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2015 Impact Evaluation of San Diego Gas & Electric's Residential Peak Time Rebate and Small Customer Technology Deployment Programs

Ex Post and Ex Ante Final Report
Public Version

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Executive Summary

ES.1 Executive Summary

This report presents the findings of the 2015 *ex post* and *ex ante* evaluation for San Diego Gas and Electric's (SDG&E) Peak Time Rebate (PTR) Program. SDG&E's PTR Program is marketed as the *Reduce Your Use*SM (RYU) *Rewards*. If customers are able to save electricity between 11 a.m. and 6 p.m. on a RYU Reward days, they earn a credit on their SDG&E bill. To earn rewards, customers must set up an alert (text, email, phone, or a combination) preference and SDG&E will let them know when to expect an RYU day.

This report also includes the evaluation finding of the Small Customer Technology Deployment (SCTD) program. SDG&E marketed the SCTD pilot by offering free smart thermostats to customers who enrolled in the program. The smart thermostats are demand response technology enabled so that SDG&E can either cycle the customer's central air conditioning or raise their thermostat setting between the hours of 2 p.m. and 6 p.m. on PTR event days. SCTD participants are encouraged to enroll in RYU Rewards in order to receive an incentive for reducing their electricity use on RYU days.

ES.2 Ex Post Evaluation Summary

ES.2.1 *PTR Ex Post Evaluation*

There were a total of four PTR events during the summer of 2015. One event occurred in August and three (consecutive) in September. The average temperature during event hours was 91.2°F. Table ES-1 shows the average and aggregate PTR *ex post* load impact estimates for the participant groups of interest in this evaluation. Across all of the 2015 PTR events, the overall PTR population had an average event hour load reduction of 0.08 kW per participant, representing an average reduction of 5.4% relative to the reference load. The average aggregate load reduction during event hours was 6.07 MW. Large participants delivered 73% of the aggregate load reduction (4.51 MW), while Medium and Small participants delivered the remaining 27% (1.19 MW and 0.46 MW, respectively). Inland customers experienced higher temperatures during events (93.7°F) than Coastal customers (88.8°F) and had a higher average load reduction during event hours (0.11 kW versus 0.06 kW). Low income participants had very little load reduction during events, with an average of 0.05 kW (3.6%). The participants who first enrolled in 2014 saved the most during the 2015 PTR events, with an average of 0.10 kW (6.9%) during event hours. Having both email and text event notification resulted a higher average event hour reduction of 0.11 kW (7.3%). The net energy metered (NEM) participants, as a group, did not see a load reduction at the meter but rather saw an increase in their energy exports as a result of there being less internal load to satisfy with the photovoltaic generation. This increase in energy export is expressed as a negative load drop (-38.7%).

Table ES-1: PTR Ex Post Load Impact Estimates by Customer Category - Average 2015 Event (11 a.m. to 6 p.m.)

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	74,433	1.54	1.45	0.08	5.4%	6.07	91.2
Large	32,166	2.35	2.21	0.14	6.0%	4.51	91.9
Medium	26,115	1.13	1.08	0.05	4.1%	1.19	91.0
Small	16,150	0.52	0.50	0.03	5.6%	0.46	90.1
Coastal	38,381	1.29	1.23	0.06	4.5%	2.16	88.8
Inland	36,050	1.80	1.69	0.11	6.0%	3.84	93.7
No SCTD	69,976	1.52	1.44	0.08	5.5%	5.72	91.1
No Load Control (SCTD or Summer Saver)	65,797	1.49	1.43	0.07	4.5%	4.31	90.9
Low Income*	23,117	1.32	1.27	0.05	3.6%	1.08	91.0
Non-Low Income*	36,161	1.60	1.51	0.09	6.1%	3.40	90.9
Enroll. Year – 2012*	20,871	1.52	1.49	0.03	2.4%	0.72	91.0
Enroll. Year – 2013*	6,641	1.53	1.51	0.01	1.0%	0.09	91.1
Enroll. Year – 2014*	26,473	1.48	1.38	0.10	6.9%	2.71	90.9
Enroll. Year – 2015*	11,812	1.43	1.36	0.07	4.8%	0.81	90.9
Notification – Email Only*	43,573	1.49	1.43	0.06	4.3%	2.74	90.9
Notification – Text Only*	11,277	1.43	1.39	0.05	3.3%	0.52	91.0
Notification – Both*	9,592	1.56	1.45	0.11	7.3%	1.08	91.1
Net Energy Metered	7,331	0.90	0.64	0.26	-38.7%	1.91	92.2
Electric Vehicles	1,637	2.21	1.96	0.25	11.3%	0.41	90.4

* Participants excluding load control (no SCTD or Summer Saver).

The PTR customers who were also enrolled in Summer Saver had higher incremental[1] event hour load reductions overall, with an average of 0.27 kW (14.7%). Table ES-2 summarizes the incremental impacts associated with these dually enrolled customers, for the Summer Saver event hours of 3 p.m. to 6 p.m.

[1] Attributable to the PTR event and not to AC cycling.

Table ES-2: Summer Saver Dually Enrolled in PTR Ex Post Load Impact Estimates by Customer Category - Average 2015 Event (3 p.m. to 6 p.m.)

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	4,179	1.84	1.57	0.27	14.7%	1.13	92.5
Summer Saver – 50% Cycling	1,487	2.09	2.10	-0.01	-0.4%	-0.01	92.9
Summer Saver – 100% Cycling	2,690	1.69	1.27	0.42	24.8%	1.12	92.3

ES.2.2 *SCTD Ex Post Evaluation*

There were four SCTD event days in 2015 which overlapped with the August and September PTR events. Participants received either a 4 degree setback on their thermostats or 50% AC cycling. The average temperature during SCTD events was 92.1°F. Table ES-3 shows the average and aggregate SCTD *ex post* load impact estimates for the overall SCTD group, those dually enrolled in PTR, and those only enrolled in SCTD. Participants dually enrolled in the two programs had the highest event hour load reduction with an average of 0.52 kW, representing 21.4% of the reference load. The average aggregate load reduction for the dually enrolled group was 3.44 MW. Generally, the participants with 4 degree setbacks had higher event hour load reductions, averaging 0.59 kW in the overall SCTD group, compared to those with 50% AC cycling, who averaged 0.43 kW.

Table ES-3: SCTD Ex Post Load Impact Estimates by Customer Category - Average 2015 Event (2 p.m. to 6 p.m.)*

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	6,602	2.45	1.93	0.52	21.4%	3.44	92.1
4 Degree Setback	3,511	2.51	1.92	0.59	23.5%	2.05	92.0
50% Cycling	3,002	2.38	1.94	0.43	18.4%	1.30	92.1
PTR	3,899	2.46	1.82	0.63	25.9%	2.47	92.1
PTR – 4 Deg. Setback	2,085	2.52	1.82	0.70	28.0%	1.46	92.0
PTR – 50% Cycling	1,746	2.39	1.84	0.54	22.9%	0.95	92.2
SCTD Only	2,703	2.45	2.08	0.37	15.1%	0.99	92.0
SCTD Only – 4 Degree Setback	1,426	2.50	2.08	0.42	17.0%	0.60	92.1
SCTD Only – 50% Cycling	1,256	2.37	2.08	0.29	12.4%	0.36	92.0

* Participants excluding Summer Saver load control.

ES.3 Ex Ante Evaluation Summary

The ex ante evaluation is based on taking the results from the ex post analysis and using them to estimate per participant impacts for different weather scenarios and then multiplying these by forecasts of enrollment for different participant segments.

The current PTR enrollment is approximately 75,000 SDG&E residential customers. Of these, approximately 4,200 are dually enrolled in the Summer Saver Program. SDG&E forecasts that the SCTD program will grow from around 7,600 participants to approximately 15,600 by the end of 2017, with around 60% of that total jointly participating in PTR.

Similar to last year (2014), the weather conditions in 2015 were particularly hot and generally fell in line with the 1-in-10 weather scenarios used for the *ex ante* analysis. Table ES-3 shows the average hourly resource availability (RA) estimates for each of the participant groups and sub-groups, for the two types of weather conditions. The 1-in-10 estimates are higher and more indicative of years similar in weather to 2016, while the 1-in-2 estimates are lower and represent years with more temperate weather. The PTR-only group is estimated to have average event hour load impacts of 0.05 kW in 1-in-10 conditions and 0.04 kW in 1-in-2 conditions. The dually enrolled PTR-SCTD participants are estimated to have the highest average event hour load impacts of 0.51 kW in 1-in-10 scenarios and 0.36 kW in 1-in-2 scenarios.

Table ES-4: Ex Ante Average Hourly Load Impact Estimates by Customer Category – 2016 Typical Event Hours

Program Segment and Weather Scenario			Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean Temp. °F
PTR Only	**Overall**	**1-in-10**	1.42	1.36	0.05	3.8%	3.60	86.59
		1-in-2	1.17	1.13	0.04	3.3%	2.59	80.59
PTR/SS	**100% Cycle**	**1-in-10**	1.64	1.32	0.32	19.6%	0.90	89.18
		1-in-2	1.31	1.08	0.23	17.4%	0.64	82.05
	50% Cycle	**1-in-10**	2.04	1.98	0.06	3.0%	0.10	90.57
		1-in-2	1.57	1.53	0.04	2.6%	0.06	82.83
	Overall	**1-in-10**	1.79	1.55	0.23	13.1%	1.02	89.69
		1-in-2	1.41	1.24	0.16	11.7%	0.72	82.33
PTR/SCTD	**4 Degree Setback**	**1-in-10**	2.06	1.50	0.57	27.5%	1.82	88.24
		1-in-2	1.59	1.18	0.40	25.4%	1.30	81.52
	50% Cycle	**1-in-10**	1.96	1.53	0.44	22.2%	1.18	88.35
		1-in-2	1.51	1.20	0.31	20.5%	0.84	81.58
	Overall	**1-in-10**	2.02	1.51	0.51	25.3%	3.08	88.28
		1-in-2	1.55	1.19	0.36	23.4%	2.20	81.54
SCTD Only	**4 Degree Setback**	**1-in-10**	2.09	1.73	0.35	17.0%	0.79	88.39
		1-in-2	1.62	1.36	0.25	15.6%	0.56	81.60
	50% Cycle	**1-in-10**	1.98	1.74	0.24	12.1%	0.48	88.43
		1-in-2	1.53	1.36	0.17	11.1%	0.34	81.62
	Overall	**1-in-10**	2.04	1.74	0.30	14.9%	1.30	88.42
		1-in-2	1.41	1.24	0.16	11.7%	0.92	82.33

1

Introduction

This report provides estimates of the 2015 ex post and ex ante load impacts for San Diego Gas and Electric's (SDG&E) Peak Time Rebate (PTR) program. The program provides customers with notification on a day-ahead basis that a PTR event will occur on the following day. In emergency situations, a PTR event can be called on a day-of basis to help address an emergency, but day-of events are not the primary design or intended use of the program.

This report also provides estimates of the 2015 ex post and ex ante load impacts for the Small Customer Technology Deployment (SCTD) program. SDG&E continues to offer free programmable communicating thermostats (PCT) with DR enabling technology to residential customers through the SCTD program. Half of SCTD customers have their central air-conditioner cycled by 50% through the thermostat and half receive a 4 degree thermostat setback during PTR events. Although PTR events are 7 hours long from 11 a.m. – 6 p.m. the SCTD thermostats will only be curtailed for 4 hours, typically from 2 p.m. – 6 p.m.

1.1 Evaluation Objectives

This project has four principal objectives:

- Estimate *ex post* load impacts for the PTR opt-in and SCTD programs,
- Make comparisons of the impacts of several program participant sub-groups,
- Estimate conservation effects resulting from the installation of SCTD thermostats, and
- Estimate *ex ante* load impacts for the PTR opt-in and SCTD programs for the future.

1.2 Opt-In Peak Time Rebate Program Overview

The PTR program provides customers with notification on a day-ahead basis that a PTR event will occur on the following day. In emergency situations, an PTR event can be called on a day-of basis to help address an emergency, but day-of events are not the primary design or intended use of the program. PTR is a two-level incentive program, providing a basic incentive level ($0.75/kWh) to customers that reduce energy use through manual means and a premium incentive ($1.25/kWh) to customers that reduce energy use through automated demand response (DR) enabling technologies. The PTR bill credit is calculated based on their event day reduction in electric usage below their established customer-specific reference level (CRL). The program is marketed under the name Reduce Your Use (RYU) and is an opt-in program for residential customers. CPUC Decision D-13-07-003 directed SDG&E to require residential customers to enroll in PTR to receive a bill credit beginning in 2014. Prior to 2014, the PTR program was a default program for all SDG&E residential customers with an opt-in component whereby customers could receive notification of events.

Table 1-1 summarizes the PTR program enrollment. A total of nearly 75,000 customers had enrolled in PTR as of the last event of 2015 (September 11th). Six percent of these participants were dually enrolled in the Summer Saver Program and six percent were dually enrolled in the SCTD program. These dually enrolled participants were eligible for the premium incentive ($1.25/kWh) for reducing energy use through automated DR enabling technologies. Not all of the SCTD participants enrolled in PTR, however. Of the roughly 7,600 SCTD participants, only 58% of them also enrolled in PTR.

Approximately 65% of PTR participants enrolled for email notification only, with another 15% enrolled jointly in email and text notifications. Text message-only notifications account for most of the remaining participants at 17%. Only 2% of participants received only telephone notifications.

Table 1-1: Summary of PTR Enrollment by Customer Category[1]

Customer Category	All PTR Participants	
	N	**%**
PTR without Enabling Technology	65,797	88%
Dually enrolled in Summer Saver	4,177	6%
Dually enrolled in SCTD	4,457	6%
SCTD not enrolled in PTR[2]	3,190	N/A
Coastal Climate Zone	38,381	52%
Inland Climate Zone	36,050	48%
Notification Type – Email Only	48,712	65%
Notification Type – Text Only	12,725	17%
Notification Type – Both	11,410	15%
All Participants	**74,433**	**100%**

[1] As of the end of September 2015

[2] These customers are not included in the total PTR enrollment counts

1.3 Overview of the SCTD Residential Program

The program provides demand response enabling technology to residential. In 2015 the enabling technology was offered at no cost to qualifying customers through the PTR program. The enabling technology offered in 2015 was the Ecobee Smart Si thermostat (https://www.ecobee.com/faqs/smartsi/). This thermostat is signaled by SDG&E through Wi-Fi through use of an Ecobee utility portal. Two cycling strategies were implemented. The first strategy was a four degree thermostat setback and the other was a 50% AC cycling strategy. Customers were randomly assigned to one of the two strategies. Although PTR events were seven hours long, SCTD participant's thermostats were curtailed for 4 hours, typically from 2 p.m. – 6 p.m.

Since PTR is opt-in as of May 2014, a customer must enroll to receive a bill credit. Not all SCTD customers enrolled themselves in PTR. If the customers did not enroll in PTR their thermostat was curtailed but they did not receive a bill credit.

SDG&E also offers an air-conditioning cycling program called Summer Saver. Residential customers are either enrolled on a 50% cycling option or a 100% cycling option. Some of these customers are also enrolled in PTR and receive the higher bill credit of $1.25. The Summer Saver program is run by a third party aggregator and the contract expires after summer of 2016.

1.4 Overview of Methods

For both the overall opt-in PTR population and the SCTD participants, Itron estimated *ex post* impacts using aggregate models for participants using a control group based on a set of accounts from the non-alert population that has been matched based on their similarity with the participant accounts. These aggregate models will mitigate the variability from the individual accounts while the control group will account for other factors that influence consumption for both the alert participant and non-participant populations. The models were estimated for a number of participant segments to ensure that the results have the granularity necessary to address all research questions.

The ex ante forecasts combined the models developed for the ex post analysis, an enrollment forecast provided by SDG&E, and normal weather forecasts for both 1 in 2 and 1 in 10 weather scenarios for SDG&E and Cal ISO system peaks.

For the purposes of this report, the SCTD *ex ante* impacts are provided separately as part of the SCTD program. Therefore, the opt-in PTR *ex ante* load impact estimates specifically refer to the non-SCTD customers.

1.5 Report Organization

The remainder of this report contains the following sections:

- Ex Post Methods,
- Ex Post Results,
- Ex Ante Methodology and Results,
- Appendix A – Ex Post Impact Tables, and
- Appendix B – Ex Ante Forecast Tables

2

Ex Post Methods and Validation

To estimate ex post load impacts for the PTR opt-in and SCTD programs, Itron developed regression-based models using a difference in differences (DiD) format, comparing participant and reference aggregate hourly residential loads. The reference loads for these models were calculated from matched control groups selected from SDG&E's population of non-program participants. The methods for matching and ex post estimations are described in detail below.

2.1 Control Group Selection

Control groups were used to measure impacts from the PTR and SCTD programs. The use of control groups helps to improve the estimation of reference loads and impacts when obfuscating conditions exist, such as: a) few events, with the potential of these events being the hottest days during the summer, b) some events occurring during non-cooling months and/or months where hot weather is not typical, c) small average impacts relative to the overall size of the average participant load during the events. To develop control groups for this evaluation, Itron used a Stratified Propensity Score Matching (SPSM) method.

2.1.1 Pre-Matching Stratification and Design

Prior to generating propensity scores, the participant sites were stratified to control for variables that may observationally influence participation. Strata were defined using a combination of climate zone (coastal and inland) and annual usage group (small, medium, large). Low income, Net Energy Metering (NEM), Summer Saver, and electric vehicle charging participants were each handled separately as they required non-participant populations that were equivalent for control group matching. In total, this provided 25 different strata from which to develop control groups:

- PTR – Coastal (Small/Medium/Large) and Inland (Small/Medium/Large),
- Low Income – Coastal (Small/Medium/Large) and Inland (Small/Medium/Large),
- SCTD – Coastal (Small/Medium/Large) and Inland (Small/Medium/Large),
- Electric Vehicles, and
- NEM – Coastal (Small/Medium/Large) and Inland (Small/Medium/Large).

Using these customer segments and strata, the SPSM methodology used a logistic regression (logit) model to estimate the probability of participation within each stratum. The matching routine paired each participant with a non-participant that had the most similar estimated probability of participation.

The control group selection was based on a two-stage approach. In the first stage, PSM was used to identify an initial set of ten control group candidate premises for every participant based on variables calculated using 2014 monthly billing data. After requesting the hourly interval data for these candidate premises, a second stage of PSM selected the final control group using variables developed from interval data. Second-stage matching was done separately for all PTR participants, as well as for the other various participant subgroups, namely, NEM, electric vehicle (EV), SCTD, Summer Saver, and Low Income.

After experimenting with various combinations, the final set of variables chosen for the first stage's logit model included: monthly kWh usage, average monthly kWh, correlation coefficients between monthly CDD65 and kWh usage for summer and winter months, coefficient of variation of kWh usage, ratio of average monthly usage between summer and winter months, ratio of summer kWh usage to total CDD65, and dummy variables for Low Income and Summer Saver customers. Also, accounts were compared to databases of 2013-2014 tracking data for energy efficiency programs and Energy Savings Assistance Programs (ESAP) to create an additional dummy variable for EE program participation for matching.

The second stage of matching saw the additional inclusion of hourly kWh usage during the event hours for summer hot days[1], correlation coefficient of usage and cooling degree hours (CDH65) on hot days, coefficient of variation of kWh usage during event hours, as well as monthly event hour kWh usage.

2.1.2 Propensity Score Matching Results

One of the key methods of assessing the effectiveness of the PSM is to conduct t-tests on the independent variables used in the logistic regression for the groups both before and after matching. If the matching is successful, the participant and control groups should not be statistically significantly different for these variables. The results of the t-tests for both stages of the PTR and SCTD participant PSM matching show that none of the PSM variables had a statistically significant difference after selecting the control premise candidates. A final assessment of the efficacy of the PSM is a graphical comparison of the annual load profiles of

[1] For hot days, Itron selected the twelve non-event days in 2014 with the highest average peak temperatures across the different weather stations used for the analysis. The dates with these peak temperatures were the 29th and 30th of April, 1st, 2nd, 13th, and 16th of May, 8th of September, 2nd, 3rd, 6th, and 7th of October, and the 5th of November, 2014. Load profiles by season were also compared to confirm that the groups were sufficiently similar.

the participant premises with the control premises before and after matching. As seen in Figure 2-1, the candidate premises selected in the stage one PSM have virtually the same profile as the participants, whereas the load profile for all control premises before matching has substantially lower consumption. Figure 2-2 shows a comparison of the average hourly load profile on hot days for the participant and control groups before and after matching. The event window is marked by vertical lines and it is clear that the control and participants line up much more closely after the matching during these key hours. While the t-test results presented above are strong evidence that the PSM method worked well, these visual representations provide further confirmation of its success.

