63
Apr-18	All	1,335	0.99	0.04	0.74	0.03	3.6%	65
May-18	All	1,535	1.08	0.00	0.71	0.00	-0.4%	65
Jun-18	All	1,729	1.52	0.18	0.88	0.10	11.6%	70
Jul-18	All	1,917	2.91	0.27	1.52	0.14	9.3%	78
Aug-18	All	2,456	3.96	0.38	1.61	0.16	9.7%	79
Sep-18	All	2,869	3.31	0.44	1.15	0.16	13.5%	73

<sup>21</sup> 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 689 incremental customers on the TOU-DR rate with quality load data that were used in estimating the TOU load impacts. The aggregate TOU load impacts are then scaled to total enrollments.

Table 5.2 shows results by season and climate zone. The coastal climate had at least one and a half times larger level and percentage load impacts for each season.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	1,102	1.28	0.16	1.17	0.14	12.1%	74
	Inland	896	1.25	0.08	1.40	0.09	6.6%	76
	<b>All</b>	<b>1,998</b>	<b>2.54</b>	<b>0.24</b>	<b>1.27</b>	<b>0.12</b>	<b>9.4%</b>	<b>75</b>
Winter	Coastal	742	0.61	0.02	0.82	0.02	2.5%	63
	Inland	556	0.50	0.01	0.89	0.01	1.1%	63
	<b>All</b>	<b>1,298</b>	<b>1.11</b>	<b>0.02</b>	<b>0.85</b>	<b>0.02</b>	<b>1.9%</b>	<b>63</b>

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their energy consumption in each the summer months as well as March and April; however, they increased daily usage during the remaining winter months.<sup>22</sup> The overall change was an average annual *decrease* of 3 percent.

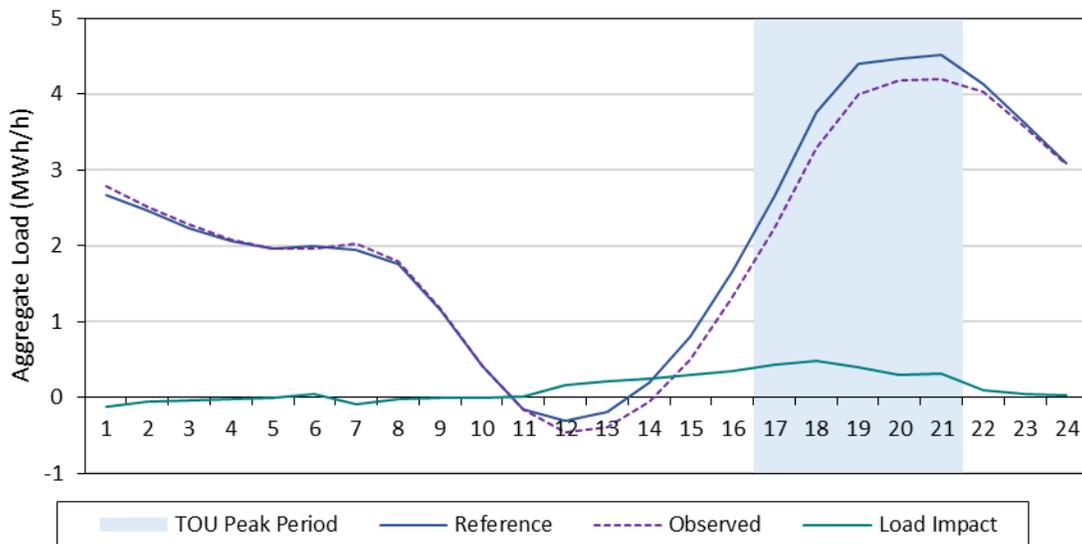
**Table 5.3: TOU Average Daily Load Impacts for TOU Customers, by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)		
Oct-17	All	1,019	18.38	0.24	18.04	0.23	1.3%	70
Nov-17	All	1,103	17.57	-0.10	15.93	-0.09	-0.6%	64
Dec-17	All	1,233	21.56	-0.12	17.48	-0.10	-0.6%	59
Jan-18	All	1,290	20.95	-0.14	16.24	-0.11	-0.7%	60
Feb-18	All	1,290	20.28	-0.17	15.72	-0.14	-0.9%	56
Mar-18	All	1,298	18.86	0.16	14.53	0.12	0.8%	59
Apr-18	All	1,335	17.30	0.07	12.96	0.05	0.4%	61
May-18	All	1,535	19.00	-0.52	12.38	-0.34	-2.7%	62
Jun-18	All	1,729	22.22	1.26	12.85	0.73	5.7%	67
Jul-18	All	1,917	40.45	2.03	21.10	1.06	5.0%	74
Aug-18	All	2,456	51.32	3.01	20.90	1.22	5.9%	76
Sep-18	All	2,869	36.69	3.82	12.79	1.33	10.4%	69

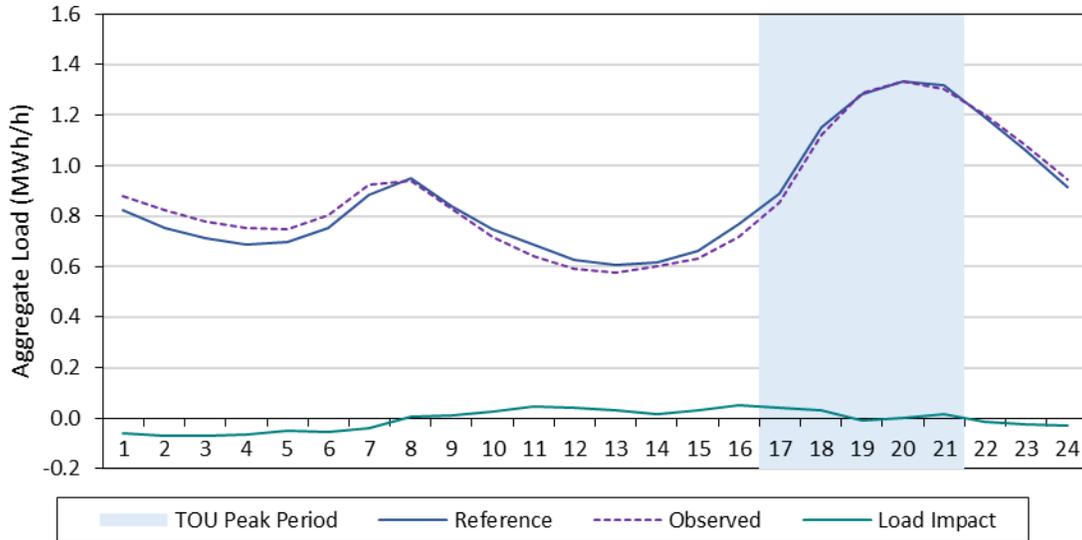
<sup>22</sup> The increase in usage during the winter period occurs mostly during the morning hours.

Figure 5.3 shows aggregate hourly observed and estimated reference loads, along with hourly estimated TOU load impacts for the TOU customers for the average weekday in August. Figure 5.4 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a reduction in load during the peak hours as well as during a portion of the partial peak hours (*i.e.*, HE 7-16 and HE 22-24). There isn't much evidence of load shifting to non-peak hours as represented by similar reference and observed loads during the super off-peak periods. The TOU load impacts during the winter are smaller and have more load shifting, with a decrease in usage during the middle of the day, and an increase of usage overnight and in the morning. The greatest decreases in usage, however, do not occur during the TOU peak period, when prices are largest.

**Figure 5.3: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers (Average Weekday, August 2018)**



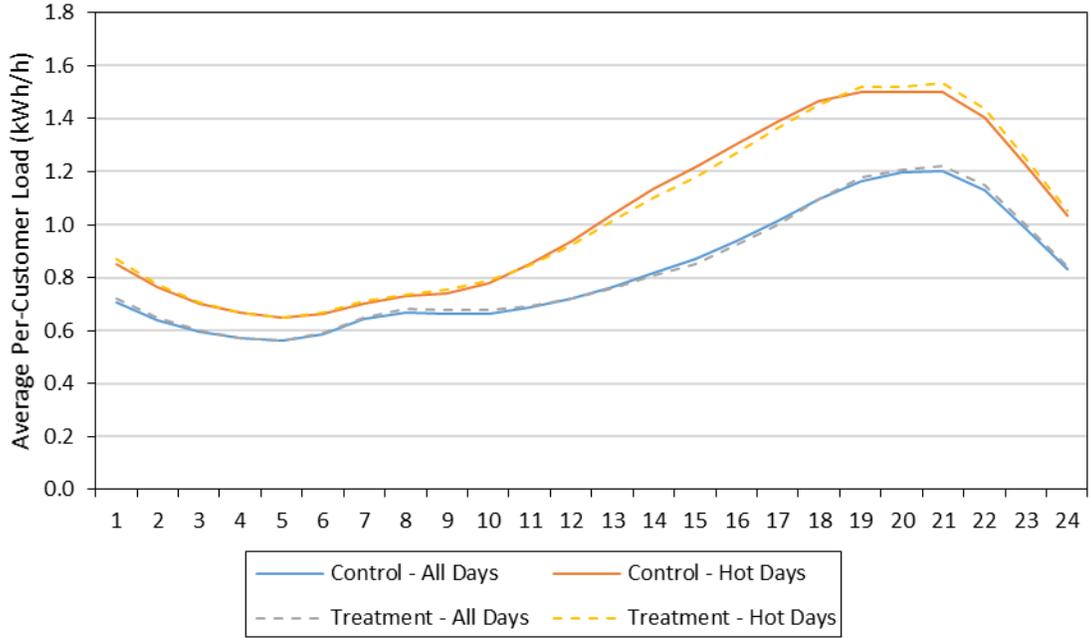
**Figure 5.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers  
(Average Weekday, January 2018)**



