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2025 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates

CALMAC Study ID PGE0513

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Table of Contents

List of Figures

List of Tables

EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations for Pacific Gas and Electric Company's (PG&E) residential time-of-use (TOU) rates for the program year 2025 (PY2025), defined as October 2024 through September 2025. The report addresses the two primary objectives of providing: 1) estimates of ex-post load impacts for E-TOU-C, E-TOU-D, EV2-A, and E-ELEC incremental enrollments during PY2025 and 2) ex-ante forecasts of load impacts for 2026 through 2036, which are based on PG&E's enrollment forecasts and the ex-post load impact estimates produced in this study and prior studies.

ES.1 Resources Covered

The following rates are included in this evaluation (all have seasonally differentiated rates):

1. E-TOU-C: serves as the default residential TOU rate beginning October 1, 2020 and available as a voluntary rate for existing customers. It has two TOU pricing periods (Peak and Off-Peak) that apply on all days of the year.
2. E-TOU-D: available as a voluntary rate beginning in 2020. It differs from E-TOU-C by having a slightly shorter Peak period (5 to 8 p.m. vs. 4 to 9 p.m.), having weekends and holidays be all Off-Peak, and omitting the Baseline Credit.
3. EV2-A: a voluntary whole-house electric vehicle (EV) rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak). This rate is also available to customers with electric heat pumps and, on a pilot basis, to customers that have installed battery storage.
4. E-ELEC: available as a voluntary rate to customers with qualifying electric technologies (e.g., EVs, heat pumps, or battery storage) and serves as the default residential TOU rate for customers on the Net Billing Tariff (NBT). It contains the same pricing period definitions as EV2-A but adds a daily Basic Service Charge (BSC), expressed in $ per meter per day, to the rate structure.

Table ES.1 provides a comparison of the TOU rates, including the presence/level of the BSC, the presence/level of the minimum bill, the energy rates by season and pricing period, and the season and pricing period definitions.

Table ES.1: TOU Rate Summaries[1]

Season	Charge Type	E-TOU-C	E-TOU-D	EV2-A	E-ELEC
All	BSC ($/Day)	N/A			$0.49281
	Min. Bill ($/Day)	$0.40317			N/A
Summer	Peak	$0.58943	$0.53623	$0.59724	$0.57908
	Part-Peak	N/A	N/A	$0.48675	$0.41720
	Off-Peak	$0.46643	$0.40127	$0.28474	$0.36052
	Baseline Credit	($0.09566)	N/A		
Winter	Peak	$0.46460	$0.44662	$0.47013	$0.34756
	Part-Peak	N/A	N/A	$0.45343	$0.32547
	Off-Peak	$0.43460	$0.40801	$0.28474	$0.31161
	Baseline Credit	($0.09566)	N/A		
Definitions	Summer	Jun-Sep			
	Peak Period	4-9 pm all days	5-8 pm NHWD	4-9 pm all days	
	Part-Peak Period	N/A		3-4 pm, 9 pm-midnight all days	

The Baseline Credit contained in E-TOU-C is applicable up to a tariff-specified Baseline Quantity defined by the customer's Baseline Territory and whether the customer qualifies as All-Electric space heating customers. This feature makes E-TOU-C more appealing to low-use customers (by lowering the marginal energy rate for lower-use customers), while E-TOU-D is likely to appeal to higher-use customers due to the lower rates compared to E-TOU-C for usage above the Baseline Quantity. EV2-A and E-ELEC also do not contain the tiered structure.

Residential customers may also choose to be served on Schedule E-1, which is a tiered (i.e., increasing block), non-time differentiated rate that once served as the default residential rate. E-1 has the same minimum bill provision as the TOU rates (except for E-ELEC) and an energy rate that increases at usage levels above 100% of the customer's Baseline Quantity (which is defined in the same manner as in E-TOU-C).

ES.2 Evaluation Methodologies

The study examines customers who change rates to E-TOU-C, E-TOU-D, EV2-A, or E-ELEC during the program year. Load impacts may differ depending on the rate the customer is coming from. For example, an E-1 customer that changes to a TOU rate may shift more load across pricing periods than a customer that changes from one TOU rate to another. Table ES.2 lists the ten rate transitions included in the study, along with indications of the method used to estimate load impacts. We report NEM and non-NEM results separately for each rate transition.

[1] Based on rates effective January 1, 2025.

Table ES.2: Rate Transitions Included in the Study

Rate Transition	Load Impact Estimation Methodology	
	Include Control Group?	Basis of Load Impact Estimate[2]
E-1 to E-TOU-C	Yes	Difference-in-differences $(T_1 - C_1) - (T_0 - C_0)$
E-1 to E-TOU-D		
E-TOU-C to E-TOU-D		
E-1 to EV2-A		
E-1 to E-ELEC		
EV2-A to E-ELEC		
E-TOU-C to EV2-A	No[3]	Within-treatment, pre-treatment vs. treatment periods $(T_1 - T_0)$
E-TOU-D to EV2-A		
E-TOU-C to E-ELEC		
E-TOU-D to E-ELEC		

The evaluation methodology differed by rate transition. For customers transition to E-TOU-C and E-TOU-D, as well as for customers transition from E-1 to EV2-A, E-1 to E-ELEC and EV2-A to E-ELEC, we select quasi-experimental matched control groups and conduct difference-in-differences estimation using regression analysis. For customers transitioning from E-TOU-C to EV2-A, E-TOU-D to EV2-A, E-TOU-C to E-ELEC, and E-TOU-D to E-ELEC, we conduct an analysis using only treatment customers. For all EV2-A and E-ELEC rate transitions, the analysis is supplemented by applying a structural break methodology to identify and exclude customers who experienced large shifts in their usage throughout the analysis period, likely as a result of adopting a qualifying end-use technology (e.g., an electric vehicle) and not a response to rate price differences. This structural break approach is applied to all EV2-A and E-ELEC treatment customers, as well as control customers (when applicable).

The load impacts are estimated using a sample of customers that meet specific criteria to be included in the regression analysis (see Appendix D). We calculate the load impact for the population of incremental customers by applying percentage load impacts, estimated from the sample of customers in the analysis, to the loads of a sample of incremental treatment customers that represent the population (e.g., these customers were randomly sampled before applying any data restrictions).[4] Results are then scaled to incremental enrollment numbers.

[2] T_1 = the treatment customer usage in the treatment period; C_1 = the control-group customer usage in the treatment period; T_0 = the treatment customer usage in the pre-treatment period; and C_0 = the control-group customer usage in the pre-treatment period.

[3] We assessed the feasibility of a control group for these rate transitions but found that year-to-year changes among potential control customers did not provide a valid counterfactual for the treatment group.

[4] A separate sample of incremental customers is drawn from the full population of incremental customers prior to applying any data quality or eligibility screens. This sample is used to adjust reference load profiles in cases where the exclusion criteria applied to the analysis sample may introduce bias relative to the full incremental population.

ES.3 Ex-Post Load Impacts

Tables ES.3 and ES.4 show the estimated peak-period load impacts for the average weekday in February and August 2025, respectively. The brackets in the "% Impact" column show the 90% confidence interval around the estimated load impacts.

We have the following observations about the results:

- **E-TOU-D customers have the highest average per-customer reference loads out of all groups.** This aligns with the rate designs for each rate schedule, with E-TOU-D expected to benefit customers with higher usage levels due to the absence of a tiered rate structure (via the Baseline Credit). **E-TOU-D customers show the smallest percentage load impacts during an August average weekday, however they still show the second highest per-customer load impact after EV2-A customers**.
- Customers transitioning to E-ELEC tend to have higher percentage load impacts than customers transitioning to other TOU rates. This is likely because of the end use technologies that can be shifted out of the peak period (primarily EVs).
- August average temperature differences are indicative of participating customer locations, particularly the share of customers in the Greater Bay Area LCA. **For example, 71% of EV2-A customers are in the Greater Bay Area while E-TOU-D, the rate with the next largest portion, has 41% of customers in the same area.** The result is lower temperatures, on average, for EV2-A customers compared to other rate transitions.
- **August load impacts are higher than February impacts for each rate transition.** This is primarily driven by higher reference loads in the summer.
- The number of incremental customers increased throughout the study period for each rate, as demonstrated by the enrollment counts between February and August. **Rate E-TOU-C has the most incremental customers and experienced the largest increase in customers between February and August; however, EV2-A experienced the largest relative increase with 2.5x growth between February and August**.

Table ES.3: Peak-Period Load Impacts by Rate, February Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	35,935	24.3	1.4	0.677	0.04	5.94% [3.65% - 8.22%]	56.6
E-TOU-D	12,986	15.6	1.1	1.203	0.087	7.25% [6.05% - 8.45%]	56.0
EV2-A	9,446	9.6	0.6	1.018	0.066	6.50% [4.44% - 8.57%]	55.7
E-ELEC	35,379	33.6	3.0	0.950	0.086	9.01% [5.92% - 12.11%]	56.0

Table ES.4: Peak-Period Load Impacts by Rate, August Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	71,895	93.4	8.8	1.298	0.123	9.48% [7.72% - 11.24%]	84.6
E-TOU-D	25,224	54.3	3.5	2.154	0.138	6.41% [5.27% - 7.54%]	82.6
EV2-A	23,672	38.3	3.5	1.619	0.148	9.13% [7.61% - 10.64%]	79.2
E-ELEC	65,671	76.1	7.4	1.159	0.112	9.67% [6.86% - 12.49%]	83.1

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts are developed for each of the TOU rates. In each case, the forecast represents *incremental* TOU load impacts attributable to customers joining TOU rates during the forecast period. Customers already on TOU rates contribute to an *embedded* TOU load impact already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

Load impacts are forecast for each month from 2026 through 2036, distinguished by:

- Monthly system worst day and average weekday;
- Whether the peak conditions are determined using the utility's peak or the utility's load at the time of CAISO's peak; and
- Incremental enrollment forecasts provided by PG&E.

Figures ES.1 illustrates the incremental enrollment forecast over time since 2025. By 2036, customers moving to E-ELEC (from E-1, E-TOU-C, E-TOU-D, or EV2-A) account for the highest share of incremental TOU customers (586,000 customers). This is a significant contrast to the previous year's forecast where EV2-A accounted for the highest share of incremental TOU customer enrollment. Specifically, the PY2024 enrollment forecast projected incremental 767,000 EV2-A customers in the final year of the forecast, whereas the PY2025 enrollment forecast anticipates about 233,500 incremental customers. Rate E-TOU-C has the second largest share of incremental TOU enrollment by 2036 with 404,000 customers.

Figure ES.1: Incremental Enrollment Forecast (since 2025) – August by Year and Adopted TOU Rate

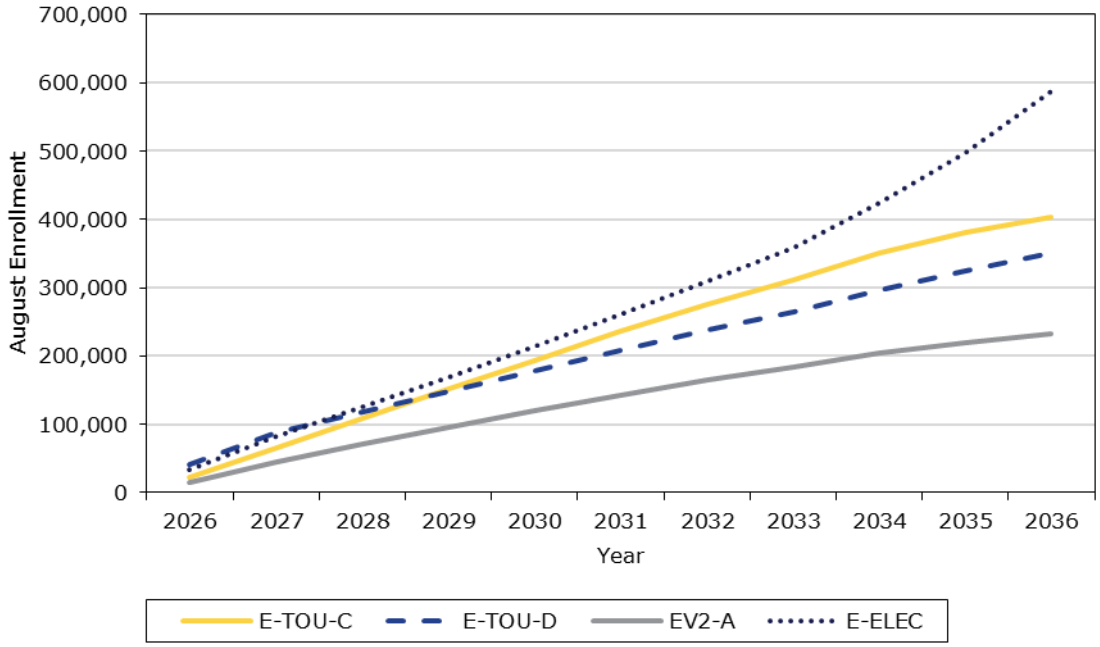


Figure ES.2 illustrates the forecasted load impacts of incremental enrollment for each August during 2026-2036, using PG&E 1-in-2 system worst day weather conditions. The values are the average load impacts during the Resource Adequacy window (4 to 9 p.m. June through September, and 5 to 10 p.m. in all other months) for the PG&E 1-in-2 average weekday weather conditions. The load impacts increase over time due to the enrollment pattern shown in Figure ES.2 The share of E-ELEC load impacts increases over time due to the increasing share of incremental enrollment relative to other TOU rates. Table ES.5 shows the same data in tabular form. **The total incremental TOU load impact increases from 12.9 MWh/hr in 2026 to 182.0 MWh/hr in 2036.**

Figure ES.2: Average RA Window Load Impacts of Incremental Enrollment (since 2025) for 2026-2036, PG&E 1-in-2 August System Worst Day

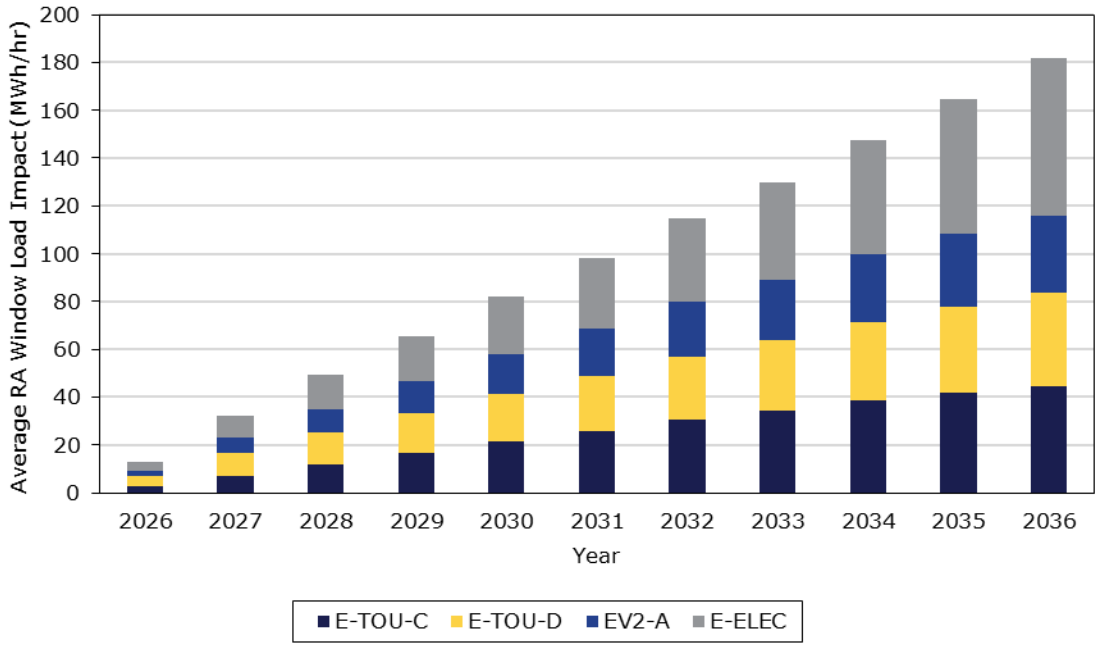


Table ES.5: Average RA Window Load Impacts of Incremental Enrollment (since 2025) for 2026-2036, PG&E 1-in-2 August System Worst Day

Year	Load Impact by Adopted TOU Rate (MWh/hr)				Total
	E-TOU-C	E-TOU-D	EV2-A	E-ELEC	
2026	2.5	4.5	2.0	3.9	12.9
2027	7.2	9.7	6.1	9.4	32.4
2028	12.0	13.0	10.0	14.2	49.2
2029	16.7	16.4	13.4	19.1	65.6
2030	21.4	19.7	16.7	24.2	82.0
2031	26.0	23.0	19.9	29.5	98.4
2032	30.5	26.3	22.9	35.0	114.7
2033	34.4	29.3	25.5	40.5	129.7
2034	38.7	32.8	28.3	47.8	147.6
2035	42.1	35.9	30.5	56.0	164.5
2036	44.6	38.9	32.4	66.2	182.0

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations for Pacific Gas and Electric Company's (PG&E) residential time-of-use (TOU) rates for the program year 2025 (defined as October 2024 through September 2025), where the evaluations conform to the Load Impact Protocols adopted by the CPUC in D-08-04-050. The following rates are included in this evaluation (all have seasonally differentiated rates):

1. E-TOU-C: serves as the default residential TOU rate beginning October 1, 2020, and available as a voluntary rate for existing customers. It has two TOU pricing periods (Peak and Off-Peak) that apply on all days of the year.
2. E-TOU-D: available as a voluntary rate beginning in 2020. It differs from E-TOU-C by having a slightly shorter Peak period (5 to 8 p.m. vs. 4 to 9 p.m.), having weekends and holidays be all Off-Peak, and omitting the Baseline Credit.
3. EV2-A: a voluntary whole-house electric vehicle (EV) rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak)[5]. This rate is also available to customers with electric heat pumps and, on a pilot basis, to customers that have installed battery storage.
4. E-ELEC: available as a voluntary rate to customers with qualifying electric technologies (e.g., EVs, heat pumps, or battery storage) and serves as the default residential TOU rate for customers on the Net Billing Tariff (NBT). It contains the same pricing period definitions as EV2-A but adds a daily Basic Service Charge (BSC), expressed in $ per meter per day, to the rate structure.

The primary goals of the evaluation are the following:

1. Estimate ex-post load impacts for each rate for program year 2025; and
2. Develop ex-ante load impact forecasts for the rates for 2026 through 2036.

The report is organized as follows:

- Section 2 contains descriptions of the TOU rates;
- Section 3 describes the methods used to estimate ex-post load impacts and forecast ex-ante load impacts;
- Section 4 contains the ex-post load impact results, including analyses of load impacts by climate region and for customers expected to be a structural benefiter on E-TOU-C;
- Section 5 contains the ex-ante load impact forecasts; and
- Section 6 provides a series of comparisons of ex-post and ex-ante results for the current and previous evaluations.

Throughout this report, all hours reported are in prevailing time.

- [5] EV-A rate was eliminated on November 30, 2025, and all remaining EV-A customers have been moved to EV-2A.

2. DESCRIPTION OF TIME-OF-USE RATES

Included in this evaluation are the following major residential TOU rates offered by PG&E : E-TOU-C became available in 2018 and now serves as the default TOU rate;[6] E-TOU-D opened for enrollment in May 2020; EV2-A is a whole-house electric vehicle (EV) rate;[7] and E-ELEC became available in December 2022 and is currently available to customers with qualifying electric technologies (e.g., electric vehicles, heat pumps, or battery storage). Net energy metered (NEM) customers became eligible to join E-ELEC in April 2023.

Table 2.1 provides a comparison of the TOU rates, including the presence/level of the Basic Service Charge (BSC), presence/level of the of the minimum bill, the energy rates by season and pricing period, and the season and pricing period definitions. The baseline credit contained in E-TOU-C is applicable up to a tariff-specified Baseline Quantity defined by the customer's Baseline Territory and whether the customer qualifies as All-Electric. This feature makes E-TOU-C more appealing to low-use customers (by lowering the marginal energy rate for lower-use customers), while E-TOU-D is likely to appeal to higher-use customers due to the lower rates compared to E-TOU-C for usage above the Baseline Quantity. EV2-A and E-ELEC also do not contain a tiered structure.

Table 2.1: TOU Rate Summaries[8]

Season	Charge Type	E-TOU-C	E-TOU-D	EV2-A	E-ELEC
All	BSC ($/Day)	N/A			$0.49281
	Min. Bill ($/Day)	$0.40317			N/A
Summer	Peak	$0.58943	$0.53623	$0.59724	$0.57908
	Part-Peak	N/A	N/A	$0.48675	$0.41720
	Off-Peak	$0.46643	$0.40127	$0.28474	$0.36052
	Baseline Credit	($0.09566)	N/A		
Winter	Peak	$0.46460	$0.44662	$0.47013	$0.34756
	Part-Peak	N/A	N/A	$0.45343	$0.32547
	Off-Peak	$0.43460	$0.40801	$0.28474	$0.31161
	Baseline Credit	($0.09566)	N/A		
Definitions	Summer	Jun-Sep			
	Peak Period	4-9 pm all days	5-8 pm NHWD	4-9 pm all days	
	Part-Peak Period	N/A		3-4 pm, 9 pm-midnight all days	

[6] On July 3, 2015, the CPUC issued D.15-07-001, *CPUC Decision on Residential Rate Reform*, setting the course for residential rate reform, and for each of California's major investor-owned utilities (IOU)—PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (the IOUs)—to implement residential Default Time-of-Use rates. Per the requirements of this Decision, the first phase of this transition Default Pilot was limited to a subset of the total eligible population, with the objective of understanding the operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU. The Default Pilot and subsequent application of the default process to all applicable PG&E customers were evaluated in previous studies.

[7] PG&E also offers EV-B, which is an EV-only TOU rate. EV-B is excluded from this analysis due to an inability to estimate TOU load impacts. That is, we do not observe EV-only usage patterns in the absence of a TOU rate so there is no counterfactual upon which to base EV-B load impacts. That is, while EV-B separately meters EV charging, there is no corresponding non-TOU rate that can be used in either a treatment-only before vs. after analysis, or in a treatment vs. control-group analysis.

[8] Based on rates effective January 1, 2025.

Table 2.2 provides the rates for Schedule E-1, which is a tiered (i.e., increasing block), non-time differentiated rate that once served as the default residential rate. E-1 has the same minimum bill provision as the TOU rates (except for E-ELEC) and an energy rate that increases at usage levels above 100% of the customer's Baseline Quantity (which is defined in the same manner as in E-TOU-C). This rate serves as one of the counterfactual rates when estimating incremental TOU load impacts. For example, we estimate load impacts as customers change from E-1 to E-TOU-C.

Table 2.2: Rate Schedule E-1 Summary[9]

Charge Type	Rate
Minimum Bill ($/Day)	$0.40317
Tier 1 Usage (0% to 100% of Baseline)	$0.37839
Tier 2 Usage (101% to 400% of Baseline)	$0.47405
Tier 3 Usage (Over 400% of Baseline)	$0.47405

3. STUDY METHODOLOGY

The study examines customers who change rates to one of E-TOU-C, E-TOU-D, EV2-A, or E-ELEC during the program year, defined as October 2024 through September 2025. Load impacts may differ depending on the rate the customer is coming from. For example, an E-1 customer that changes to a TOU rate may shift more load across pricing periods than a customer that changes from one TOU rate to another. Table 3.1 lists the ten rate transitions included in the study, along with indications of the method used to estimate load impacts. We report NEM and non-NEM results separately for each rate transition.