Figure 2-1: Comparison of Annual Monthly Load Profiles for Control Group with All and Only Matched Participants – PTR Stage One PSM

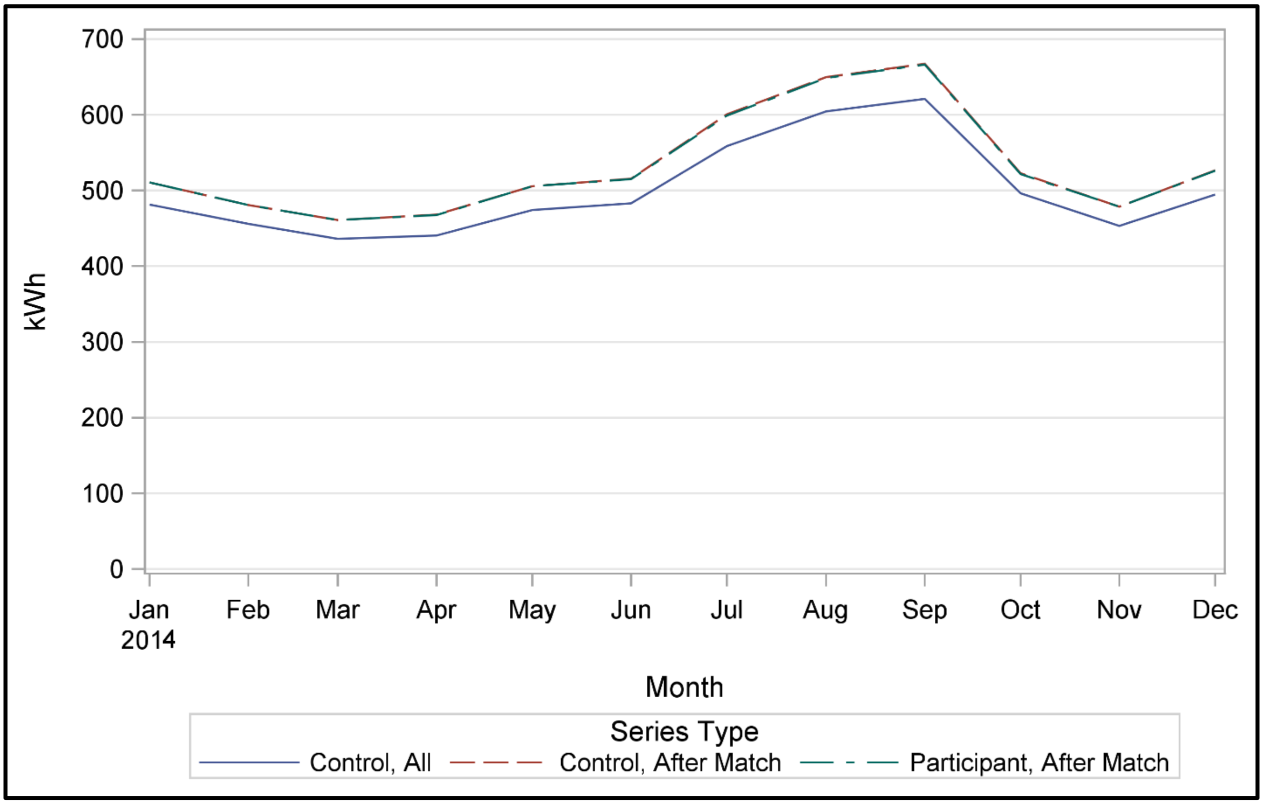
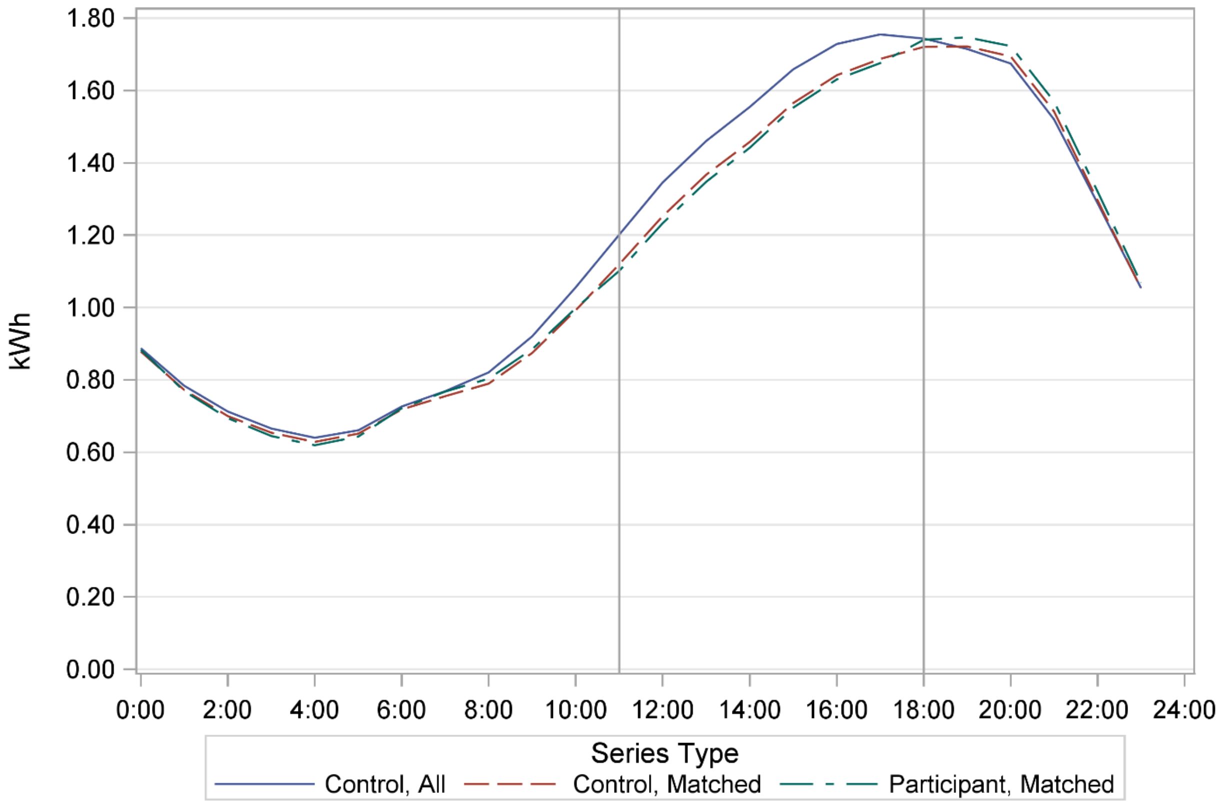


Figure 2-2: Comparison of Hourly Hot Day Load Profiles for Control Group with All and Only Matched Participants – PTR Stage Two PSM



2.2 Estimating Ex Post Load Impacts

Following validation of the control group matching processes, *ex post* load impact models were developed based on aggregate hourly residential loads for both the opt-in alert customers and the matched control groups for each of the identified segments. Load impacts were estimated using a DiD methodology, controlling for event hours and factors such as weather conditions, day of the week, and month.

2.2.1 PTR Ex Post Estimation

A number of different combinations of specifications were tested in developing the aggregate *ex post* model. The final model specifications used for the analysis included variables for hour, day of the week, month, cooling degree hours (CDH65), and event indicators. Additionally, because enrollment increased during the summer, the model included a binary variable to indicate whether a participant was "active," meaning that they had opted in to the program by the date in question. This means that for periods prior to enrollment, some participants were effectively part of the control group.

Expressed symbolically, the model is as follows:

$$
\begin{aligned}
kWh_t = \beta_0 &+ \sum_d \beta_1^d \times DOW_d + \sum_m \beta_2^m \times Month_m + \sum_h \beta_3^h \times Hour_h \\
&+ \sum_d \sum_h \beta_4^{h,d} \times Hour_h \times DOW_d + \sum_m \sum_h \beta_5^{h,m} \times Hour_h \times Month_m + \beta_6 \\
&\times CDH65 + \sum_h \beta_7^h \times Hour_h \times CDH65_h \\
&+ \sum_h \beta_8^h \times Hour_h \times CDH65_h \times Event \\
&+ \sum_h \beta_9^h \times Hour_h \times CDH65_h \times Event \times InactivePart \\
&+ \sum_h \beta_{10}^h \times Hour_h \times CDH65_h \times Event \times ActivePart + \varepsilon_t
\end{aligned}
$$

Where

kWh_t	Is the kWh in hour t
β_0	Is the intercept
β_1^d	Is the set coefficient for day of week (DOW) d
β_2^m	Is the set of coefficient for month m
β_3^h	Is the set of coefficients for hour h
$\beta_4^{h,d}$	Is the set of coefficients for the interaction of hour h and DOW d
$\beta_5^{h,m}$	Is the set of coefficients for the interaction of hour h and month m
β_6	Is the coefficient for cooling degree hours (CDH)
β_7^h	Is the set of coefficients for CDH interacted with hour h
β_8^h	Is the set of coefficients for the interaction of CDH with event days
β_9^h	Is the set of coefficients for interaction of CDH with hour h and event days for inactive participants
β_{10}^h	Is the set of coefficients for interaction of CDH with hour h and event days for active participants
ε_t	Is the error

The program impacts were based on the interaction of four variables: the event day flag, the active participant flag, the hour, and the cooling degree hours (CDH). The interaction with CDH served two purposes. First, it allowed for the estimation of savings for individual events, since temperatures were obviously not the same. Second, it allows for the use of the results to develop ex ante impacts. The remainder of the variables allowed controlling for weather and other periodic factors that determine aggregate customer loads.

2.2.2 SCTD Ex Post Estimation

The model used to estimate savings for the SCTD participants was nearly identical to that applied to the PTR opt-in alert customers. Using the population of SCTD participants and its associated matched control group, *ex post* impacts were estimated in an analogous fashion to the PTR groups. Each set of estimated impacts were grouped by SCTD cycling strategy (4 degree setback or 50% cycling) as well as overall.

2.2.3 Data Attrition

Underlying all of the analysis were the many steps that were necessary to integrate the many data sources into the structure required for analysis. These steps, in addition to diagnostics to identify outliers or other problematic data, mean that participants analyzed in the estimation of impacts was lower than the actual number of active participants. In the case of this analysis, the primary source of data attrition was a lack of information necessary to associate the appropriate weather station with a participant, followed by confusing or contradictory program participation information.

Table 2-2 shows the count of PTR participants for each stage of the analysis enrolled by the primary analysis sub-groups. Prior to the first stage of PSM, participants were excluded from the analysis if they had an average monthly consumption or coefficient of variation greater than 5 standard deviations from the mean. Participants were also excluded if any of the inputs for the PSM logistic regression were missing (CDD, monthly consumption, etc.). NEM participants dropped if they became NEM at some point in 2014, suggesting that they did not have a full year of pre-treatment data with NEM consumption. After the second stage of PSM, additional criteria were implemented that the difference between matched propensity scores was less than 0.0005 and that participants with PV generation that were not identified as NEM were excluded. These counts represent the final set of participants used to model the *ex post* impacts. The aggregate results incorporate the initial counts of participants to determine the total impact of the programs for each of the sub-groups.

Table 2-1: PTR Participant Counts by Analysis Stage

Participant Group	Initial Counts	After PSM Phase 1	After PSM Phase 2
All PTR	74,433	69,704	69,610
PTR with no Load Control	65,797	61,898	61,829
PTR Dually Enrolled in SCTD*	3,899	3,797	3,786
PTR Dually Enrolled in Summer Saver	4,177	4,009	3,995
SCTD Only*	2,703	2,489	2,483
Net Energy Metered	7,331	4,570	4,504

* Participants excluding Summer Saver load control.

Unless the data attrition results in a shortage of the needed accounts to estimate the impacts, the main concern is whether it results in bias. That is, is there some systematic difference associated with the reason for dropping the accounts that would strongly influence the results in one direction or the other? While this is typically difficult to determine with certainty, in the case of this analysis there is no reason to assume that the removal of the participants had any influence on the results.

3

Ex Post Results

3.1 Comparison of Ex Post Load Impacts

In 2015, SDG&E called a total of four PTR events and four SCTD events. The events were all on the same days for both programs: August 28th and September 9th-11th. The event hours for PTR were from 11 a.m. to 6 p.m. and the event hours for SCTD were from 2 p.m. to 6 p.m.

This section presents the *ex post* load impact estimates for each of the analysis program participant sub-groups. These are:

- All PTR customers,
- PTR customers without SCTD,
- PTR customers without Load Control (SCTD or Summer Saver),
- PTR customers Dually Enrolled in Summer Saver, by Cycling Strategy,
- PTR customers Dually Enrolled in SCTD, by Cycling Strategy,
- SCTD customers not enrolled in PTR, by Cycling Strategy,
- PTR customers without Load Control by Notification Type,
- PTR customers without Load Control by Low Income Status,
- PTR customers without Load Control by Year of Enrollment,
- PTR customers with Net Energy Metered, and
- PTR customers with Electric Vehicle charging.

Table 3-1, Table 3-2, and Table 3-3 present a high-level summary of these sub-groups for the PTR and SCTD programs, respectively.

The PTR participants who were dually enrolled in the Summer Saver (SS) program were evaluated in terms of their incremental impacts attributable to just PTR and not AC cycling. Their incremental impacts are shown in Table 3-2 by cycling strategy. The load reduction from the SS participants was significantly larger (14.7%) than that of the general PTR population with no load control (5.4%).

Table 3-1: PTR Ex Post Load Impact Estimates by Customer Category - Average 2015 Event (11 a.m. to 6 p.m.)

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	74,433	1.54	1.45	0.08	5.4%	6.07	91.2
Large	32,166	2.35	2.21	0.14	6.0%	4.51	91.9
Medium	26,115	1.13	1.08	0.05	4.1%	1.19	91.0
Small	16,150	0.52	0.50	0.03	5.6%	0.46	90.1
Coastal	38,381	1.29	1.23	0.06	4.5%	2.16	88.8
Inland	36,050	1.80	1.69	0.11	6.0%	3.84	93.7
No SCTD	69,976	1.52	1.44	0.08	5.5%	5.72	91.1
No Load Control (SCTD or SS)	65,797	1.49	1.43	0.07	4.5%	4.31	90.9
Low Income*	23,117	1.32	1.27	0.05	3.6%	1.08	91.0
Non-Low Income*	36,161	1.60	1.51	0.09	6.1%	3.40	90.9
Enroll. Year – 2012*	20,871	1.52	1.49	0.03	2.4%	0.72	91.0
Enroll. Year – 2013*	6,641	1.53	1.51	0.01	1.0%	0.09	91.1
Enroll. Year – 2014*	26,473	1.48	1.38	0.10	6.9%	2.71	90.9
Enroll. Year – 2015*	11,812	1.43	1.36	0.07	4.8%	0.81	90.9
Notification – Email Only*	43,573	1.49	1.43	0.06	4.3%	2.74	90.9
Notification – Text Only*	11,277	1.43	1.39	0.05	3.3%	0.52	91.0
Notification – Both*	9,592	1.56	1.45	0.11	7.3%	1.08	91.1
Net Energy Metered	7,331	0.90	0.64	0.26	-38.7%	1.91	92.2
Electric Vehicles	1,637	2.21	1.96	0.25	11.3%	0.41	90.4

* Participants excluding load control (no SCTD or Summer Saver).

Table 3-2: PTR Dually Enrolled in Summer Saver Ex Post Load Impact Estimates - Average 2015 Event (3 p.m. to 6 p.m.)

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	4,179	1.84	1.57	0.27	14.7%	1.13	92.5
Summer Saver – 50% Cycling	1,487	2.09	2.10	-0.01	-0.4%	-0.01	92.9
Summer Saver – 100% Cycling	2,690	1.69	1.27	0.42	24.8%	1.12	92.3

Table 3-3: SCTD Ex Post Load Impact Estimates by Customer Category - Average 2015 Event (2 p.m. to 6 p.m.)*

Customer Category	Mean Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	6,602	2.45	1.93	0.52	21.4%	3.44	92.1
4 Degree Setback	3,511	2.51	1.92	0.59	23.5%	2.05	92.0
50% Cycling	3,002	2.38	1.94	0.43	18.4%	1.30	92.1
PTR	3,899	2.46	1.82	0.63	25.9%	2.47	92.1
PTR – 4 Deg. Setback	2,085	2.52	1.82	0.70	28.0%	1.46	92.0
PTR – 50% Cycling	1,746	2.39	1.84	0.54	22.9%	0.95	92.2
SCTD Only	2,703	2.45	2.08	0.37	15.1%	0.99	92.0
SCTD Only – 4 Degree Setback	1,426	2.50	2.08	0.42	17.0%	0.60	92.1
SCTD Only – 50% Cycling	1,256	2.37	2.08	0.29	12.4%	0.36	92.0

* Participants excluding Summer Saver load control.

Table 3-4 presents the *ex post* load impacts for PTR participants without any load control (SCTD or Summer Saver), including those that are Net Energy Metered. These results are presented by each of the four event days in 2015. Table 3-5 presents the *ex post* load impacts for all SCTD participants by event date. Table 3-6 and Table 3-7 present the *ex post* load impacts for the 4 degree setback and 50% AC cycling subgroups, respectively.

Table 3-4: PTR with No Load Control (Including NEM) Ex Post Load Impact Estimates – By Event Date (11 a.m. to 6 p.m.)

Event Date	Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
August 28th, 2015	71,497	1.40	1.32	0.08	5.4%	5.37	90.66
September 9th, 2015	71,497	1.52	1.44	0.08	5.6%	6.08	94.10
September 10th, 2015	71,497	1.46	1.38	0.08	5.5%	5.73	92.46
September 11th, 2015	71,497	1.40	1.33	0.06	4.6%	4.59	86.86
Average 2015 Event	71,497	1.44	1.37	0.08	5.3%	5.44	91.02

Table 3-5: SCTD Overall Ex Post Load Impact Estimates – By Event Date (2 p.m. to 6 p.m.)

Event Date	Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
August 28th, 2015	6,531	2.53	1.88	0.65	26.0%	4.25	92.2
September 9th, 2015	6,616	2.57	1.97	0.60	23.5%	3.96	95.0
September 10th, 2015	6,625	2.35	2.04	0.30	13.1%	2.02	93.3
September 11th, 2015	6,635	2.36	1.83	0.53	22.5%	3.50	87.8
Average 2015 Event	6,602	2.45	1.93	0.52	21.4%	3.44	92.1

Table 3-6: SCTD 4 Degree Setback Ex Post Load Impact Estimates – By Event Date (2 p.m. to 6 p.m.)

Event Date	Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
August 28th, 2015	3,481	2.57	1.87	0.70	27.5%	2.44	92.2
September 9th, 2015	3,516	2.63	1.97	0.67	25.5%	2.35	95.0
September 10th, 2015	3,523	2.40	2.04	0.36	15.2%	1.28	93.3
September 11th, 2015	3,524	2.43	1.82	0.61	25.2%	2.14	87.7
Average 2015 Event	3,511	2.51	1.92	0.59	23.5%	2.05	92.0

Table 3-7: SCTD 50% Cycling Ex Post Load Impact Estimates – By Event Date (2 p.m. to 6 p.m.)

Event Date	Active Participants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
August 28th, 2015	2,972	2.48	1.90	0.58	23.8%	1.74	92.2
September 9th, 2015	3,007	2.49	1.98	0.51	20.4%	1.52	95.0
September 10th, 2015	3,009	2.28	2.05	0.23	10.1%	0.68	93.3
September 11th, 2015	3,018	2.27	1.85	0.42	18.6%	1.27	87.8
Average 2015 Event	3,002	2.38	1.94	0.43	18.4%	1.30	92.1

3.1.1 Peak Time Rebate (PTR) Total

Figure 3-1 and Table 3-8 show the hourly event load impacts for the overall PTR customer population compared with the reference loads. Across all 2015 events, there was a definitive load reduction during event hours (11 a.m. to 6 p.m.), averaging 0.08 kW per participant, representing an average reduction of 5.4% relative to the reference load. Average load reductions grew gradually, starting around 10 a.m. with 0.02 kW, peaking around 3-4 p.m. with 0.10 kW. In the hours following events, there are noticeable snapback effects, with an average hourly increase in load of 0.07 kW per customer from 6 p.m. to midnight. The average hourly aggregate load reduction from the 74,433 participants during event hours was 6.07 MW. The average temperature across all the events and the associated event hours was 91.2°F.