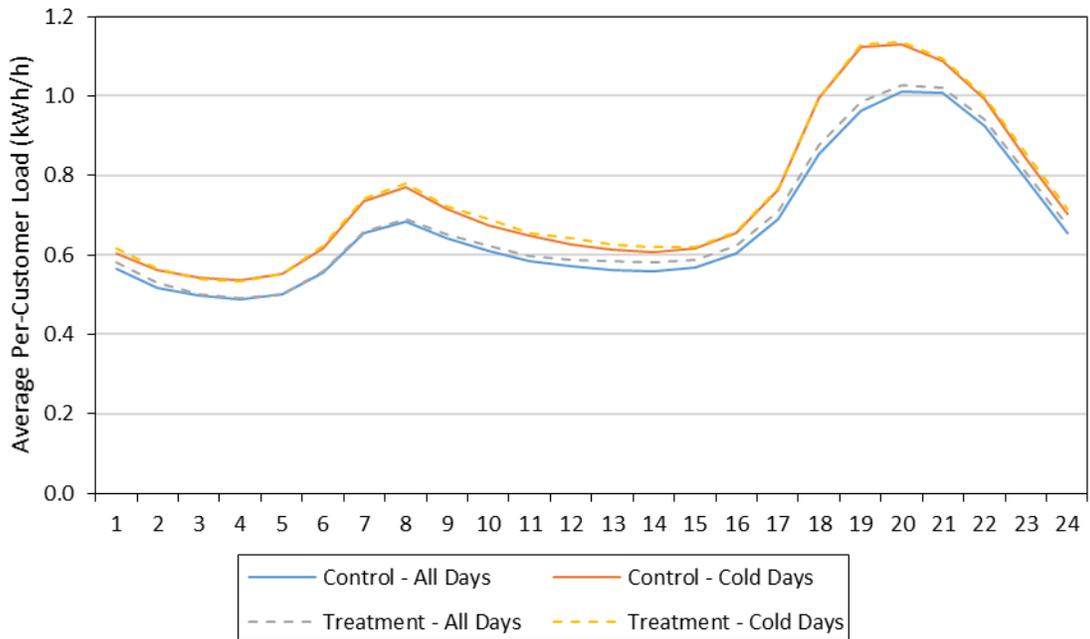
### **5.3 TOU control group matching results for CPP customers**

Figures 5.5 and 5.6 illustrate the quality of the matches for the CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is 0.3 percent, while the mean absolute percentage error (MAPE) is 1.3 percent. In the winter months, the MPE is 1.5 percent and the MAPE is 1.5 percent.

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



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



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

Since TOU-DR-P customers experience TOU prices on all weekdays that are not RYU/CPP event days, it is of interest to examine their usage changes on non-event days, similar to TOU customers. This sub-section reports *ex-post* TOU load impact results for those customers enrolled on the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average summer (October 2017, and June through September 2018) and winter (November 2017 through May 2018) weekdays, by month. Reported enrollment in CPP grew from 4,086 in October 2017 to just over 8,000 in September 2018.<sup>23</sup> Peak load impacts varied across months, with estimated load reductions in all months except for near-zero amounts in October, November, December, and February. The largest load reduction occurred in August, corresponding to the highest average peak-hour temperature. Peak load reductions ranged from zero reduction (in October) to 8.2 percent of the reference load (in July).

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

Month	Climate Zone	Enrolled	Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	% Peak Load Impact	Ave. Peak Temp.
Oct-17	All	4,086	5.01	0.00	1.23	0.00	0.0%	75
Nov-17	All	4,280	3.90	0.02	0.91	0.00	0.4%	66
Dec-17	All	4,528	4.49	0.00	0.99	0.00	0.0%	62
Jan-18	All	4,807	4.42	0.05	0.92	0.01	1.1%	62
Feb-18	All	5,433	4.67	0.02	0.86	0.00	0.4%	59
Mar-18	All	6,032	4.56	0.10	0.76	0.02	2.2%	63
Apr-18	All	6,227	4.54	0.17	0.73	0.03	3.7%	64
May-18	All	6,364	4.63	0.19	0.73	0.03	4.1%	64
Jun-18	All	6,542	5.40	0.31	0.83	0.05	5.7%	70
Jul-18	All	6,817	8.62	0.70	1.27	0.10	8.2%	78
Aug-18	All	7,488	9.90	0.79	1.32	0.11	8.0%	79
Sep-18	All	8,048	8.12	0.59	1.01	0.07	7.2%	73

Table 5.5 summarizes results by season and climate zone. Summer load impacts are similar between the Coastal and Inland climate zones; while winter load impacts are larger for the coastal climate zone.

<sup>23</sup> The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days were required for measuring CPP load impacts. There were 4,539 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.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	3,945	4.11	0.27	1.04	0.07	6.6%	74
	Inland	2,651	3.34	0.21	1.26	0.08	6.3%	76
	<b>All</b>	<b>6,596</b>	<b>7.45</b>	<b>0.48</b>	<b>1.13</b>	<b>0.07</b>	<b>6.5%</b>	<b>75</b>
Winter	Coastal	3,247	2.64	0.07	0.81	0.02	2.7%	63
	Inland	2,134	1.82	0.01	0.85	0.00	0.3%	63
	<b>All</b>	<b>5,382</b>	<b>4.46</b>	<b>0.08</b>	<b>0.83</b>	<b>0.01</b>	<b>1.7%</b>	<b>63</b>

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers *increased* their average daily usage during October through April, and then *decreased* usage in the subsequent months. The overall effect is an average annual *decrease* of about 0.4 percent.

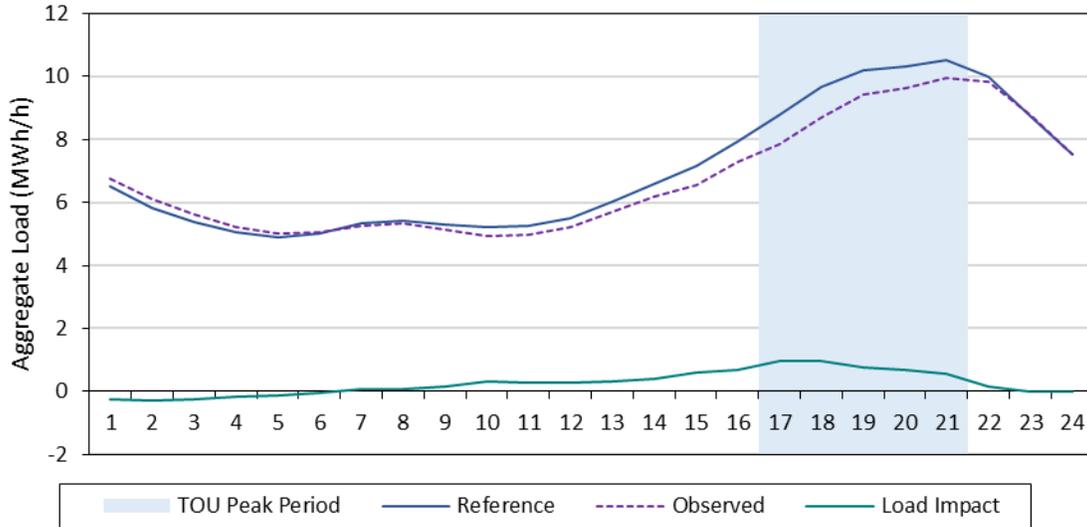
**Table 5.6: TOU Average Daily Load Impacts for CPP Customers, by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Daily Load Impact	Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)		
Oct-17	All	4,086	83.08	-2.87	20.33	-0.70	-3.4%	71
Nov-17	All	4,280	67.78	-1.85	15.84	-0.43	-2.7%	64
Dec-17	All	4,528	78.05	-2.15	17.24	-0.48	-2.8%	59
Jan-18	All	4,807	78.38	-1.60	16.31	-0.33	-2.0%	60
Feb-18	All	5,433	83.40	-2.16	15.35	-0.40	-2.6%	56
Mar-18	All	6,032	84.79	-0.77	14.06	-0.13	-0.9%	59
Apr-18	All	6,227	83.18	-0.02	13.36	0.00	0.0%	61
May-18	All	6,364	85.56	0.37	13.44	0.06	0.4%	62
Jun-18	All	6,542	95.27	1.94	14.56	0.30	2.0%	67
Jul-18	All	6,817	146.13	5.45	21.44	0.80	3.7%	74
Aug-18	All	7,488	168.18	6.12	22.46	0.82	3.6%	76
Sep-18	All	8,048	137.76	2.48	17.12	0.31	1.8%	69

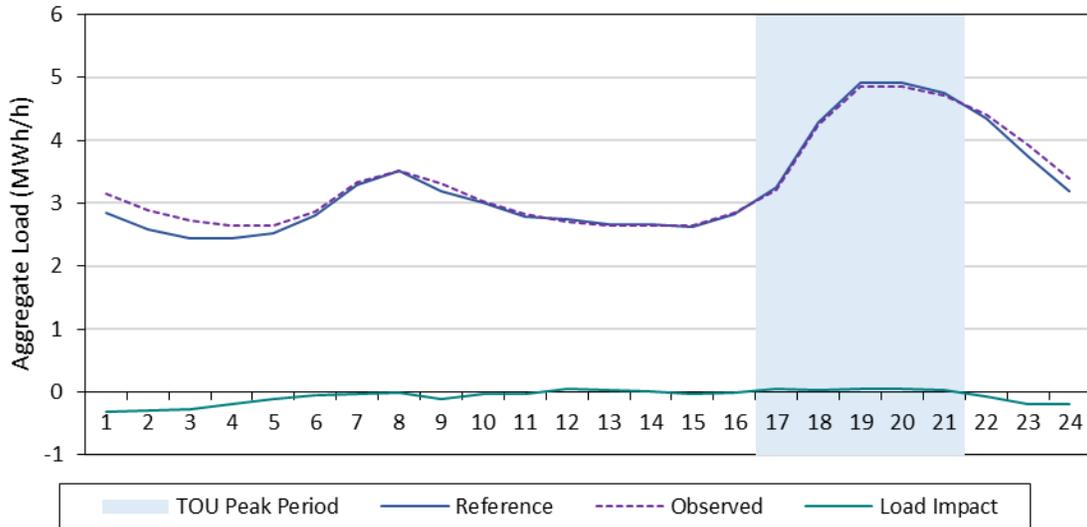
Figure 5.7 shows aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the CPP customers for the average weekday in August. Figure 5.8 shows the same information for the average weekday in January. The average weekday in August loads illustrates a load shift out of the peak period to the super off-peak periods. However, the January average loads exhibit an increase in usage

during the overnight and morning hours, and close to zero change during all other hours.