Table 3.1: Rate Transitions Included in the Study

Rate Transition	Load Impact Estimation Methodology	
	Include Control Group?	Basis of Load Impact Estimate[10]
E-1 to E-TOU-C	Yes	Difference-in-differences $(T_1 - C_1) - (T_0 - C_0)$
E-1 to E-TOU-D		
E-TOU-C to E-TOU-D		
E-1 to EV2-A		
E-1 to E-ELEC		
EV2-A to E-ELEC		
E-TOU-C to EV2-A	No[11]	Within-treatment, pre-treatment vs. treatment periods $(T_1 - T_0)$
E-TOU-D to EV2-A		
E-TOU-C to E-ELEC		
E-TOU-D to E-ELEC		

[9] Based on rates effective January 1, 2025.

[10] T_1 = the treatment customer usage in the treatment period; C_1 = the control-group customer usage in the treatment period; T_0 = the treatment customer usage in the pre-treatment period; and C_0 = the control-group customer usage in the pre-treatment period.

[11] We assessed the feasibility of a control group for these rate transitions but found that year-to-year changes among potential control customers did not provide a valid counterfactual for the treatment group.

The evaluation methodology differed by rate transition. For customers transition to E-TOU-C and E-TOU-D, as well as for customers transition from E-1 to EV2-A, E-1 to E-ELEC and EV2-A to E-ELEC we select quasi-experimental matched control groups and conduct difference-in-differences estimation using regression analysis. For customers transitioning from E-TOU-C to EV2-A, E-TOU-D to EV2-A, E-TOU-C to E-ELEC and E-TOU-D to E-ELEC, we conduct an analysis using only treatment customers. For all EV2-A and E-ELEC rate transitions, the analysis is supplemented by applying a structural break methodology in an attempt to confirm ownership and use of the relevant electric end-use (e.g., an electric vehicle) throughout the analysis period. This structural break approach is applied to all EV2-A and E-ELEC treatment customers and (when used) control customers. Additional details are included below.

3.1 Ex-Post Load Impact Evaluation

3.1.1 Project Objectives

For non-event-based programs such as TOU rates, the load impact Protocols call for estimating hourly load impacts for each required day type, including the average weekday in each month and monthly system worst days. The ex-post study estimates *incremental* TOU load impacts, which are the TOU load impacts attributable to newly enrolled customers. *Embedded* TOU load impacts (those attributable to existing TOU customers) are not included in the study. For the embedded customers, the current-year load profiles reflect TOU demand response. However, that response was also present prior to the current program year, making it difficult to estimate the impacts of joining a TOU rate.

The primary ex-post analyses are conducted for the ten rate transition groups listed above in Table 3.1 and summarized at the level of the "destination" TOU rate. While the TOU analysis previously focused on customers migrating from the E-1 tiered rate, other transitions have increased in importance now that E-1 is no longer the default residential rate.

3.1.2 Evaluation Methods

Estimating the load impacts of the TOU rates, as in all evaluations, requires a method for estimating what a customers' usage would have been in the absence of the program; that is, what their usage pattern would have been had they not experienced the static time-varying TOU rates. Since the rates do not vary across days within a season, the logical sources of reference loads include: 1) contemporaneous control group customers, resulting in a treatment/control evaluation approach, or 2) pre-treatment usage data of the TOU participants, resulting in a before/after evaluation approach. Where possible, we combine both approaches to implement a difference-in-differences approach. For rate transitions where establishing a valid control groups was not feasible, we applied a before/after treatment only evaluation approach. The incremental TOU load impacts are estimated using customers who enrolled in the TOU rate on or after October 1, 2024.

For rate transitions with controls customers, the analysis is based on developing a control group that involves matching the newly enrolled TOU customers to customers who remain on the counterfactual throughout the analysis period. A two-step matching process is used, however the first step of selecting control groups differs between E-TOU-C/E-TOU-D and EV2-A/E-ELEC rate transitions. For rate transitions without control customers both steps are omitted.

Control Group Selection for E-TOU-C and E-TOU-D Rate Transitions

In the first step, we request monthly billing data for the pre-treatment year (i.e., October 2023 through September 2024) for the TOU and potential control-group customers. During this period, both groups of customers are served on the counterfactual rate, thus excluding treatment effects from the matching process. We then apply Euclidean distance matching using pre-treatment monthly billing data summary variables (average daily usage in summer and winter) to reduce the large number of available control customers to a reduced set of preliminary matches for each TOU customer.[12]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles[13] for all TOU customers and the preliminary matched control customers. We apply Euclidean distance minimization to load profiles for the pre-enrollment period (including a variable representing the average temperature for the dates included in the profile) and select control group matches (with replacement) for each TOU customer. In addition to matching on seasonal profiles, the matching process is conducted by local capacity area (LCA) and CARE status, ensuring perfect matches by those characteristics. Separate matches are selected by season. Finally, we request hourly load data for the full analysis period for the TOU customers and selected control group customers. These data are used in the ex-post load impact analysis and in the development of reference loads for the ex-ante analysis.

Once the matched control group customers are selected, we use regression analysis to compare treatment and control group loads in the post-enrollment period while controlling for differences in the pre-enrollment period (i.e., difference-in-differences).

Structural Break Identification and Control Group Selection for EV2-A and E-ELEC Rate Transitions

Schedule EV2-A is a whole-house EV rate, which means the entirety of the customer's usage (including the EV charging) is billed using the TOU rate.[14] Schedule E-ELEC is a whole-house rate available to residential customers who have one or more of the following electric end uses: EV charging, energy storage, or electric heat pump for water heating or climate control.

The key challenge in estimating the incremental TOU load impacts for these rates is distinguishing between TOU rate effects and technology adoption effects. That is, we are interested in understanding how EV charging behavior is affected by the TOU rate but do not want to include the effect of purchasing (and beginning to charge) the EV on the customer's

[12] We then select the three nearest neighbors (six for NEM customers) for each treatment customer for inclusion in the Stage 2 match. Exact matching was conducted within LCA, CARE status, and climate region.

[13] CA Energy Consulting selects the days to be included in the seasonal profiles from "core" months (June through August for summer; December through February for winter). Within each season, two profiles are developed based on daily average temperatures, weighted across the weather stations associated with the segment. The top 10% of days are defined as the extreme (i.e., hot in summer) profile, while the middle 50% of days are defined as the typical profile.

[14] In contrast, EV-B requires a separate meter and applies only to customer's EV charging. The EV-B rate presents further challenges that prevent the direct estimating of their ex-post load impacts. That is, because the rate only applies to metered EV usage, we are unable to obtain a counter-factual load that represents EV charging behavior in the absence of TOU pricing. If the customer joined from rate E-1, their usage on that rate will represent the whole house and thus not be comparable to the EV-only usage on EV-B. We therefore exclude this rate from our study.

usage profile. Because the technology acquisition and rate adoption are likely to occur at the same time (e.g., if a customer switches to EV2-A shortly after buying an EV or switches to E-ELEC after installing a heat pump), we will not be able to distinguish between TOU response and technology adoption effects for many transitioning customers. Studying the TOU response requires observing usage behavior with the EV (or other qualifying end use) while being served on the counterfactual rate.

To identify treatment customers who had an EV or qualifying end use prior to enrolling in EV2-A or E-ELEC as well as control customers on a counterfactual rate that have an EV or other qualifying end use, we estimate customer-specific structural breaks in usage. We start by identifying all customers that potentially own an EV or qualifying end-use (such as heat pump or battery storage). This includes all treatment customers that made a transition to EV2-A or E-ELEC during the analysis period as these rates are restricted to customers with qualifying end-uses. To identify potential control customers that own a qualifying end-use but that have not transitioned to EV2-A or E-ELEC rates we used data provided by PG&E. We then apply a structural break model that identifies the most likely date (if any) on which there is a change to a customer's total usage that isn't accounted for in the regression specification. A statistical test identifies customers who do not have a statistically significant structural break in their usage level. Customers that do not exhibit a statistically significant change in total usage during the analysis period (which included the current program year and the twelve months prior to it) are assumed to have been charging an EV (or have other E-ELEC eligible end use) during the entire analysis period. This step is applied to all EV2-A and E-ELEC treatment customers, including groups without a control group.

For E-1 to EV2-A, E-1 to E-ELEC, and EV2-A to E-ELEC rate transitions treatment and control customers that passed the structural break test are then matched, using a similar methodology described above for the E-TOU-C and E-TOU-D rate transitions. The only deviation from this methodology is that the matching for EV2-A and E-ELEC customers is conducted by climate region instead of LCA because of the smaller potential control customer sample sizes available for EV2-A and E-ELEC analyses.

Load Impact Estimation

For customers transitioning to E-TOU-C and E-TOU-D, as well as E-1 to EV2-A, E-1 to E-ELEC and EV2-A to E-ELEC rate transitions, a control group is employed to estimate load impacts as the difference between treatment and control group usage during the program year, adjusted for the difference between the two group's usage during the pre-treatment year. For rate transitions without a control customer group, the load impacts are estimated using a before/after approach with naturally staggered treatment adoption timing while controlling for weather conditions across years. The analyses are implemented using hour-specific models for each rate transition group.[15]

[15] Load impacts are estimated using annual models with season-specific matches, so differences across months primarily reflect variation in weather conditions.

The model allows the load impact to vary by LCA, climate region, and temperature conditions. The weather variables are cooling degree days (CDDs) and heating degree days (HDDs).[16] The weather effect is allowed to differ by climate region to account for factors such as varying air conditioner penetration rates. The model takes the following form:

$$
\begin{aligned}
kWh_{C,D} = \alpha &+ \sum_{L} \beta_{L,T} \times (TOU_C \times Post_{C,D} \times LCA_{L,C}) \\
&+ \sum_{R} \beta_{CDD,R,T} \times (TOU_C \times Post_{C,D} \times CDD_{C,D} \times Region_{R,C}) \\
&+ \sum_{R} \beta_{HDD,R,T} \times (TOU_C \times Post_{C,D} \times HDD_{C,D} \times Region_{R,C}) \\
&+ \sum_{R} \beta_{CDD,R} \times (Region_{R,C} \times CDD_{C,D}) + \sum_{R} \beta_{HDD,R} \times (Region_{R,C} \times HDD_{C,D}) \\
&+ \beta_{CDD,T} \times \left(TOU_C \times Post_{C,D} \times CDD_{C,D}\right) \\
&+ \beta_{HDD,T} \times \left(TOU_C \times Post_{C,D} \times HDD_{C,D}\right) + \beta_{NEM} \times NEM_C \\
&+ \beta_{NEM,CDD} \times (NEM_C \times CDD_{C,D}) + \beta_{NEM,CDD} \times (NEM_C \times HDD_{C,D}) \\
&+ \beta_{Post} \times Post_{C,D} + \beta_{CDD} \times CDD_{C,D} + \beta_{HDD} \times HDD_{C,D} + C_C + D_D + \varepsilon_{C,D}
\end{aligned}
$$

NEM and non-NEM customers are pooled in the same regression. For rate transitions to E-TOU-D, the model doesn't include weather (HDD and CDD) and region interactions with treatment variables. For E-TOU-C to EV2-A, E-TOU-D to EV2-A, E-TOU-C to E-ELEC, and E-TOU-D to E-ELEC rate transitions, the model specification excludes the TOU_C variables, as it only includes treatment customers. Instead, the time-of-use response is captured by the coefficients for the $Post_{C,D}$ variables. The model is estimated separately for each hour.

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

Table 3.2: Descriptions of Variables in the Ex-Post Estimation Model

Variable/Parameter	Description
$kWh_{C,D}$	Load in a particular hour for customer *C* on day *D*
TOU_C	Variable indicating whether customer *C* is a TOU (1) or Control (0) customer
$LCA_{L,C}$	Variable indicating that customer *C* is in LCA *L*
$Post_D$	Variable indicating that day *D* is in the customer's post-enrollment period
$CDD_{C,D}$	CDDs for customer *C* on day *D*
$HDD_{C,D}$	HDDs for customer *C* on day *D*
NEM_C	NEM status for customer C
$Region_{R,C}$	Variable indicating that customer *C* is in climate region *R*
α and various βs	Estimated coefficients
C_C	Customer fixed effects
D_D	Date fixed effects
$e_{C,D}$	Error term
T	Subscript indicating a TOU customer coefficient

[16] Cooling degree days are calculated on a daily basis as follows: CDD = MAX{0,(Max Temp + Min Temp)/2 – 60}. Heating degree days are calculated on a daily basis as follows: HDD = MAX{0,60 – (Max Temp + Min Temp)/2}.

After a model is estimated, the relevant load impacts and standard errors are produced from the coefficient estimates and the associated variance-covariance matrix. That is, any given reported load impact combines the LCA-specific load impact (when applicable) with the effect of weather on the load impact (including the climate region effects interacted with weather).

The load impacts are estimated using a sample of customers that meet specific criteria to be included in the regression analysis (see Appendix D). We calculate the load impact for the population of incremental customers by transforming the load impacts from the analysis into percentage load impacts and applying them to the loads of a random sample of incremental treatment sampled before applying any data restrictions.[17] Results are then scaled to incremental enrollment numbers.

Other Analysis Objectives

In addition to the overall load impacts by TOU rate, PG&E is interested in the following analyses:

- Load impacts by climate region; and
- Load impacts by CARE status.

The load impacts by CARE status and climate region can be estimated using a straightforward extension of our proposed analysis, by simply including the appropriate interaction terms in the model. Specifically, the CARE load impacts are produced from an interaction of a CARE indicator variable with the load impact estimate. Further differentiating CARE status by climate region is accomplished using the climate region interaction terms described above.

NEM Customer Load Impacts

For NEM analyses of customers transitioning from an E-1 rate, only NEM 1.0 customers can be analyzed since NEM 2.0 customers were required to enroll in a TOU rate upon attaining NEM status.

The NEM customers are analyzed using methods like those described above, with three major distinctions. First, only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included.[18] Second, the solar PV generation capacity size is included in the matching process. Third, customers with changes in load profiles between periods that are not matched by their matched control-group customer (i.e., the difference-in-difference load change for the pair is large) are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system or electricity

[17] A separate sample of incremental customers is drawn from the full population of incremental customers prior to applying any data quality or eligibility screens. This sample is used to adjust reference load profiles in cases where the exclusion criteria applied to the analysis sample may introduce bias relative to the full incremental population.

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

demand.[19] Each of these requirements helps prevent estimating TOU load impacts 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.

Once the matches are developed, the NEM customer load impacts are estimated using the same methods described above.

3.2 Forecasting Ex-Ante Load Impacts

3.2.1 Objectives

The objectives of the ex-ante portion of the evaluation involve developing eleven-year forecasts of estimated program load impacts based on the ex-post findings of per-customer load impacts (to the extent possible) and PG&E's enrollment projections. The load impacts are to be provided for several customer sub-groups, day types, and weather scenarios, including the following:

- An average weekday in each month under each of the two weather scenarios (CAISO 1-in-2 and PG&E 1-in-2 weather years);
- The monthly system worst day in each month under the two weather scenarios.

Only incremental TOU impacts are forecast. While the ex-ante study is conducted at the level of the ten rate changes in the ex-post study (listed in Section 2), the forecasts are summarized at the rate level (e.g., all customers joining E-TOU-C) to reduce the volume of reported results. The methods used to develop the forecasts are described below.

3.2.2 Ex-Ante Evaluation Approach

We first develop regression equations for the purposes of simulating reference loads using the temperature conditions contained in the scenarios required by the Protocols. The models use hourly treatment customer load data from the treatment period. The reference load model explains hourly usage as a function of weather conditions, day type, climate region, time of day, and month. The following model is run for each season and LCA:

$$
\begin{aligned}
kWh_{C,D} = \alpha &+ \sum_{R} \beta_{CDD,R} \times (Post_{C,D} \times CDD_{C,D} \times Region_{R,C}) \\
&+ \sum_{R} \beta_{HDD,R} \times (Post_{C,D} \times HDD_{C,D} \times Region_{R,C}) \\
&+ \sum_{R} \beta_{CDD,R} \times (Region_{R,C} \times CDD_{C,D}) + \sum_{R} \beta_{HDD,R} \times (Region_{R,C} \times HDD_{C,D}) \\
&+ \sum_{M} (\beta_{M} \times MONTH_{M,D}) + \beta_{CDD,T} \times \left(Post_{C,D} \times CDD_{C,D}\right) \\
&+ \beta_{HDD,T} \times \left(Post_{C,D} \times HDD_{C,D}\right) + \beta_{Post} + \beta_{CDD} \times CDD_{C,D} + \beta_{HDD} \times HDD_{C,D} \\
&+ C_{C} + \varepsilon_{C,D}
\end{aligned}
$$

[19] This screen was applied for E-1 to E-TOU-D NEM customers and for all E-1 to E-TOU-C, E-TOU-C to EV2-A and E-TOU-C to E-ELEC customers.

The variables are explained in Table 3.3 below.

Table 3.3: Descriptions of Variables in the Ex-Ante Reference Load Model

Variable/Parameter	Description
$kWh_{C,D}$	Load in a particular hour for customer *C* on day *D*
$LCA_{L,C}$	Variable indicating that customer *C* is in LCA *L*
$Post_D$	Variable indicating that day *D* is in the customer's post-enrollment period
$CDD_{C,D}$	CDDs for customer *C* on day *D*
$HDD_{C,D}$	HDDs for customer *C* on day *D*
$Region_{R,C}$	Variable indicating that customer *C* is in climate region *R*
$MONTH_{M,D}$	Dummy variable indicating that day D is in month M
α and various βs	Estimated coefficients
C_C	Customer fixed effects
$e_{C,D}$	Error term

Per-customer *reference loads* are produced from the estimated equations by simulating (i.e., predicting) observed loads using the appropriate day type and weather conditions for each required month and then adjusting the simulated observed loads using percentage load impacts from the ex-post analysis. They are then scaled up to total reference loads using the forecast enrollments provided by PG&E.

Ex-ante load impacts are calculated by applying percentage load impacts from the ex-post analysis to the estimated reference loads. For NEM customers, the load impacts are based on ex-post level load impacts to avoid issues with percentage load impacts for these customers (e.g., large percentage load impacts when reference loads are near zero).

Uncertainty-adjusted load impacts are based on the standard errors associated with the load impact predictions from ex-post. Scenario-specific load impacts are developed for the 5th, 50th, and 95th percentile scenarios.

As in all recent load impact evaluations, we present results of analyses of the relationship between current ex-post and ex-ante load impacts, focusing on key factors causing differences between them (e.g., differences between observed temperatures in 2025 and the temperatures in the various weather scenarios). We will also compare current and previous ex-post load impacts and current and previous ex-ante load impacts.

4. EX-POST LOAD IMPACT STUDY FINDINGS

This section reports ex-post load impact findings for each of the four TOU rates listed in Section 2. Relevant subsections report reference loads and load impacts for the average weekday by season, climate region, and CARE status. Typical hourly load profiles are also shown.

Many of the tables include the number of enrolled customers. Note that this is often higher than the number of customers included in the regression model, which is constrained to customers within a range of TOU start dates and the rate from which they migrated. In some cases, a low number of customers contributes to a wide confidence interval around the percentage load impact. Appendix Table D.1 shows the number of treatment customers represented in each of the analyses.

4.1 Peak-Period Load Impact Summaries

In the sub-sections below, we summarize average peak-period load impacts by rate and the following: by season, climate region, and CARE status. In each case, the Peak period is defined according to the schedule's TOU period definitions, as shown in Table 2.1. The load impacts reflect customers who adopted the TOU rate sometime between October 2024 and September 2025.

4.1.1 Peak-Period Impacts by Season

Table 4.1 and Table 4.2 show the estimated peak-period load impacts for the average weekday in February and August 2025, respectively. The brackets in the "% Impact" column show the 90% confidence interval around the estimated load impacts.

We have the following observations about the results:

- **E-TOU-D customers have the highest average per-customer reference loads out of all groups.** This aligns with the rate designs for each rate schedule, with E-TOU-D expected to benefit customers with higher usage levels due to the absence of a tiered rate structure (via the Baseline Credit). **E-TOU-D customers show the smallest percentage load impacts during an August average weekday, however they still show the second highest per-customer load impact after EV2-A customers.**
- **Customers transitioning to E-ELEC tend to have higher percentage load impacts than customers transitioning to other TOU rates.** This is likely because of the end use technologies that can be shifted out of the peak period (primarily EVs).
- August average temperature differences are indicative of participating customer locations, particularly the share of customers in the Greater Bay Area LCA. **For example, 71% of EV2-A customers are in the Greater Bay Area while E-TOU-D, the rate with the next largest portion, has 41% of customers in the same area.** The result is lower temperatures, on average, for EV2-A customers compared to other rate transitions.
- **August load impacts are higher than February impacts for each rate transition.** This is primarily driven by higher reference loads in the summer.
- The number of incremental customers increased throughout the study period for each rate, as demonstrated by the enrollment counts between February and August. **TOU Rate E-TOU-C has the most incremental customers and experienced the largest increase in customers between February and August; however, EV2-A experienced the largest relative increase with 2.5x growth between February and August**.

Table 4.1: Peak-Period Load Impacts by Rate, February 2025 Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact[20]	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	35,935	24.3	1.4	0.677	0.040	5.94% [3.65% - 8.22%]	56.6
E-TOU-D	12,986	15.6	1.1	1.203	0.087	7.25% [6.05% - 8.45%]	56.0
EV2-A	9,446	9.6	0.6	1.018	0.066	6.50% [4.44% - 8.57%]	55.7
E-ELEC	35,379	33.6	3.0	0.950	0.086	9.01% [5.92% - 12.11%]	56.0

Table 4.2: Peak-Period Load Impacts by Rate, August 2025 Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	71,895	93.4	8.8	1.298	0.123	9.48% [7.72% - 11.24%]	84.6
E-TOU-D	25,224	54.3	3.5	2.154	0.138	6.41% [5.27% - 7.54%]	82.6
EV2-A	23,672	38.3	3.5	1.619	0.148	9.13% [7.61% - 10.64%]	79.2
E-ELEC	65,671	76.1	7.4	1.159	0.112	9.67% [6.86% - 12.49%]	83.1

4.1.2 Peak-Period Impacts by Climate Region

Table 4.3 and Table 4.4 show the average peak-period load impact for the August 2025 average weekday, reported by climate region.[21] Table 4.3 contains the results for E-TOU-C and E-TOU-D while Table 4.4 contains results for rates EV2-A and E-ELEC. Blue shading is used to help separate the rate-specific results.

[20] The brackets accompanying the percentage load impacts represent the 5th and 95th percentile uncertainty adjusted load impacts.

[21] Climate regions are defined by the customer's Baseline Territory. The "hot" region includes the P, R, S, and W territories; the "moderate" region includes the Q, X, and Y territories; and the "cool" region includes the T, V, and Z territories.