Figure 3-1: Hourly Load Profile for All PTR Customers – 2015 Event Average

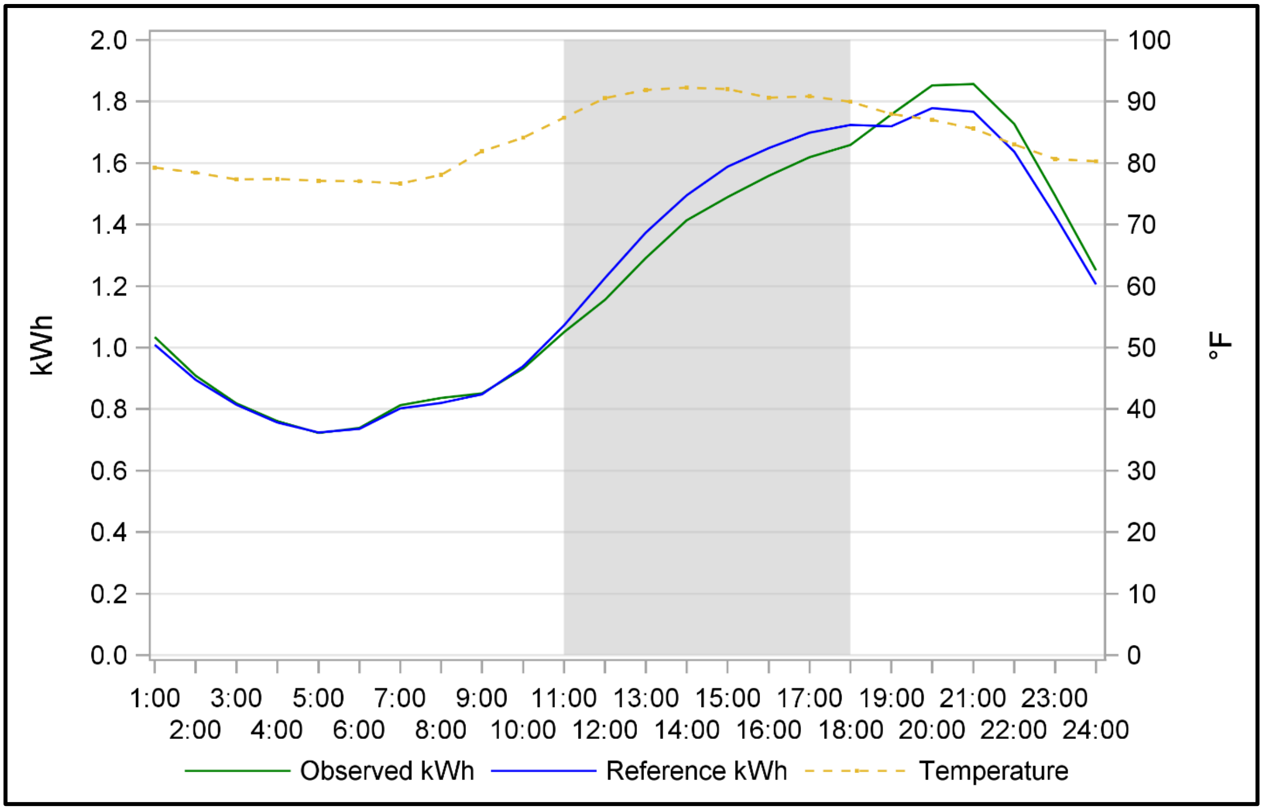


Table 3-8: Summary of Event Impacts for All PTR Customers – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	81.9	0.85	0.85	-0.003	-0.3%	74,433	-213
9:00	10:00	No	84.1	0.94	0.93	0.007	0.8%	74,433	539
10:00	11:00	No	87.4	1.07	1.05	0.022	2.1%	74,433	1,644
11:00	12:00	Yes	90.5	1.23	1.16	0.071	5.8%	74,433	5,254
12:00	13:00	Yes	91.9	1.37	1.29	0.082	6.0%	74,433	6,140
13:00	14:00	Yes	92.3	1.49	1.41	0.081	5.4%	74,433	6,059
14:00	15:00	Yes	92.0	1.59	1.49	0.100	6.3%	74,433	7,447
15:00	16:00	Yes	90.6	1.65	1.56	0.090	5.4%	74,433	6,662
16:00	17:00	Yes	90.8	1.70	1.62	0.081	4.7%	74,433	6,000
17:00	18:00	Yes	90.0	1.72	1.66	0.066	3.8%	74,433	4,920
18:00	19:00	No	88.0	1.72	1.76	-0.039	-2.3%	74,433	-2,904
19:00	20:00	No	87.0	1.78	1.85	-0.074	-4.1%	74,433	-5,488
20:00	21:00	No	85.6	1.77	1.86	-0.090	-5.1%	74,433	-6,678
Total - Entire Day			84.1	29.71	29.59	0.119	0.4%	74,433	8,854
Total - Event Hours			91.2	10.75	10.18	0.571	5.3%	74,433	42,482

<u>PTR by Climate Zone</u>

Figure 3-2 and Figure 3-3 show the hourly load profiles during 2015 events for PTR customers in the Coastal and Inland climate zones, respectively. The average temperature during event hours was 88.8°F for Coastal customers compared to 93.7°F for Inland customers. Perhaps owing to these differences in temperature, Inland participants had a higher average event hour load reduction of 0.11 kW compared to the Coastal participants' load reduction of 0.06 kW. The average aggregate load reduction during event hours was 2.16 MW (4.5%) for Coastal participants and 3.84 MW (6.0%) for Inland participants.

Figure 3-2: Hourly Load Profile for Coastal PTR Customers – 2015 Event Average

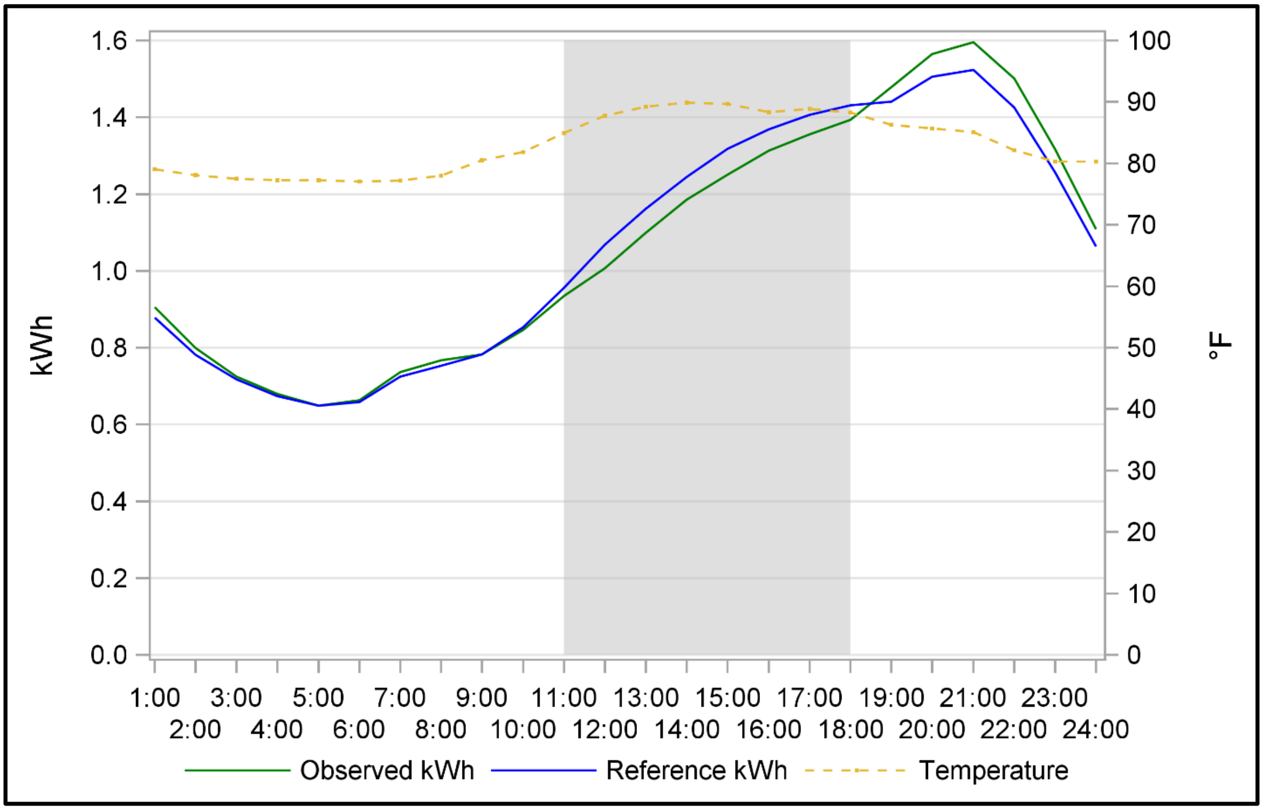
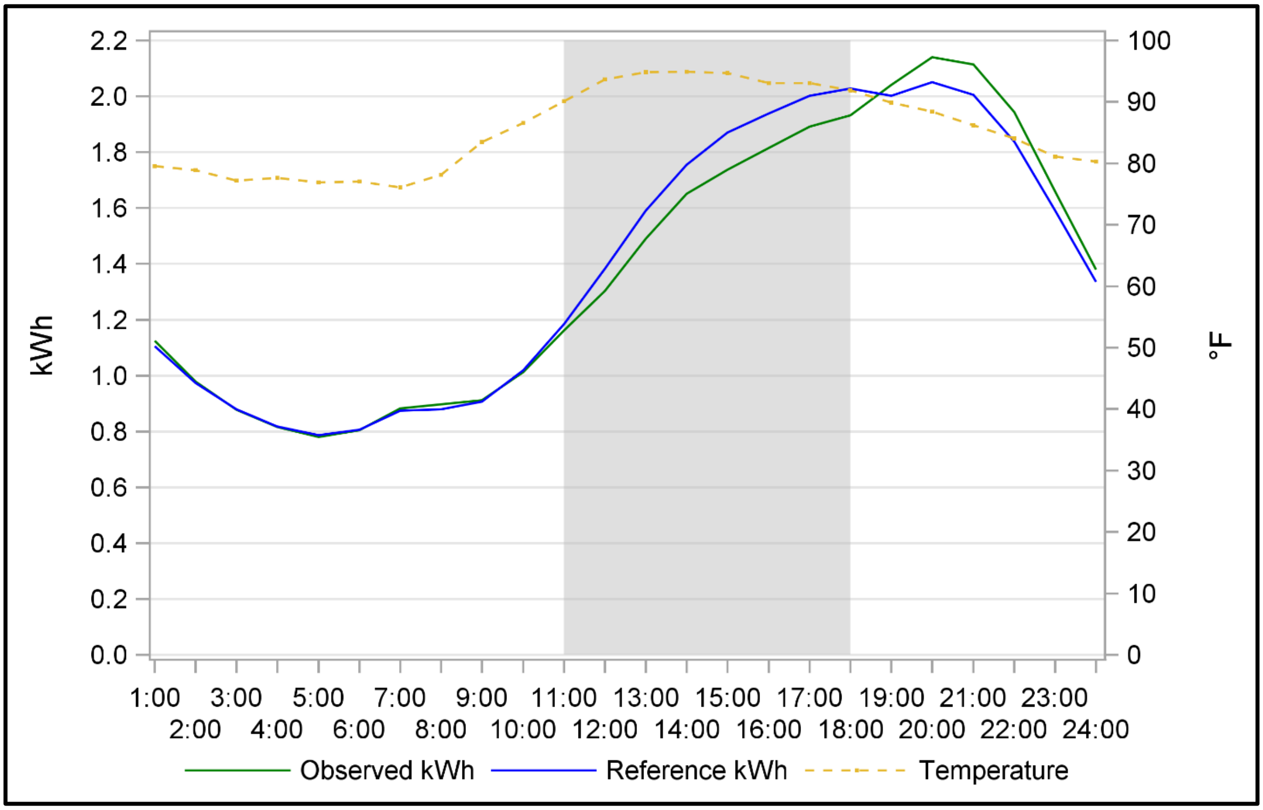


Figure 3-3: Hourly Load Profile for Inland PTR Customers – 2015 Event Average



PTR by Usage Size

The PTR participants were was stratified into three size categories based on their electric consumption – small, medium, and large. Figure 3-4, Figure 3-5, and Figure 3-6 show the average participant hourly load profiles during 2015 events for these three categories of customers. There are marked differences between each of them. Large participants had an average event hour load reduction of 0.14 kW, representing a total reduction of 4.51 MW (6.0%). Medium participants had an average event hour load reduction of 0.05 kW, representing a total reduction of 1.19 MW (4.1%). Lastly, small participants had an average load reduction of 0.03 kW, representing a total reduction of 0.46 MW (5.6%).

Figure 3-4: Hourly Load Profile for Large PTR Customers – 2015 Event Average

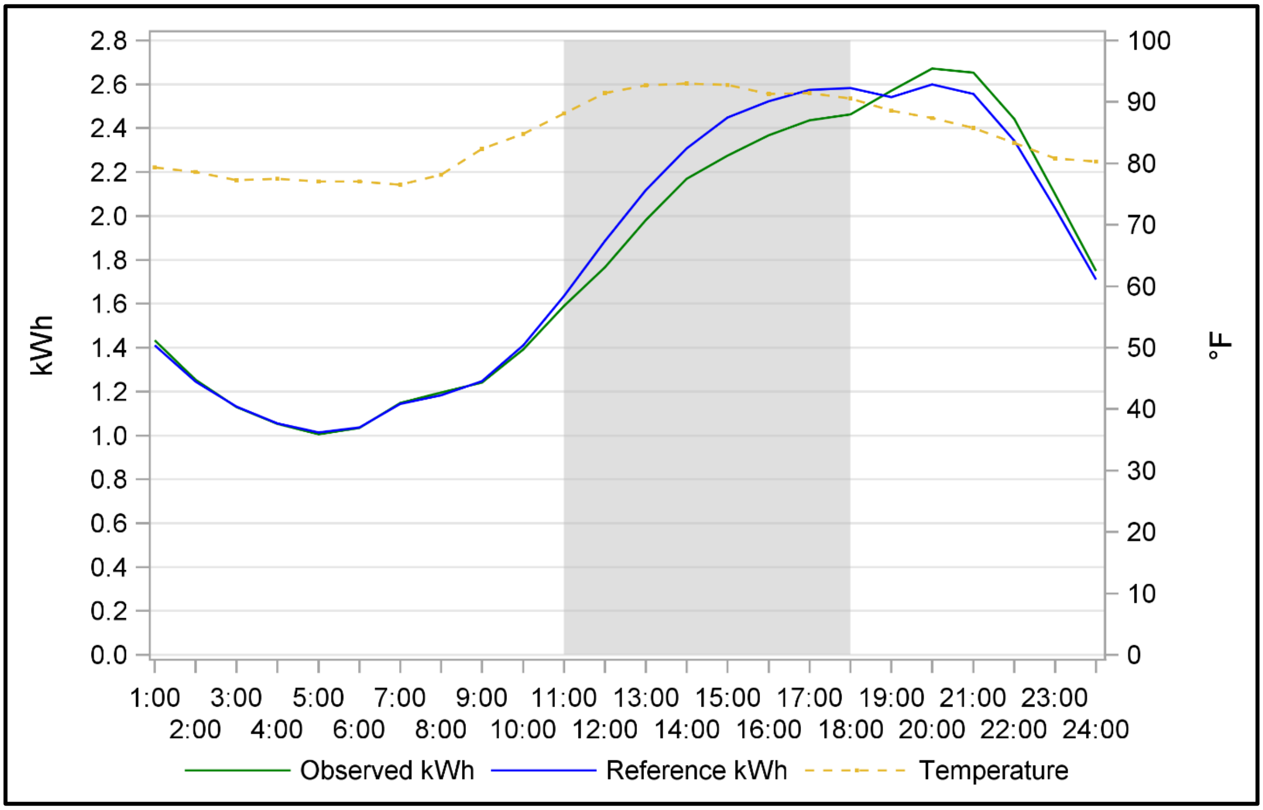


Figure 3-5: Hourly Load Profile for Medium PTR Customers – 2015 Event Average

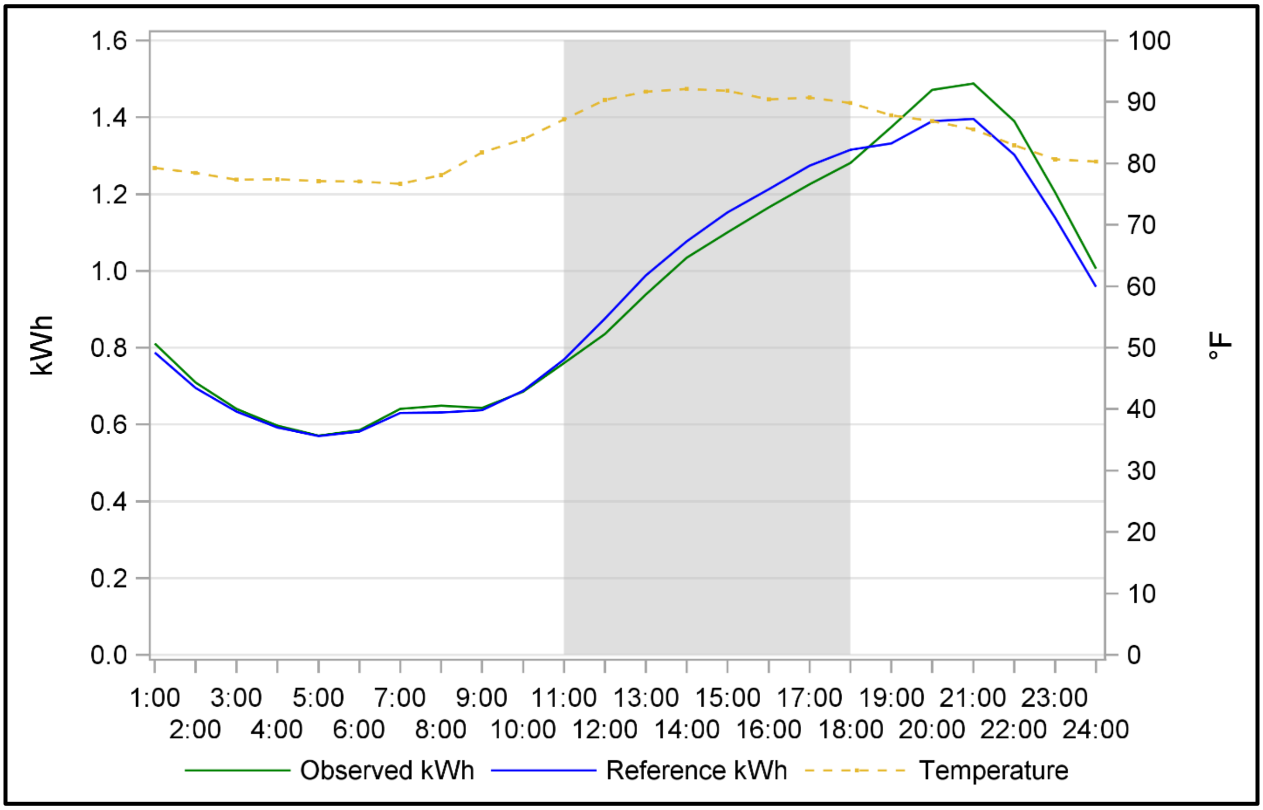
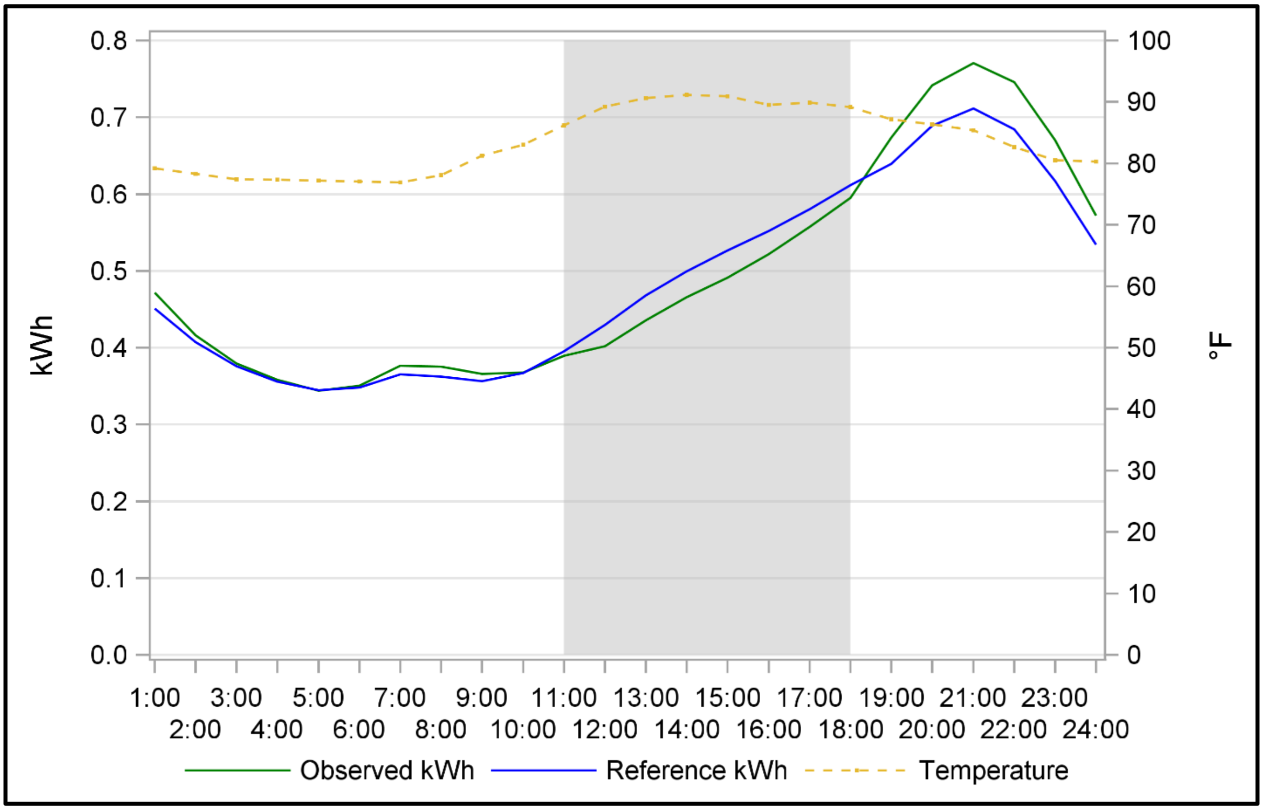