**Figure 5.7: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers  
(Average Weekday, August 2018)**



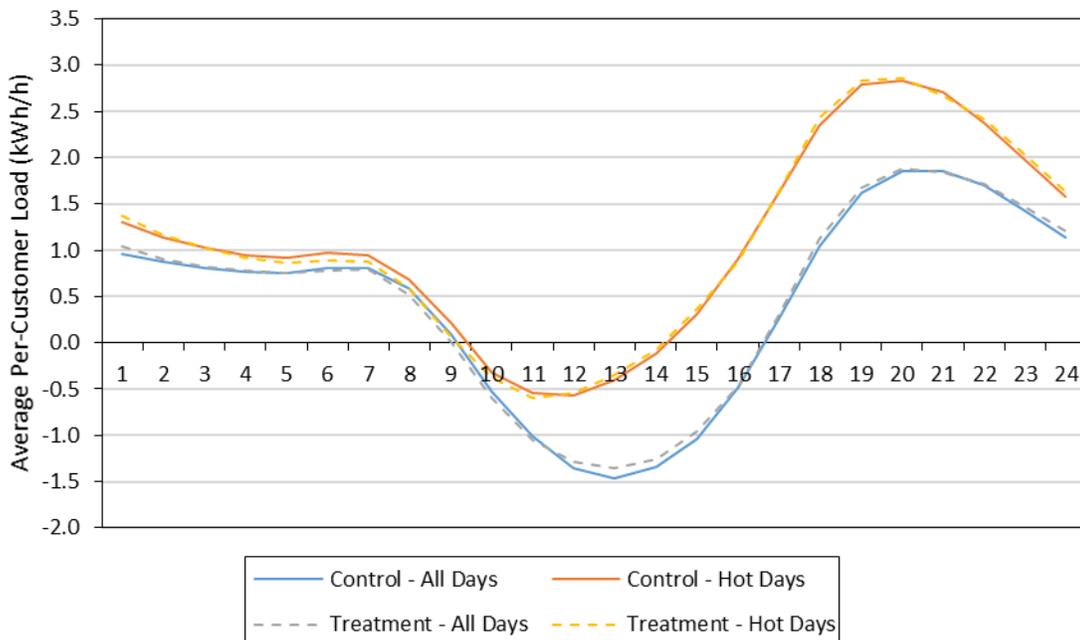
**Figure 5.8: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers  
(Average Weekday, January 2018)**



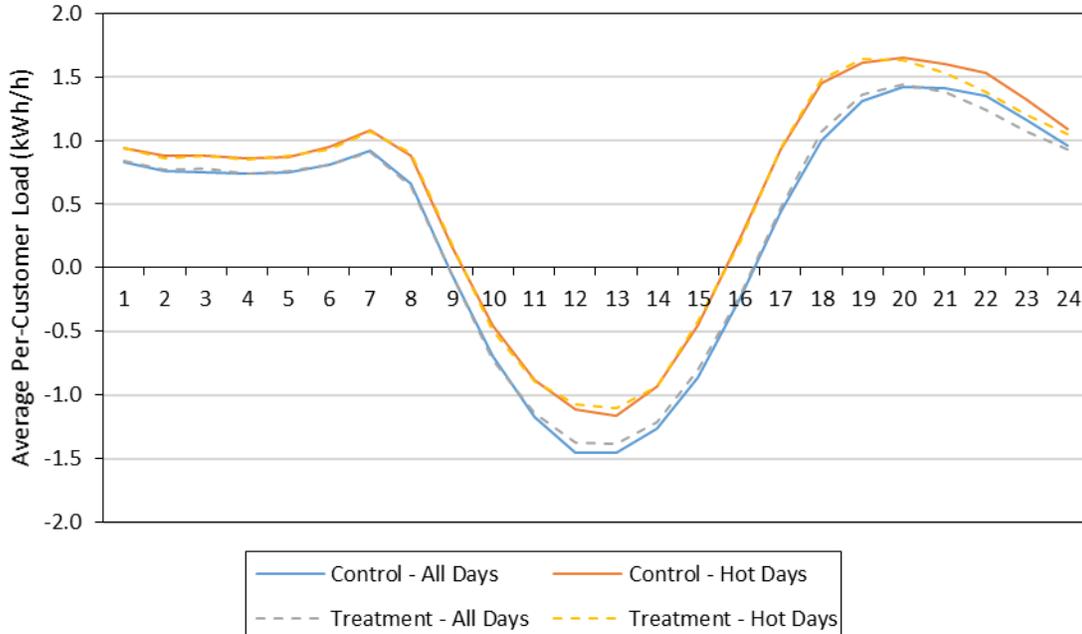
## 5.5 TOU control group matching results for Grandfathered customers

Figures 5.9 and 5.10 illustrate the quality of the matches for the grandfathered CPP (GTOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average grandfathered CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile is 0.01 kWh/h, while the mean absolute error (MAE) is 0.05 kWh/h. In the winter months, the ME is -0.002 kWh/h and the MAE is 0.03 kWh/h.

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



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



### 5.6 Ex-post TOU load impacts for Grandfathered customers

This sub-section shows *ex-post* TOU load impact results for Grandfathered customers (enrolled in GTOU-DR-P). Table 5.7 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 11 a.m. to 6 p.m. during summer months, 5 to 8 p.m. during winter months), for the average weekday *by month*, on an aggregate and per-customer basis. The period covers October 2016 through November 2017 because TOU load impacts are estimated using incremental customer from the PY2017 analysis. However, monthly enrollment number are from the November 2017 through October 2018 period. The winter months are indicated by light blue shading.<sup>24</sup> Enrollments gradually decline throughout the period.<sup>25</sup> The per-customer load impacts remain constant by season because of the methodology implemented, resulting in per-customer load impacts of 0.04 kWh/h and 0.02 kWh/h for the summer and winter seasons, respectively. Positive reference loads during the winter and negative reference loads during the summer occur because of the different TOU peak-period, where the summer peak-period covers a more of the day when customers are generating more than they are using.

<sup>24</sup> The summer and season month definitions, however, differed during the PY2017 analysis. Specifically, May was categorized as a summer month, but is now included in the winter season period.

<sup>25</sup> 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 140 grandfathered customers that were considered as incremental customers during the PY2017 analysis period. The aggregate TOU load impacts are then scaled to total enrollments during the PY2018 period.

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

Month	Climate Zone	Enrolled	Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	Ave. Peak Temp.
Oct-16	All	404	-0.46	0.02	-1.14	0.04	75
Nov-16	All	436	0.73	0.01	1.68	0.02	65
Dec-16	All	474	0.83	0.01	1.75	0.02	61
Jan-17	All	469	0.72	0.01	1.53	0.02	62
Feb-17	All	460	0.68	0.01	1.47	0.02	59
Mar-17	All	453	0.47	0.01	1.03	0.02	63
Apr-17	All	451	0.33	0.01	0.72	0.02	65
May-17	All	445	0.32	0.01	0.71	0.02	65
Jun-17	All	438	-0.96	0.02	-2.19	0.04	75
Jul-17	All	433	-0.32	0.02	-0.74	0.04	83
Aug-17	All	430	-0.28	0.02	-0.65	0.04	83
Sep-17	All	418	-0.47	0.02	-1.12	0.04	77

Table 5.8 summarizes results by season and climate zone. The coastal climate had no load impact in the summer period and an *increase* in usage during the winter period, whereas the inland climate zone exhibited similar TOU peak-period load impacts each season.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	182	-0.24	0.00	-1.32	0.00	77
	Inland	243	-0.26	0.02	-1.07	0.07	80
	<b>All</b>	<b>425</b>	<b>-0.50</b>	<b>0.02</b>	<b>-1.17</b>	<b>0.04</b>	<b>78</b>
Winter	Coastal	201	0.24	-0.02	1.21	-0.08	63
	Inland	255	0.33	0.02	1.31	0.08	63
	<b>All</b>	<b>455</b>	<b>0.58</b>	<b>0.01</b>	<b>1.27</b>	<b>0.01</b>	<b>63</b>

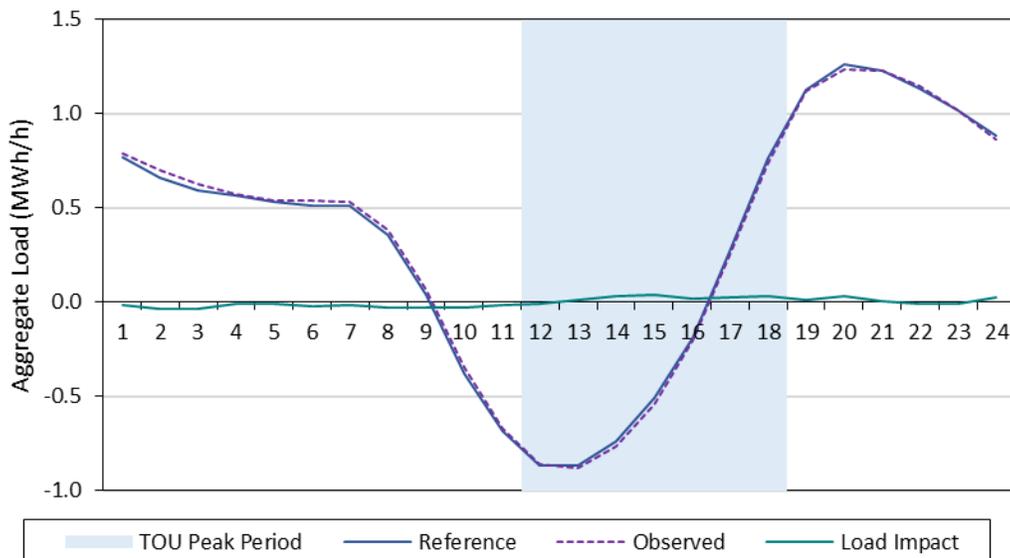
Table 5.9 shows the effect of TOU on average daily usage by month. Grandfathered customers *increased* overall usage during the summer months and *decreased* overall usage during the winter months. The overall effect is an average annual *decrease* of about 0.47 kWh/h per customer.