Many of the results in the table make intuitive sense: reference loads and temperatures are progressively higher as one moves from cool to moderate to hot climate regions. **The level load impact (in kWh/hour/customer) is higher in hotter climate regions, though the percentage load impacts are often higher in the cooler climate regions.** A larger portion of CARE customers reside in hotter climate regions than non-CARE customers. For instance, 68% of E-TOU-C CARE customers reside in the hot climate zone while 52% of non-CARE customers reside in the hot climate zone.

Table 4.3: Peak-Period Load Impacts by Rate (E-TOU-C, E-TOU-D) and Climate Region, August 2025 Average Weekday

Rate	CARE	Climate	Enrolled	Reference (kWh/hr/ cust)	Impact (kWh/hr /cust)	% Impact	Temp. (°F)
E-TOU-C	No	Cool	10,811	0.422	0.067	15.9% [10.5% - 21.4%]	64.6
		Moderate	16,226	0.741	0.104	14.0% [10.4% - 17.7%]	74.3
		Hot	29,176	1.485	0.148	10.0% [7.3% - 12.7%]	90.9
	Yes	Cool	1,981	0.531	0.027	5.0% [-1.7% - 11.8%]	63.9
		Moderate	3,048	0.838	0.058	6.9% [1.9% - 11.9%]	74.7
		Hot	10,656	2.017	0.098	4.8% [1.9% - 7.8%]	90.9
E-TOU-D	No	Cool	3,377	0.829	0.103	12.4% [9.6% - 15.3%]	64.0
		Moderate	6,830	1.615	0.120	7.4% [6.1% - 8.7%]	74.5
		Hot	9,106	2.532	0.113	4.5% [3.6% - 5.3%]	91.1
	Yes	Cool	742	1.002	0.049	4.9% [-0.2% - 10.0%]	63.8
		Moderate	1,199	1.386	0.040	2.9% [-0.5% - 6.3%]	74.5
		Hot	3,970	2.932	0.043	1.5% [0.0% - 2.9%]	91.6

Table 4.4: Peak-Period Load Impacts by Rate (EV2-A, E-ELEC) and Climate Region, August 2025 Average Weekday

Rate	CARE	Climate	Enrolled	Reference (kWh/hr/ cust)	Impact (kWh/hr/ cust)	% Impact	Temp. (°F)
EV2-A	No	Cool	4,944	0.729	0.079	10.9% [8.9% - 12.9%]	64.5
		Moderate	12,836	1.222	0.134	11.0% [9.5% - 12.5%]	73.9
		Hot	3,544	2.255	0.217	9.6% [8.3% - 11.0%]	89.9
	Yes	Cool	477	0.785	0.030	3.9% [-3.3% - 11.0%]	63.7
		Moderate	1,028	1.204	0.093	7.7% [3.2% - 12.2%]	73.9
		Hot	846	3.107	0.193	6.2% [4.2% - 8.2%]	90.1
E-ELEC	No	Cool	7,101	0.556	0.121	21.8% [18.1% - 25.6%]	64.2
		Moderate	21,446	0.931	0.165	17.7% [14.7% - 20.7%]	74.7
		Hot	24,570	1.451	0.258	17.8% [13.6% - 22.0%]	90.0
	Yes	Cool	896	0.506	0.063	12.4% [0.5% - 24.2%]	63.8
		Moderate	1,780	0.899	0.140	15.5% [8.8% - 22.3%]	73.8
		Hot	9,883	1.710	0.202	11.8% [5.0% - 18.6%]	91.2

4.1.3 Peak-Period Impacts by CARE Status

Table 4.5 shows the average peak-period per-customer load impact for the August 2025 average weekday, reported by CARE status.[22] Blue shading is used to help separate the rate-specific results. CARE customers tend to experience higher temperatures and have higher reference loads than non-CARE customers. **CARE customers have a lower percentage load impact than non-CARE customers for each rate.** CARE customers have higher level load impacts than non-CARE customers on rates E-TOU-C and E-ELEC.

[22] CARE customers include customers who are always or sometimes reported to be CARE during our analysis period.

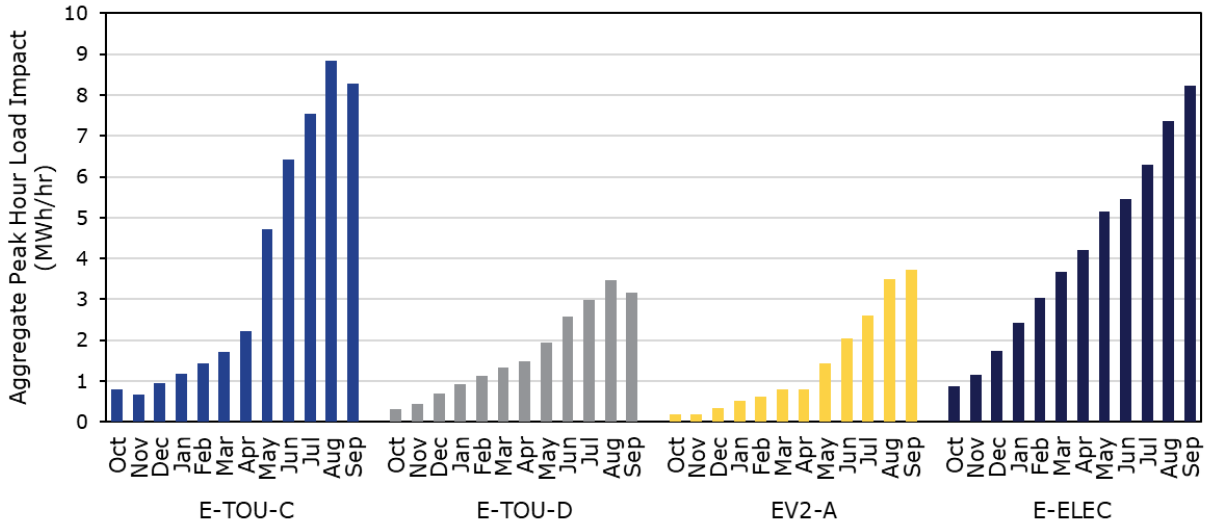
Table 4.5: Peak-Period Load Impacts by Rate and CARE Status, August 2025 Average Weekday

Rate	CARE	Enrolled	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-C	No	56,210	1.194	0.133	11.2% [8.9% - 13.5%]	84.3
	Yes	15,685	1.673	0.086	5.1% [2.9% - 7.3%]	85.5
E-TOU-D	No	19,313	2.080	0.161	7.8% [6.5% - 9.0%]	82.2
	Yes	5,911	2.396	0.062	2.6% [0.1% - 5.0%]	84.1
EV2-A	No	21,323	1.563	0.152	9.7% [8.1% - 11.3%]	78.9
	Yes	2,349	2.127	0.109	5.1% [1.0% - 9.2%]	81.5
E-ELEC	No	53,115	1.118	0.129	11.5% [8.7% - 14.3%]	82.4
	Yes	12,556	1.332	0.041	3.1% [-5.0% - 11.2%]	85.9

4.1.4 Peak-Period Ex-Post Load Impacts by Month

Figure 4.1 shows monthly aggregate hourly peak-period load impacts for each "to" rate. The aggregate load impacts increase over the analysis period, primarily due to rising enrollments and higher summer temperatures. For E-TOU-C and E-TOU-D, load impacts peak in August, whereas E-ELEC and EV2-A aggregate load impacts are the highest in September.

Figure 4.1: Aggregate Hourly Peak-Period Load Impacts, by Rate and Month

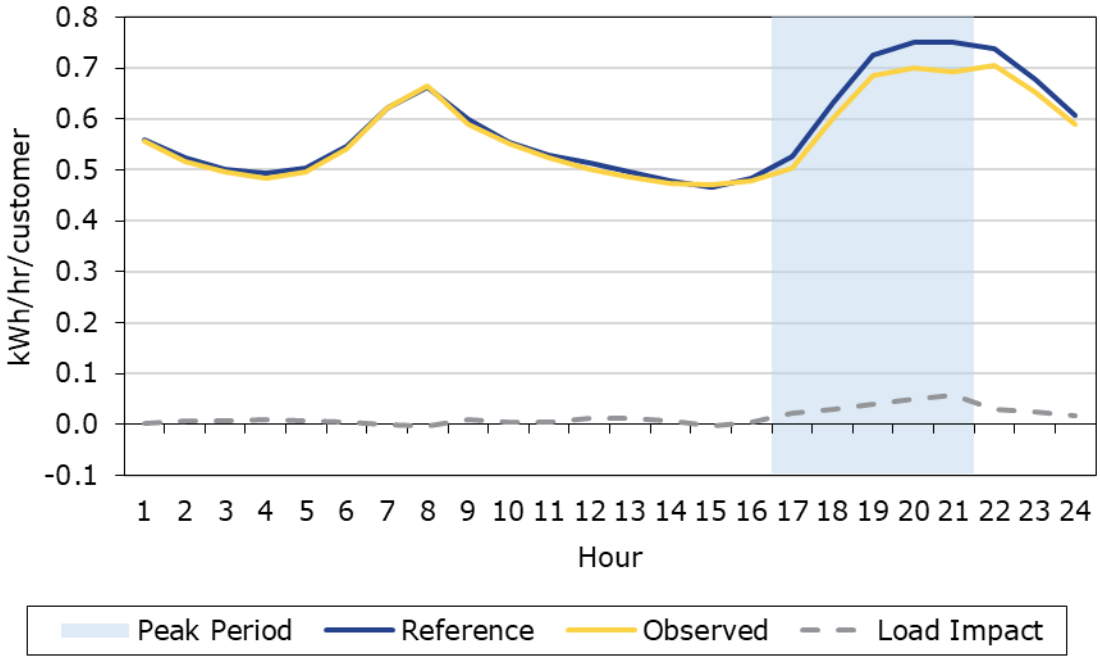


4.2 Average Hourly Load Impacts

This subsection illustrates the hourly load and load impact profiles for the average weekdays in February and August 2025.[23] In each case, we graph per-customer reference loads, observed loads, and load impacts with shading provided to indicate the rate's peak period. The blue line represents the reference load, which is our estimate of the load that would have occurred had the customers remained on the counterfactual rate instead of changing to the TOU rate in question. The orange line is the observed load, while the dashed green line is the hourly load impact (the difference between the reference and observed loads).

Figure 4.2 and Figure 4.3 show the estimates for E-TOU-C customers in February and August 2025, respectively. The February results show a 5.9% reduction in peak-period usage. The August estimates show a 9.5% reduction in peak-period usage. **The percentage load impact in August is higher than that observed last year (7.9%) likely driven by a higher average peak period temperature of 84.6° F compared to last year's temperature of 77.1° F.**

Figure 4.2: E-TOU-C February 2025 Average Weekday Hourly Impacts



[23] For rate transitions to E-ELEC, we also show a July average weekday since the E-ELEC battery customers show atypical usage in August 2025.

Figure 4.3: E-TOU-C August 2025 Average Weekday Hourly Impacts

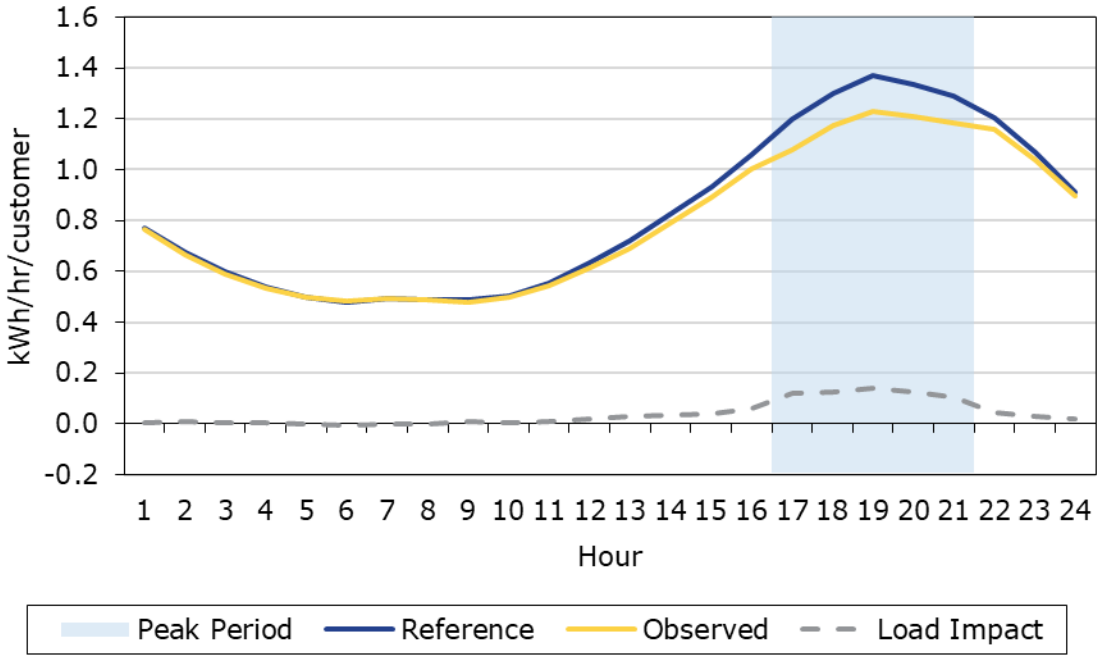


Figure 4.4 and Figure 4.5 show the estimates for E-TOU-D customers in February and August, respectively. The February results show a 7.3% reduction in peak-period usage. The August load impacts show a 6.4% reduction during the peak period. **Despite the lower percentage load impacts in August, the level load impacts are higher in August (0.138 kWh/hour) than February (0.87 kWh/hour) due to higher reference loads in August.**

Figure 4.4: E-TOU-D February 2025 Average Weekday Hourly Impacts

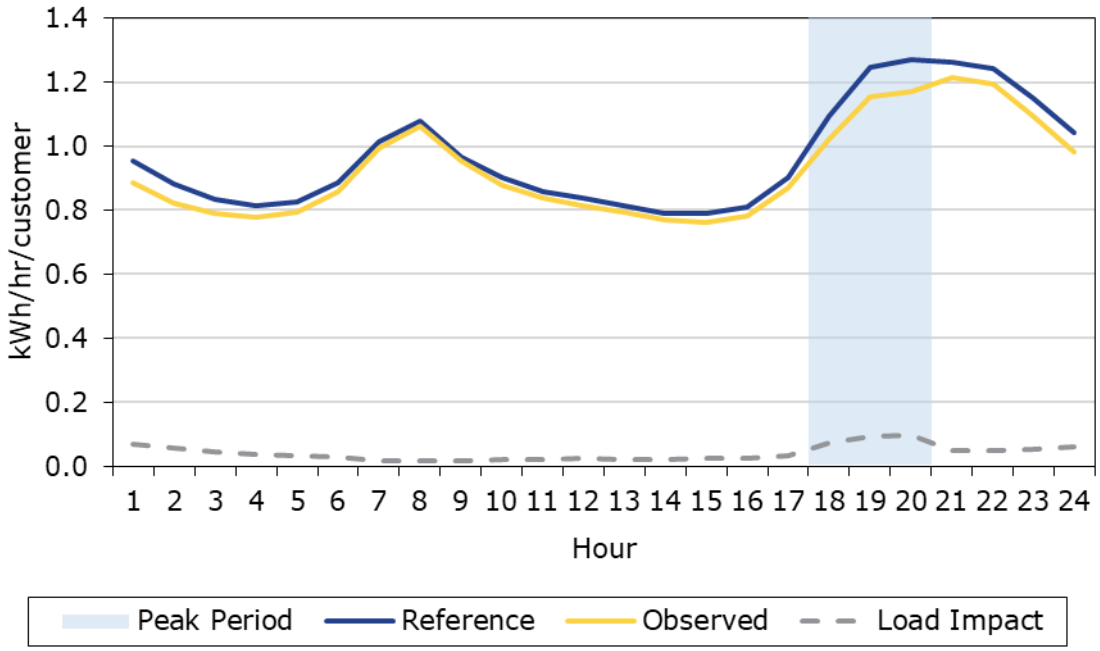


Figure 4.5: E-TOU-D August 2025 Average Weekday Hourly Impacts

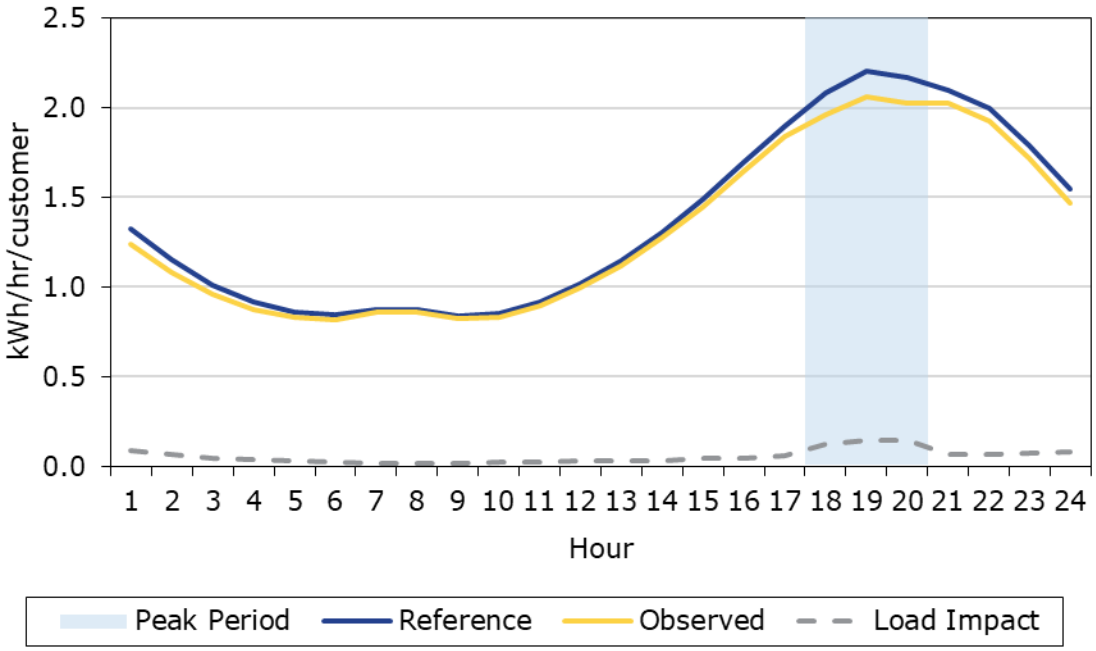


Figure 4.6 and Figure 4.7 show the estimates for EV2-A customers in February and August, respectively. The load impacts reflect somewhat large changes throughout the day, with usage generally being shifted from peak-period and the final hours of the day to overnight and early morning hours. The February results show a 6.5% reduction in peak-period usage. The August estimates show a 9.1% reduction in peak-period usage.

Figure 4.6: EV2-A February 2025 Average Weekday Hourly Impacts

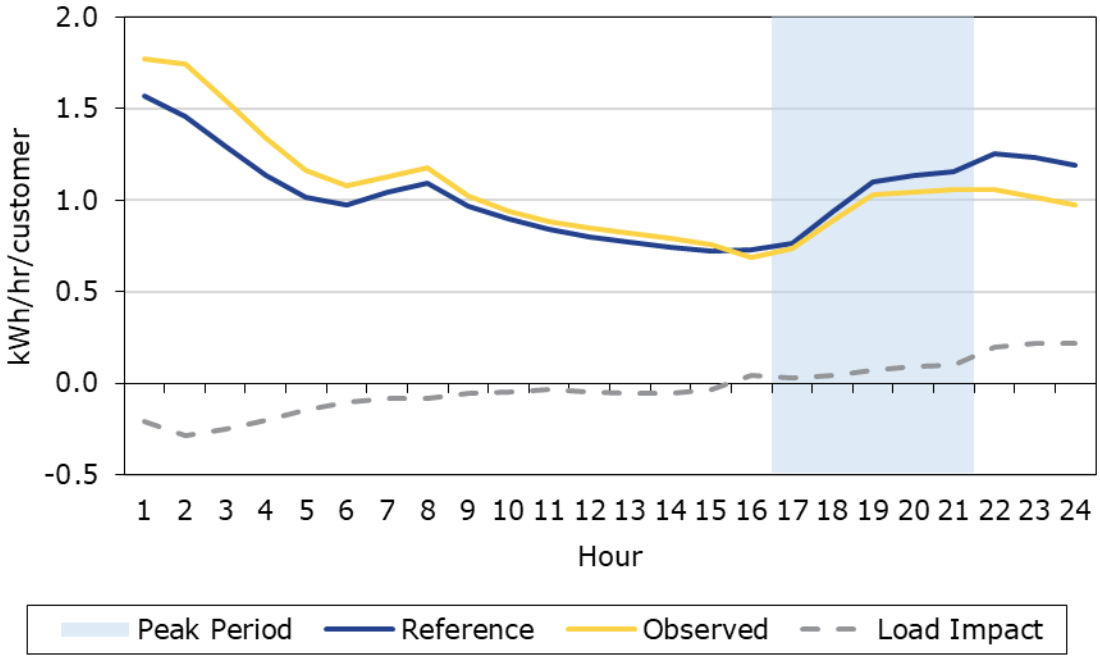


Figure 4.7: EV2-A August 2025 Average Weekday Hourly Impacts

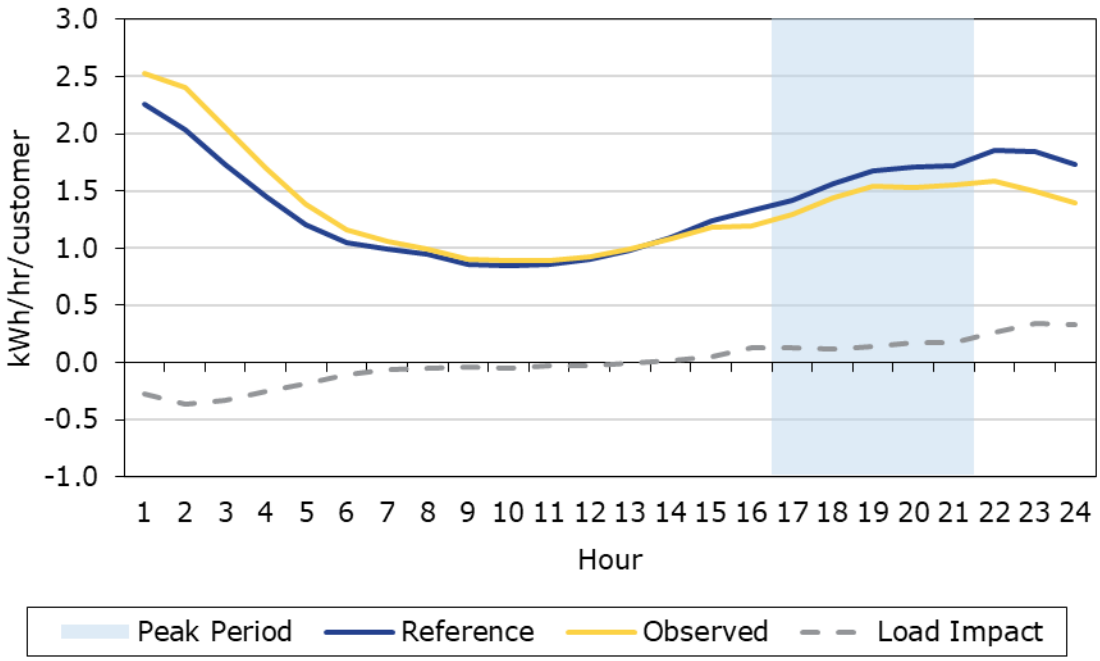


Figure 4.8, Figure 4.9, and Figure 4.9 show the estimates for E-ELEC customers in February, July and August, respectively. The load impact pattern is like that of EV2-A customers. The February results show a 9.0% reduction in peak-period usage. The July estimates show a 11.5% reduction in peak-period usage which corresponds to an average per-customer reduction of 0.102 kWh/hr. The August results show a peak hour load reduction of 9.7%. **In August 2025, some PG&E customers with batteries showed a significant reduction during HE20. This effect is pronounced for customers transitioning to E-ELEC due to a higher share of customers with battery storage. This spike in usage was likely driven by a battery vendor sending signals to battery customers to discharge during HE20 in August.** There's some evidence that during September 2025 customers also were discharging batteries during HE17 to HE19.