Figure 3-6: Hourly Load Profile for Small PTR Customers – 2015 Event Average



3.1.2 PTR without SCTD

Figure 3-7 and Table 3-9 show the hourly event load impacts for PTR customers that are not dually enrolled in the SCTD thermostat program. Although each of the four events were for both PTR and SCTD participants, there were significantly fewer SCTD participants than PTR participants. Therefore, the differences in load reduction between the overall PTR population and the PTR without SCTD population are relatively small. The average event hour load reduction for this latter group is the same at 0.08 kW. However, because of the lower participant count, the PTR without SCTD group had a slightly lower average aggregate event hour reduction with 5.72 MW (5.5%) than the overall PTR group, with 6.07 MW (5.4%).

Figure 3-7: Hourly Load Profile for PTR Customers without SCTD – 2015 Event Average

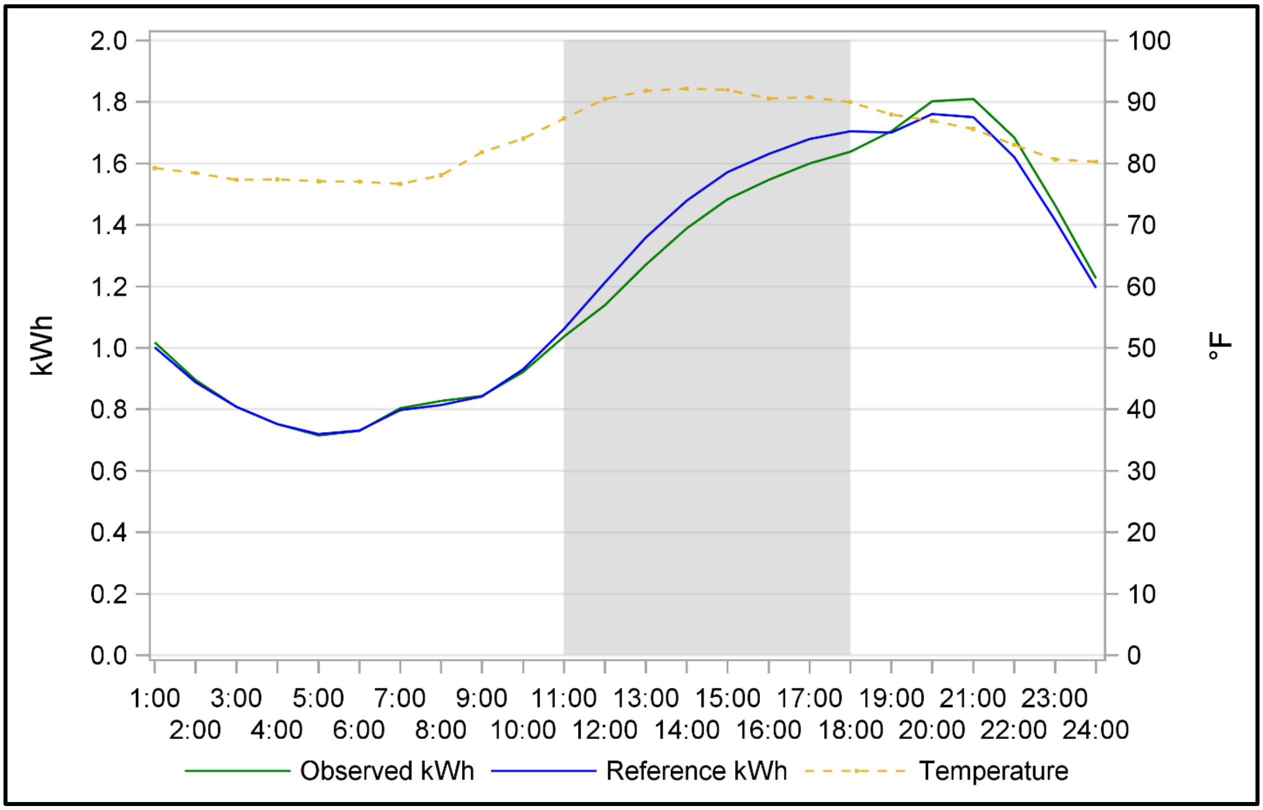


Table 3-9: Summary of Event Impacts for PTR Customers without SCTD – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	81.8	0.84	0.84	-0.002	-0.2%	69,976	-113
9:00	10:00	No	84.0	0.93	0.92	0.010	1.0%	69,976	680
10:00	11:00	No	87.3	1.06	1.04	0.026	2.4%	69,976	1,786
11:00	12:00	Yes	90.4	1.21	1.14	0.075	6.1%	69,976	5,216
12:00	13:00	Yes	91.8	1.36	1.27	0.088	6.5%	69,976	6,172
13:00	14:00	Yes	92.2	1.48	1.39	0.090	6.1%	69,976	6,286
14:00	15:00	Yes	91.9	1.57	1.48	0.089	5.7%	69,976	6,223
15:00	16:00	Yes	90.5	1.63	1.55	0.084	5.1%	69,976	5,871
16:00	17:00	Yes	90.8	1.68	1.60	0.079	4.7%	69,976	5,555
17:00	18:00	Yes	89.9	1.71	1.64	0.068	4.0%	69,976	4,727
18:00	19:00	No	87.9	1.70	1.70	-0.005	-0.3%	69,976	-334
19:00	20:00	No	86.9	1.76	1.80	-0.041	-2.3%	69,976	-2,868
20:00	21:00	No	85.6	1.75	1.81	-0.059	-3.4%	69,976	-4,132
Total - Entire Day			84.0	29.43	29.11	0.320	1.1%	69,976	22,371
Total - Event Hours			91.1	10.64	10.07	0.572	5.4%	69,976	40,050

3.1.3 PTR without Any Load Control (SCTD or Summer Saver)

Another participant subgrouping saw the additional exclusion of Summer Saver participants from the overall PTR group. This leaves a PTR participant group without the effects of any load control devices during events. Figure 3-8 and Table 3-10 show the hourly event load impacts for this group. The average event hour load reduction for this group was 0.07 kW, which was slightly lower than the 0.08 kW for the overall PTR group. The average aggregate load reduction during event hours was 4.31 MW (4.5%), which was also lower than the overall group. This suggests that the load control programs did have an effect on increasing the overall program impact, which will be explored in the subsequent sections.

Figure 3-8: Hourly Load Profile for PTR Customers without Any Load Control – 2015 Event Average

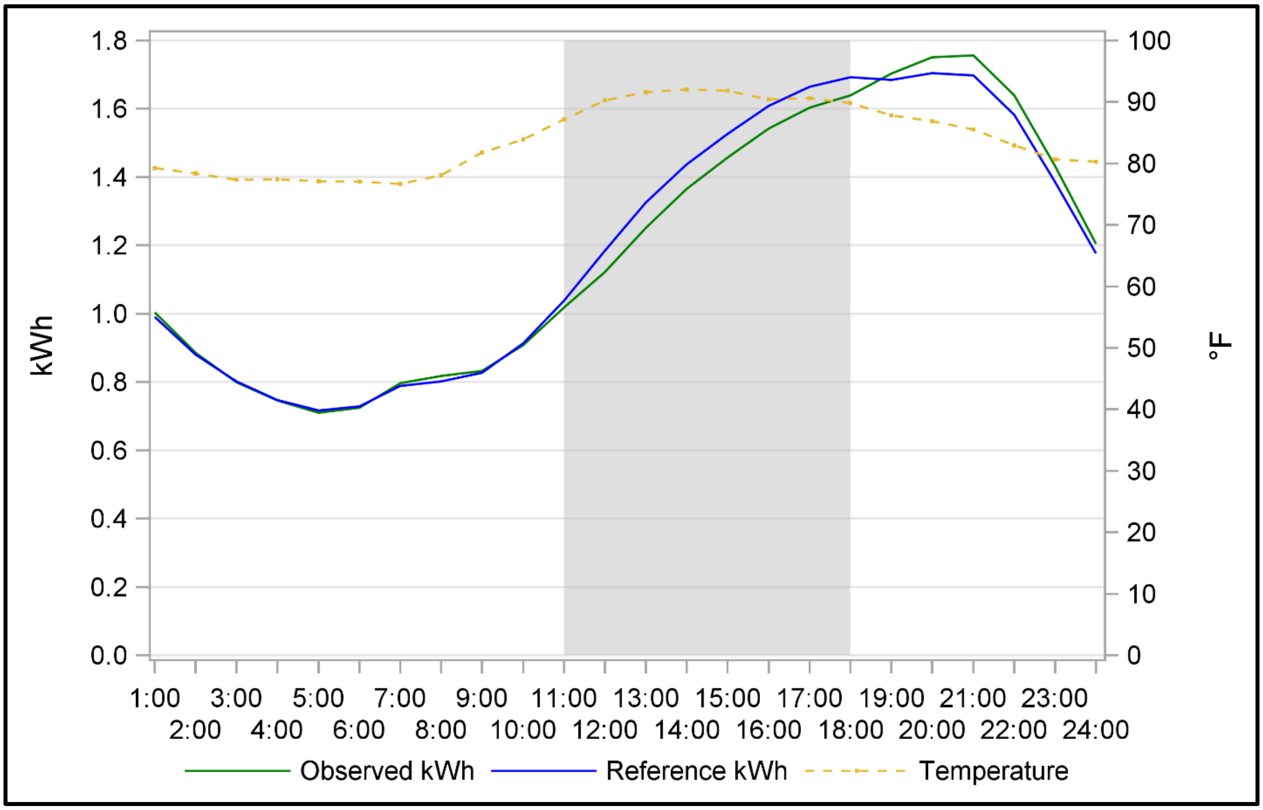


Table 3-10: Summary of Event Impacts for PTR Customers without Any Load Control – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	81.8	0.83	0.83	-0.005	-0.6%	65,797	-346
9:00	10:00	No	83.9	0.91	0.91	0.006	0.7%	65,797	397
10:00	11:00	No	87.1	1.04	1.02	0.019	1.9%	65,797	1,273
11:00	12:00	Yes	90.3	1.18	1.12	0.063	5.3%	65,797	4,145
12:00	13:00	Yes	91.6	1.33	1.25	0.075	5.6%	65,797	4,925
13:00	14:00	Yes	92.0	1.44	1.37	0.071	5.0%	65,797	4,701
14:00	15:00	Yes	91.8	1.53	1.46	0.068	4.5%	65,797	4,505
15:00	16:00	Yes	90.4	1.61	1.54	0.067	4.1%	65,797	4,390
16:00	17:00	Yes	90.6	1.66	1.60	0.061	3.7%	65,797	3,997
17:00	18:00	Yes	89.8	1.69	1.64	0.053	3.2%	65,797	3,507
18:00	19:00	No	87.8	1.68	1.70	-0.019	-1.1%	65,797	-1,233
19:00	20:00	No	86.9	1.70	1.75	-0.046	-2.7%	65,797	-2,999
20:00	21:00	No	85.6	1.70	1.76	-0.059	-3.5%	65,797	-3,880
Total - Entire Day			83.9	28.90	28.70	0.197	0.7%	65,797	12,943
Total - Event Hours			90.9	10.44	9.98	0.459	4.4%	65,797	30,170

3.1.4 PTR Dually Enrolled in Summer Saver

As referenced above, there are subsets of customers that are enrolled in several energy-saving programs through SDG&E. This section examines the group of participants that are dually enrolled in the PTR and Summer Saver programs. These participants, in addition to receiving notifications on RYU event days, have a device installed on their central AC units that are activated on Summer Saver event days, cycling their AC on and off for several hours. In 2015, each of the PTR events were also Summer Saver events. The summer saver events on all of the PTR event days ran from 3 p.m. to 7 p.m. Because this analysis focuses on the impact of the PTR program, the impacts described are incremental savings over and above those realized from the Summer Saver program. Just as a reminder, the control group for these dually enrolled participants are Summer Saver participants that are not dually enrolled in PTR. The Summer Saver only impacts are evaluated under a different project. Figure 3-9 and Table 3-11 show the hourly PTR event load impacts for these dually enrolled customers. Their average event hour load reduction (during PTR event hours) was 0.25 kW, which is about three times higher than the overall PTR group. In general, Summer Saver participants have much higher peak consumption, and thus have a higher potential to save. Being dually-enrolled in PTR suggests that they are also well in-tune with demand response programs and may be more likely to lower their peak consumption. These larger savings resulted in an average aggregate load reduction during event hours of 1.05 MW, representing a 13.3% reduction compared to the reference load.

Figure 3-9: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – All – 2015 Event Average

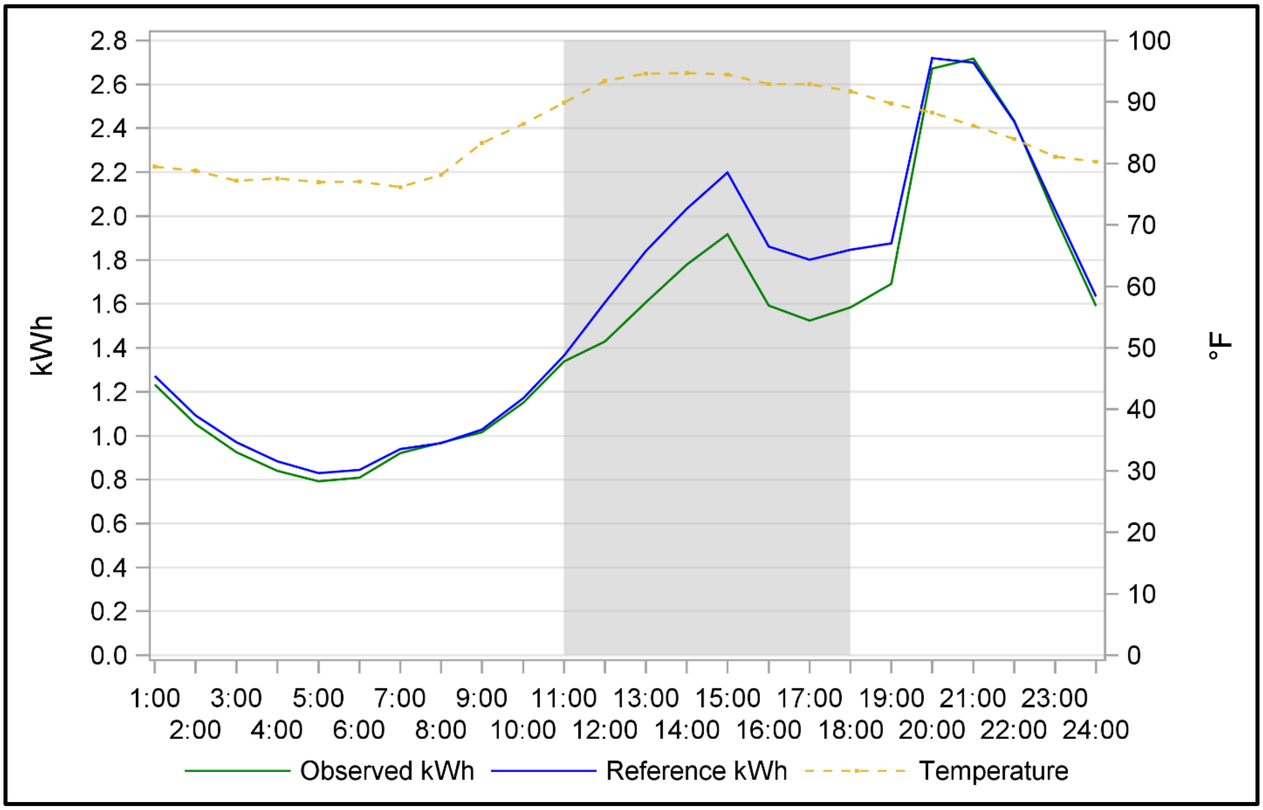


Table 3-11: Summary of PTR Event Impacts for Customers Dually Enrolled in Summer Saver – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	83.3	1.03	1.01	0.014	1.3%	4,179	58
9:00	10:00	No	86.4	1.17	1.15	0.021	1.8%	4,179	89
10:00	11:00	No	89.9	1.36	1.34	0.027	2.0%	4,179	111
11:00	12:00	Yes	93.4	1.61	1.43	0.178	11.1%	4,179	743
12:00	13:00	Yes	94.6	1.84	1.61	0.235	12.8%	4,179	984
13:00	14:00	Yes	94.7	2.03	1.78	0.253	12.5%	4,179	1,059
14:00	15:00	Yes	94.5	2.20	1.92	0.281	12.8%	4,179	1,172
15:00	16:00	Yes	92.9	1.86	1.59	0.270	14.5%	4,179	1,128
16:00	17:00	Yes	92.9	1.80	1.52	0.276	15.3%	4,179	1,155
17:00	18:00	Yes	91.7	1.85	1.58	0.262	14.2%	4,179	1,096
18:00	19:00	No	89.7	1.88	1.69	0.185	9.9%	4,179	773
19:00	20:00	No	88.3	2.72	2.67	0.048	1.8%	4,179	201
20:00	21:00	No	86.1	2.70	2.72	-0.018	-0.7%	4,179	-74
Total - Entire Day			85.2	37.93	35.58	2.359	6.2%	4,179	9,857
Total - Event Hours			93.5	13.19	11.43	1.755	13.3%	4,179	7,336

PTR Dually Enrolled in Summer Saver by Cycling Strategy

Figure 3-10 and Figure 3-11 show the hourly event load impacts for participants dually enrolled in PTR and Summer Saver by the two cycling strategies, 50% and 100%, respectively. The participants with 50% cycling showed an average load reduction of 0.16 kW during the first five hours of the PTR event, but then had slightly negative reduction for the remaining two hours, resulting in an overall average event hour reduction of 0.10 kW. Those with 100% cycling had a significantly larger incremental load reduction of 0.33 kW.