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

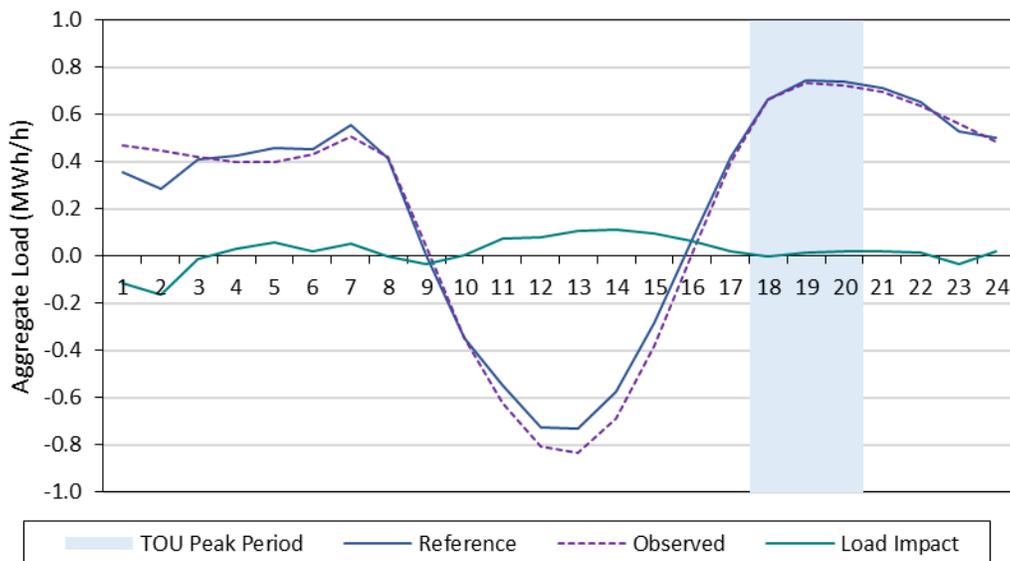
Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-17	All	404	2.40	-0.07	5.95	-0.17	67
Nov-17	All	436	6.05	0.40	13.87	0.93	63
Dec-17	All	474	5.98	0.44	12.63	0.93	58
Jan-18	All	469	5.21	0.43	11.10	0.93	59
Feb-18	All	460	2.52	0.43	5.47	0.93	55
Mar-18	All	453	0.14	0.42	0.32	0.93	58
Apr-18	All	451	-1.92	0.42	-4.25	0.93	61
May-18	All	445	-0.26	0.41	-0.58	0.93	62
Jun-18	All	438	-2.07	-0.07	-4.73	-0.17	67
Jul-18	All	433	6.33	-0.07	14.61	-0.17	75
Aug-18	All	430	7.30	-0.07	16.97	-0.17	76
Sep-18	All	418	3.49	-0.07	8.35	-0.17	69

Figure 5.11 and Figure 5.12 shows aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the grandfathered customers for the average weekday in August and January, respectively. The TOU peak periods are represented by the hours with blue highlighting. The summer period appears to exhibit load shifting from the TOU peak period of off-peak hours. However, the winter load profile illustrates a larger response during the middle of the day, outside of the peak TOU period.

**Figure 5.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, August 2018)**



**Figure 5.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, January 2018)**



## 6. Ex-Ante Load Impacts

This section describes the development of *ex-ante* load impact forecasts for the CPP and TOU rates. The first part describes the methodologies used and then the resulting

forecasts are presented. *Ex-ante* load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on analyses of per-customer load impact findings from *ex-post* evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

## **6.1 Methodology**

### **6.1.1 Per-customer load impacts**

In cases where multiple events have been called in the historical period for event-based programs such as CPP, a relationship between the estimated event-day *ex-post* load impacts and the weather conditions is developed. That relationship is used to produce weather-sensitive *ex-ante* load impacts for the relevant weather scenarios. In 2018 SDG&E called six RYU/CPP events, which means there are six events on which to base the *ex-ante* forecasts. The percentage load impact is used for the average weekday event to simulate the *ex-ante* CPP load impact. CPP load impacts for different weather scenarios are developed by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads.

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

An additional issue in producing the *ex-ante* load impact forecasts is that the Protocols call for estimating load impacts for the RA hours of 4 to 9 p.m., while the CPP events are called during the program hours of 2 p.m. to 6 p.m. year-round. Load impacts are simulated using the event hours that are indicated by the tariff, however the load impacts are summarized across the RA window as required.

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

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

## 6.1.2 Per-customer reference loads

Weather-sensitive reference loads for the average customer in each of the two climate zones were developed through a regression analysis of hourly load data for weekday non-event days for the period of October 2017 through September 2018 for the CPP and TOU customers. Customers are first sorted as weather sensitive or not.<sup>26</sup> Regression models were estimated separately for each hour of the day, by weather sensitivity, using daily observations for weekdays, and a form similar to that of the *ex-post* load impact models. The primary differences between this analysis compared to the *ex-post* analysis are:

- The analysis included only the treatment customers;
- Weather variables were included (Mean17, CDH60, and HDH60)<sup>27</sup>;
- Data for all months were included, rather than estimating separate models by month or season; and
- Month-year indicator variables were added to account for monthly and yearly differences in usage patterns.

The resulting equations allow the simulation of “observed” (*i.e.*, post TOU load impacts) loads under the four different weather scenarios. Reference loads for the alternative scenarios were then obtained by adjusting the above observed loads by the relevant estimated percentage TOU load impacts from the *ex-post* analysis (seasonal values for TOU, and monthly values for CPP).<sup>28</sup> For NEM customers, reference loads are calculated by adjusting observed loads by the relevant seasonal *ex-post* level load impacts. The

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<sup>26</sup> Customer-specific regressions are implemented to categorize customers as weather sensitive or not. Weather sensitive customers change usage in response to changes in the weather, while non-weather sensitive customers do not. Determining which customers are non-weather sensitive allows for a more parsimonious regression model by not including weather variables as explanatory variables for these customers. The following regression specification is used to determine whether a customer is weather sensitive:

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

, where  $Q_t$  represents the average customer usage during event hours on day  $t$  in the summer months of June through September.  $DTYPE_{i,t}$  represents the day of week, while  $MONTH_{i,t}$  represents each month. The  $EVT_{i,t}$  variables control for any event days a customer faces (BIP, CPP, etc.). The variable of importance is  $Weather_t$ , which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient ( $b^{Weather}$ ) is positive and statistically significant for any of the three separate weather specifications.

<sup>27</sup> Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree hours (CDH) for each hour of the day are defined as:  $CDH60 = \max(0, \text{Temperature in } ^\circ\text{F} - 60)$ . Likewise, heating degree hours (HDH) for each hour of the day are defined as:  $HDH60 = \max(0, 60 - \text{Temperature in } ^\circ\text{F})$ .

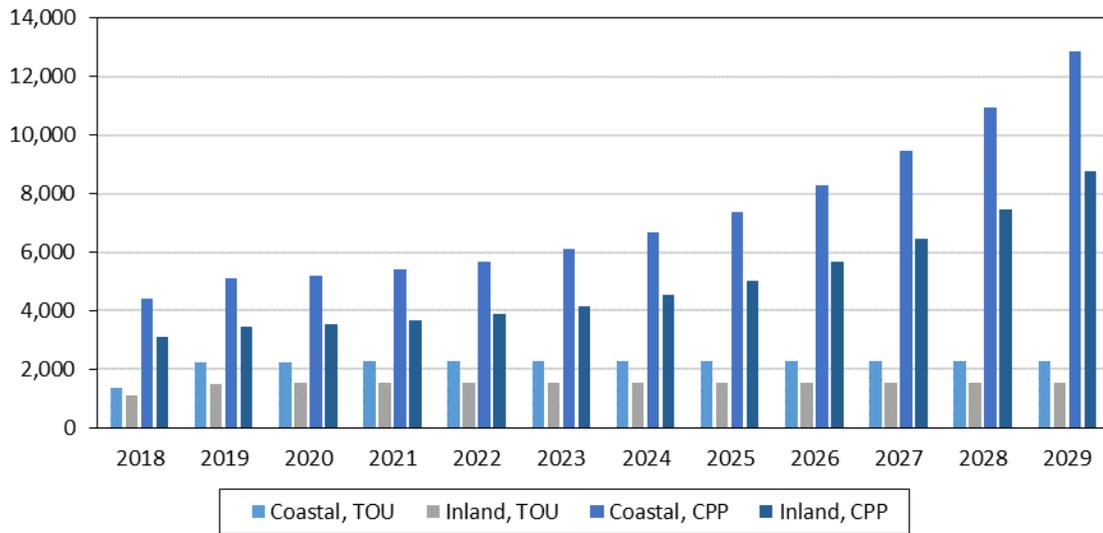
<sup>28</sup> The adjustment takes the form of  $\text{Reference} = \text{Observed} / (1 - \% \text{TOULoadImpact})$ . CA Energy examined several alternative approaches to developing the weather-sensitive reference load, including the same type of regression analysis using load data for the matched control group customers. The resulting reference loads were not very sensitive to the data and approach used, although the selected approach produced more accurate loads during the swing months.

process for obtaining simulated reference and observed loads is completed separately for each reporting category.<sup>29</sup>

### 6.1.3 Enrollment forecast

Figure 6.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU, while enrollment in CPP is forecasted to nearly triple by the end of the forecast period. TOU load impact Enrollment is expected to be somewhat greater in the Coastal climate zone than in the Inland for both rates which is consistent with *ex-post*. Enrollment for grandfathered customers (GTOU-DR-P) is assumed to remain constant at 418 customers until the grandfathering term expires on July 31, 2027.