Figure 4.8: E-ELEC February2025 Average Weekday Hourly Impacts

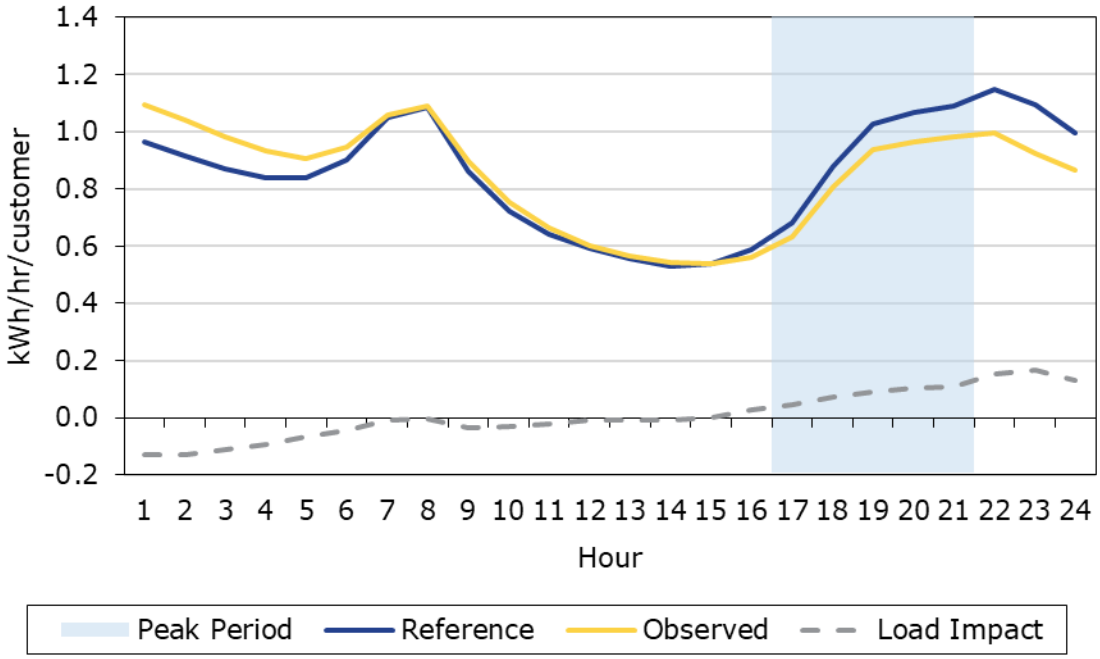


Figure 4.9: E-ELEC July 2025 Average Weekday Hourly Impacts

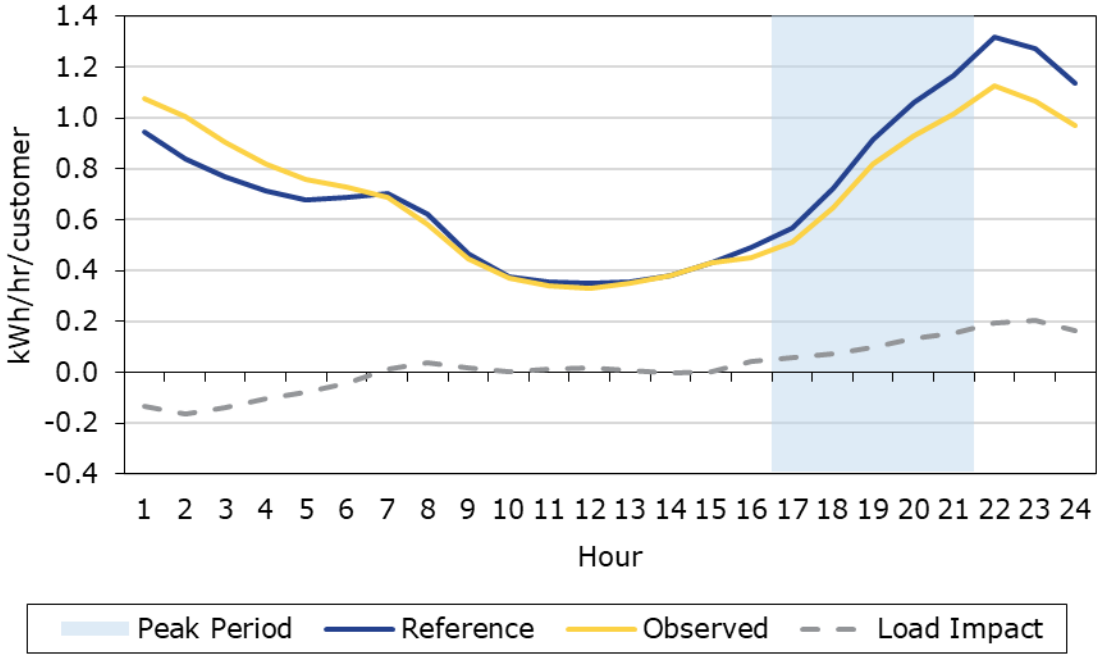
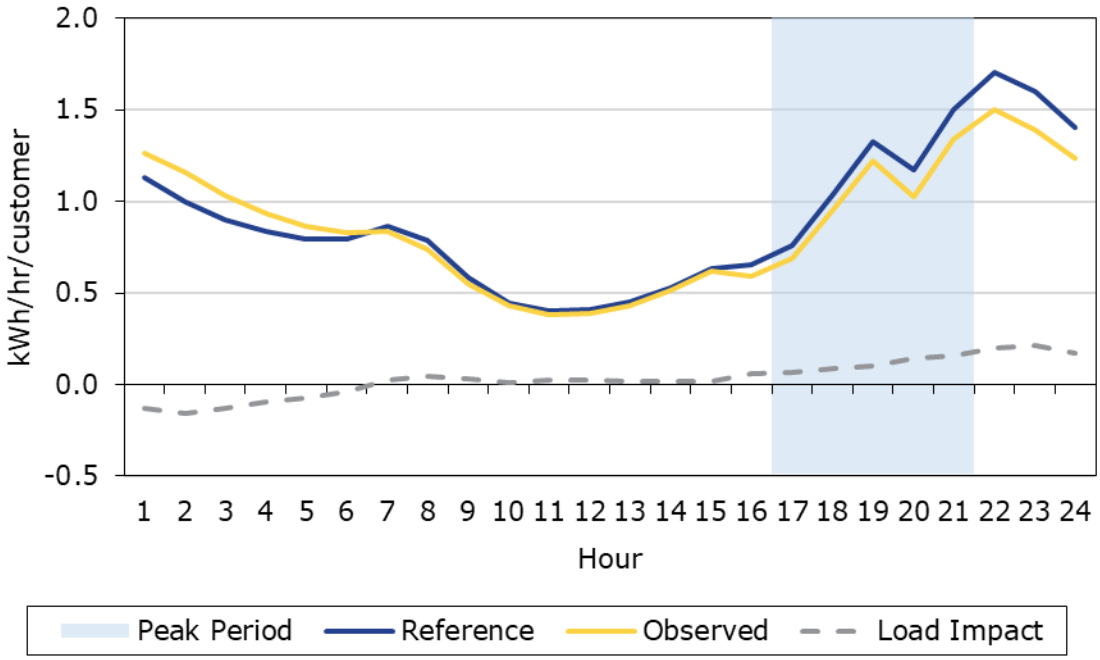


Figure 4.10: E-ELEC August 2025 Average Weekday Hourly Impacts



5. EX-ANTE LOAD IMPACTS

5.1 Overview and Enrollment Forecasts

Ex-ante load impacts are developed for customers in the following ten rate transition groups[24]:

1. E-1 to E-TOU-C;
2. E-1 to E-TOU-D;
3. E-TOU-C to E-TOU-D;
4. E-1 to EV2-A;
5. E-TOU-C to EV2-A;
6. E-TOU-D to EV2-A;
7. E-1 to E-ELEC;
8. E-TOU-C to E-ELEC;
9. E-TOU-D to E-ELEC; and
10. EV2-A to E-ELEC.

We then combine the transition-level forecasts (e.g., E-1 to E-TOU-D and E-TOU-C to E-TOU-D) to the rate level (e.g., to E-TOU-D), separately summarizing forecasts for all customers transitioning to E-TOU-C, E-TOU-D, EV2-A, and E-ELEC. In each case, the forecast represents *incremental* TOU load impacts attributable to customers joining TOU rates during the forecast period. Customers already on TOU rates contribute to an *embedded* TOU load impact already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

We develop two sets of results associated with distinct weather scenarios, which are distinguished by 1-in-2 weather conditions and whether the peak conditions are determined using the utility's peak or the utility's load at the time of CAISO's peak. The weather conditions for each scenario were provided by PG&E.

Residential customers frequently transition between rates each month, either voluntarily or through a default process. To forecast enrollments for the TOU load impact analysis, PG&E first develops a forecast for all available residential rates and then selects the forecast for those rates used in the analysis. For each year, growth or attrition for each individual rate is determined by either the calendar year 2025 or an average of calendar year 2024 and 2025 enrollments. Throughout the forecast period, certain adjustments are made between rates to accommodate rate closures (e.g., E-TOU-B), required rate transitions of specific eligible customer groups (e.g., legacy NEM 1.0), or program and policy goals. To ensure that customer transitions do not exceed the total expected residential population, the forecast is bounded by the CPUC-approved Electric Customer Billings Forecast.[25]

E-TOU-C: Given the sunset of E-6 and the closure of E-TOU-B in October 31, 2025, E-TOU-C is expected to be the primary rate for the majority of residential customers moving forward. The forecast utilizes a growth rate based on calendar year 2025, in which more than 75,000 customers either transitioned on to E-TOU-C or began service on E-TOU-C. As PG&E is no longer defaulting E-1 customers on the E-TOU-C rate, any transitions onto the rate were voluntary.

[24] Load impacts are reported separately for NEM and non-NEM customers for each rate transition.

[25] Only incremental, cumulative enrollments are utilized for the ex-ante load impacts.

Eligible NEM 1.0 customers transition away from E-TOU-C onto E-ELEC throughout the forecast horizon. PG&E expects E-TOU-C to reach 2.95 million active enrollments by the end of 2036, a total increase of about 400,000 customers.

E-TOU-D: Since Commission Decision 19-07-004 in July 2019, PG&E has also offered E-TOU-D as an optional rate which has a shorter peak hour window than E-TOU-C. The forecast uses an average growth rate from calendar years 2024 and 2025, during which approximately 30,000 customers transitioned to E-TOU-D each year. As E-TOU-B was discontinued in late 2025, E-TOU-D is expected to be the primary rate for higher-use PG&E customers. Eligible NEM 1.0 customers transition away from E-TOU-D onto E-ELEC throughout the forecast horizon. PG&E expects E-TOU-D to reach approximately 690,000 active enrollments by the end of 2036, a total increase of about 350,000 customers.

EV2-A: The EV rate series are non-tiered TOU rates intended to encourage electric vehicle owners to charge their vehicles during off-peak hours. PG&E transitioned the majority of EV-A customers to EV2-A in November 2019; and transitioned legacy solar customers periodically until November 2024. In PY2025, PG&E significantly reduced their forecasted enrollment of EV2-A customers relative to the PY2024 forecast, largely driven by the expiration of federal EV tax incentives in 2025.[26] The forecast begins by utilizing a growth rate based on an average of calendar year 2024 and 2025, in which about 24,000 customers transitioned on to EV2-A. EV2-A enrollment is forecasted to grow by about 230,500 customers to reach approximately 374,000 active enrollments by 2036. This is almost half of the forecasted enrollment in PY2024. Eligible NEM 1.0 customers transition away from EV2-A onto E-ELEC throughout the forecast horizon.

E-ELEC: The General Rate Case 2020 Phase II proceeding requires the implementation of the Electric Home (E-ELEC) rate plan to support California Senate Bill 1020 future renewable energy and zero-carbon electricity goals. The rate is designed for residential customers with EV Charging, energy storage charging, and electric heat pumps, encouraging load shift to off-peak hours. E-ELEC began enrolling customers in December 2022. The forecast starts by applying a growth rate based on the average enrollment in calendar years 2024 and 2025, when roughly 50,000 customers each year made the move to E-ELEC. In addition, legacy NEM 1.0 customers from E-TOU-B, EV2-A, E-TOU-C, E-1, EV-B, E-TOU-D default to E-ELEC throughout the forecast horizon. PG&E expects E-ELEC to reach approximately 806,000 active enrollments by the end of 2036, a total increase of about 586,000 customers.

Figure 5.1 shows the yearly enrollment forecast of each adopted TOU rate in August.[27] Additional detail by rate transition is shown in Table 5.1, which shows enrollments for each of the twelve rate transitions for 2026 and every third year until the last year of the forecast.

[26] Specifically, the PY2024 enrollment forecast projected incremental 767,000 EV2-A customers in the final year of the forecast, whereas the PY2025 enrollment forecast anticipates 233,500 incremental customers.
[27] August is referenced here because it is likely to be the CAISO/PG&E peak period in a given year.

In accordance with the outlined assumptions, enrollment changes shown in the figure increase over time since 2025. By 2036, customers moving to E-ELEC (from E-1, E-TOU-C, E-TOU-D, or EV2-A) account for the highest share of incremental TOU customers (586,000 customers). This is a significant contrast to the previous year's forecast where EV2-A accounted for the highest share of incremental TOU customer enrollment. Specifically, the PY2024 enrollment forecast projected 767,000 incremental EV2-A customers in the final year of the forecast, whereas the PY2025 enrollment forecast anticipates about 233,500 incremental customers. Rate E-TOU-C has the second largest share of incremental TOU enrollment by 2036 with 404,000 customers.

Figure 5.1: Forecast of Incremental Enrollment (since 2025) – August by Year and Adopted TOU Rate

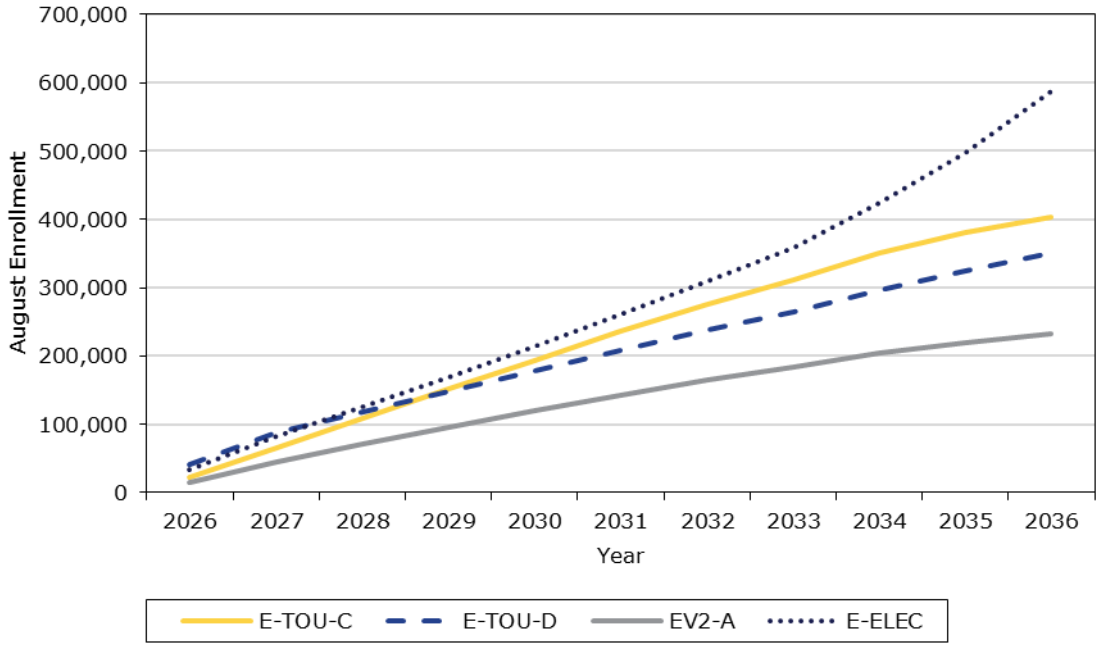


Table 5.1: Forecast of Incremental Enrollments (since 2025) — August by Year, Customer Group, and NEM Status

Rate Transition	NEM	Enrollment			
		2026	2029	2032	2036
E-1 to E-TOU-C	No	18,183	119,536	217,823	318,841
E-1 to E-TOU-C	Yes	4,870	32,015	58,342	85,401
E-1 to E-TOU-D	No	17,014	62,009	99,717	147,063
E-1 to E-TOU-D	Yes	1,727	6,287	10,112	14,914
E-TOU-C to E-TOU-D	No	15,160	55,254	88,856	131,044
E-TOU-C to E-TOU-D	Yes	6,660	24,275	39,039	57,573
E-1 to EV2-A	No	3,323	22,220	38,050	53,790
E-1 to EV2-A	Yes	337	2,253	3,858	5,454
E-TOU-C to EV2-A	No	6,516	43,592	74,650	105,530
E-TOU-C to EV2-A	Yes	2,383	15,936	27,291	38,580
E-TOU-D to EV2-A	No	1,270	8,496	14,553	20,572
E-TOU-D to EV2-A	Yes	593	3,968	6,796	9,609
E-1 to E-ELEC	No	1,079	5,310	9,736	18,407
E-1 to E-ELEC	Yes	9,862	48,499	88,915	168,121
E-TOU-C to E-ELEC	No	1,227	6,035	11,067	20,925
E-TOU-C to E-ELEC	Yes	15,247	74,991	137,483	259,961
E-TOU-D to E-ELEC	No	512	2,518	4,616	8,729
E-TOU-D to E-ELEC	Yes	3,827	18,827	34,515	65,262
EV2-A to E-ELEC	No	211	1,037	1,902	3,597
EV2-A to E-ELEC	Yes	2,441	12,012	22,020	41,636

5.2 Ex-Ante Load Impact Results

The following sub-sections present the ex-ante forecasts for each of the four TOU rates.

Figure 5.2 illustrates the forecasted load impacts of incremental enrollment for each August during 2026-2036, using PG&E 1-in-2 system worst day weather conditions. The values are the average load impacts during the Resource Adequacy (RA) window (4 to 9 p.m. June through September, and 5 to 10 p.m. in all other months) for the PG&E 1-in-2 average weekday weather conditions. The load impacts increase over time due to the enrollment pattern shown in Figure 5.2. The share of E-ELEC load impacts increases over time due to the high share of incremental enrollment relative to other TOU rates. Table 5.2 shows the same data in tabular form. **The total incremental TOU load impact increases from 12.9 MWh/hr in 2026 to 182.0 MWh/hr in 2036.**

The largest difference in aggregate load impacts between this forecast and the one prepared following PY2024 is due to the lower EV2-A and higher E-ELEC customer enrollment in PY2025. E-TOU-C customers also show larger aggregate load impacts due to the higher enrollment forecast and slightly higher percentage load impacts relative to the previous year.

Figure 5.2: Average RA Window Load Impacts of Incremental Enrollment (since 2025) for 2026-2036, PG&E 1-in-2 August System Worst Day

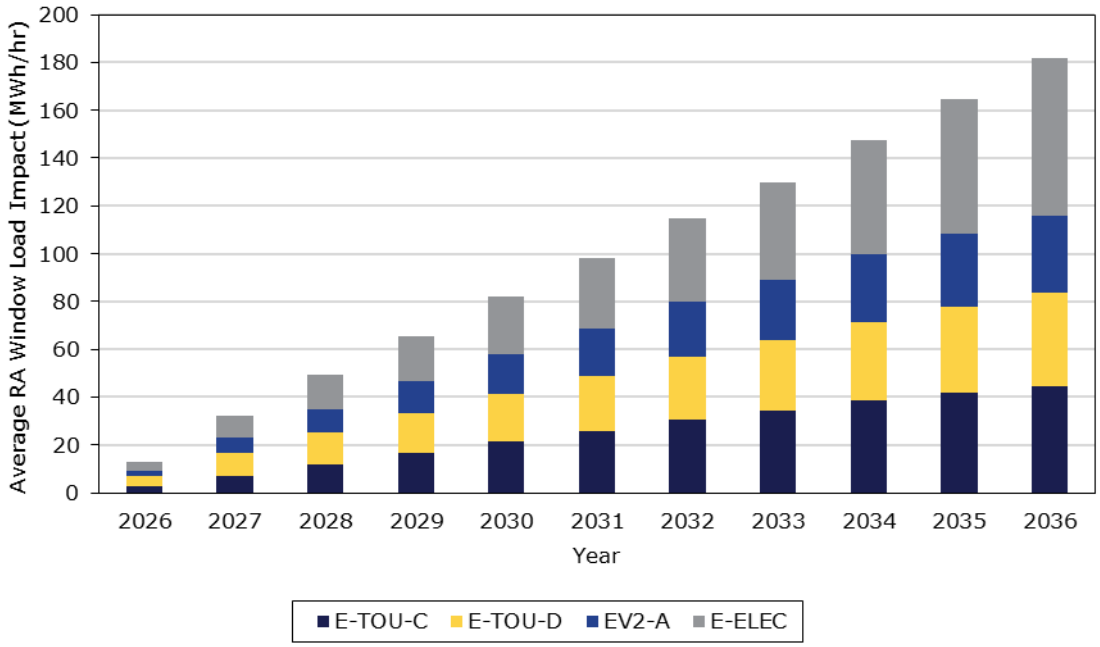


Table 5.2: Average RA Window Load Impacts of Incremental TOU Enrollment (since 2025) for 2026-2036, PG&E 1-in-2 August System Worst Day

Year	Load Impact by Adopted TOU Rate (MWh/hr)				Total
	E-TOU-C	E-TOU-D	EV2-A	E-ELEC	
2026	2.5	4.5	2.0	3.9	12.9
2027	7.2	9.7	6.1	9.4	32.4
2028	12.0	13.0	10.0	14.2	49.2
2029	16.7	16.4	13.4	19.1	65.6
2030	21.4	19.7	16.7	24.2	82.0
2031	26.0	23.0	19.9	29.5	98.4
2032	30.5	26.3	22.9	35.0	114.7
2033	34.4	29.3	25.5	40.5	129.7
2034	38.7	32.8	28.3	47.8	147.6
2035	42.1	35.9	30.5	56.0	164.5
2036	44.6	38.9	32.4	66.2	182.0

5.2.1 Ex-Ante Load Impacts for E-TOU-C Customers

Table 5.3 contains the aggregate E-TOU-C customer load impacts, averaged over the RA window. The tables show monthly system worst day load impacts in 2026 associated with the two weather scenarios. Aggregate load impacts increase with enrollments and tend to be higher in during the summer months.