Figure 3-10: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – 50% Cycling – 2015 Event Average

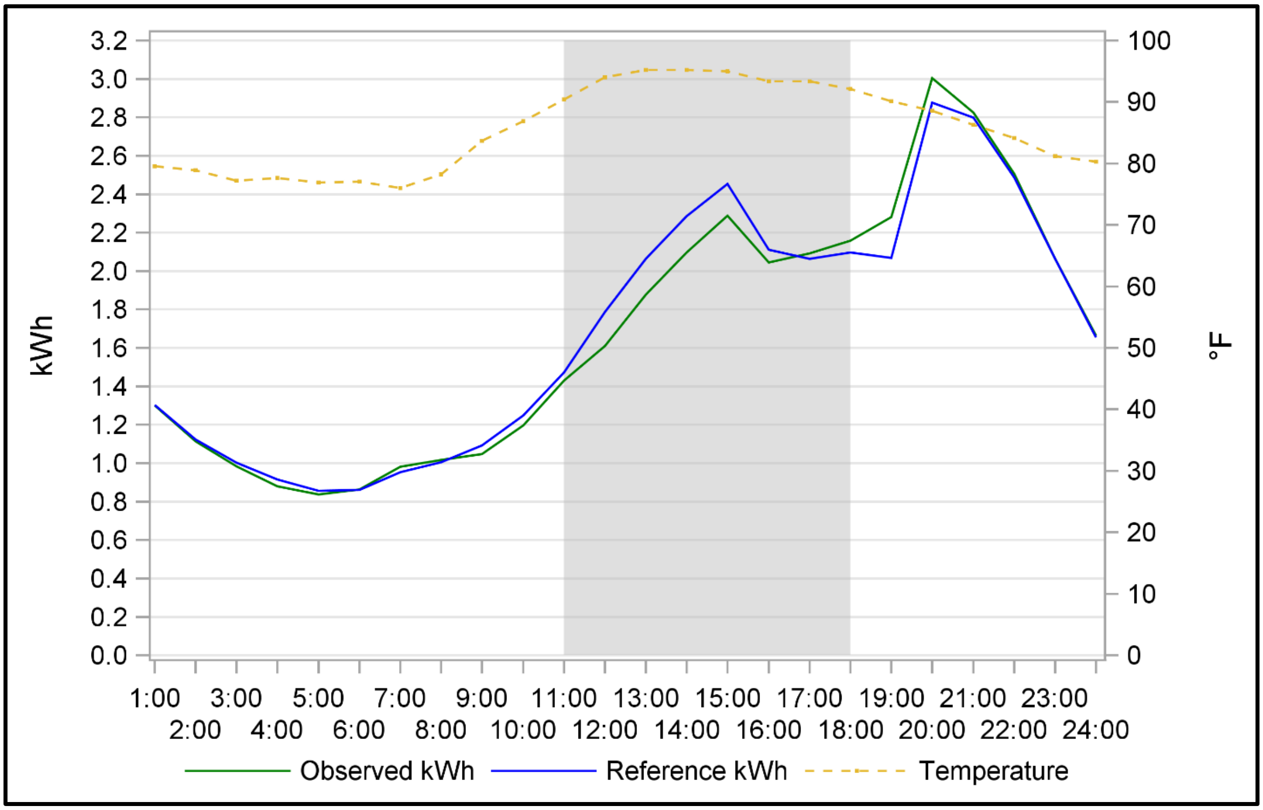
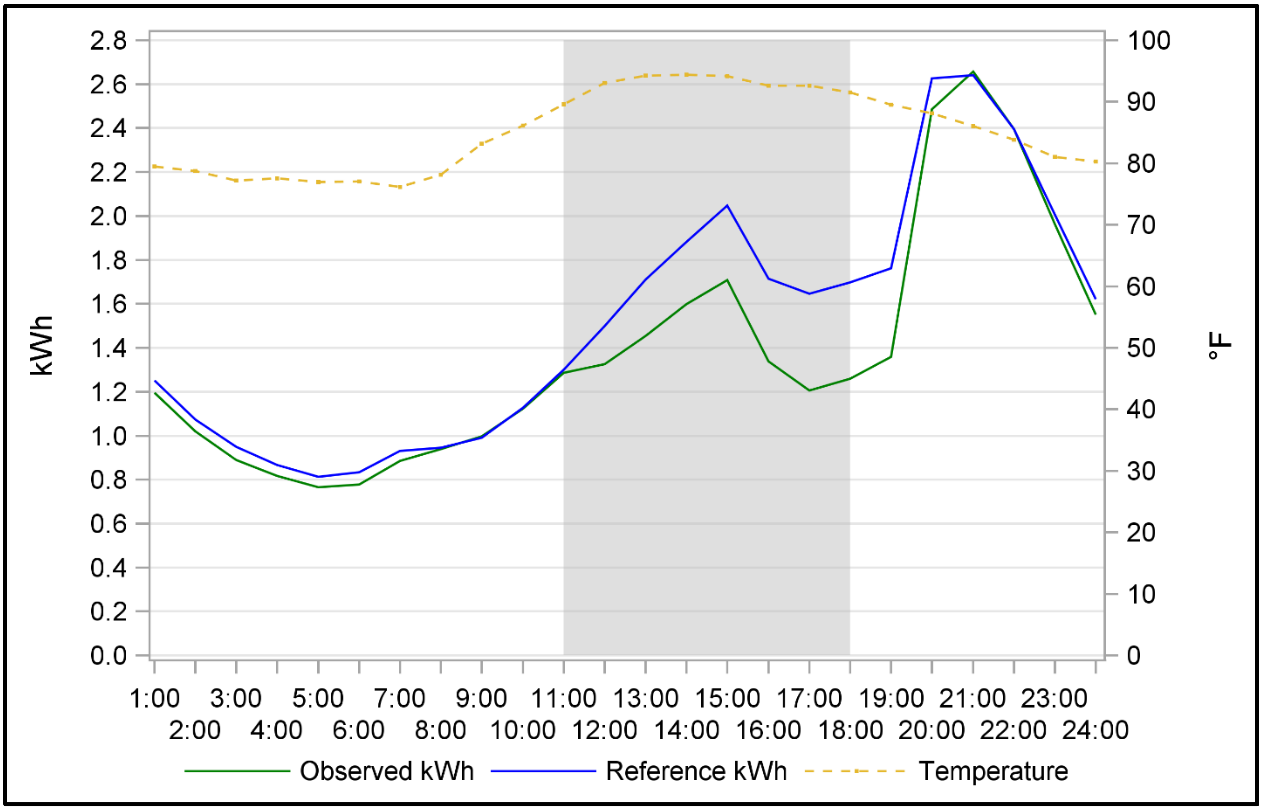


Figure 3-11: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – 100% Cycling – 2015 Event Average



3.1.5 PTR Dually Enrolled in SCTD

SDG&E PTR customers are also eligible to participate in the SCTD program, which involves demand response enabling thermostats signaled through Wi-Fi. Two cycling strategies were implemented on PTR-SCTD event days – four degree thermostat setback and 50% AC cycling. The SCTD event hour window was only 4 hours long, from 2 p.m. to 6 p.m. Figure 3-12 and Table 3-12 show the hourly event load impacts for entire group of dually enrolled participants. Like the Summer Saver enrollees, the participant load shows a sharp drop as the demand response technology kicks in, and subsequently rising through the duration of the event and in the hour following. The average event hour load reduction for this group (during PTR event hours) was 0.48 kW, which is about six times higher than the overall PTR group. The average load reduction was 0.63 kW during the SCTD event hours from 2 p.m. to 6 p.m. In the hours of 11 a.m. to 2 p.m., when only the PTR event was in effect, the average load reduction was 0.27 kW, which was higher than the average for PTR participants without any load control devices. The average aggregate load reduction was 1.86 MW during PTR event hours, representing 20.8% of the reference load. The average aggregate reduction during SCTD event hours was 2.47 MW, or 25.9%. Lastly, the average aggregate reduction during the PTR-only hours was 1.05 MW, or 13.9%.

Figure 3-12: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 2015 Event Average

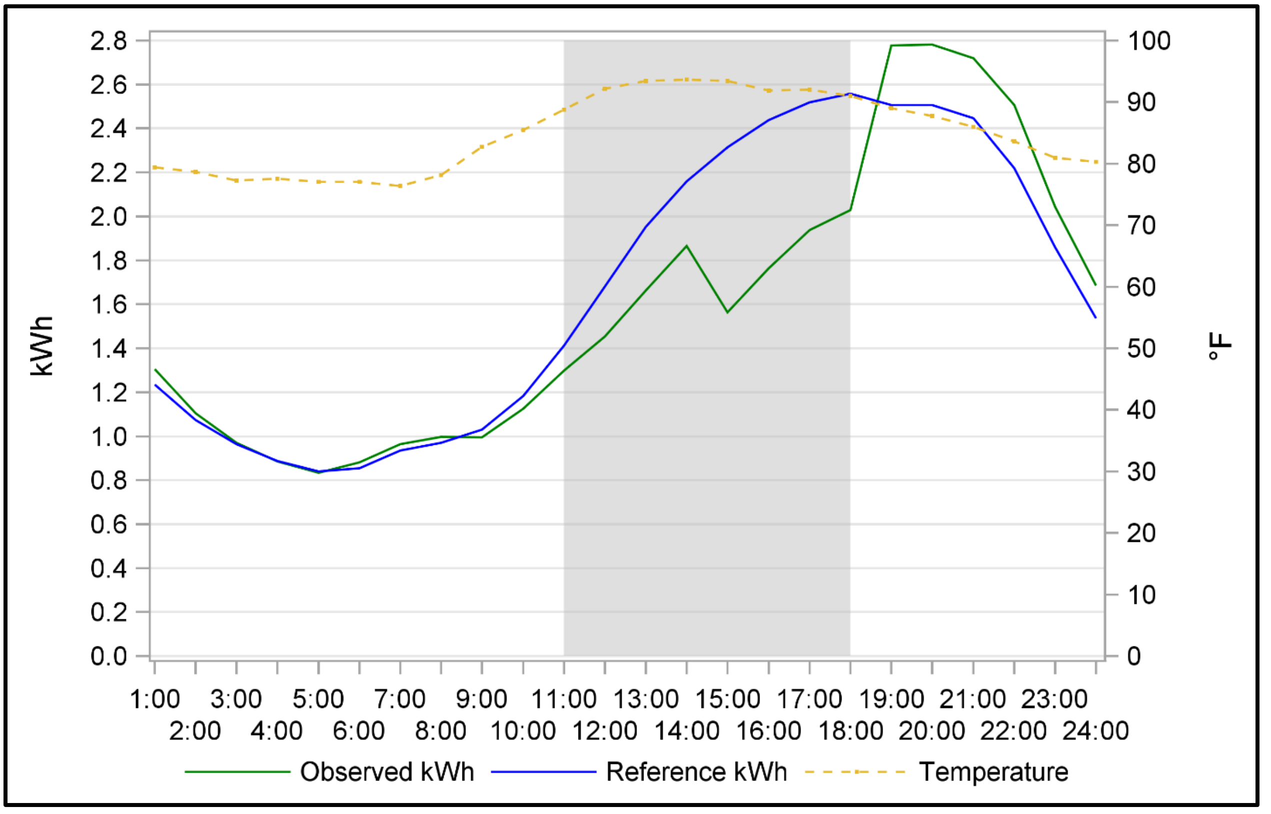


Table 3-12: Summary of PTR Event Impacts for Customers Dually Enrolled in SCTD – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	82.7	1.03	1.00	0.035	3.4%	3,899	136
9:00	10:00	No	85.4	1.18	1.12	0.059	5.0%	3,899	229
10:00	11:00	No	88.8	1.41	1.30	0.113	8.0%	3,899	442
11:00	12:00	No	92.2	1.68	1.45	0.226	13.5%	3,899	882
12:00	13:00	No	93.4	1.95	1.66	0.288	14.8%	3,899	1,122
13:00	14:00	No	93.7	2.16	1.87	0.293	13.6%	3,899	1,141
14:00	15:00	Yes	93.4	2.31	1.56	0.750	32.4%	3,899	2,923
15:00	16:00	Yes	91.9	2.44	1.76	0.674	27.6%	3,899	2,626
16:00	17:00	Yes	92.0	2.52	1.94	0.580	23.0%	3,899	2,260
17:00	18:00	Yes	91.0	2.56	2.03	0.530	20.7%	3,899	2,067
18:00	19:00	No	89.0	2.51	2.78	-0.271	-10.8%	3,899	-1,057
19:00	20:00	No	87.7	2.51	2.78	-0.275	-11.0%	3,899	-1,073
20:00	21:00	No	85.9	2.45	2.72	-0.272	-11.1%	3,899	-1,062
Total - Entire Day			84.7	40.08	38.15	1.931	4.8%	3,899	7,529
Total - Event Hours			92.1	9.83	7.30	2.534	25.8%	3,899	9,877

PTR Dually Enrolled in SCTD, by Cycling Strategy

Figure 3-13 and Figure 3-14 show the hourly event load impacts for dually enrolled PTR and SCTD participants, by cycling strategy. During SCTD event hours, the 4 degree setback group had a higher average hourly load reduction of 0.70 kW (28.0%) compared to the 50% cycling group, which had an average of 0.54 kW (22.9%). Over the entire event period, the 4 degree setback group had an average hourly load reduction of 0.53 kW (22.5%), while the 50% cycling group had an average of 0.41 kW (18.2%).

Figure 3-13: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 4 Degree Setback – 2015 Event Average

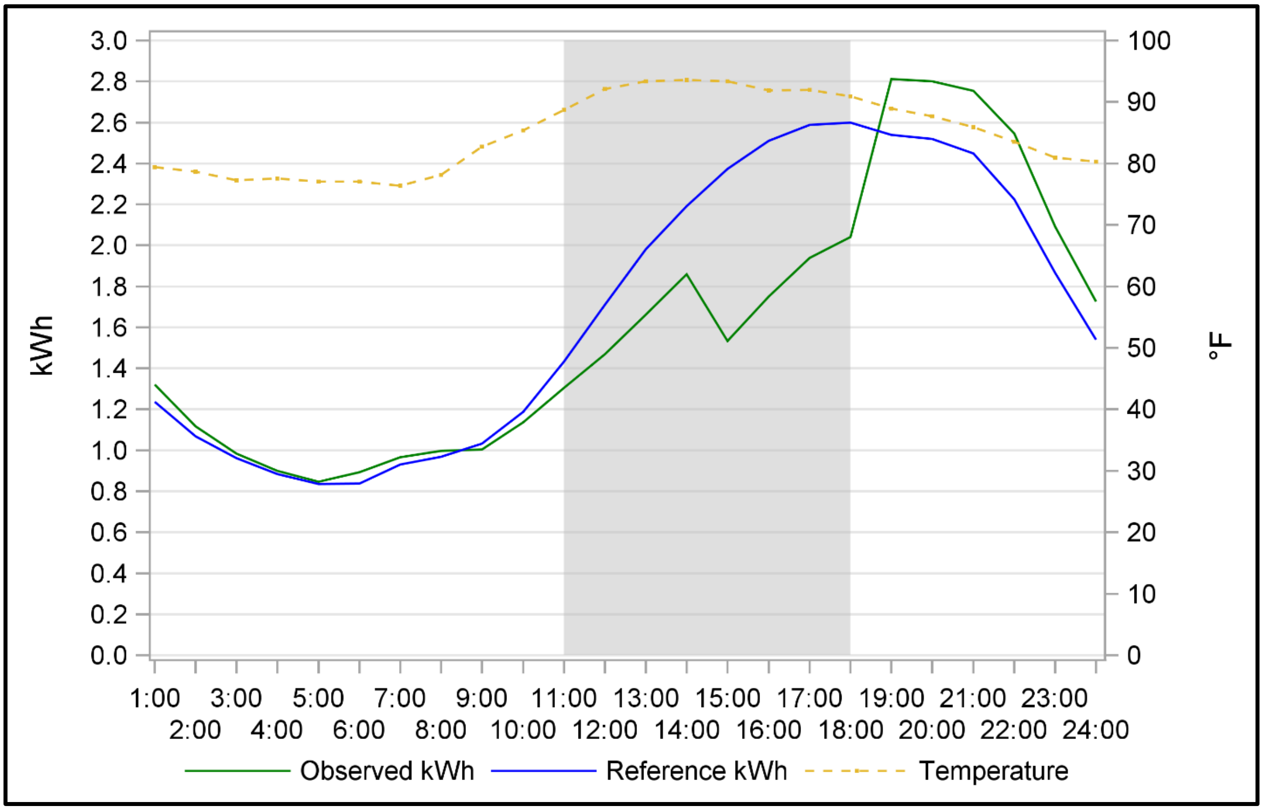
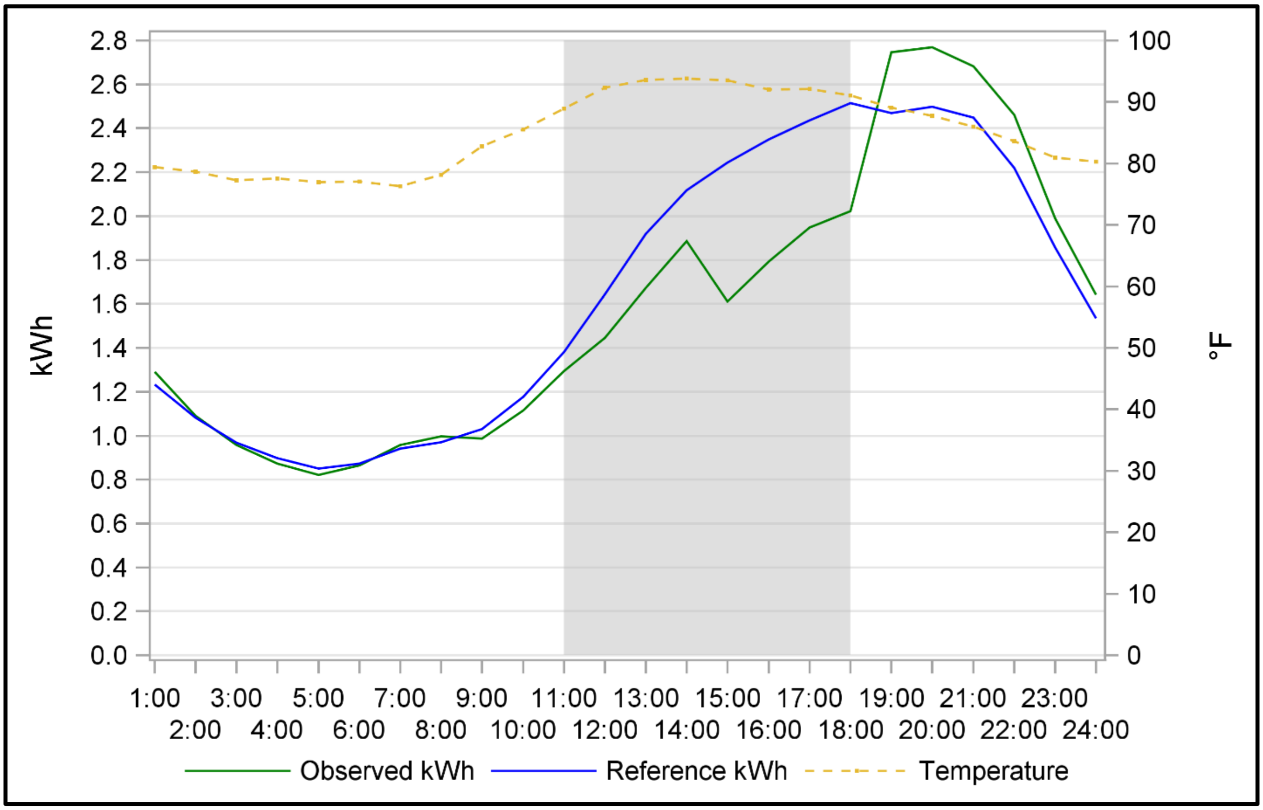


Figure 3-14: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 50% Cycling – 2015 Event Average



3.1.6 SCTD Not Enrolled in PTR

Figure 3-15 and Table 3-13 show the hourly event load impacts for SCTD customers that are not enrolled in the PTR program. There were relatively fewer participants in this group than the dually-enrolled group, as it was comprised of those customers that received a thermostat but did not opt-in to the PTR program. These participants still had a 4 degree setback or 50% AC cycling on PTR-SCTD event days. During SCTD event hours, their average load reduction was 0.37 kW, which is smaller than the dually-enrolled PTR-SCTD participants. The average aggregate impact during the event hours was 0.99 MW, representing 15.1% of the reference load. The group showed snapback effects averaging 14.4% during the hours following the SCTD event.