**Figure 6.1: Enrollments in TOU and CPP Rates**



### 6.2 Ex-Ante load impacts – Residential CPP

This subsection summarizes the *ex-ante* load impact forecasts for future CPP event days, for customers anticipated to be enrolled in CPP. Figure 6.2 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2020 for the SDG&E 1-in-2 weather scenario. The average event-period percentage load impact is 16 percent.

<sup>29</sup> The use of panel regressions limits results to only apply to the customer type included in the regressions, as opposed to customer-specific regressions for which sub-categories can be created by combining pieces from the individual regressions. Therefore, any sub-categorization of results needs to be processed separately to account for possible differences in weather sensitivity and load profiles. For example, customers dually enrolled in CPP and TD have larger loads. Therefore, separate panel regressions including only dually enrolled CPP and TD customers would be estimated to simulate reference and observed loads for these customers.

**Figure 6.2: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) – (August 2020 SDG&E 1-in-2 Peak Day)**

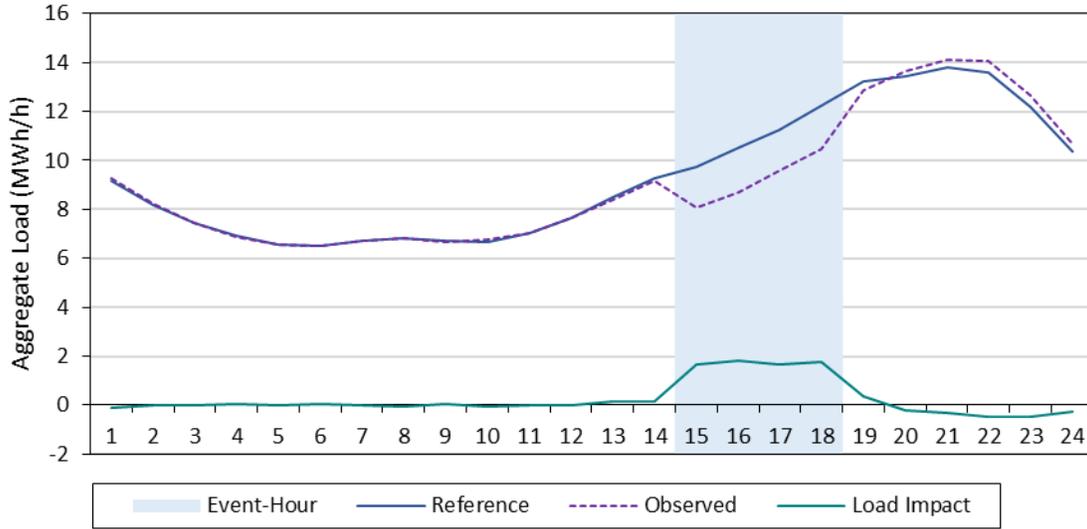


Figure 6.3 shows the monthly pattern of aggregate average *ex-ante* load impacts (RA window) in 2020 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in August. The difference in load impacts between months also indicates the seasonal pattern in customer reference loads.

**Figure 6.3: Aggregate CPP Load Impacts (MWh/h), by Month – (2020 SDG&E 1-in-2 Peak Day, RA Window)**

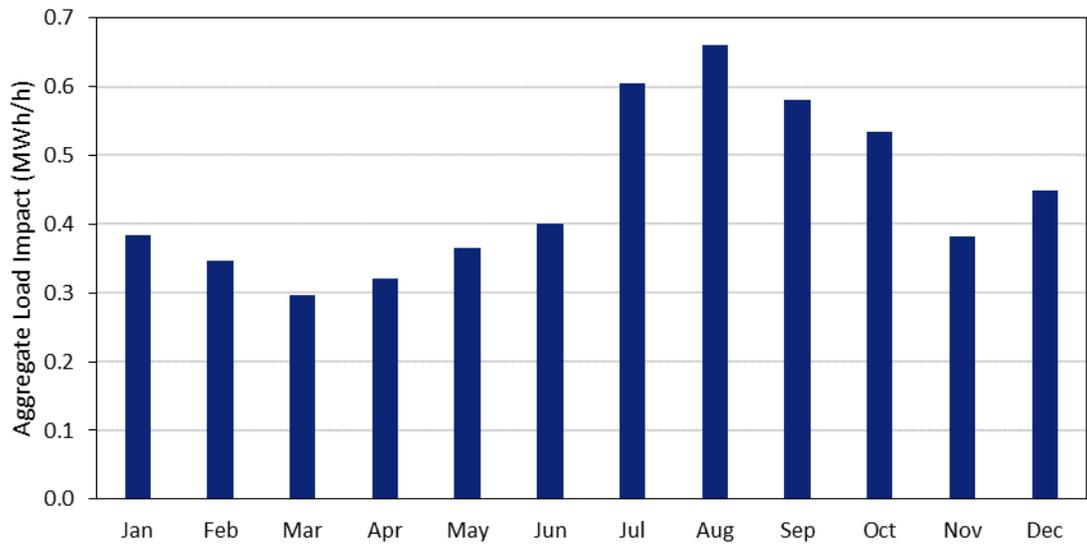
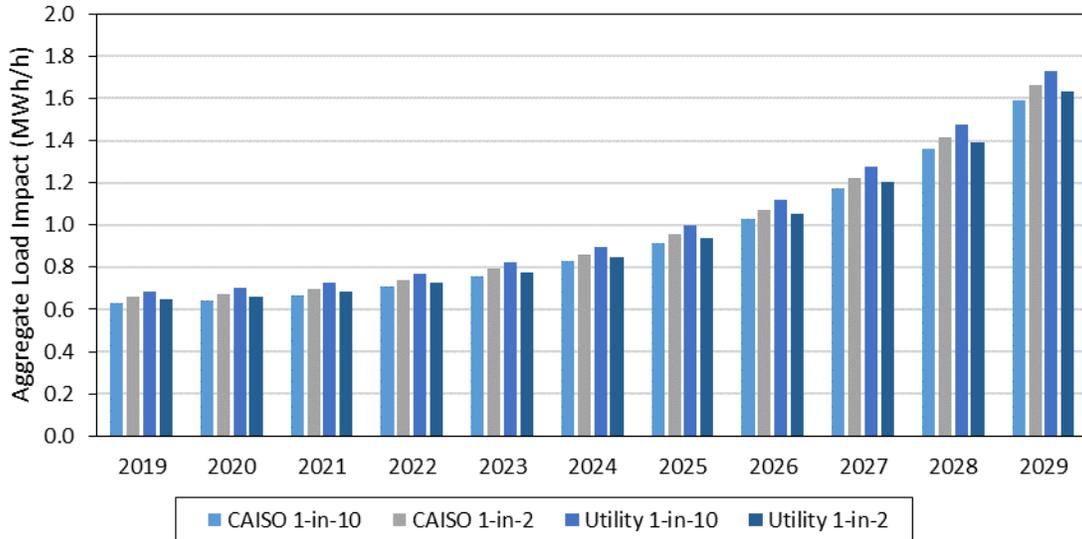


Figure 6.4 illustrates the growth in forecast CPP load impacts, and the relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios over the forecast period. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

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



### 6.3 Ex-Ante load impacts – Residential TOU

This subsection summarizes the *ex-ante* TOU peak load impact forecasts for customers anticipated to be enrolled in both the TOU and CPP rates (TOU-DR and TOU-DR-P). Figure 6.5 shows aggregate loads and load impacts for TOU and CPP customers, in 2020 for an August SDG&E 1-in-2 average weekday. The average peak load impact is 9 percent of the reference load.

**Figure 6.5: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, (August 2020 SDG&E 1-in-2 Average Weekday)**

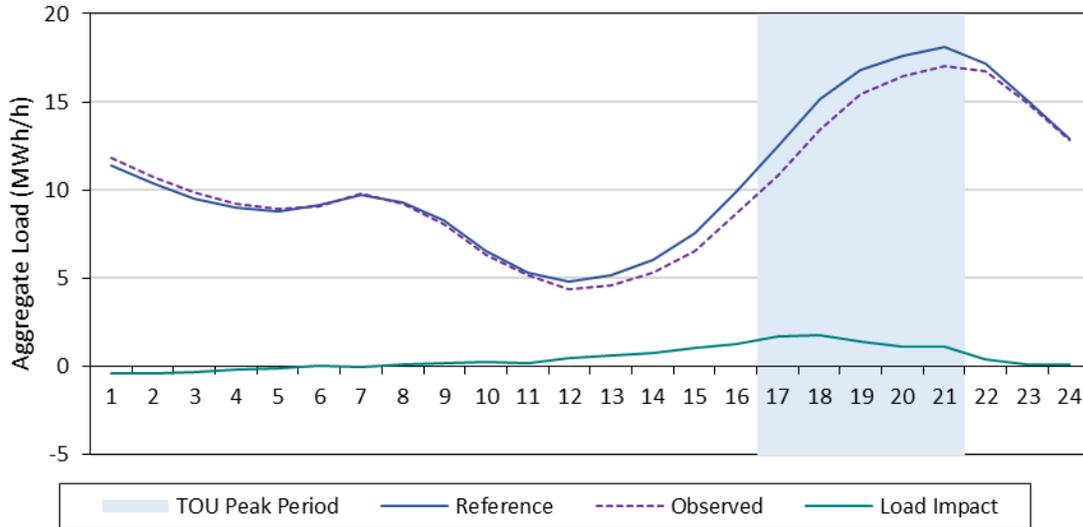


Figure 6.6 shows the monthly distributions of the peak-period TOU load impacts (TOU peak period aligns with the RA window) for TOU and CPP customers. Load impacts are greatest in the summer months, June through October. Results for the winter months are considerably smaller, with a near zero change in November and even an *increase* in usage for the months of February and December. Higher peak load impacts are expected to occur during the summer months based on the higher peak-hour prices, relative to the standard non-TOU rate prices, of the summer rate schedule.