Table 5.3: E-TOU-C Ex-Ante Aggregate Load Impacts, 2026 Monthly System Worst Day During RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-2	PG&E 1-in-2
January	39,516	1.80	1.82
February	43,180	1.87	1.88
March	46,845	3.40	3.14
April	50,511	3.11	3.41
May	54,172	4.55	4.69
June	57,840	6.52	6.47
July	61,504	7.25	7.13
August	65,169	7.33	7.19
September	68,833	6.83	7.04
October	72,499	7.27	7.24
November	76,164	3.19	3.05
December	79,828	3.26	3.30

Figure 5.3 shows the hourly per-customer loads and load impacts associated with the August 2025 PG&E 1-in-2 system worst day weather scenario. The RA window and peak-period load impact averages 7.4%. **Like the results in ex-post, the August percentage load impact of 7.4% is higher in the current study than the percentage load impact of 7.0% from the previous year's study.** Figure 5.4 shows the same information for February 2026. The RA window load impact averages 4.5%, while the peak-period load impact averages 3.9%.

Figure 5.3: E-TOU-C Ex-Ante Per-Customer Load Impacts, August 2026 PG&E 1-in-2 System Worst Day

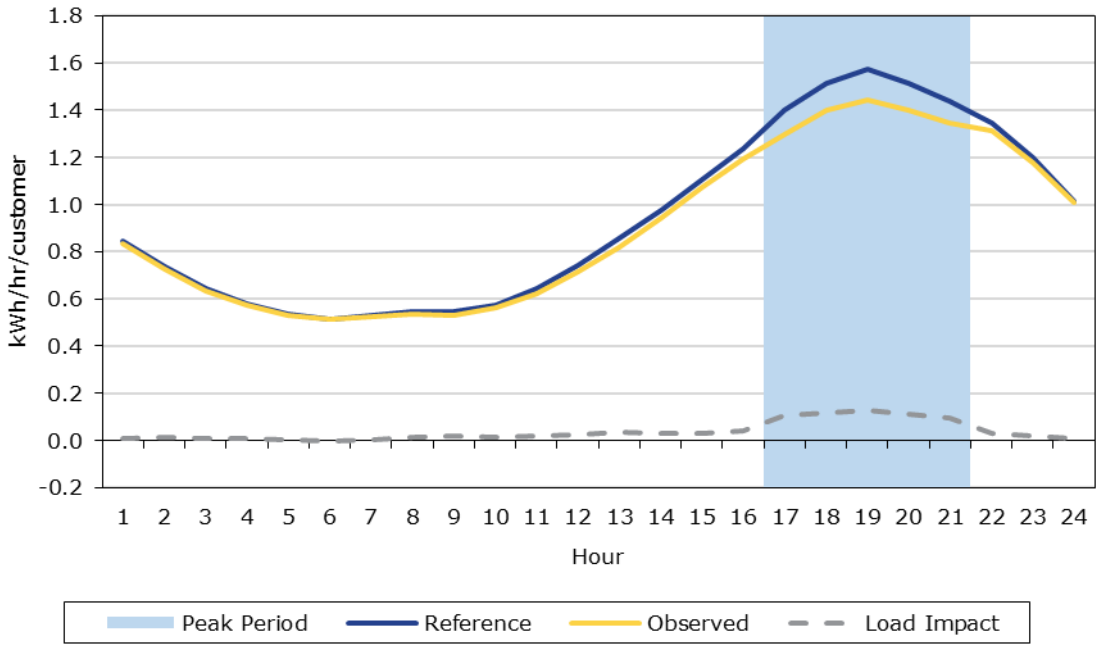
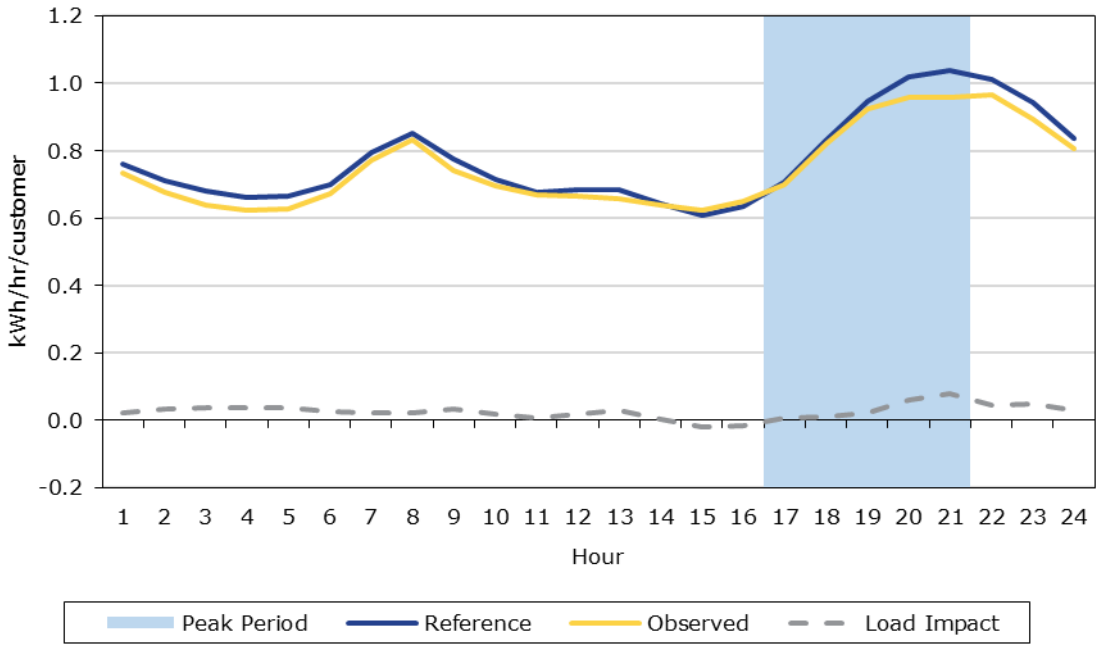


Figure 5.4: E-TOU-C Ex-Ante Per-Customer Load Impacts, February 2027 PG&E 1-in-2 System Worst Day



5.2.2 Ex-Ante Load Impacts for E-TOU-D Customers

Table 5.4 contains the aggregate E-TOU-D customer load impacts, averaged over the RA window. The tables show monthly system worst day load impacts in 2027 associated with the two weather scenarios. When examining the PG&E 1-in-2 weather scenario, the aggregate load impact is highest in July due higher reference loads.

Table 5.4: E-TOU-D Ex-Ante Aggregate Load Impacts, 2027 Monthly System Worst Day During RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-2	PG&E 1-in-2
January	69,528	5.67	5.74
February	72,068	5.79	5.77
March	74,603	5.40	5.37
April	77,144	5.73	6.33
May	79,684	7.50	7.76
June	82,219	9.61	9.49
July	84,757	9.90	9.71
August	87,295	9.96	9.67
September	89,833	8.87	9.37
October	92,371	7.45	7.40
November	94,911	7.06	6.55
December	97,450	8.13	8.19

Figure 5.5 shows the hourly per-customer loads and load impacts associated with the August 2026 PG&E 1-in-2 system worst day weather scenario. The RA window load impact averages 4.6% and the peak-period load impact averages 5.8%. This is higher than the 4.2% peak-period load impact forecasted from the previous study. Figure 5.6 shows the same information for February 2027. The RA window load impact averages 5.7% and the peak-period load impact averages 7.0%.

Figure 5.5: E-TOU-D Ex-Ante Per-Customer Load Impacts, August 2026 PG&E 1-in-2 System Worst Day

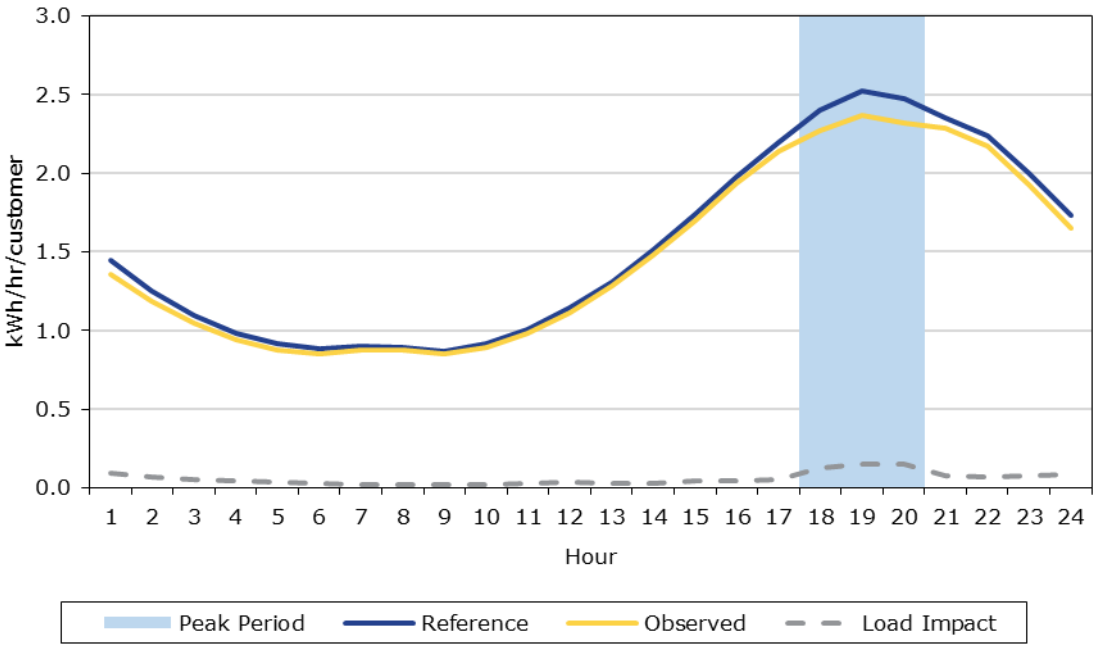
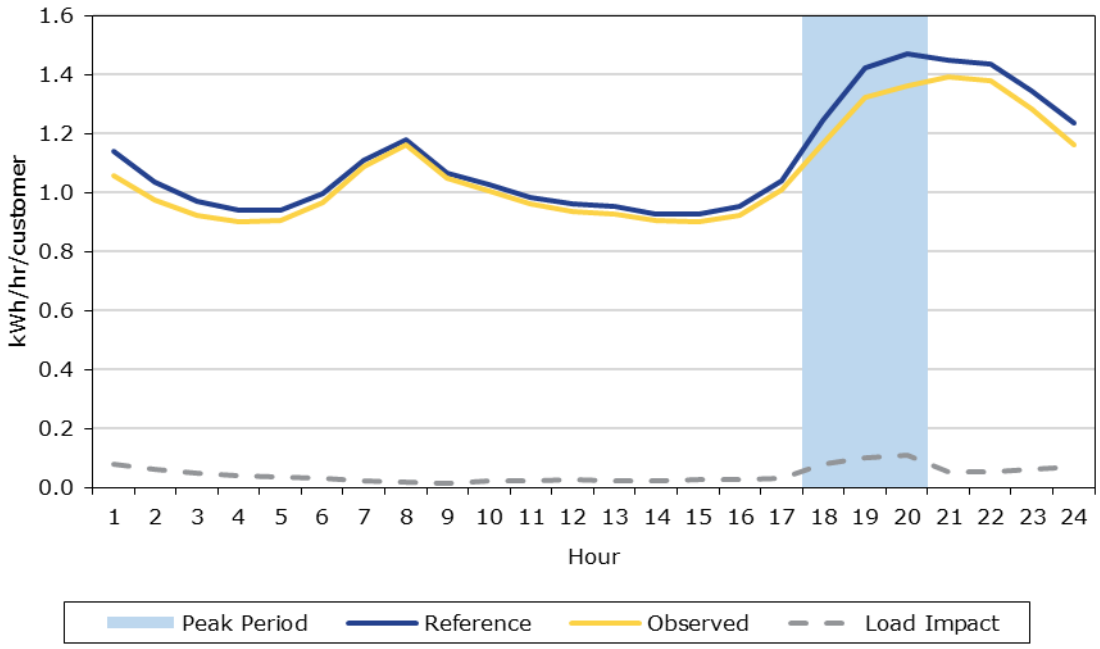


Figure 5.6: E-TOU-D Ex-Ante Per-Customer Load Impacts, February 2027 PG&E 1-in-2 System Worst Day



5.2.3 Ex-Ante Load Impacts for EV2-A Customers

Table 5.5 contains the aggregate EV2-A customer load impacts, averaged over the RA window. The tables show monthly system worst day load impacts in 2027 associated with the two weather scenarios. Load impacts peak in October.

Table 5.5: EV2-A Ex-Ante Aggregate Load Impacts, 2027 Monthly System Worst Day During RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-2	PG&E 1-in-2
January	24,721	3.09	3.13
February	27,478	3.36	3.34
March	30,237	4.73	4.53
April	32,992	3.87	4.29
May	35,750	5.76	5.99
June	38,505	6.18	5.89
July	41,267	5.75	5.68
August	44,024	6.52	6.10
September	46,785	5.67	6.52
October	49,538	7.54	7.46
November	52,300	6.11	5.82
December	55,058	6.80	6.84

Figure 5.7 shows the hourly per-customer loads and load impacts associated with the August 2026 PG&E 1-in-2 system worst day weather scenario. The RA window and peak-period load impact averages 9.1%. Figure 5.8 shows the same information for February 2027. The peak-period load impact averages 8.1% and the RA window load impact averages 9.8%.

Figure 5.7: EV2-A Ex-Ante Per-Customer Load Impacts, August 2026 PG&E 1-in-2 System Worst Day

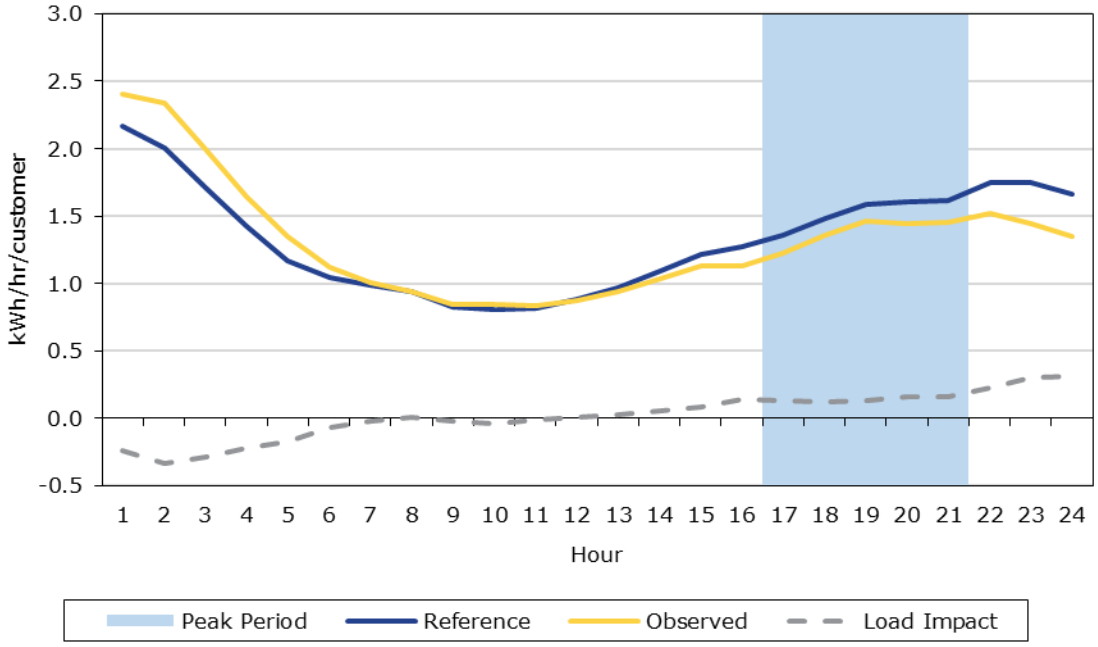
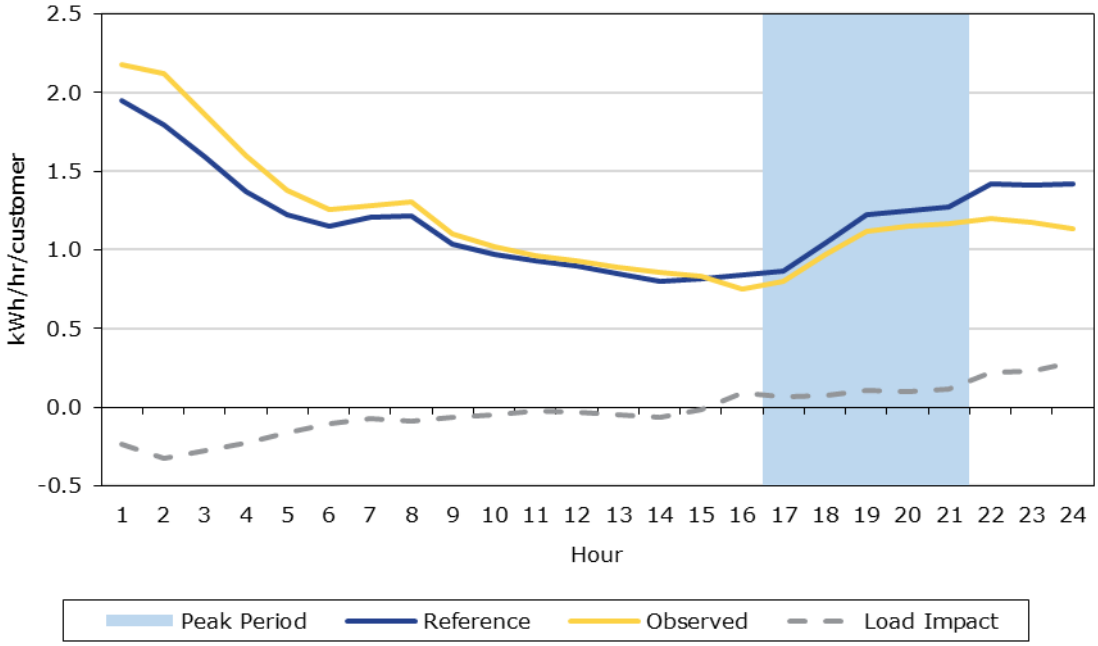


Figure 5.8: EV2-A Ex-Ante Per-Customer Load Impacts, February 2027 PG&E 1-in-2 System Worst Day



5.2.4 Ex-Ante Load Impacts for E-ELEC Customers

Table 5.6 contains the aggregate E-ELEC customer load impacts, averaged over the RA window. The tables show monthly system worst day load impacts in 2027 associated with the two weather scenarios.

Table 5.6: E-ELEC Ex-Ante Aggregate Load Impacts, 2027 Monthly System Worst Day During RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-2	PG&E 1-in-2
January	58,990	5.55	5.56
February	62,444	5.44	5.43
March	65,905	8.85	8.69
April	69,361	7.75	7.82
May	72,818	9.77	9.81
June	76,280	8.27	8.19
July	79,739	8.48	8.47
August	83,197	9.49	9.39
September	86,653	9.55	9.75
October	90,113	11.18	11.17
November	93,572	8.31	8.30
December	97,030	9.20	9.20

Figure 5.9 shows the hourly per-customer loads and load impacts associated with the August 2026 PG&E 1-in-2 system worst day weather scenario. The RA window and peak-period load impact averages 8.3%. Figure 5.10 shows the same information for February 2027. The RA window load impact averages 7.4% and the peak-period load impact averages 7.1%. While E-ELEC was available to customers with electric heat pumps, battery storage, or EVs; the load impacts from this program year appear to primarily reflect EV charging behavior.