Figure 3-15: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 2015 Event Average

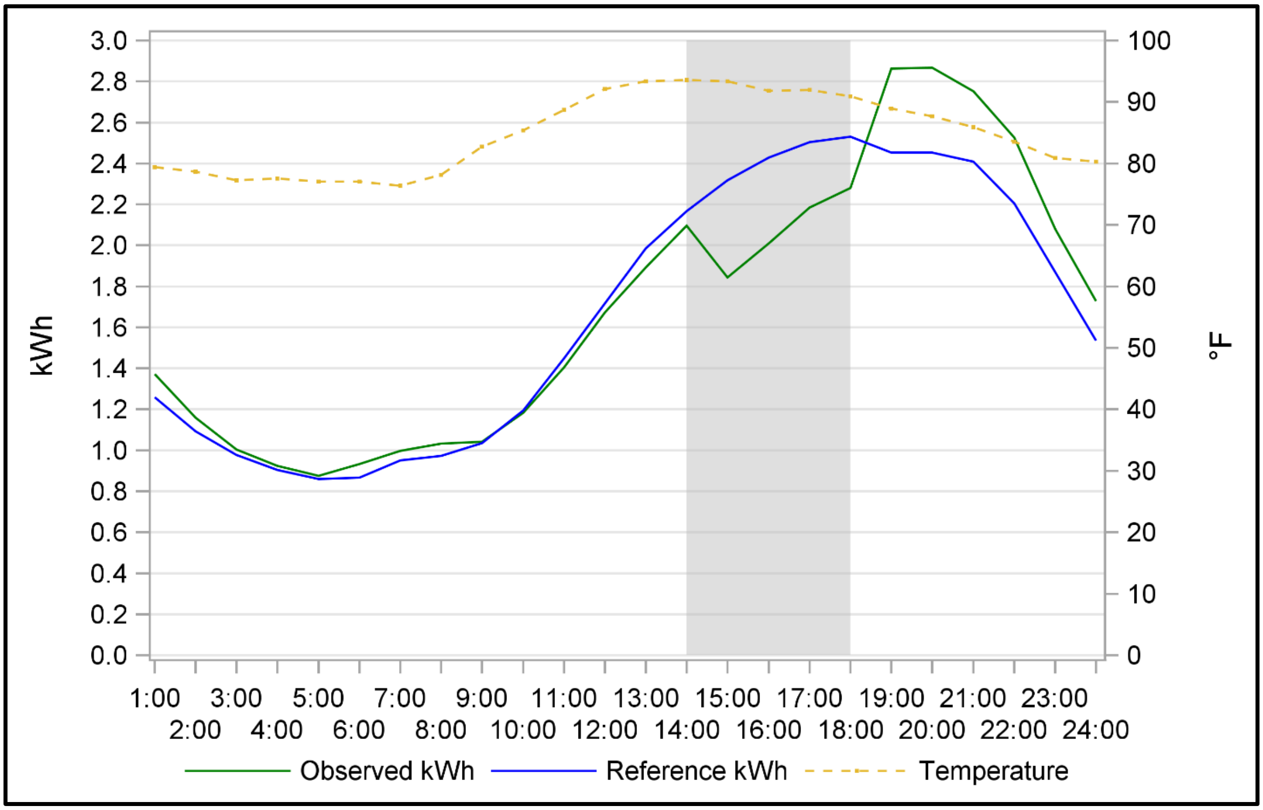


Table 3-13: Summary of Event Impacts for SCTD Customers Not Enrolled in PTR – 2015 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	82.7	1.03	1.04	-0.007	-0.7%	2,703	-19
9:00	10:00	No	85.3	1.19	1.18	0.011	0.9%	2,703	28
10:00	11:00	No	88.7	1.45	1.41	0.043	3.0%	2,703	117
11:00	12:00	No	92.1	1.72	1.67	0.045	2.6%	2,703	121
12:00	13:00	No	93.4	1.98	1.89	0.093	4.7%	2,703	251
13:00	14:00	No	93.6	2.17	2.10	0.072	3.3%	2,703	194
14:00	15:00	Yes	93.3	2.32	1.84	0.475	20.5%	2,703	1,283
15:00	16:00	Yes	91.8	2.43	2.01	0.418	17.2%	2,703	1,130
16:00	17:00	Yes	92.0	2.50	2.19	0.319	12.8%	2,703	863
17:00	18:00	Yes	90.9	2.53	2.28	0.251	9.9%	2,703	678
18:00	19:00	No	88.9	2.45	2.86	-0.412	-16.8%	2,703	-1,113
19:00	20:00	No	87.7	2.45	2.87	-0.414	-16.9%	2,703	-1,118
20:00	21:00	No	85.9	2.41	2.75	-0.344	-14.3%	2,703	-929
Total - Entire Day			84.7	40.14	40.72	-0.586	-1.5%	2,703	-1,585
Total - Event Hours			92.0	9.78	8.32	1.463	15.0%	2,703	3,954

SCTD Not Enrolled in PTR, by Cycling Strategy

Figure 3-16 and Figure 3-17 show the hourly event load impacts for SCTD participants that are not enrolled in PTR. The 50% cycling participants had smaller event impacts than the 4 degree setback participants. The former had an average event hour load reduction of 0.29 kW (12.4%) while the latter had an average of 0.42 kW (17.0%).

Figure 3-16: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 4 Degree Setback – 2015 Event Average

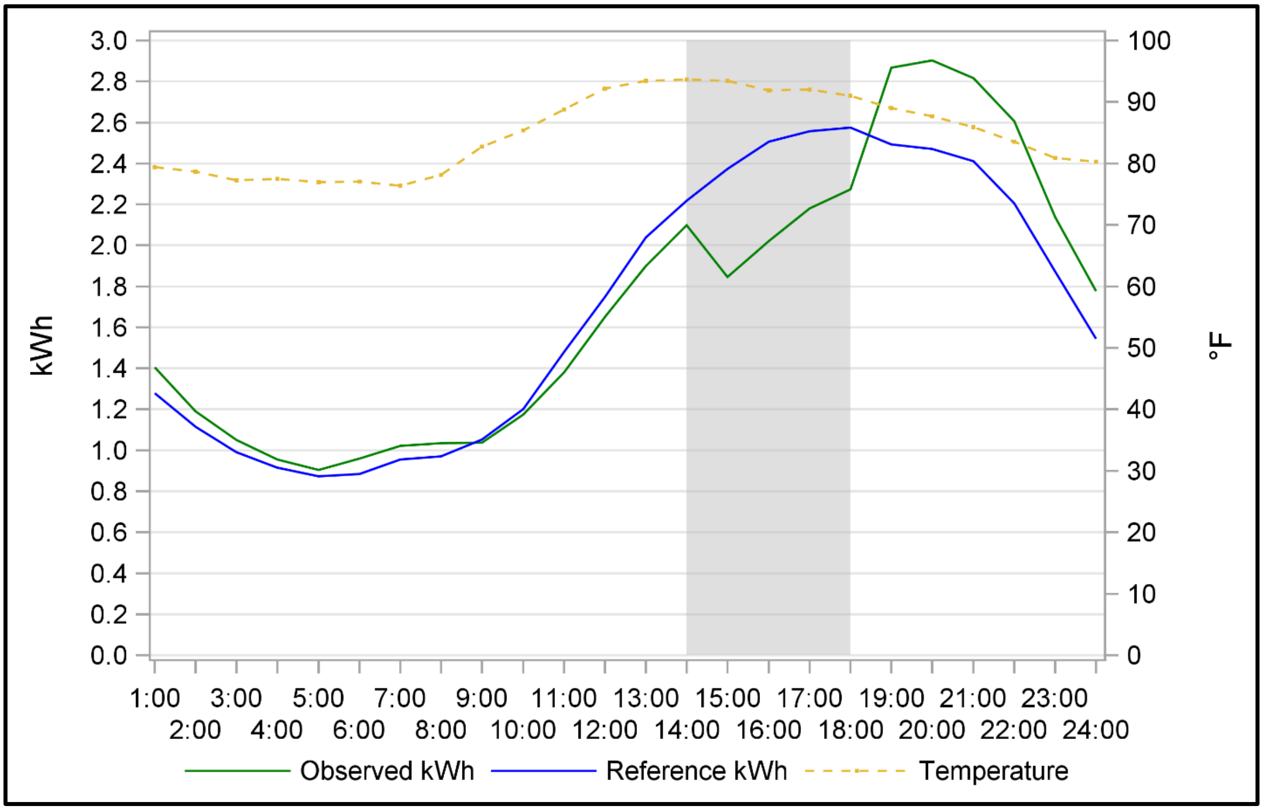
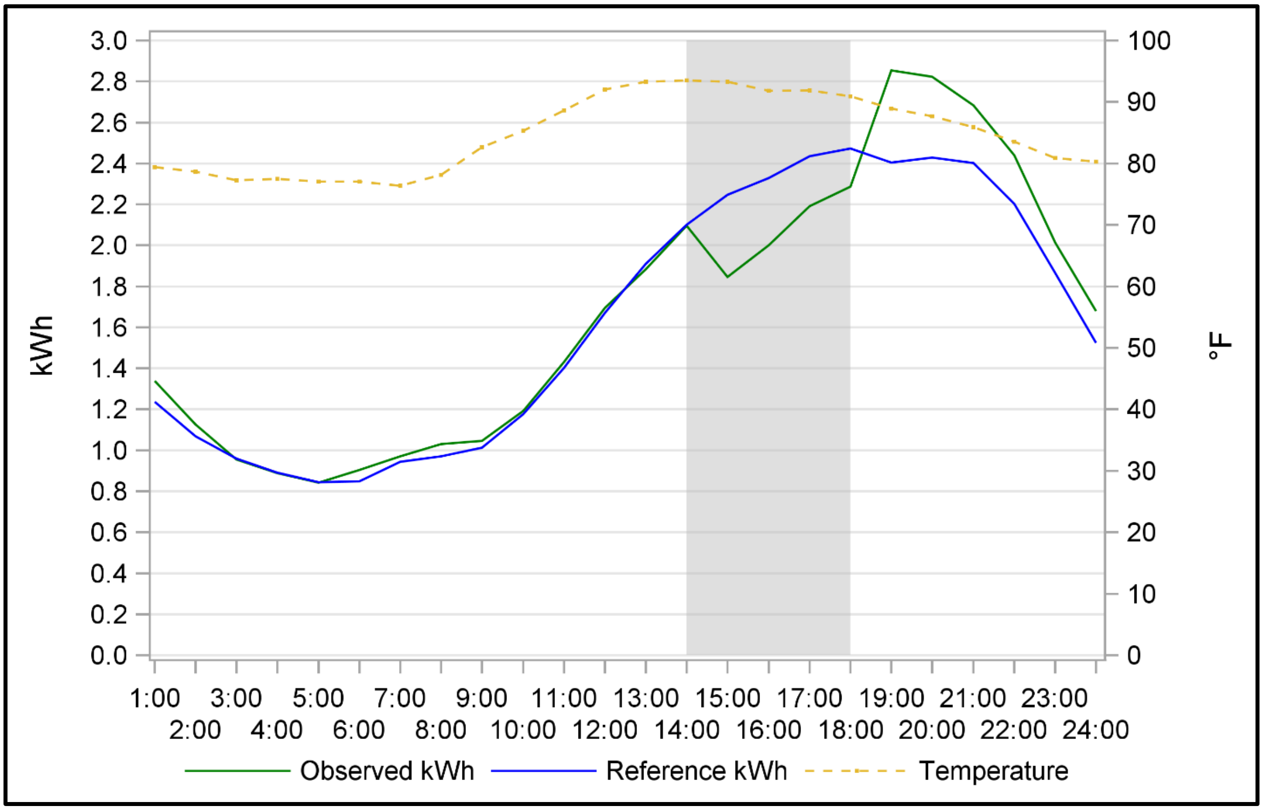


Figure 3-17: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 50% Cycling – 2015 Event Average



3.1.7 PTR without Load Control by Notification Type

There were three methods of notification for 2015 PTR event days – email, text message, and phone call. Only about 7% of the final participant group had opted for phone notification (only 2% opted for phone-only notification), so this sub-group analysis focused on the email and text message notifications. About two-thirds of the analysis group opted for email-only notification, about 17% opted for text-only notification, and about 16% opted for both email and text notifications. Figure 3-18 through Figure 3-20 show the hourly event load impacts for each of these groups, respectively. The email-only notification group had an average event hour load reduction of 0.06 kW (4.3%), which is approximately in line with the general PTR population average. The text message-only group had an average event hour load reduction of 0.05 kW (3.3%), which was below average. The group with both types of notifications had the greatest average event hour reduction of 0.11 kW (7.3%), which was above the overall population average. The email-only group also had very little snapback effects of only 1.0%, compared to the text-only group, which had 6.6% and the group with both types, which had 6.0%.

Figure 3-18: Hourly Load Profile for PTR Customers without Any Load Control – Email-Only Notification – 2015 Event Average

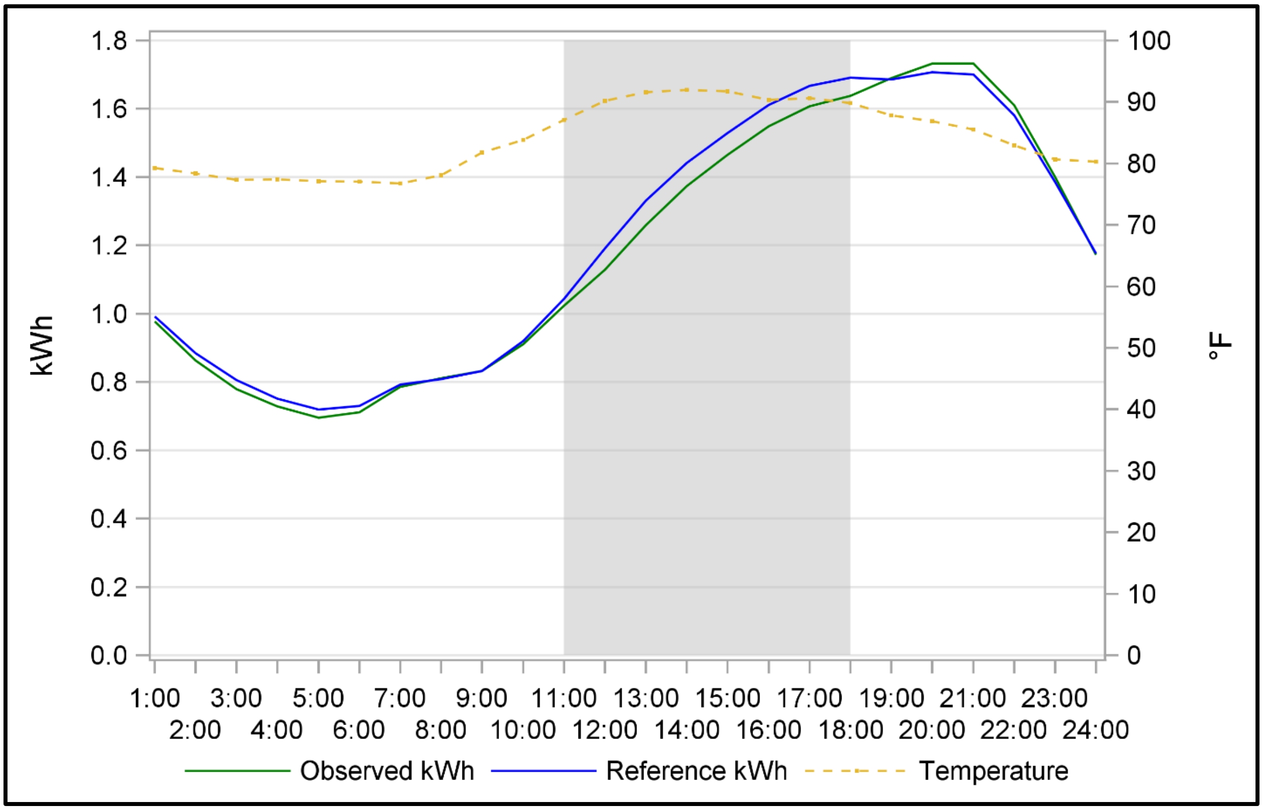


Figure 3-19: Hourly Load Profile for PTR Customers without Any Load Control – Text-Only Notification – 2015 Event Average

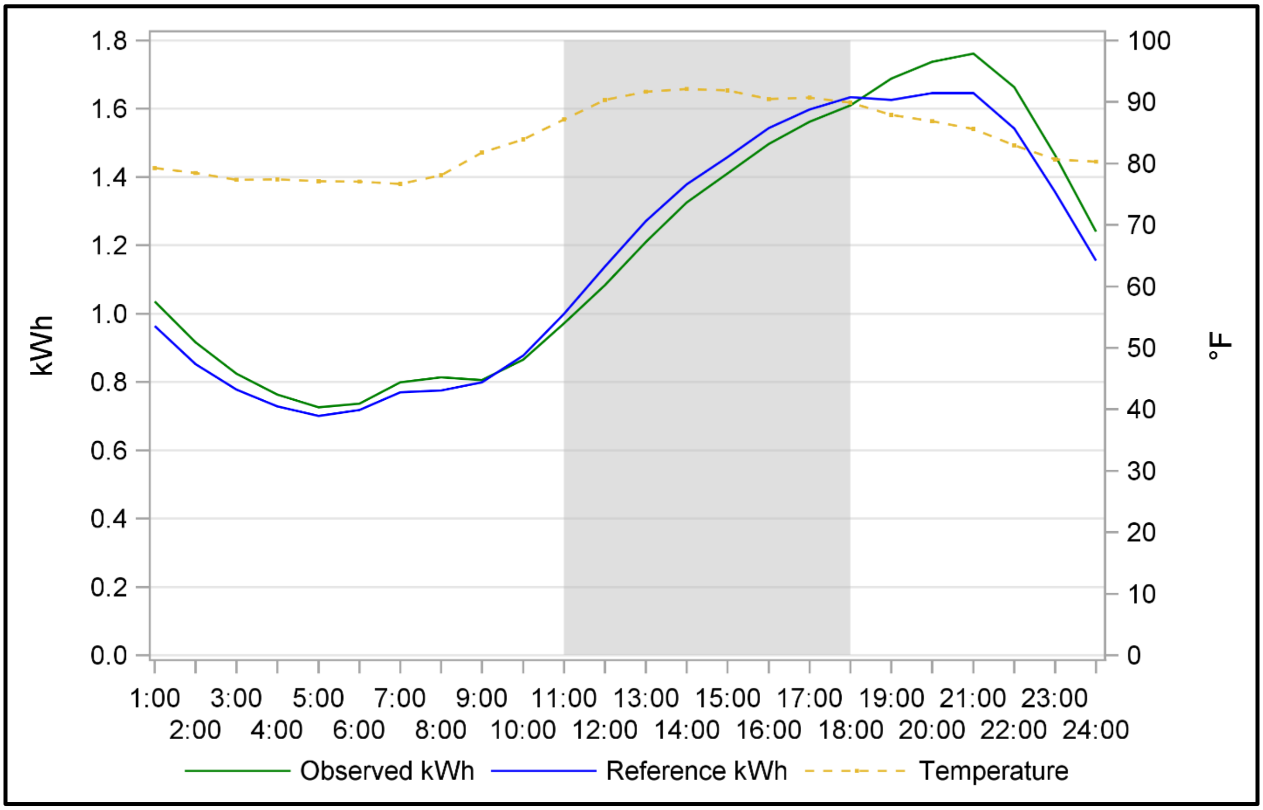
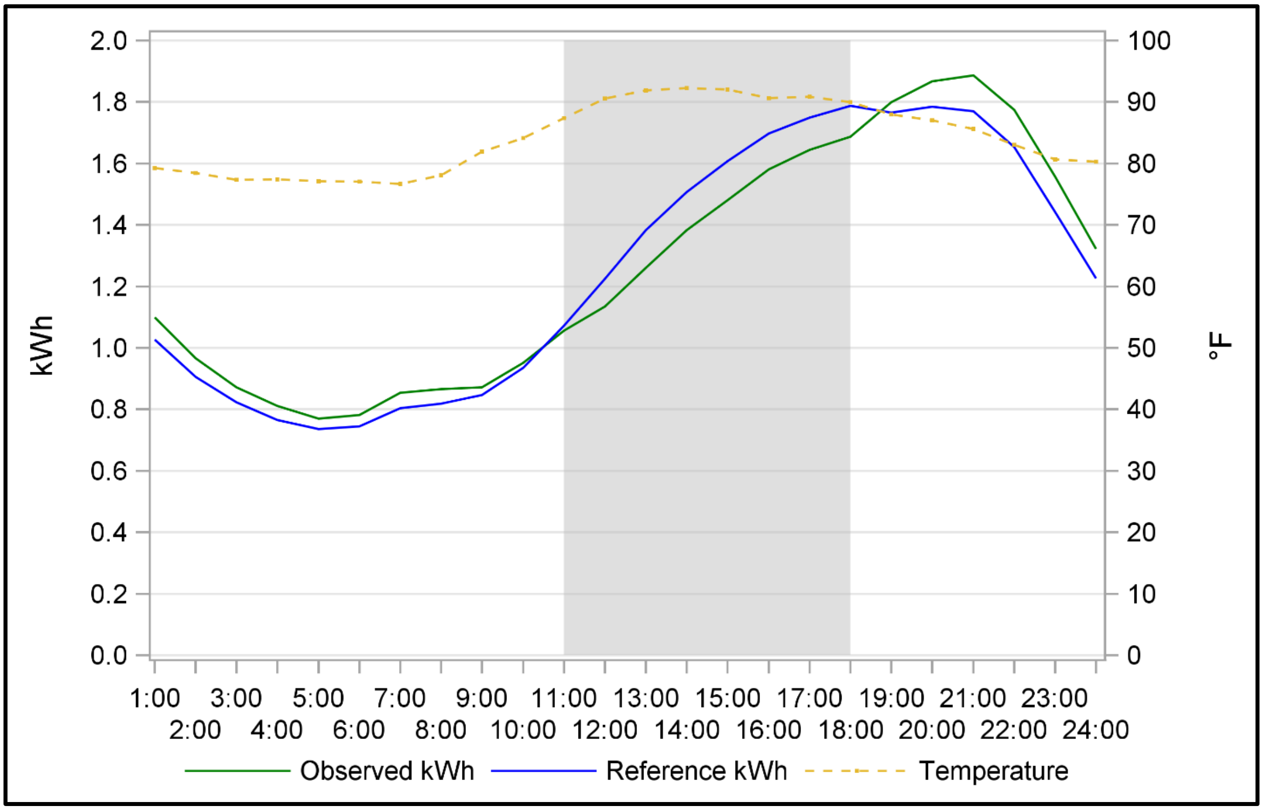


Figure 3-20: Hourly Load Profile for PTR Customers without Any Load Control – Both Email and Text Notifications – 2015 Event Average



3.1.8 PTR without Load Control by Low Income Status

SDG&E has several programs that allow households with low incomes to receive a lower rate for their electricity use. Figure 3-21 and Figure 3-22 show the hourly event load impacts for both non-low income and low income PTR participants with no load control. Over one-third of this subset of PTR participants had a low income billing rate. The non-low income participants had an average event hour load reduction that was slightly higher than the overall PTR population, saving 0.09 kW (6.1%). The low income participants had smaller load reduction during events, with an average of 0.05 kW (3.6%).