**Figure 6.6: Aggregate TOU Load Impacts (MWh/h) by Month – TOU-DR and TOU-DR-P Customers, (2020 SDG&E 1-in-2 Average Weekday, RA Window)**

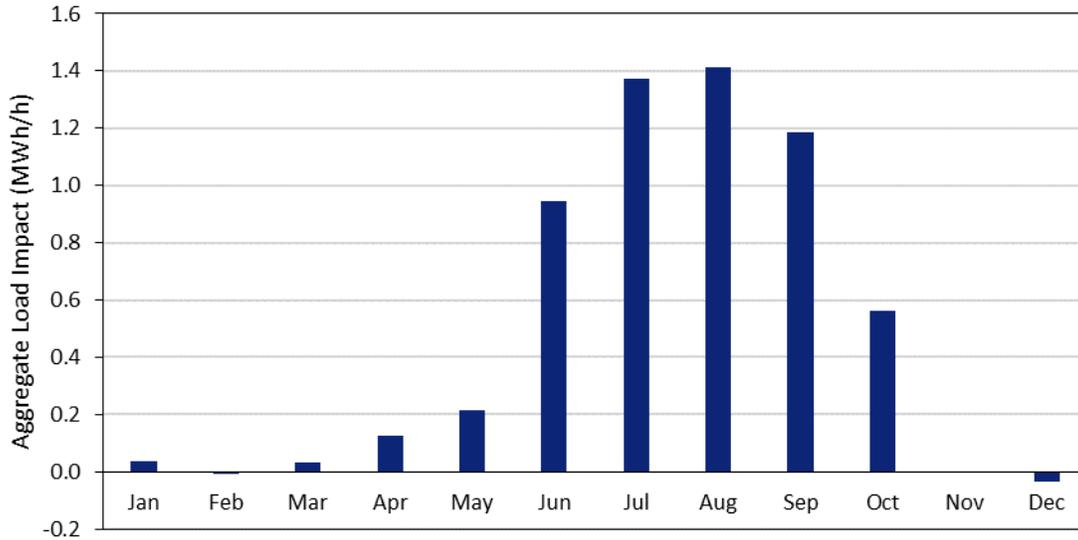
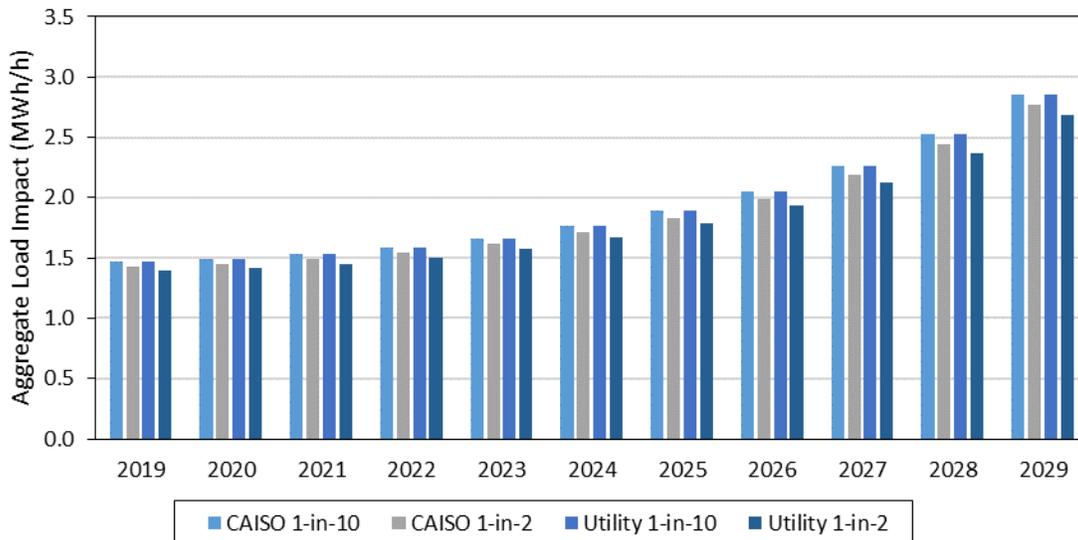


Figure 6.7 shows the aggregate average August weekday TOU load impacts over the forecast period, differentiated by weather scenario. The load impacts are largest for the CAISO and Utility 1-in-10 scenarios, which have equivalent temperatures for the average August weekday. (TOU load impacts are largest for the Utility 1-in-10 scenarios on monthly peak days.) The increase of enrollment numbers over time is greater for TOU-DR-P customers. Consequently, the *ex-ante* TOU load impact results reflect more of the *ex-post* TOU load impacts for DR-TOU-P customers as their relative proportion grows.

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



## 6.4 Ex-Ante load impacts – Residential Grandfathered CPP

This subsection summarizes the *ex-ante* both TOU and CPP load impact forecasts for grandfathered customers enrolled in GTOU-DR-P. The enrollment forecast is assumed to remain constant at 418 customers, though some attrition is likely. Figure 6.8 shows monthly aggregate CPP loads and load impacts for grandfathered customers, in 2020 for an August SDG&E 1-in-2 average weekday. The CPP load impact remains constant for all months because level load impacts from the *ex-post* analysis are applied to the number of customers within the program. Consequently, the load impacts also do not vary by weather scenario.<sup>30</sup> It is assumed that grandfathered customers will have a CPP load impact of 0.023 MWh/h during the RA window.

**Figure 6.8: Aggregate CPP Load Impacts (MWh/h) by Month– Grandfathered Customers, (2020 SDG&E 1-in-2 Peak Day, RA Window)**

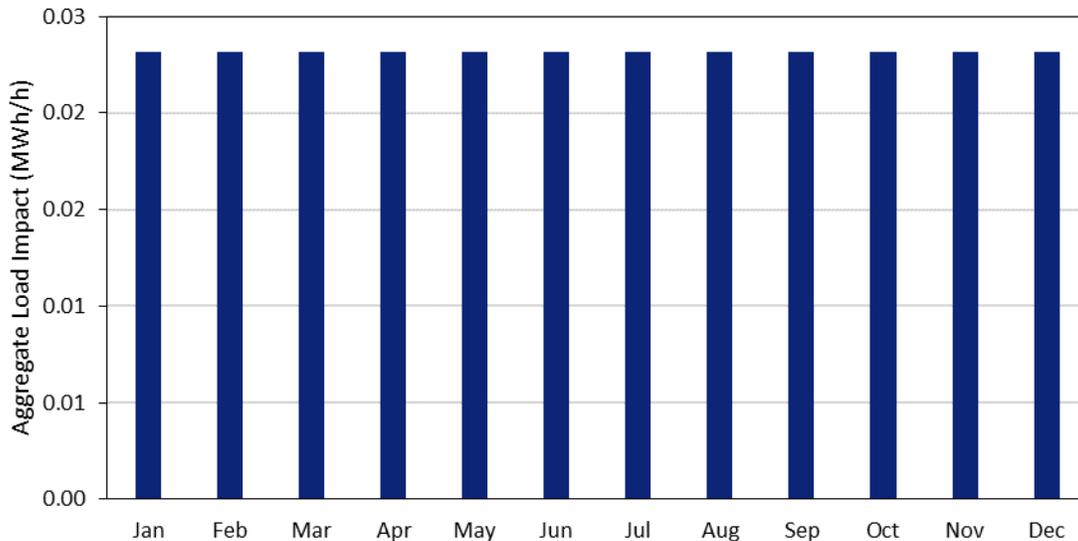
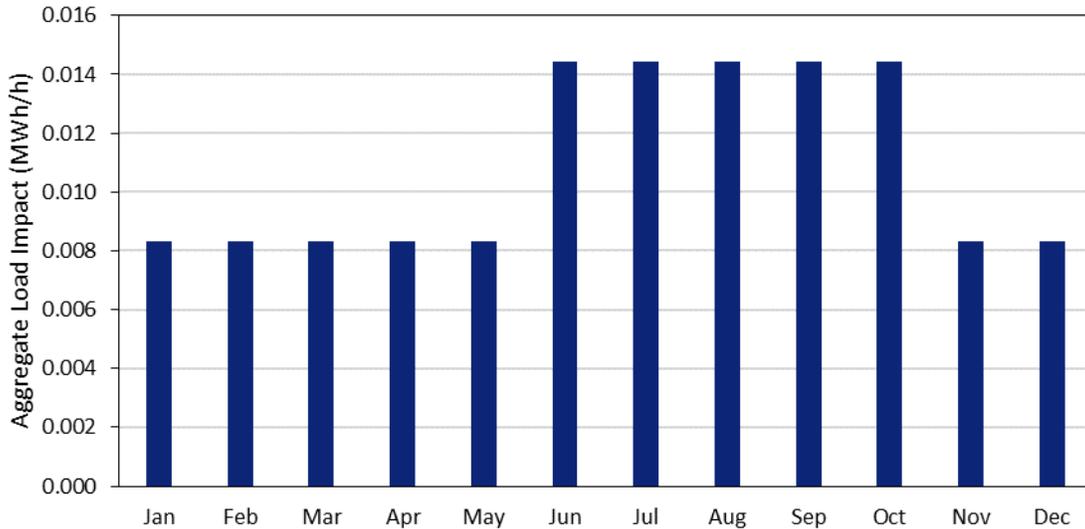


Figure 6.9 shows the monthly distributions of the peak-period TOU load impacts for grandfathered customers. Load impacts are greatest in the summer months, June through October, at 0.014 MWh/h. Results for the winter months are 0.008 MWh/h. Similar to the CPP load impact forecast for grandfathered customers, the TOU load impact does not vary by weather scenario and year. Therefore, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2027.