Figure 5.9: E-ELEC Ex-Ante Per-Customer Load Impacts, August 2025 PG&E 1-in-2 System Worst Day

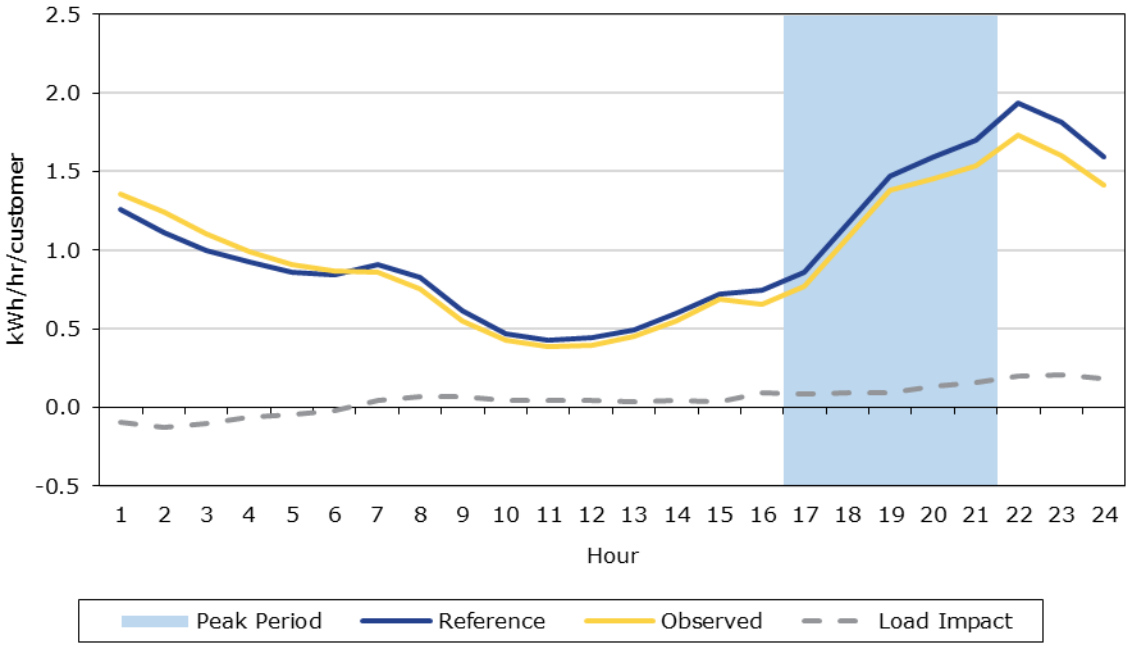
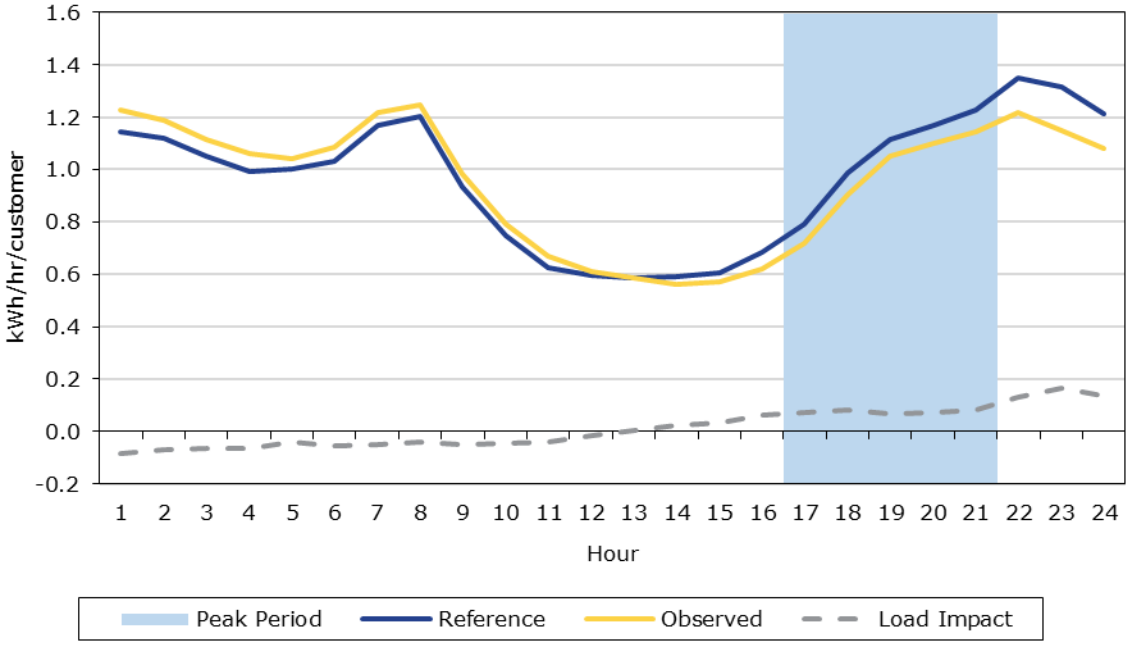


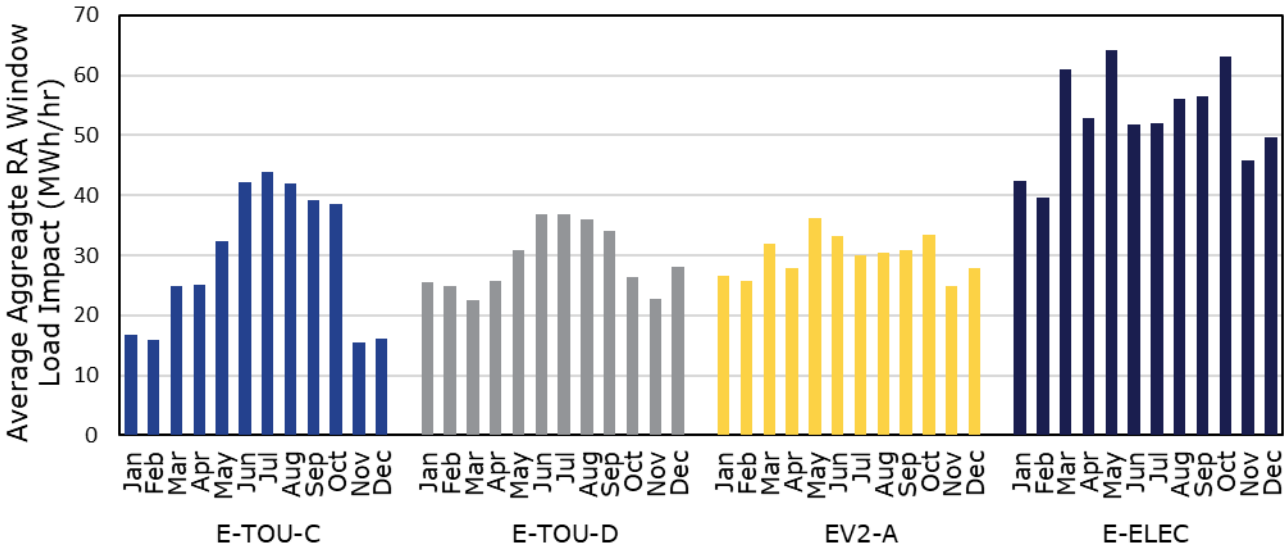
Figure 5.10: E-ELEC Ex-Ante Per-Customer Load Impacts, February 2026 PG&E 1-in-2 System Worst Day



5.2.5 RA Window Ex-Ante Load Impacts by Month

Figure 5.11 shows monthly ex-ante aggregate hourly RA window system worst day load impacts for each "to" rate for the 2035 forecast year. Across all rates, aggregate RA window load impacts exhibit a clear seasonal pattern, with lowest values occurring in winter months. This is explained by lower average temperatures in winter months. For E-TOU-C and E-TOU-D the aggregate load impact peaks in July, while the EV2-A and E-ELEC aggregate load impact is the highest in May. The lowest aggregate load impact for E-TOU-C and EV2-A is in November. For E-TOU-D and E-ELEC the lowest aggregate load impact is in March and February, respectively.

Figure 5.11: Aggregate Hourly RA Window Load Impacts for the PG&E 1-in-2 System Worst Day 2035, by Rate and Month



6. COMPARISONS OF RESULTS

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts, including the following:

- Ex-post load impacts from the current and previous studies;
- Ex-ante load impacts from the current and previous studies;
- Current ex-post and previous ex-ante load impacts; and
- Current ex-post and ex-ante load impacts.

The term "current" refers to the present study, which includes ex-post for PY2025 and ex-ante forecasts for 2026 through 2036. The term "previous" refers to findings in the report for PY2024. In the final comparison above, we compare the PY2025 ex-post load impacts to the ex-ante forecast (of the PG&E 1-in-2 August system worst day) for 2026. The sub-sections below summarize results by TOU rate.

Appendix H provides additional detail by summarizing the results of this section by rate transition. For example, this section jointly summarizes all customers who adopted EV2-A, while Appendix H separately summarizes EV2-A customers who transitioned from E-1, E-TOU-C, and E-TOU-D.

6.1 Previous Versus Current Ex-Post Load Impacts

Table 6.1 contains the average peak-period load impacts, aggregate and per-customer (PC), for the August average weekday during the current and previous program years. Ex-post enrollment rate has accelerated in the current study for EV2-A and E-ELEC and slowed down for E-TOU-C and E-TOU-D. **E-ELEC experienced the largest enrollment increase of 33,497 customers, while E-TOU-D enrollments decreased by 7,543 this year**. The aggregate load impacts increased for each, due to a combination of higher per customer load impacts (for E-TOU-C, E-TOU-D, and EV2-A) and higher enrollments (EV2-A and E-ELEC)

The E-ELEC ex-post percentage load impact is larger in the current study than the previous study, but the per-customer level load impacts are lower. This difference reflects lower reference loads in the current study, likely attributable to a methodological change that establishes observed loads based on a random sample of customers before necessary analysis exclusions are made (see Appendix D). As a result, reference loads in the previous study may have been overstated due to a sample bias.

Table 6.1: Comparison of Average August Weekday Peak-Period Ex-Post Impacts Across Studies

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	Previous Ex-Post	73,115	0.103	7.53	7.9%	77.1
	Current Ex-Post	71,895	0.123	8.85	9.5%	84.6
E-TOU-D	Previous Ex-Post	32,767	0.105	3.46	4.6%	79.8
	Current Ex-Post	25,224	0.138	3.48	6.4%	82.6
EV2-A	Previous Ex-Post	22,603	0.113	2.55	9.4%	73.3
	Current Ex-Post	23,672	0.148	3.50	9.1%	79.2
E-ELEC	Previous Ex-Post	32,174	0.129	4.15	7.0%	76.7
	Current Ex-Post	65,671	0.112	7.36	9.7%	83.1

6.2 Previous Versus Current Ex-Ante Load Impacts

In this sub-section, we compare the ex-ante forecast prepared following PY2024 (the "previous study") to the ex-ante forecast contained in this study (the "current study").

Table 6.2 reports the incremental load impact forecast for the August 2026 system worst day under PG&E 1-in-2 system worst day weather conditions. The "Previous Ex-Ante" results are based on the difference between enrollments in August 2026 and December 2025. (In contrast, the filed PY2024 study contains an ex-ante forecast with incremental enrollments relative to 2024.) This "re-basing" improves comparability to the "Current Ex-Ante" results, which represent load impacts incremental to 2025.

Incremental enrollment in the current study is higher for all rates except EV2-A. PG&E updated their forecast to significantly lower EV2-A enrollment over the next eleven years. The forecast instead allows for more growth in E-ELEC, E-TOU-D, and E-TOU-C, as well as slower attrition in E-1. The percentage load impacts are higher in the current ex-ante study.

Table 6.2: Comparison of August 2025 System Worst Day RA Window Ex-Ante Impacts in the Previous and Current Studies

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	Previous Ex-Ante	20,470	0.113	2.32	7.0%	88.2
	Current Ex- Ante	23,053	0.110	2.54	7.4%	88.8
E-TOU-D	Previous Ex-Ante	10,752	0.079	0.85	3.0%	87.5
	Current Ex-Ante	40,561	0.111	4.50	4.6%	88.0
EV2-A	Previous Ex-Ante	54,581	0.106	5.79	8.2%	80.5
	Current Ex-Ante	14,422	0.139	2.00	9.1%	81.3
E-ELEC	Previous Ex-Ante	19,601	0.146	2.87	6.5%	87.3
	Current Ex-Ante	34,406	0.113	3.88	8.3%	88.6

6.3 Previous Ex-Ante Versus Current Ex-Post Load Impacts

Table 6.3 provides a comparison of the ex-ante forecast of August 2025 average weekday peak-period load impacts prepared following PY2024 and the ex-post PY2025 peak-period load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the August average weekday during a PG&E 1-in-2 weather year. Enrollment was higher in the ex-post study for all rates except EV2-A, primarily due to the high EV2-A enrollment forecast in PY2024.

The current ex-post percentage load impact for EV2-A is lower than the previous ex-ante figure, but the per customer load impact is higher, likely due to increased temperatures.

Table 6.3: Comparison of Previous Ex-Ante and Current Ex-Post Load Impacts for Average August Weekday Peak-Period

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	Previous Ex-Ante	18,245	0.101	1.85	7.4%	83.0
	Current Ex-Post	71,895	0.123	8.85	9.5%	84.6
E-TOU-D	Previous Ex-Ante	9,491	0.106	1.01	4.6%	83.1
	Current Ex-Post	25,224	0.138	3.48	6.4%	82.6
EV2-A	Previous Ex-Ante	89,295	0.112	9.99	10.4%	76.0
	Current Ex-Post	23,672	0.148	3.50	9.1%	79.2
E-ELEC	Previous Ex-Ante	16,510	0.146	2.41	7.7%	82.1
	Current Ex-Post	65,671	0.112	7.36	9.7%	83.1

6.4 Current Ex-Post Versus Current Ex-Ante Load Impacts

Table 6.4 compares the PY2025 ex-post peak-period load impacts for the August average weekday to the corresponding ex-ante peak-period forecast for 2026 produced in this study.[28] The ex-ante per-customer load impacts are produced from the same model that estimates the ex-post load impacts, so any differences in those impacts are due to a change in the distribution of enrolled customers (across rate transitions, LCAs, and NEM status) and/or a difference between ex-post vs. ex-ante temperatures.[29]

Table 6.4: Comparison of Current Ex-Post and Ex-Ante Load Impacts for Average August Weekday Peak-Period

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	Current Ex-Post	71,895	0.123	8.85	9.5%	84.6
	Current Ex-Ante	23,053	0.095	2.20	7.5%	83.7
E-TOU-D	Current Ex-Post	25,224	0.138	3.48	6.4%	82.6
	Current Ex-Ante	40,561	0.125	5.09	6.0%	83.6
EV2-A	Current Ex-Post	23,672	0.148	3.50	9.1%	79.2
	Current Ex-Ante	14,422	0.121	1.75	9.4%	76.6
E-ELEC	Current Ex-Post	65,671	0.112	7.36	9.7%	83.1
	Current Ex-Ante	34,406	0.104	3.56	9.2%	83.2

[28] To ensure comparability between ex-post and ex-ante, the August average weekday is used instead of the August system worst day.

[29] Ex-ante and ex-post reference loads have different sources. Specifically, ex-ante reference loads are simulated from regression models whereas ex-post reference loads are based on the observed loads of treatment customers during the applicable historical month plus the estimated load impacts. These differences in reference loads have the potential to produce differences in *percentage* load impacts at the same level of load impact for NEM customers.

7. APPENDICES

Appendix A Ex-Post Load Impact Tables:

- 1a. PGE_2025_Res_TOU_Ex_Post_CONFIDENTIAL.xlsx
- 1a. PGE_2025_Res_TOU_Ex_Post_PUBLIC.xlsx

Appendix B Incremental Ex-Ante Load Impact Tables:

- 1b. PGE_2025_Res_TOU_Inc_Ex_Ante_PUBLIC.xlsx

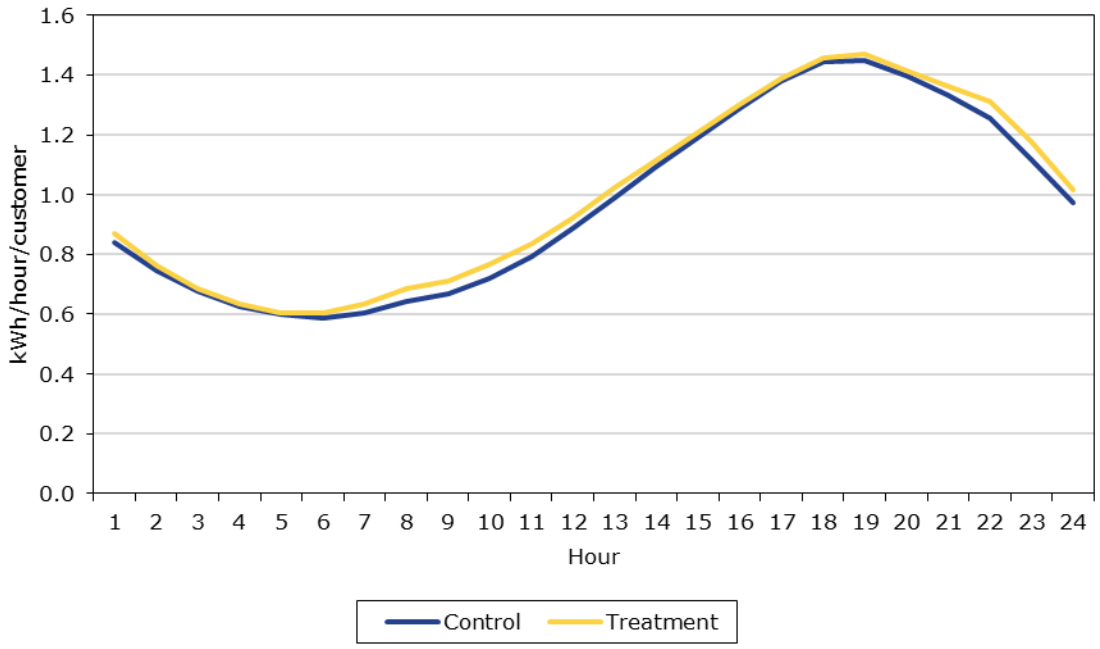
Appendix C Ex-Post Analysis Match Quality
Appendix D Regression Sample Sizes
Appendix E Comparison of Results by Rate Transition

Note: the Excel-based ex-ante appendices do not contain confidential information.

APPENDIX C. MATCH QUALITY

This appendix presents the summaries of our control-group matching process. Figures C.1 through C.16 illustrate the seasonal matches for E-TOU-C, E-TOU-D, EV2-A and E-ELEC by NEM status.[30] Each figure contains the average hourly profiles for the treatment and matched control-group customers on the average weekday that was withheld from the matching process (i.e., it represents an out-of-sample match quality). The mean percentage error (MPE) and mean absolute percentage error (MAPE) values associated with each figure are summarized in Table C.1.

Figure C.1: E-TOU-C (Non-NEM) Summer Match Quality



[30] EV2-A and E-ELEC match quality figures include rate transitions that used a control group for the analysis: E-1 to EV2-A, E-1 to E-ELEC and EV2-A to E-ELEC.