Figure 3-21: Hourly Load Profile for Non-Low Income PTR Customers without Any Load Control – 2015 Event Average

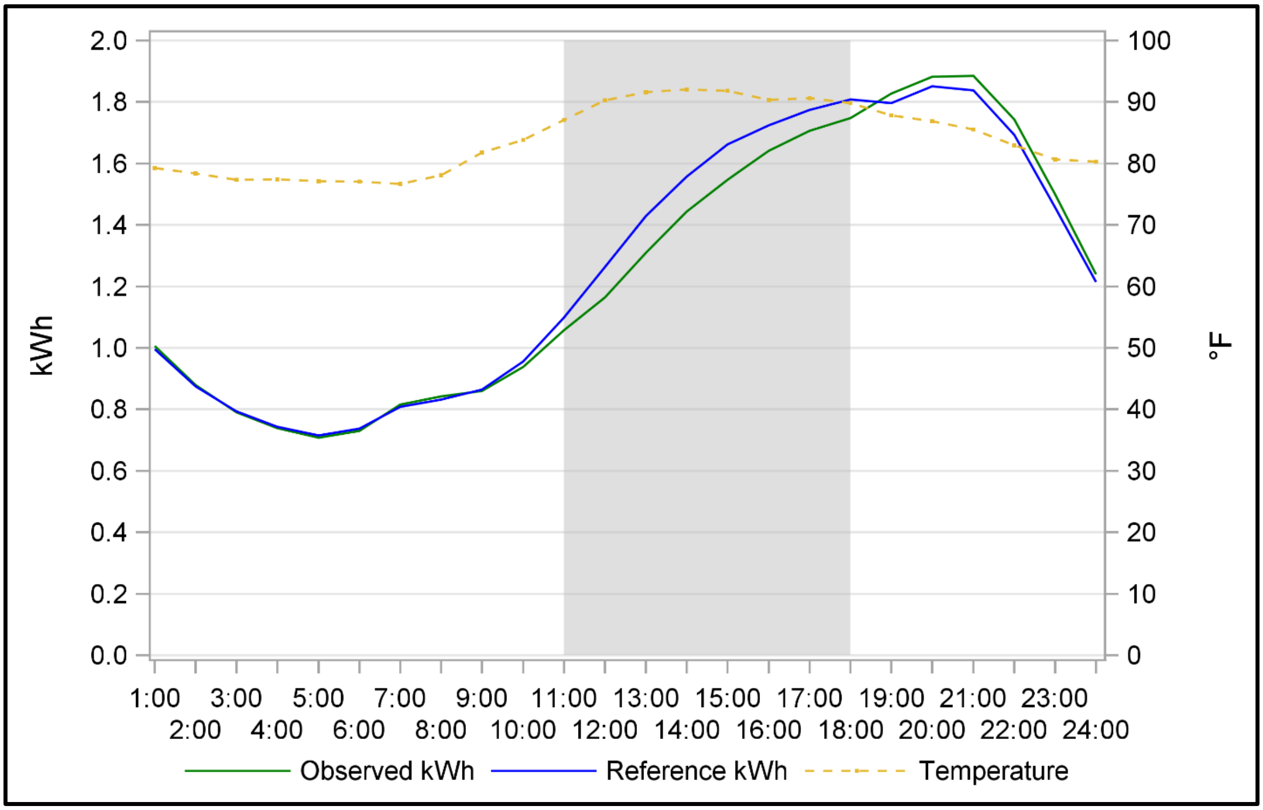
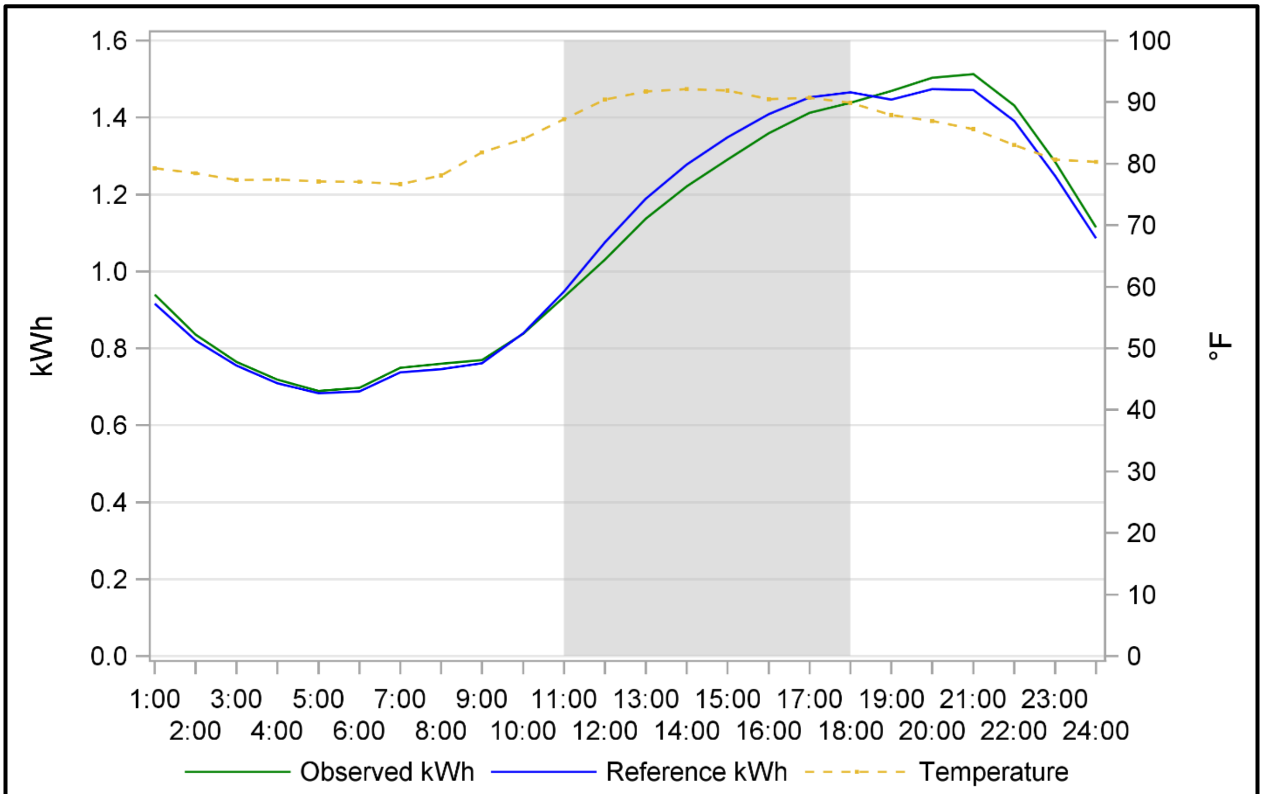


Figure 3-22: Hourly Load Profile for Low Income PTR Customers without Any Load Control – 2015 Event Average



3.1.9 PTR without Load Control by First Year of Enrollment

Figure 3-23 through Figure 3-25 show the hourly event load impacts for PTR customers without any load control by their first year of enrollment in the PTR program, from 2012 to 2015. The participants who first enrolled in 2014 saved the most during the 2015 PTR events, with an average of 0.10 kW (6.9%) during event hours. This group also showed the least snapback effects, with an average increase of only 0.5% from 6 p.m. to midnight. The "oldest" group of participants who first enrolled in 2012 had an average event hour load reduction of only 0.03 kW (2.4%), and an average post-event snapback of 2.0%. The "newest" group of participants who first enrolled in 2015 had an average event hour load reduction that was mostly in line with the overall PTR population, 0.07 kW (4.8%), and an average post-event snapback of 8.3%. Lastly, the 2013 enrollees had very little reduction during event hours of 0.01 kW (1.0%), and an average post-event snapback of 5.0%.

Figure 3-23: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2012 – 2015 Event Average

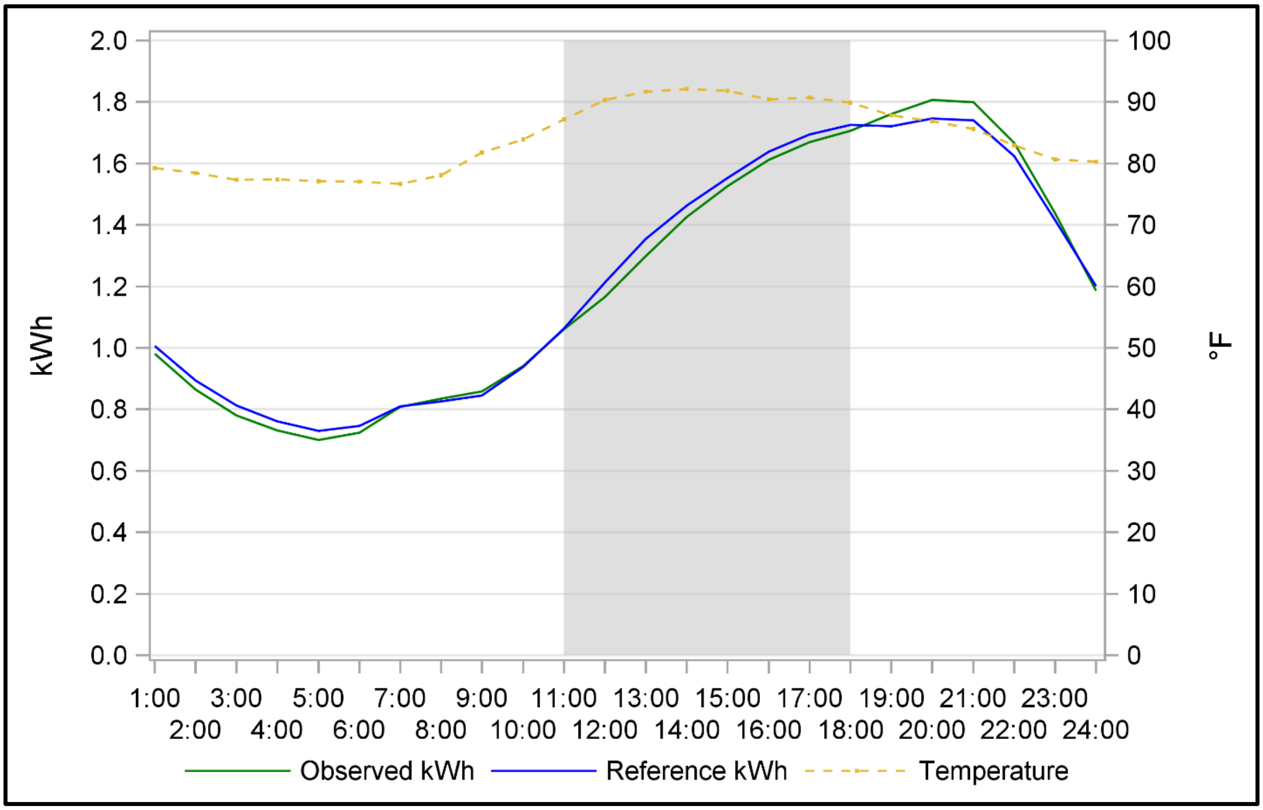


Figure 3-24: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2013 – 2015 Event Average

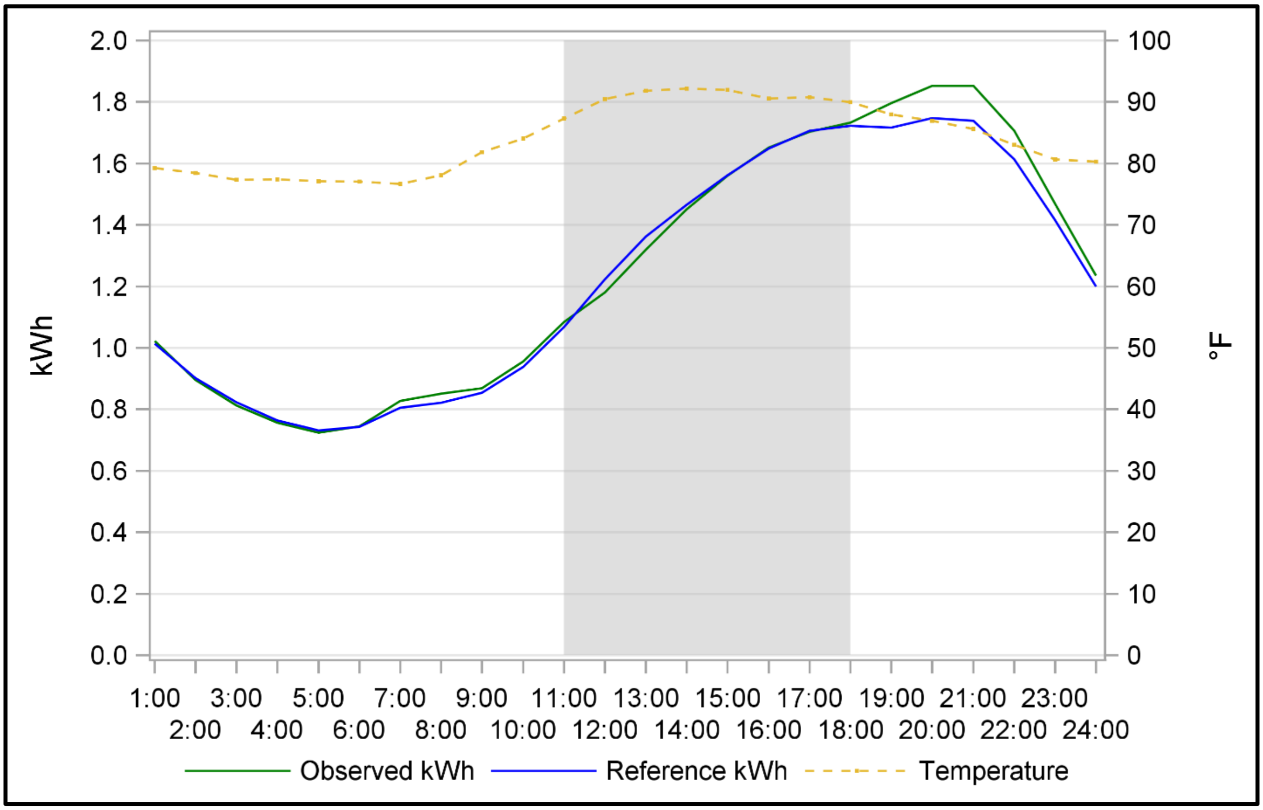


Figure 3-25: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2014 – 2015 Event Average