<sup>30</sup> CA Energy investigated the weather sensitivity of load impacts but determined that constant level load impacts provided a more accurate representation of forecast demand response for grandfathered customers. This is due to a combination of the number of events and idiosyncratic patterns between events for the NEM customers lead to unexpected *a priori* results (i.e., higher temperatures leading to smaller CPP load impacts).

**Figure 6.9: Aggregate TOU Load Impacts (MWh/h) by Month – Grandfathered Customers, (2020 SDG&E 1-in-2 Average Weekday, RA Window)**



## 7. 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 2018 program year; and “previous study” refers to the report that was developed following the 2017 program year.

### 7.1 Residential CPP

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

Table 7.1 shows the average event-hour reference loads and CPP load impacts for the average weekday event during the current and previous program years. The event hours were longer in the *ex-post* PY2017 study, lasting from 11 a.m. to 6 p.m., as opposed to the current event hours of 2 p.m. to 6 p.m. The aggregate enrollments increased in the current program which also increase reference loads and CPP load impacts. The per-customer reference load and load impact in the PY2018 study is slightly smaller, corresponding to slightly lower average event hour temperatures. The percentage load impact is slightly larger in the current study at 16 percent versus 13 percent in the PY2017 study. The current study also includes the load impacts of dually enrolled TD customers. The percentage load impact of CPP only customers was 14% for the current study (see Section 4.4), which is closer to the PY2017 study.

**Table 7.1 Comparison of PY2017 *Ex-Post* and Current *Ex-Post* Load Impacts, CPP Event**

Result	<i>Ex-post for 2017 Weekday Event from PY2017 Study</i>	<i>Ex-post for 2018 Weekday Event from PY2018 Study</i>
# Enrolled	4,935	6,796
Reference (MWh/h)	6.76	9.14
Load Impact (MWh/h)	0.90	1.45
Per-customer reference (kWh/h)	1.37	1.35
Per-customer load impact (kWh/h)	0.18	0.21
% Load Impact	13%	16%
Temperature	91.6	91.0

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

In this sub-section, the *ex-ante* forecast prepared following PY2017 (the “previous study”) are compared to the *ex-ante* forecast contained in this study (the “current study”). Table 7.2 reports the average event-hour load impacts for the August 2019 system peak day under utility-specific 1-in-2 weather conditions. The current study *ex-ante* forecast has larger percentage load impacts, which results from including dually enrolled customer load impacts in the current forecast, as mentioned in the previous section. Per-customer reference loads are lower in the current study. The lower temperature in the current study causes a lower reference load; however, an increase in the proportion of NEM customers has also reduced the per-customer reference loads during event hours.

**Table 7.2 Comparison of PY2017 *Ex-Ante* 2019 Forecast and Current *Ex-Ante* 2019 Forecast Load Impacts, CPP Event**

Result	<i>Ex-ante for 2019 System Peak Day from PY2017 Study</i>	<i>Ex-ante for 2019 System Peak Day from PY2018 Study</i>
# Enrolled	5,721	8,568
Reference (MWh/h)	7.88	10.72
Load Impact (MWh/h)	1.05	1.69
Per-customer reference (kWh/h)	1.38	1.25
Per-customer load impact (kWh/h)	0.18	0.20
% Load Impact	13%	16%
Temperature	87.1	86.9

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

Table 7.3 provides a comparison of the *ex-ante* forecast of 2018 load impacts prepared following PY2017 and the PY2018 load impacts estimated as part of this study, averaged over the CPP event-window. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts

are based on the 2018 average CPP event day. The increase in aggregate loads and load impacts in from the PY2018 study is mostly driven by difference in enrollment numbers. The percentage load impact is also higher which is partly explained by hotter temperatures realized in *ex-post*, as well as the inclusion of dually enrolled customer load impacts. Even with hotter PY2018 temperatures, the per-customer reference load is lower in the PY2018 study because of the increase proportion of NEM customers.

**Table 7.3 Comparison of PY2017 *Ex-Ante* 2018 Forecast and Current *Ex-Post* Load Impacts, CPP Event**

Result	<i>Ex-ante for 2018 System Peak Day from PY2017 Study</i>	<i>Ex-post for 2018 Weekday Event from PY2018 Study</i>
# Enrolled	5,611	6,796
Reference (MWh/h)	7.72	9.14
Load Impact (MWh/h)	1.03	1.45
Per-customer reference (kWh/h)	1.38	1.35
Per-customer load impact (kWh/h)	0.18	0.21
% Load Impact	13.3%	15.9%
Temperature	87.1	91.0

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

Table 7.4 compares the CPP *ex-post* load impacts for the average weekday event against the *ex-ante* load impacts for 2019 (of the SDG&E 1-in-2 August peak day), from this study. The *ex-post* and first set of *ex-ante* load impacts are averaged over the CPP event hours (HE 15-18) while the second set of *ex-ante* load impacts are summarized over the RA window (HE 17-21). Since the *ex-ante* CPP load impacts are built on the 2018 *ex-post* values, the per-customer load impact percentages are similar during the event window. The RA window includes non-event hours-ending 19 through 21, which reduces the percentage load impacts. Aggregate reference loads and load impacts increase in *ex-ante* because of the increase in enrollments. The results are consistent between the *ex-post* and *ex-ante* analyses. Per-customer reference loads decrease in *ex-ante* over the event window because of the lower temperatures; however, the *ex-ante* per-customer reference loads are larger during the RA window because the average load profile displays rising hourly loads during event and RA window.

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

Result	<i>Ex-post</i> for 2018 (Event Window)	<i>Ex-ante</i> for 2019 Peak Day (Event Window)	<i>Ex-ante</i> for 2019 Peak Day (RA Window)
# Enrolled	6,796	8,568	8,568
Reference (MWh/h)	9.14	10.72	12.54
Load Impact (MWh/h)	1.45	1.69	0.65
Per-customer reference (kWh/h)	1.35	1.25	1.46
Per-customer load impact (kWh/h)	0.21	0.20	0.08
% Load Impact	16%	16%	5%
Temperature	91.0	86.9	82.8

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

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

<b>Factor</b>	<b>Ex-Post</b>	<b>Ex-Ante</b>	<b>Expected Impact</b>
Weather	91 degrees Fahrenheit during HE 15-18.	82.8 degrees Fahrenheit during HE 17-21 of a utility-specific 1-in-2 August peak day.	Cooler <i>ex-ante</i> weather decreases the reference load and load impact.
Event window	HE 15-18 for the average weekday event.	RA Window: HE 17-21. Event Window: HE 15-18.	The RA window covers HE 19-21 which are not event hours, resulting in a lower load impact over the RA window.
% of resource dispatched	The entire program was dispatched on each of the days that comprise the average weekday event.	Assume all customers are called.	None. The <i>ex-ante</i> method assumes that all enrolled customers are dispatched.
Enrollment	6,796 customers enrolled.	8,568 customers.	The increase in <i>ex-ante</i> enrollments increases the total load impact proportionately relative to <i>ex-post</i> .
Methodology	Climate-zone-specific regressions using a matched control-group and difference-in-differences analysis on event and event-like non-event days.	Treatment only customer regressions to estimate observed loads.	No effect to percentage load impacts. The <i>ex-post</i> percentage load impacts are applied to reference loads of the various scenarios in the <i>ex-ante</i> study.

## **7.2 Residential TOU**

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

Table 7.6 shows the average reference loads and load impacts for the average August and January weekday day during the current and previous program years, averaged over the RA window. Enrollment numbers have increased resulting in higher aggregate reference loads. The per-customer reference loads are larger in during the summer in the current study because the RA window is HE 17-21, whereas the RA window for the summer period in the PY2017 analysis was HE 14-18. The TOU peak periods were also different between the PY2017 and PY2018 *ex-post* analyses, shifting to the now later TOU peak-period of HE 17-21.

**Table 7.6 Comparison of PY2017 *Ex-Post* and PY2018 *Ex-Post* TOU Load Impacts**

Season	Result	<i>Ex-post for 2017 Avg. Weekday from PY2017 Study</i>	<i>Ex-post for 2018 Avg. Weekday from PY2018 Study</i>
<b>Summer (August)</b>	# Enrolled	6,396	9,944
	Reference (MWh/h)	6.77	13.87
	Load Impact (MWh/h)	0.19	1.17
	Per-customer reference (kWh/h)	1.06	1.39
	Per-customer load impact (kWh/h)	0.03	0.12
	% Load Impact	2.9%	8.5%
	Temperature	79.8	78.9
<b>Winter (January)</b>	# Enrolled	4,006	6,097
	Reference (MWh/h)	4.01	5.61
	Load Impact (MWh/h)	0.04	0.06
	Per-customer reference (kWh/h)	1.00	0.92
	Per-customer load impact (kWh/h)	0.01	0.01
	% Load Impact	0.9%	1.1%
	Temperature	56.1	62.4

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

In this sub-section, the *ex-ante* forecast prepared following PY2017 (the “previous study”) are compared to the *ex-ante* forecast contained in this study (the “current study”). Table 7.7 reports the average RA-window load impacts for the August and January 2019 average weekday under utility-specific 1-in-2 weather conditions. The TOU peak-period remains the same in both forecasts; however, the RA-window is HE 17-21 for all months in the PY2018 study, whereas the PY2017 summer period had an RA window of HE 14-18. The later summer RA window leads to larger per-customer reference loads. The winter per-customer reference loads, on the other hand, remain fairly similar between forecasts. The current study percentage load impacts are larger in the summer period and smaller in the winter months when compared to the PY2017 *ex-ante* forecast. One significant difference between studies is the inclusion of increased NEM customers in the analysis.