Figure C.2: E-TOU-C Winter Match Quality

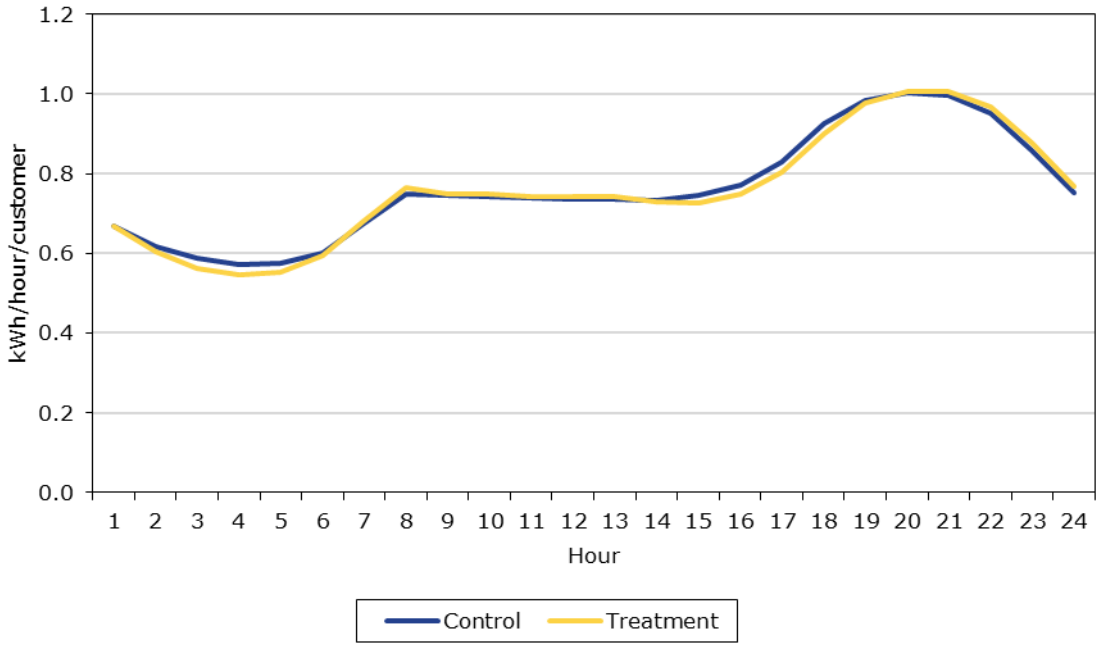


Figure C.3: E-TOU-D (Non-NEM) Summer Match Quality

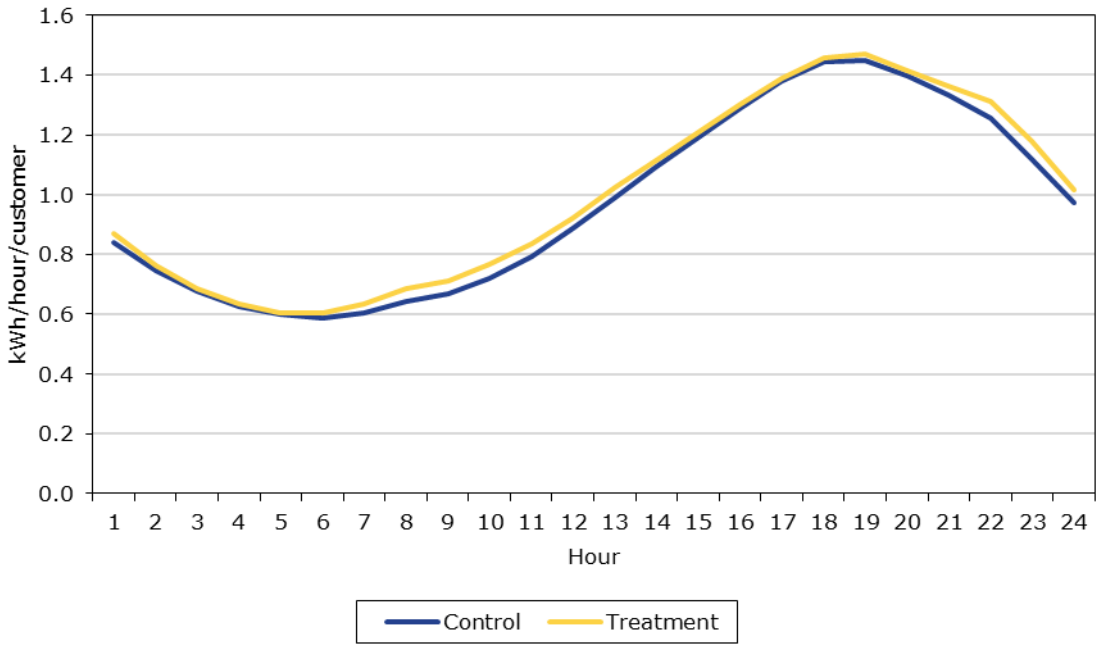


Figure C.4: E-TOU-D (Non-NEM) Winter Match Quality

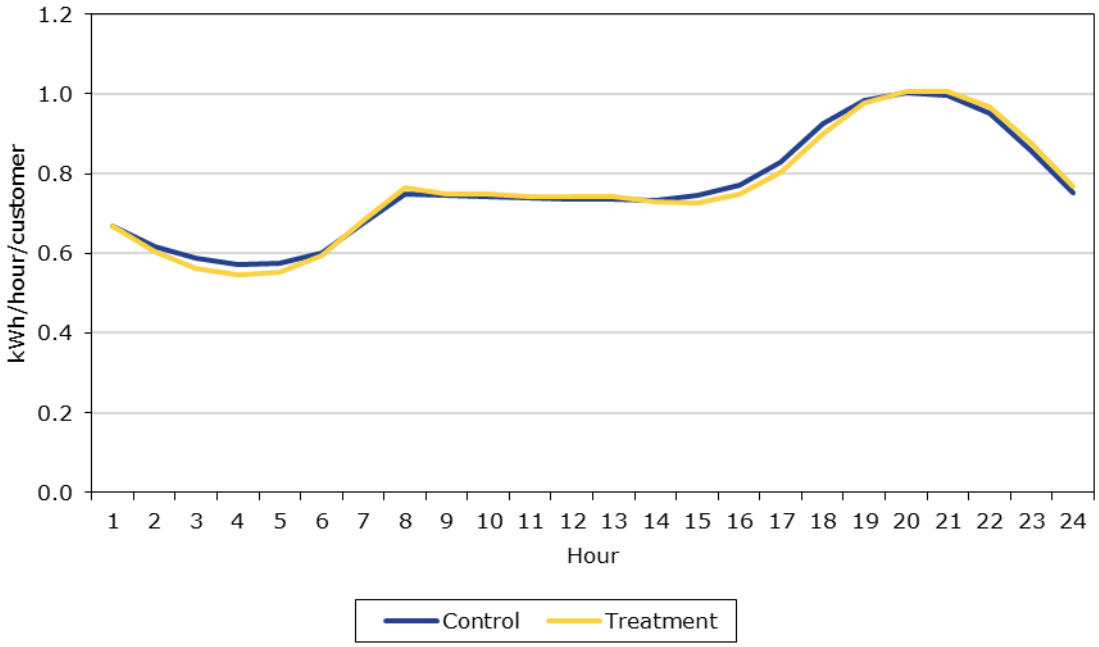


Figure C.5: E-TOU-C (NEM) Summer Match Quality

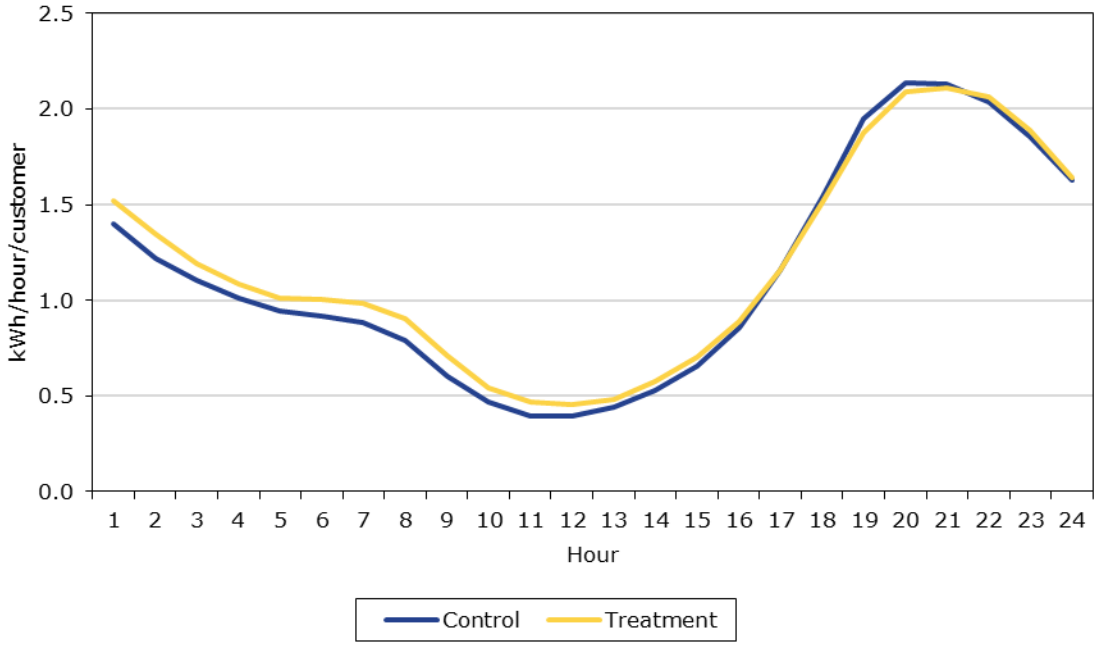


Figure C.6: E-TOU-C (NEM) Winter Match Quality

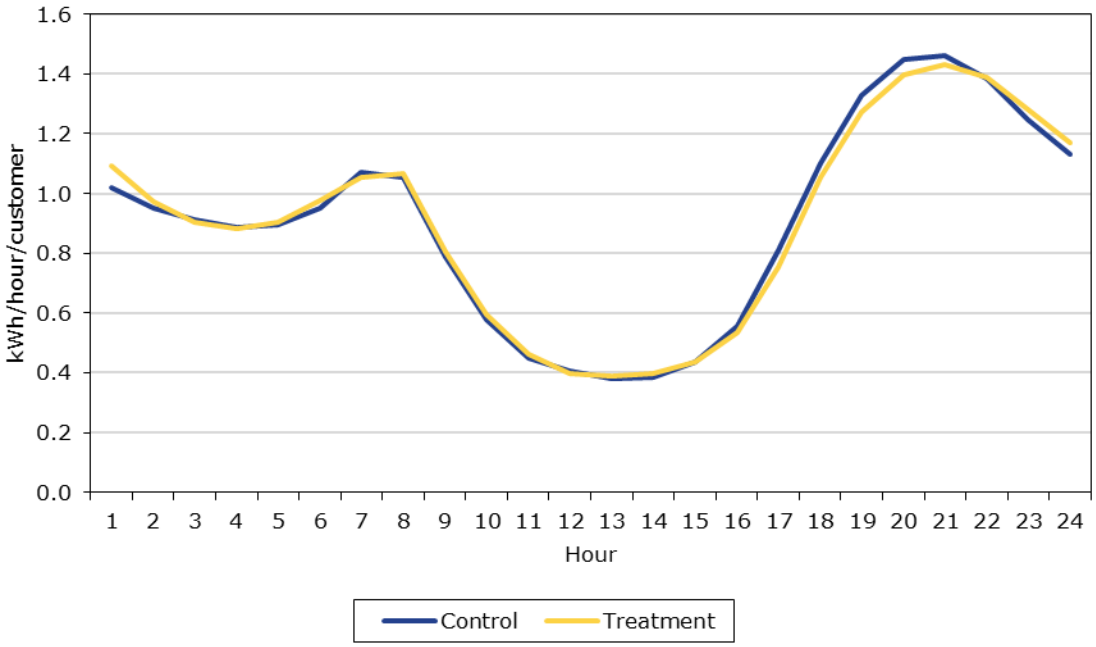


Figure C.7: E-TOU-D (NEM) Summer Match Quality

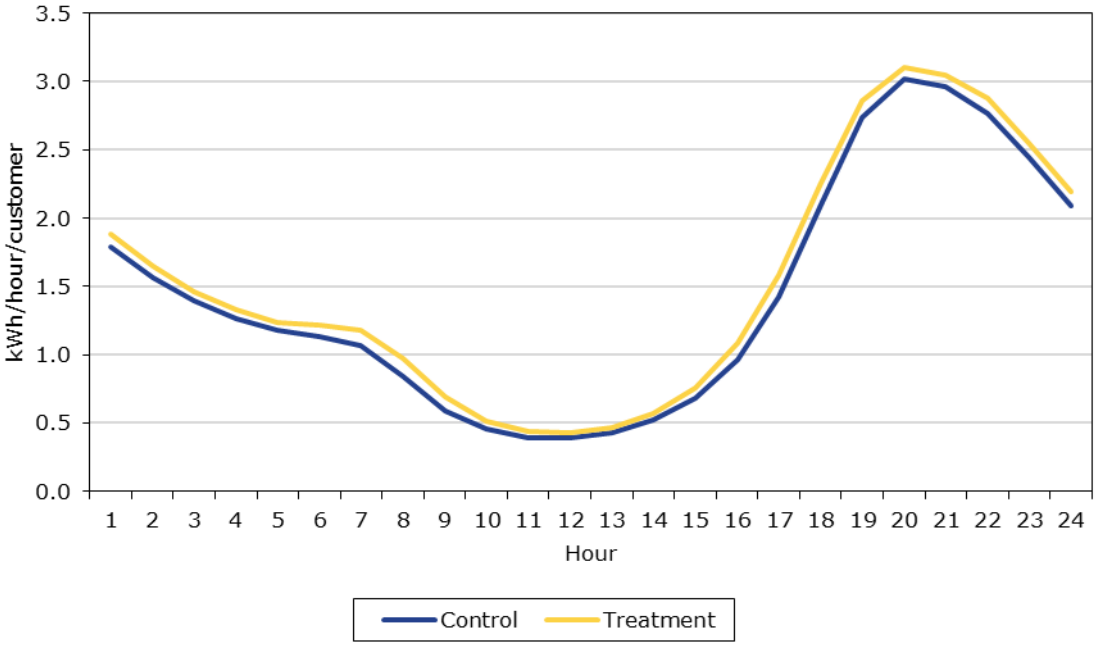


Figure C.8: E-TOU-D (NEM) Winter Match Quality

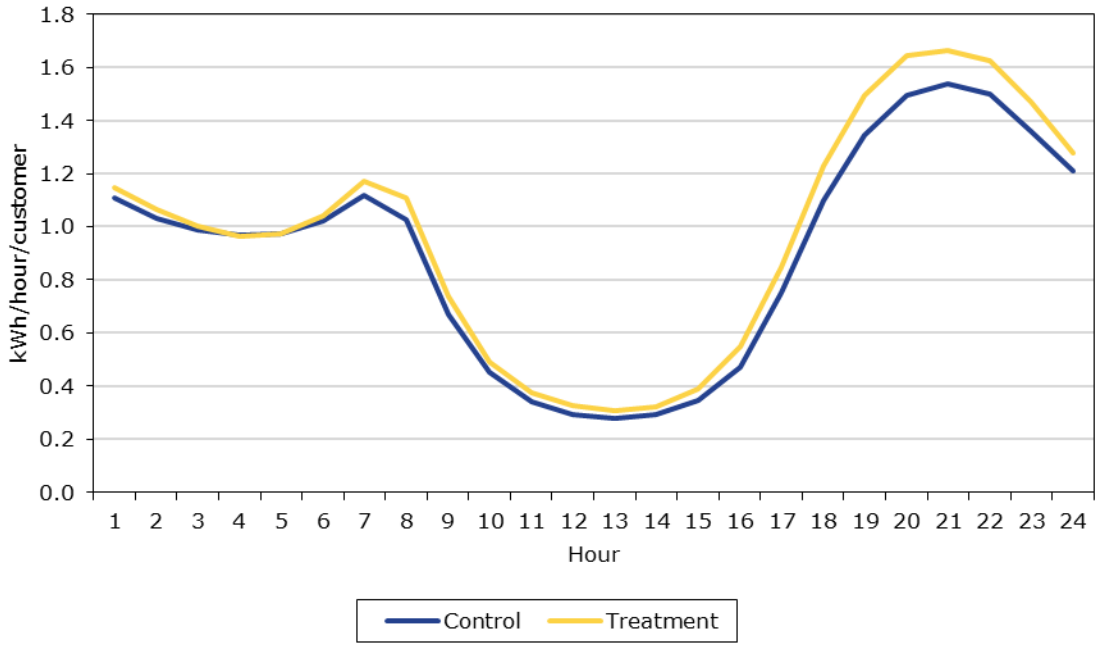


Figure C.9: EV2-A (Non-NEM) Summer Match Quality

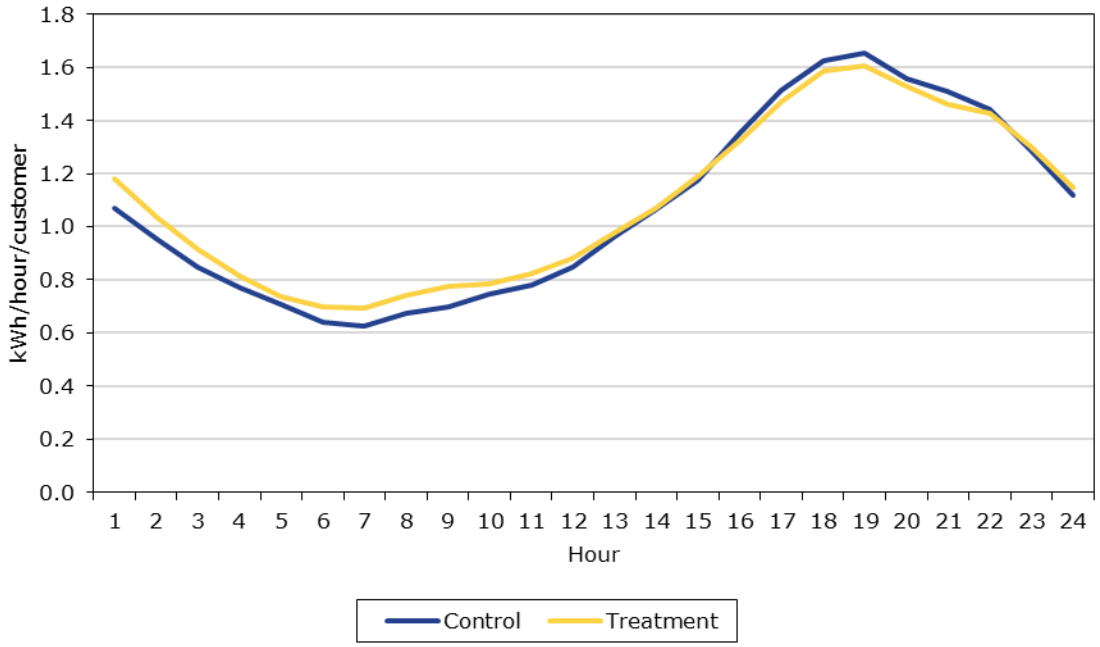


Figure C.10: EV2-A (Non-NEM) Winter Match Quality

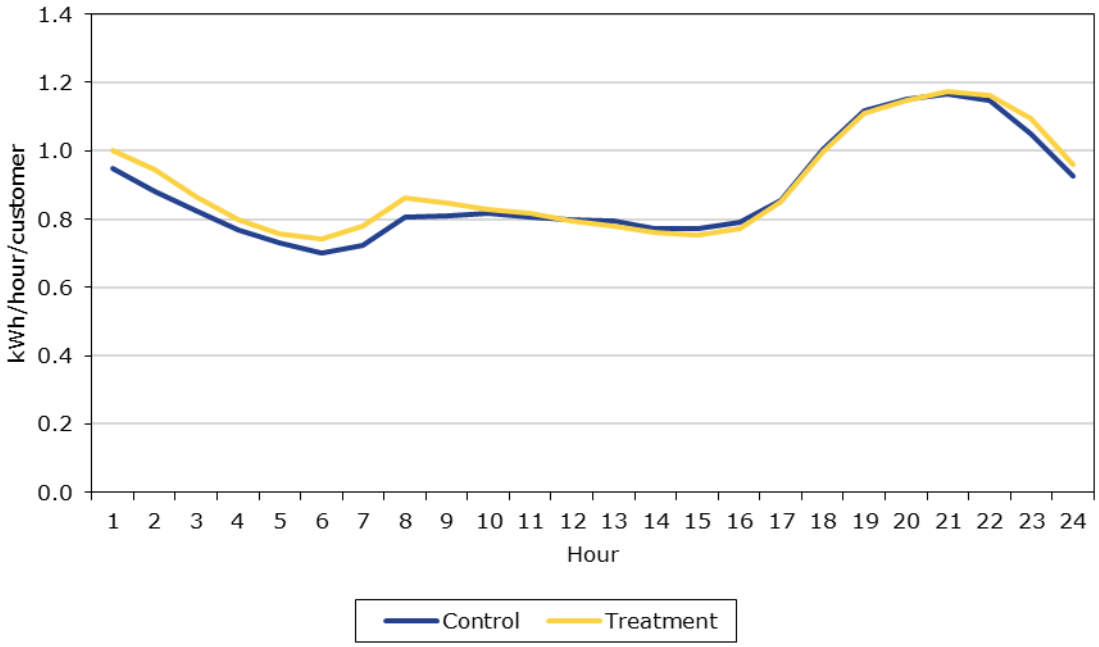


Figure C.11: E-ELEC (Non-NEM) Summer Match Quality

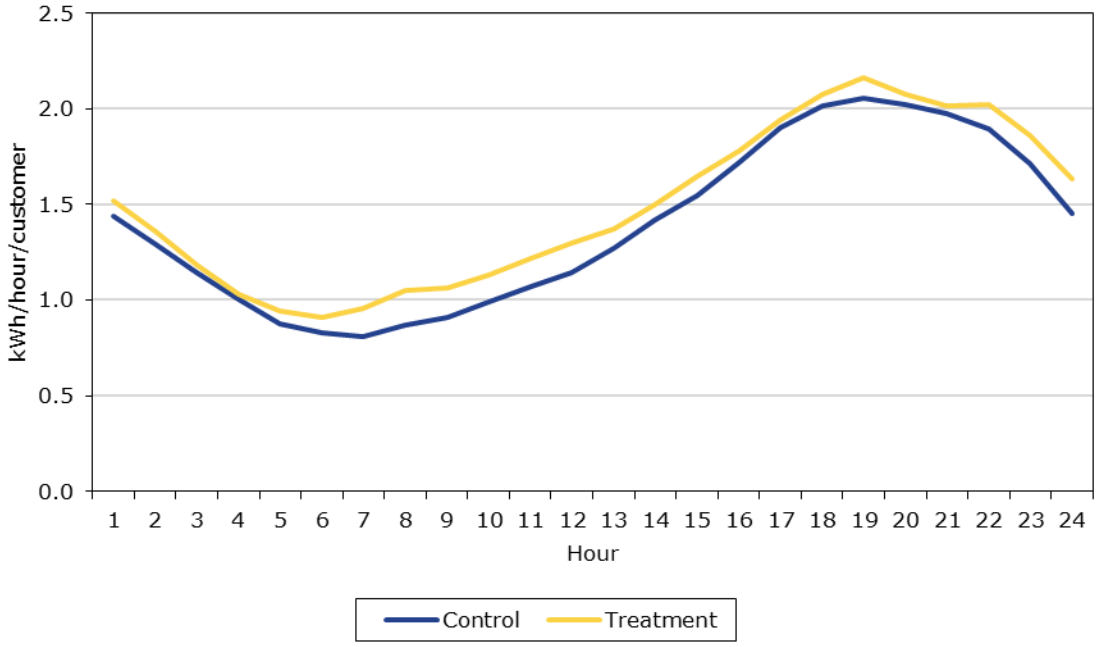


Figure C.12: E-ELEC (Non-NEM) Winter Match Quality

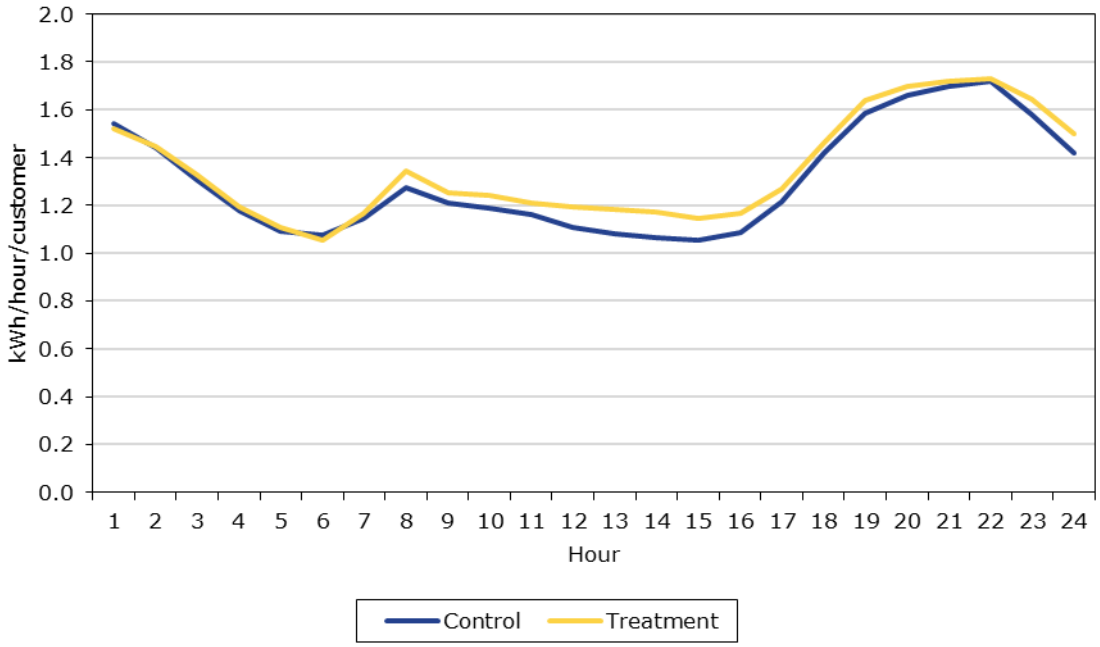


Figure C.13: EV2-A (NEM) Summer Match Quality

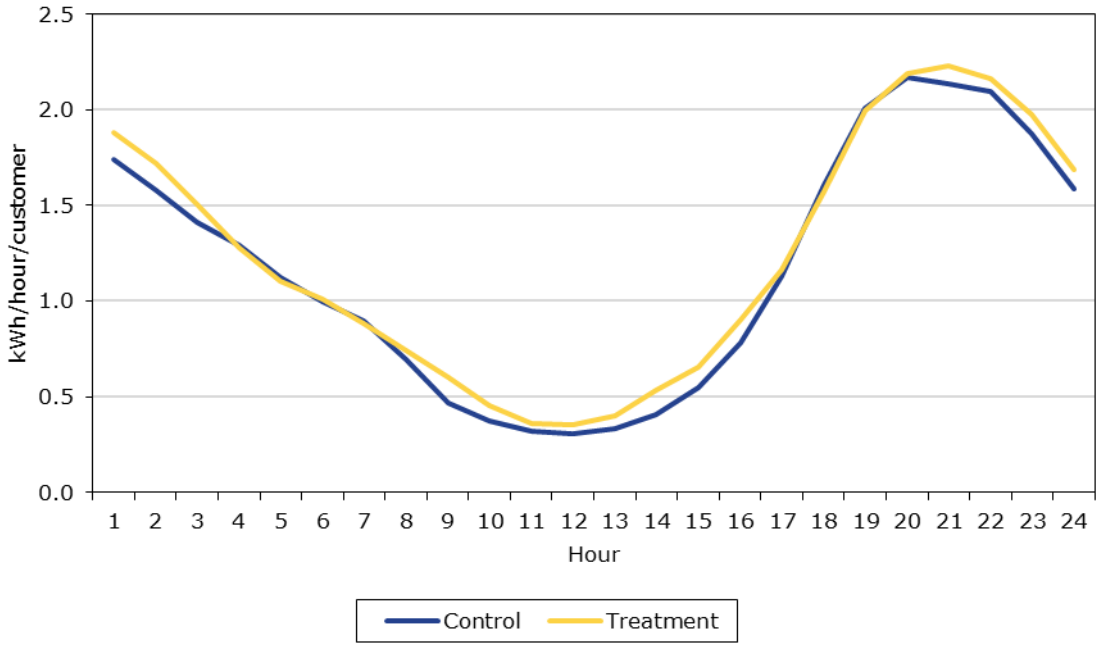


Figure C.14: EV2-A (NEM) Winter Match Quality

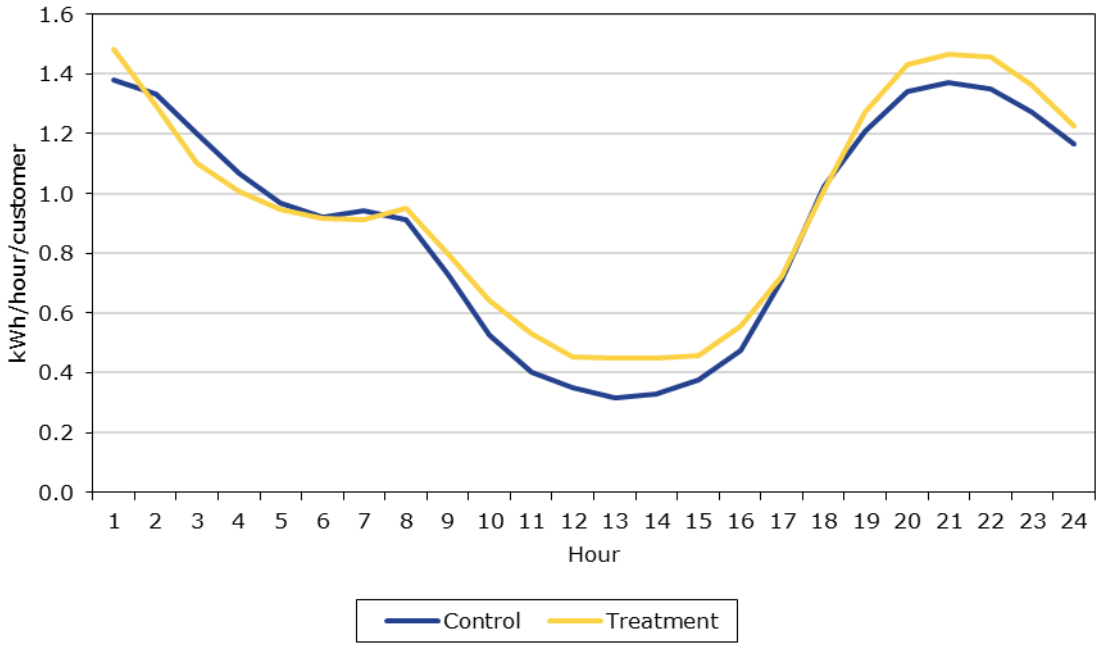


Figure C.15: E-ELEC (NEM) Summer Match Quality

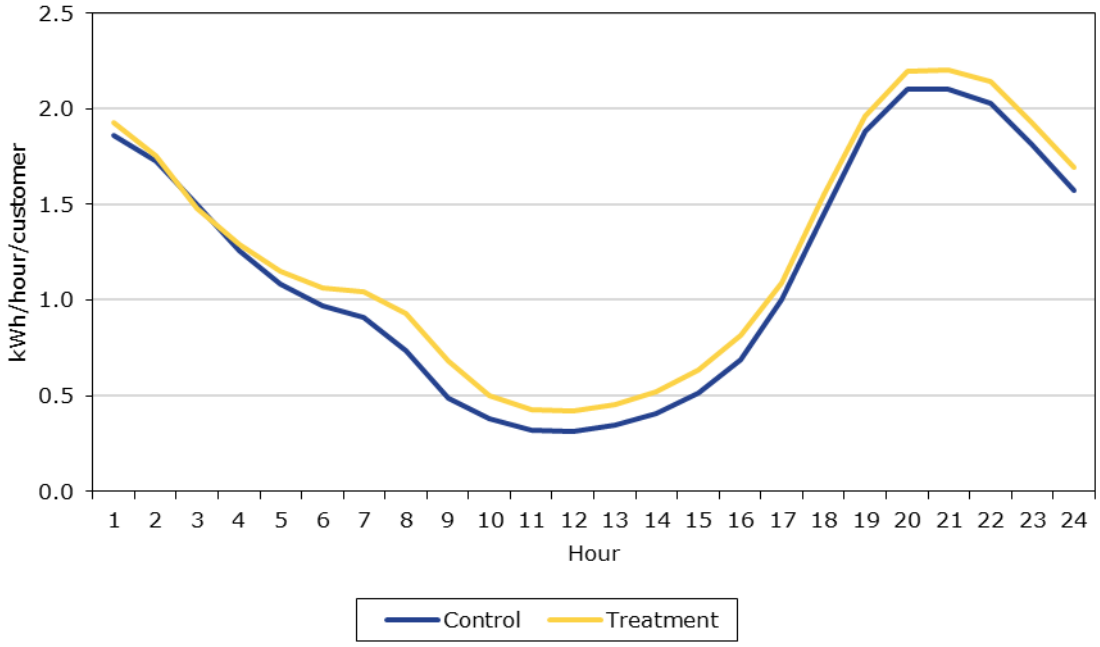


Figure C.16: E-ELEC (NEM) Winter Match Quality

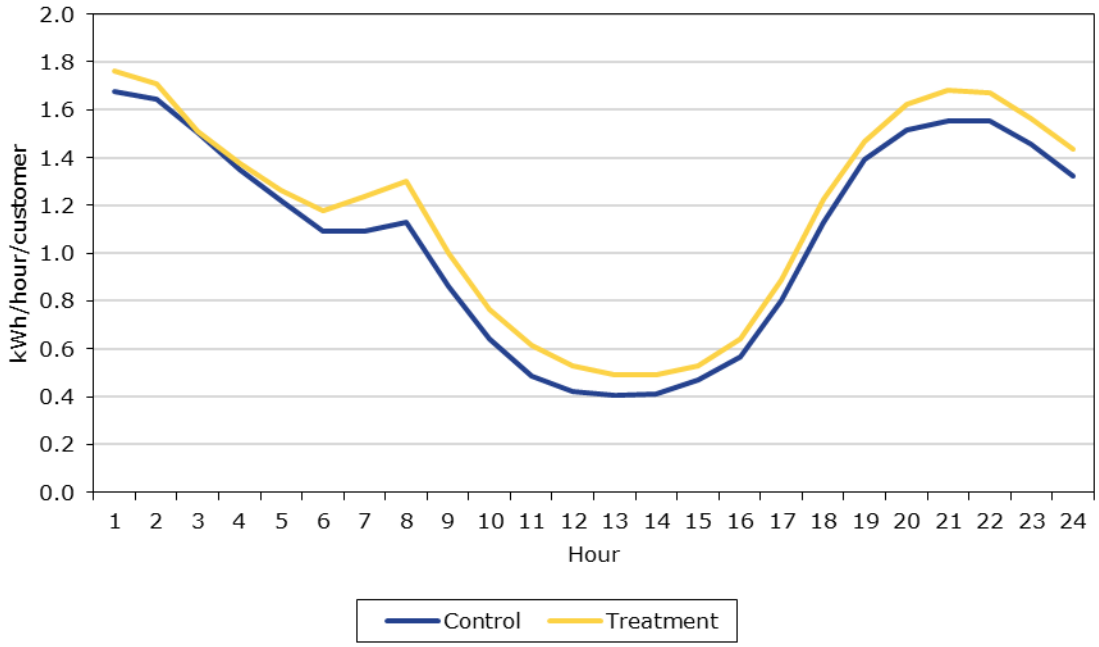


Table C.1 contains the MPE and MAPE values calculated across all 24 hours and the peak pricing period of the load profiles shown in the figures above. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy.

Table C.1: MPE and MAPE for the Withheld Profile

Season	Rate	All Hours		Peak Period	
		MPE	MAPE	MPE	MAPE
Summer	E-TOU-C (Non-NEM)	3.0%	3.0%	1.3%	1.3%
	E-TOU-C (NEM)	6.2%	7.0%	-1.8%	1.8%
	E-TOU-D (Non-NEM)	3.8%	3.8%	2.2%	2.2%
	E-TOU-D (NEM)	7.3%	7.3%	4.7%	4.7%
	EV2-A (Non-NEM)	3.1%	4.5%	-2.8%	2.8%
	EV2-A (NEM)	7.5%	8.1%	1.1%	2.2%
	E-ELEC (Non-NEM)	7.5%	7.5%	2.9%	2.9%
	E-ELEC (NEM)	11.8%	11.9%	5.4%	5.4%
Winter	E-TOU-C (Non-NEM)	-0.6%	1.8%	-1.1%	1.6%
	E-TOU-C (NEM)	0.0%	2.7%	-4.4%	4.4%
	E-TOU-D (Non-NEM)	3.6%	3.7%	4.9%	4.9%
	E-TOU-D (NEM)	7.1%	7.1%	9.9%	9.9%
	EV2-A (Non-NEM)	2.0%	3.0%	-0.3%	0.4%
	EV2-A (NEM)	7.7%	9.8%	3.7%	4.2%
	E-ELEC (Non-NEM)	3.5%	3.8%	2.8%	2.8%
	E-ELEC (NEM)	9.8%	9.8%	7.3%	7.3%

APPENDIX D. REGRESSION SAMPLE SIZES

This appendix presents the number of treatment customers represented in the ex-post impacts presented in Section 4. Table D.1 shows the number of enrolled treatment customers by rate in February and August.

Table D.1: Sample Sizes for Load Impacts by Rate and Season[31]

Adopted TOU Rate	Sample Size	
	February	August
E-TOU-C	973	2,326
E-TOU-D	2,282	5,183
EV2-A	712	2,100
E-ELEC	1,112	1,945

Table D.2 shows the various screens applied to arrive at the customer samples used in the regression models.[32] The number of customers in the models is typically quite a bit lower than the number of enrolled customers the model represents due to restrictions we apply to ensure a valid load impact estimate. Column B shows the total enrollment levels used to scale our estimated per-customer load impacts. It represents all customers who changed to a residential TOU rate during PY2025. At the far right of the table (column G), we show the number of enrolled treatment customers that are included in the regression models. The exclusions to get from column B to column G are as follows:

- Exclude customers that had a change in their NEM status (column C)
- Exclude customers with less than four months of pre-treatment data (column D);
- Exclude customers that had insufficient interval data used for matching or NEM customers that had a change in their PV system size (column E);[33]
- Exclude E-ELEC and EV2-A customers with a structural break during the two analysis years (column F); and
- Exclude customers with poor match quality.

[31] As the load impacts are estimated using annual regressions, the number of customers that are included in the analysis that inform February and August results is based on all customers within a rate pair. The table shows the number of customers that were included in the analysis from a given month.

[32] Note that the values in Table D.2 are higher than corresponding values in Table D.1 because Table D.2 represents treatment customers enrolled at any point in the program year, while Table D.1 represents treatment customers enrolled in specific months.

[33] To reduce the quantity of requested data a random sample of customers were selected prior to requesting interval data.

Table D.2: Sample Exclusions to Develop Regression Data Sets

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Rate Transition	Adopted a TOU Rate during PY2025	Exclude if switched NEM status	Exclude if insufficient pre-treatment data	Exclude if insufficient interval data or PV system size change	Exclude if structural break (only EV2-A and E-ELEC)	Exclude if poor match quality
E-1 to E-TOU-C (Non-NEM)	75,792	70,689	16,165	2,933	2,918	2,333
E-1 to E-TOU-C (NEM)	16,058	694	605	411	403	343
E-1 to E-TOU-D (Non-NEM)	13,049	12,134	5,322	2,363	2,353	1,451
E-1 to E-TOU-D (NEM)	740	457	406	347	345	228
E-TOU-C to E-TOU-D (Non-NEM)	11,626	11,405	6,609	2,464	2,464	1,939
E-TOU-C to E-TOU-D (NEM)	5,077	4,499	3,922	2,244	2,243	2,201
E-1 to EV2-A (Non-NEM)	6,310	6,022	4,836	3,248	681	582
E-1 to EV2-A (NEM)	541	512	443	407	81	76
E-TOU-C to EV2-A (Non-NEM)	12,375	12,025	8,722	3,669	761	714
E-TOU-C to EV2-A (NEM)	4,485	3,859	3,414	3,005	683	646
E-TOU-D to EV2-A (Non-NEM)	2,413	2,304	1,621	1,444	369	289
E-TOU-D to EV2-A (NEM)	1,119	1,023	818	699	178	162
E-1 to E-ELEC (Non-NEM)	2,289	2,056	1,453	1,328	297	236
E-1 to E-ELEC (NEM)	20,679	1,857	1,797	919	294	267
E-TOU-C to E-ELEC (Non-NEM)	2,600	2,440	1,737	1,544	376	356
E-TOU-C to E-ELEC (NEM)	32,160	7,392	6,987	3,082	899	828
E-TOU-D to E-ELEC (Non-NEM)	1,083	1,014	747	634	178	130
E-TOU-D to E-ELEC (NEM)	8,048	2,003	1,720	831	234	213
EV2-A to E-ELEC (Non-NEM)	448	401	272	206	67	60
EV2-A to E-ELEC (NEM)	5,130	1,186	990	446	182	171

APPENDIX E. COMPARISONS OF RESULTS BY RATE TRANSITION

This appendix presents the results comparisons from Section 6 summarized by rate transition rather than by the adopted TOU rate. The four tables below correspond to Table 6.1 through Table 6.4.[34]

Table E.1: Comparison of Average August Weekday Peak-period Ex-Post Impacts Across Studies

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C (Non-NEM)	Previous Ex-Post	46,439	0.053	2.47	5.3%	76.7
	Current Ex-Post	54,864	0.118	6.47	8.8%	84.6
E-1 to E-TOU-C (NEM)	Previous Ex-Post	26,676	0.190	5.06	10.2%	77.7
	Current Ex-Post	17,031	0.139	2.38	11.8%	84.5
E-1 to E-TOU-D (Non-NEM)	Previous Ex-Post	11,831	0.150	1.77	6.2%	81.7
	Current Ex-Post	10,117	0.142	1.43	6.4%	83.2