**Table 7.7 Comparison of PY2017 Ex-Ante 2019 Forecast and PY2018 Ex-Ante 2019 Forecast TOU Load Impacts**

Season	Result	Ex-ante for 2019 Avg. Weekday from PY2017 Study	Ex-ante for 2019 Avg. Weekday from PY2018 Study
<b>Summer (August)</b>	# Enrolled	7,221	12,305
	Reference (MWh/h)	7.44	15.79
	Load Impact (MWh/h)	0.23	1.39
	Per-customer reference (kWh/h)	1.03	1.28
	Per-customer load impact (kWh/h)	0.03	0.11
	% Load Impact	3.1%	8.8%
	Temperature	80.6	76.6
<b>Winter (January)</b>	# Enrolled	7,221	12,305
	Reference (MWh/h)	6.43	12.26
	Load Impact (MWh/h)	0.09	0.04
	Per-customer reference (kWh/h)	0.89	1.00
	Per-customer load impact (kWh/h)	0.01	0.00
	% Load Impact	1.5%	0.3%
	Temperature	61.0	61.0

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

Table 7.8 provides a comparison of the *ex-ante* forecast of 2018 TOU load impacts prepared following PY2017 and the PY2018 *ex-post* TOU load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August and January average weekday during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on August and January weekdays. Increased enrollments lead to larger aggregate load impacts and reference loads. However, the enrollments for January were smaller than the PY2017 forecast, resulting in smaller aggregate reference loads and load impacts. The current *ex-post* analysis also has larger percentage load impacts in August and smaller percentage load impacts in January.

**Table 7.8 Comparison of PY2017 *Ex-Ante* 2018 Forecast and PY2018 *Ex-Post* TOU Load Impacts**

Season	Result	<i>Ex-ante for 2018 Avg. Weekday from PY2017 Study</i>	<i>Ex-post for 2018 Avg. Weekday from PY2018 Study</i>
<b>Summer (August)</b>	# Enrolled	7,096	9,944
	Reference (MWh/h)	8.40	13.87
	Load Impact (MWh/h)	0.44	1.17
	Per-customer reference (kWh/h)	1.18	1.39
	Per-customer load impact (kWh/h)	0.06	0.12
	% Load Impact	5%	8%
	Temperature	76.6	78.9
<b>Winter (January)</b>	# Enrolled	7,096	6,097
	Reference (MWh/h)	6.31	5.61
	Load Impact (MWh/h)	0.09	0.06
	Per-customer reference (kWh/h)	0.89	0.92
	Per-customer load impact (kWh/h)	0.01	0.01
	% Load Impact	1.4%	1.1%
	Temperature	61.0	62.4

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

Table 7.9 compares the PY2018 *ex-post* TOU load impacts for the August average weekday with the corresponding *ex-ante* forecast for 2019 (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 *ex-ante* load impacts are based upon *ex-post* percentage load impacts for each TOU period. Difference in percentage load impacts between *ex-post* and *ex-ante* occur because of changes in customer composition. For example, the January *ex-post* percentage load impact is 1.1% versus 0.3% for *ex-ante*. The proportion of NEM customers was about 5% and January and increased to 15% in September. The *ex-ante* forecast assumes the same proportion of NEM customers recorded in the last month. Therefore, a greater proportion of NEM customers affect the January *ex-ante* load impacts, and NEM customers exhibited lower winter TOU load impacts.

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

Season	Result	<i>Ex-post</i> for 2018 Avg. Weekday from PY2018 Study	<i>Ex-ante</i> for 2019 Avg. Weekday from PY2018 Study
<b>Summer (August)</b>	# Enrolled	9,944	12,305
	Reference (MWh/h)	13.87	15.79
	Load Impact (MWh/h)	1.17	1.39
	Per-customer reference (kWh/h)	1.39	1.28
	Per-customer load impact (kWh/h)	0.12	0.11
	% Load Impact	8%	9%
	Temperature	78.9	76.6
<b>Winter (January)</b>	# Enrolled	6,097	12,305
	Reference (MWh/h)	5.61	12.26
	Load Impact (MWh/h)	0.06	0.04
	Per-customer reference (kWh/h)	0.92	1.00
	Per-customer load impact (kWh/h)	0.01	0.00
	% Load Impact	1.1%	0.3%
	Temperature	62.4	61.0

### **7.3 Grandfathered Customers**

This section compares the *ex-post* with *ex-ante* load impacts for grandfathered customers. No other comparisons for grandfathered customers can be made because this is their first program year.

#### **7.3.1 Current *ex-post* versus current *ex-ante*, CPP load impacts**

Table 7.10 compares the grandfathered customers' CPP *ex-post* load impacts for the average weekday event against the *ex-ante* load impacts for 2019 (of the SDG&E 1-in-2 August peak day), from this study. The *ex-post* and first set of *ex-ante* load impacts are averaged over the CPP event hours (HE 15-18) while the second set of *ex-ante* load impacts are summarized over the RA window (HE 17-21). Since the *ex-ante* CPP load impacts are built on the 2018 *ex-post* values, the per-customer load impact nearly identical during the event window. Any differences between *ex-post* and *ex-ante* stem from changes in the number of customers between climate zones because this is the only source of differentiation in the load impact estimates. The RA window includes non-event hours-ending 19 through 21, which reduces the level load impacts. Aggregate reference loads and load impacts decrease because of program enrollment attrition.

**Table 7.10: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, CPP Event for Grandfathered Customers**

Result	<i>Ex-post</i> for 2018 (Event Window)	<i>Ex-ante</i> for 2019 Peak Day (Event Window)	<i>Ex-ante</i> for 2019 Peak Day (RA Window)
# Enrolled	426	418	418
Reference (MWh/h)	0.31	0.42	1.01
Load Impact (MWh/h)	0.11	0.10	0.02
Per-customer reference (kWh/h)	0.73	1.00	2.42
Per-customer load impact (kWh/h)	0.26	0.25	0.06
Temperature	95.4	88.1	83.5

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

Table 7.11 compares the grandfathered customers' PY2018 *ex-post* TOU load impacts for the August average weekday with the corresponding *ex-ante* forecast for 2019 (of the SDG&E 1-in-2 August average weekday) produced in this study. The grandfathered customers' TOU load impacts are presented for all grandfathered customers and are averaged over the RA window, which perfectly overlaps with the TOU peak period. Similar to the CPP load impacts for grandfathered customers, any differences between *ex-post* and *ex-ante* load impacts stem from changes in the number of customers within climate zones. As well, smaller *ex-ante* enrollment numbers lead to a decrease in aggregate reference loads and load impacts.

**Table 7.11: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts for Grandfathered Customers**

Season	Result	<i>Ex-post</i> for 2018 Avg. Weekday from PY2018 Study	<i>Ex-ante</i> for 2019 Avg. Weekday from PY2018 Study
<b>Summer (August)</b>	# Enrolled	430	418
	Reference (MWh/h)	0.85	0.71
	Load Impact (MWh/h)	0.02	0.01
	Per-customer reference (kWh/h)	1.98	1.70
	Per-customer load impact (kWh/h)	0.04	0.03
	Temperature	79.4	77.2
<b>Winter (January)</b>	# Enrolled	469	418
	Reference (MWh/h)	0.66	0.58
	Load Impact (MWh/h)	0.01	0.01
	Per-customer reference (kWh/h)	1.41	1.40
	Per-customer load impact (kWh/h)	0.03	0.02
	Temperature	62.1	60.9

## 8. Recommendations

The rising adoption of net energy metering by customers poses some challenges for estimating load impacts given the data available, especially when adoption occurs during the analysis period. To fully understand the impact that NEM adoption has on CPP and/or TOU load impacts, it would be useful to have customer premise load and net loads to disentangle TOU/CPP load impacts from responses to NEM adoption or changes in solar PV characteristics (*e.g.* size, tilt, azimuth).

## Appendices

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

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

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

## 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. CA Energy attempts to reduce this by 1) including only NEM customers that are NEM for the entire analysis period, 2) matching NEM customers to other NEM customer with similar size solar PV generation, and 3) removing customers that have large changes in usage between periods. To identify what constitutes a large change in usage and its possible effect on load impact estimates, a difference-in-difference of raw load profiles was calculated for different threshold restrictions (for each rate and season). Customers that have average usage (HE 12-18) differences, in absolute value, between periods below the threshold meet the requirement and are kept in the analysis. Figure C.2 illustrates the difference-in-difference load profile based upon raw averages from TOU customer load profiles that meet specific thresholds over the summer period. The line corresponding to a threshold of 4 indicates that customers with a change in usage between periods less than 4 kWh/h are kept in the analysis. The figure illustrates that as the threshold becomes smaller, the raw difference-in-difference exhibits a load impact that appears more influenced by the TOU rate than by solar generation. The number of customers reduces as the restriction threshold becomes smaller. For the purposes of this analysis, CA Energy removed customers that have a change in usage, in absolute value, greater than or equal to 2 kWh/h.

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