E-1 to E-TOU-D (NEM)	Previous Ex-Post	3,571	0.187	0.67	6.3%	82.0
	Current Ex-Post	1,219	0.145	0.18	6.8%	87.0
E-TOU-C to E-TOU-D (Non-NEM)	Previous Ex-Post	12,091	0.035	0.42	1.9%	75.8
	Current Ex-Post	9,422	0.147	1.39	7.5%	80.2
E-TOU-C to E-TOU-D (NEM)	Previous Ex-Post	5,274	0.113	0.60	4.5%	83.0
	Current Ex-Post	4,466	0.108	0.48	4.4%	85.4
E-1 to EV2-A	Previous Ex-Post	5,770	0.143	0.83	10.7%	74.6
	Current Ex-Post	6,067	0.238	1.45	11.9%	80.9
E-TOU-C to EV2-A	Previous Ex-Post	13,943	0.101	1.41	9.5%	72.8
	Current Ex-Post	14,563	0.123	1.80	8.9%	78.3
E-TOU-D to EV2-A	Previous Ex-Post	2,890	0.106	0.31	7.0%	73.1
	Current Ex-Post	3,042	0.083	0.25	4.2%	79.8
E-1 to E-ELEC	Previous Ex-Post	11,899	0.156	1.86	7.6%	79.5
	Current Ex-Post	20,951	0.166	3.48	13.1%	85.2
E-TOU-C to E-ELEC	Previous Ex-Post	15,361	0.133	2.04	8.5%	75.2
	Current Ex-Post	31,542	0.088	2.76	8.3%	82.5
E-TOU-D to E-ELEC	Previous Ex-Post	4,914	0.050	0.25	2.2%	75.0
	Current Ex-Post	8,165	0.066	0.54	4.6%	82.5

[34] Comparisons with the previous study do not show the EV2-A to E-ELEC transition as

Table E.2: Comparison of August 2025 System Worst Day RA Window Ex-Ante Impacts in the Previous and Current Studies[35]

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C (Non-NEM)	Previous Ex-Ante	13,910	0.067	0.94	4.9%	87.2
	Current Ex-Ante	18,183	0.098	1.78	6.5%	88.2
E-1 to E-TOU-C (NEM)	Previous Ex-Ante	6,560	0.210	1.38	9.9%	90.5
	Current Ex-Ante	4,870	0.157	0.76	11.1%	91.3
E-1 to E-TOU-D (Non-NEM)	Previous Ex-Ante	4,131	0.113	0.47	4.4%	86.7
	Current Ex-Ante	17,014	0.113	1.92	4.3%	90.2
E-1 to E-TOU-D (NEM)	Previous Ex-Ante	1,000	0.106	0.11	3.1%	91.3
	Current Ex-Ante	1,727	0.094	0.16	3.9%	93.2
E-TOU-C to E-TOU-D (Non-NEM)	Previous Ex-Ante	4,006	0.026	0.10	1.2%	82.6
	Current Ex-Ante	15,160	0.116	1.75	6.0%	83.3
E-TOU-C to E-TOU-D (NEM)	Previous Ex-Ante	1,615	0.078	0.13	2.8%	90.7
	Current Ex-Ante	6,660	0.099	0.66	3.5%	92.1
E-1 to EV2-A	Previous Ex-Ante	14,018	0.131	1.84	8.9%	81.8
	Current Ex-Ante	3,660	0.207	0.76	10.4%	82.9
E-TOU-C to EV2-A	Previous Ex-Ante	33,529	0.094	3.16	8.2%	79.8
	Current Ex-Ante	8,899	0.119	1.06	9.4%	80.3
E-TOU-D to EV2-A	Previous Ex-Ante	7,034	0.113	0.80	7.1%	81.5
	Current Ex-Ante	1,863	0.097	0.18	5.1%	82.9
E-1 to E-ELEC	Previous Ex-Ante	7,264	0.185	1.34	7.2%	90.8
	Current Ex-Ante	10,941	0.180	1.97	11.3%	92.4
E-TOU-C to E-ELEC	Previous Ex-Ante	9,088	0.142	1.29	7.7%	85.1
	Current Ex-Ante	16,474	0.092	1.52	7.6%	87.1
E-TOU-D to E-ELEC	Previous Ex-Ante	3,249	0.072	0.24	2.8%	85.8
	Current Ex-Ante	4,339	0.024	0.11	1.5%	88.7

[35] The "Previous Ex-Ante" results are based on the difference between enrollments in August 2026 and December 2025. (In contrast, the filed PY2024 study contains an ex-ante forecast with incremental enrollments relative to 2024.) This "re-basing" improves comparability to the "Current Ex-Ante" results, which represent load impacts incremental to 2025.

Table E.3 Comparison of Previous Ex-Ante and Current Ex-Post Load Impacts for Average August Weekday Peak-Period

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C (Non-NEM)	Previous Ex-Ante	12,397	0.059	0.08	1.2%	78.4
	Current Ex-Post	54,864	0.118	6.47	8.8%	84.6
E-1 to E-TOU-C (NEM)	Previous Ex-Ante	5,848	0.191	1.12	10.5%	85.1
	Current Ex-Post	17,031	0.139	2.38	11.8%	84.5
E-1 to E-TOU-D (Non-NEM)	Previous Ex-Ante	3,647	0.149	0.54	6.1%	85.0
	Current Ex-Post	10,117	0.142	1.43	6.4%	83.2
E-1 to E-TOU-D (NEM)	Previous Ex-Ante	881	0.194	0.17	6.2%	88.5
	Current Ex-Post	1,219	0.145	0.18	6.8%	87.0
E-TOU-C to E-TOU-D (Non-NEM)	Previous Ex-Ante	3,539	0.037	0.13	2.0%	78.9
	Current Ex-Post	9,422	0.147	1.39	7.5%	80.2
E-TOU-C to E-TOU-D (NEM)	Previous Ex-Ante	1,424	0.115	0.16	4.8%	84.9
	Current Ex-Post	4,466	0.108	0.48	4.4%	85.4
E-1 to EV2-A	Previous Ex-Ante	22,934	0.137	3.13	11.0%	77.0
	Current Ex-Post	6,067	0.238	1.45	11.9%	80.9
E-TOU-C to EV2-A	Previous Ex-Ante	54,847	0.099	5.43	10.3%	75.4
	Current Ex-Post	14,563	0.123	1.80	8.9%	78.3
E-TOU-D to EV2-A	Previous Ex-Ante	11,514	0.124	1.43	9.3%	76.8
	Current Ex-Post	3,042	0.083	0.25	4.2%	79.8
E-1 to E-ELEC	Previous Ex-Ante	6,119	0.181	1.11	8.5%	85.2
	Current Ex-Post	20,951	0.166	3.48	13.1%	85.2
E-TOU-C to E-ELEC	Previous Ex-Ante	7,656	0.141	1.08	9.0%	80.1
	Current Ex-Post	31,542	0.088	2.76	8.3%	82.5
E-TOU-D to E-ELEC	Previous Ex-Ante	2,735	0.080	0.22	3.6%	80.5
	Current Ex-Post	8,165	0.066	0.54	4.6%	82.5

Table E.4 Comparison of Current Ex-Post and Ex-Ante Load Impacts for Average August Weekday Peak-Period

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C (Non-NEM)	Current Ex-Post	54,864	0.118	6.47	8.8%	84.6
	Current Ex-Ante	18,183	0.085	1.55	6.6%	83.2
E-1 to E-TOU-C (NEM)	Current Ex-Post	17,031	0.139	2.38	11.8%	84.5
	Current Ex-Ante	4,870	0.133	0.65	11.2%	85.8

TOU Rate	Analysis	Enrolled	Per-Customer Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-D (Non-NEM)	Current Ex-Post	10,117	0.142	1.43	6.4%	83.2
	Current Ex-Ante	17,014	0.131	2.23	5.7%	85.4
E-1 to E-TOU-D (NEM)	Current Ex-Post	1,219	0.145	0.18	6.8%	87.0
	Current Ex-Ante	1,727	0.128	0.22	6.1%	88.4
E-TOU-C to E-TOU-D (Non-NEM)	Current Ex-Post	9,422	0.147	1.39	7.5%	80.2
	Current Ex-Ante	15,160	0.122	1.85	7.2%	79.4
E-TOU-C to E-TOU-D (NEM)	Current Ex-Post	4,466	0.108	0.48	4.4%	85.4
	Current Ex-Ante	6,660	0.119	0.79	4.8%	87.2
E-1 to EV2-A (Non-NEM)	Current Ex-Post	5,495	0.243	1.34	12.0%	80.7
	Current Ex-Ante	3,323	0.197	0.66	11.9%	77.5
E-1 to EV2-A (NEM)	Current Ex-Post	572	0.194	0.11	10.4%	82.2
	Current Ex-Ante	337	0.194	0.07	12.0%	81.1
E-TOU-C to EV2-A (Non-NEM)	Current Ex-Post	10,574	0.134	1.41	9.6%	77.2
	Current Ex-Ante	6,516	0.101	0.65	9.9%	74.2
E-TOU-C to EV2-A (NEM)	Current Ex-Post	3,989	0.097	0.39	7.1%	81.3
	Current Ex-Ante	2,383	0.095	0.23	7.9%	80.2
E-TOU-D to EV2-A (Non-NEM)	Current Ex-Post	2,052	0.082	0.17	4.1%	78.0
	Current Ex-Ante	1,270	0.073	0.09	4.6%	76.2
E-TOU-D to EV2-A (NEM)	Current Ex-Post	990	0.085	0.08	4.5%	83.4
	Current Ex-Ante	593	0.088	0.05	5.6%	80.9
E-1 to E-ELEC (Non-NEM)	Current Ex-Post	1,775	0.224	0.40	9.0%	81.9
	Current Ex-Ante	1,079	0.236	0.25	10.0%	79.0
E-1 to E-ELEC (NEM)	Current Ex-Post	19,176	0.161	3.08	14.0%	85.5
	Current Ex-Ante	9,862	0.167	1.65	13.8%	87.4
E-TOU-C to E-ELEC (Non-NEM)	Current Ex-Post	2,135	0.125	0.27	7.1%	77.2
	Current Ex-Ante	1,227	0.105	0.13	7.1%	75.1
E-TOU-C to E-ELEC (NEM)	Current Ex-Post	29,407	0.085	2.50	8.5%	82.8
	Current Ex-Ante	15,247	0.070	1.06	7.4%	82.4
E-TOU-D to E-ELEC (Non-NEM)	Current Ex-Post	905	0.178	0.16	6.4%	78.7
	Current Ex-Ante	512	0.184	0.09	7.4%	76.2
E-TOU-D to E-ELEC (NEM)	Current Ex-Post	7,260	0.052	0.38	4.1%	83.0
	Current Ex-Ante	3,827	0.027	0.10	2.1%	84.3
EV2-A to E-ELEC (Non-NEM)	Current Ex-Post	347	0.143	0.05	7.3%	74.4
	Current Ex-Ante	211	0.087	0.02	5.3%	74.8
EV2-A to E-ELEC (NEM)	Current Ex-Post	4,666	0.113	0.53	13.7%	79.9
	Current Ex-Ante	2,441	0.103	0.25	16.3%	77.7