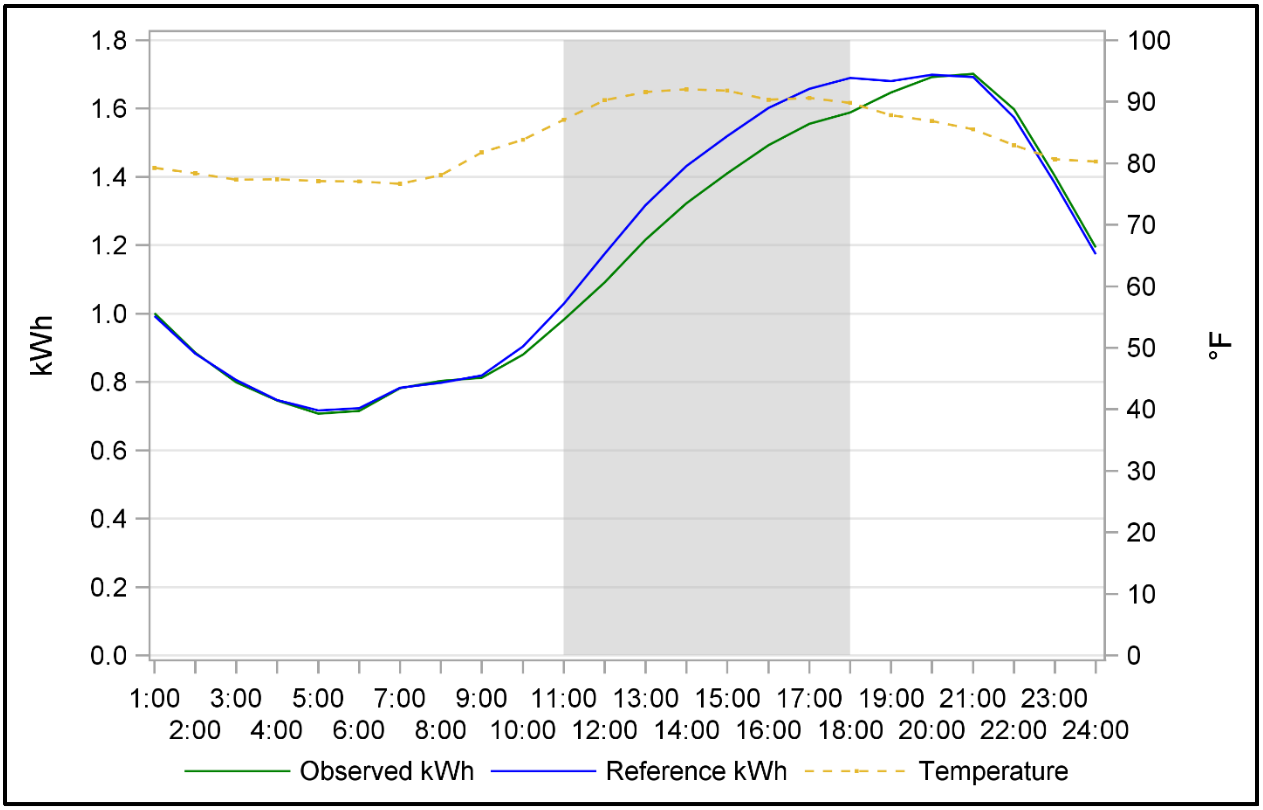
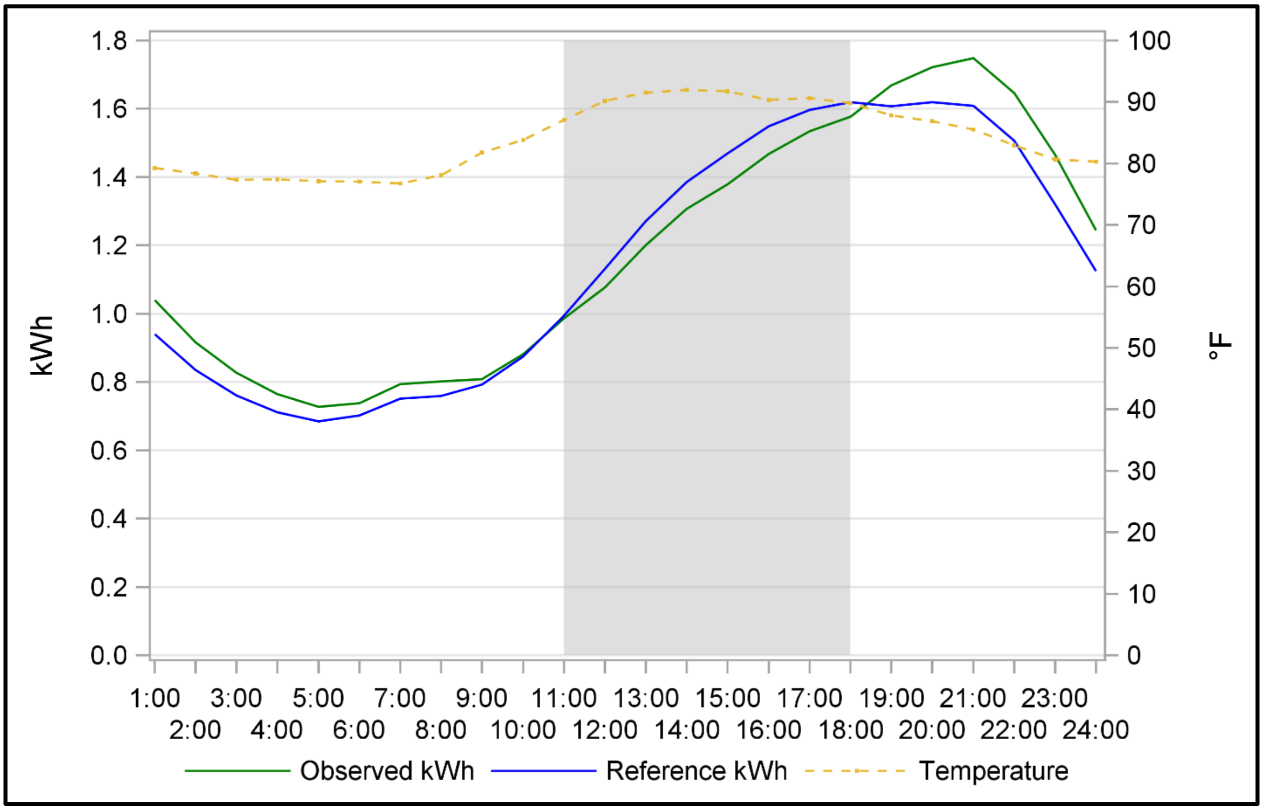


Figure 3-26: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2015 – 2015 Event Average



3.1.10 Net Energy Metered Ex Post Load Impacts

As part of its analysis, Itron separated out the set of PTR participants with photovoltaic (PV) generation, or Net Energy Metering (NEM). These customers, in addition to standard consumption, are able to export excess PV generation back to the grid. Figure 3-27 and Table 3-14 show the hourly PTR event load impacts for the NEM participants without load control. The values reported reflect these customers' net consumption of energy consumed minus energy exported. A negative value indicates that PV generation exceeds household consumption. The average event hour net load reduction for these customers is substantially greater than the general PTR population, at 0.26 kW. The average aggregate event-induced load impact for these NEM customers was 1.91 MW, which is a considerable amount given their relatively small population.

The majority of PTR participants with NEM do not have load control. However, there are approximately 1,600 participants that have load control out of the total 7,331 NEM participants; either SCTD or Summer Saver. This incidence (21.8%) of load control is higher than for the general PTR population (14.5%). As can be seen in Figure 3-27, the interactive effect of this PTR enabling technology with PV may not be desirable as it steepens the ramp of the event day load curve in the late afternoon and adds snap-back making the post event load higher than the reference load.

In 2014, the modeling of impacts did not take into consideration the possibility that there might be a correlation with higher PV production levels due to greater solar irradiance on PTR event days. To adjust for this possibility in 2015, solar irradiance was added to the modeling. The modeling was run both with and without solar irradiance. As it turns out, solar irradiance had a very small effect on the reference load estimation and subsequently the load impacts.

Figure 3-27: Hourly Load Profile for PTR NEM Customers – 2015 Event Average

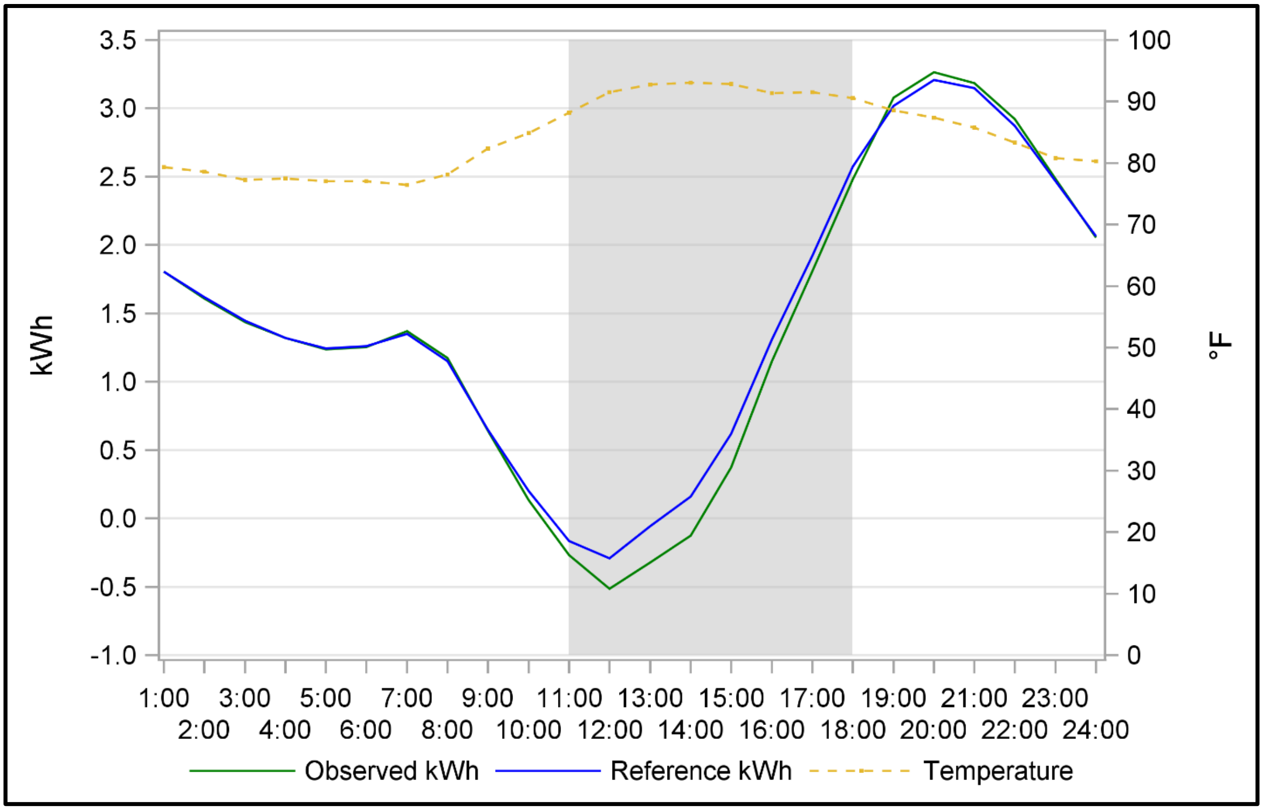


Table 3-14: Summary of PTR Event Impacts for NEM Customers – 2015 Average

Hour Beg.	Hour End	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	82.5	0.66	0.65	0.011	1.7%	7,331	82
9:00	10:00	No	85.1	0.20	0.14	0.059	30.0%	7,331	435
10:00	11:00	No	88.5	-0.16	-0.26	0.096	-58.9%	7,331	704
11:00	12:00	Yes	91.8	-0.29	-0.51	0.216	-73.5%	7,331	1,585
12:00	13:00	Yes	93.1	-0.06	-0.32	0.267	-469.6%	7,331	1,960
13:00	14:00	Yes	93.4	0.16	-0.12	0.282	179.6%	7,331	2,065
14:00	15:00	Yes	93.1	0.63	0.32	0.311	49.7%	7,331	2,282
15:00	16:00	Yes	91.6	1.33	1.04	0.291	21.9%	7,331	2,134
16:00	17:00	Yes	91.8	1.95	1.70	0.256	13.1%	7,331	1,875
17:00	18:00	Yes	90.8	2.60	2.40	0.201	7.7%	7,331	1,474
18:00	19:00	No	88.8	3.06	3.11	-0.049	-1.6%	7,331	-363
19:00	20:00	No	87.6	3.24	3.43	-0.194	-6.0%	7,331	-1,424
20:00	21:00	No	85.8	3.16	3.34	-0.170	-5.4%	7,331	-1,249
Total - Entire Day			84.6	35.10	33.97	1.132	3.2%	7,331	8,296
Total - Event Hours			92.2	6.31	4.49	1.824	28.9%	7,331	13,374

3.1.11 Electric Vehicle Ex Post Load Impacts

As part of its analysis, Itron separated out the set of PTR participants who are on an electric vehicle charging rate to investigate the PTR impacts on this group which tend to have a very different load profile and consumption pattern than the general population. Figure 3-28 and Table 3-15 show the hourly PTR event load impacts for these EV participants. The average event hour load reduction for this group was 0.25 kW, which was about three times higher than the 0.08 kW for the overall PTR group. The average aggregate load reduction during event hours was 0.41 MW (11.3%). The EV customers also showed a significant jump in consumption in the hour after midnight. This is likely due to the EV time-of-use rate schedule, which has a “Super Off-Peak” rate between the hours of 12 a.m. and 5 a.m. Figure 3-29 shows the consumption for EV participants and their reference load through each of the three September events to better illustrate this load behavior.

Figure 3-28: Hourly Load Profile for PTR Electric Vehicle Customers – 2015 Event Average

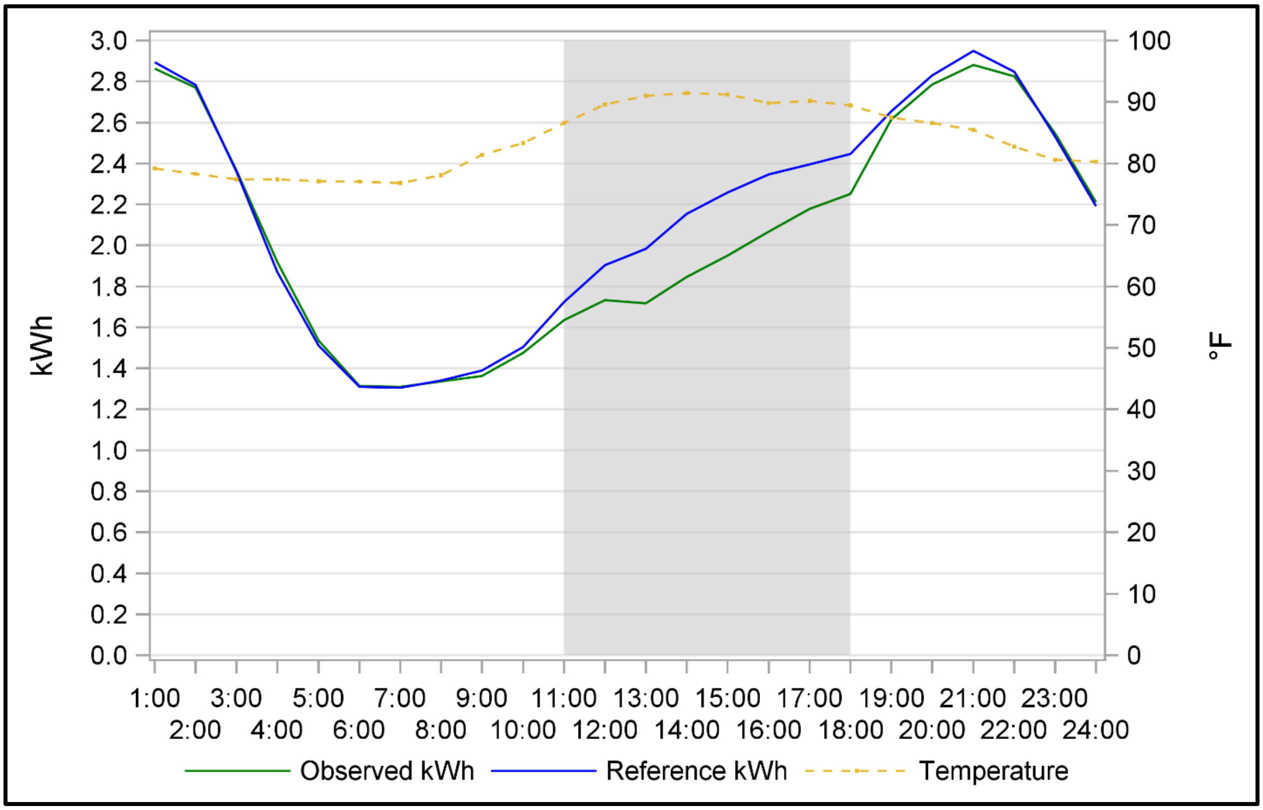
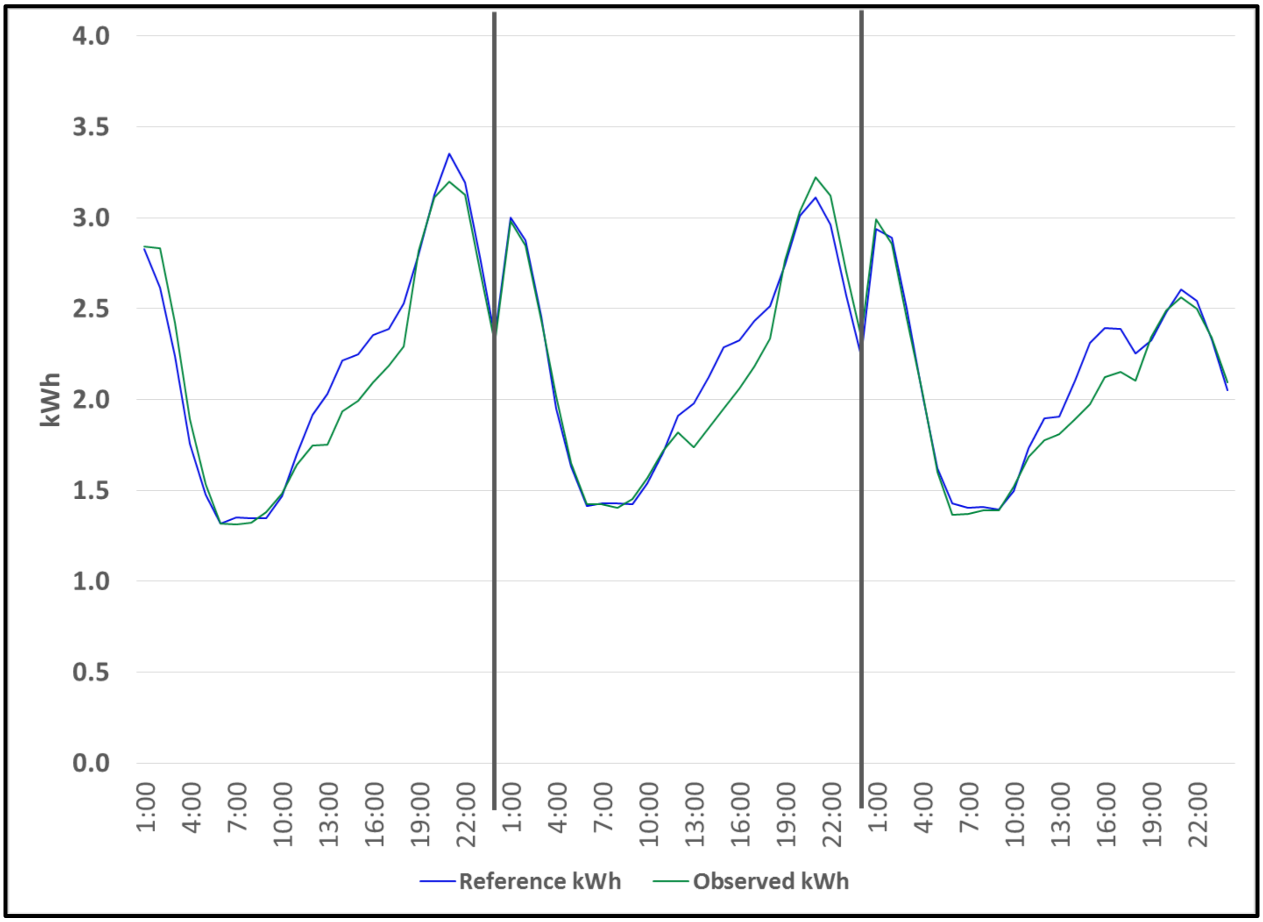


Table 3-15: Summary of PTR Event Impacts for Electric Vehicle Customers – 2015 Average

Hour Beg.	Hour End	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partici-pants	Aggregate Load Reduction (kW)
8:00	9:00	No	81.4	1.39	1.36	0.025	1.8%	1,637	42
9:00	10:00	No	83.3	1.50	1.48	0.029	1.9%	1,637	48
10:00	11:00	No	86.5	1.72	1.63	0.089	5.2%	1,637	145
11:00	12:00	Yes	89.6	1.90	1.73	0.170	8.9%	1,637	278
12:00	13:00	Yes	91.0	1.98	1.72	0.266	13.4%	1,637	436
13:00	14:00	Yes	91.5	2.15	1.85	0.308	14.3%	1,637	505
14:00	15:00	Yes	91.2	2.26	1.95	0.308	13.6%	1,637	504
15:00	16:00	Yes	89.8	2.35	2.07	0.278	11.9%	1,637	456
16:00	17:00	Yes	90.2	2.39	2.18	0.216	9.0%	1,637	354
17:00	18:00	Yes	89.4	2.45	2.25	0.194	7.9%	1,637	318
18:00	19:00	No	87.4	2.65	2.61	0.040	1.5%	1,637	65
19:00	20:00	No	86.5	2.83	2.79	0.044	1.6%	1,637	72
20:00	21:00	No	85.4	2.95	2.88	0.069	2.3%	1,637	112
Total - Entire Day			83.7	51.47	49.49	1.986	3.9%	1,637	3,251
Total - Event Hours			90.4	15.48	13.74	1.741	11.2%	1,637	2,850

Figure 3-29: Hourly Load Profile for PTR Electric Vehicle Customers – September 9th – September 11th, 2015



4

Ex Ante Methodology and Results

4.1 Estimating Ex Ante Load Impacts for the PTR Program

Ex ante impacts for the PTR program for four participant segments (Opt-In PTR-Only, PTR Dually Enrolled in Summer Saver, PTR Dually Enrolled in SCTD, and SCTD-Only) were estimated by combining the regression model results from the ex post impacts with two other sources of data. The first data source was a 10-year forecast of enrollment for four separate participant segments. The second data source was two separate versions of weather scenarios containing hourly weather for different types of weather years and day types for each month of the year, one from SDG&E and the second from CAISO. The results presented in this section use the weather conditions based on SDG&E estimates.

The *ex ante* estimation process was relatively straightforward, involving two main steps. The first step required taking the model parameters from the *ex post* regression model and combining them with the weather scenarios to calculate per participant average reference loads, observed loads, and load impacts. Because the impacts were based on variables that were interacted with temperature variables, they can be applied to the weather data from the various year and day types to generated estimated savings for those scenarios. The standard errors from the impact variable parameters from the ex post model were used to calculate the uncertainty estimates. The second step was to combine estimated per-participant impacts for the different weather scenarios and multiply them by the forecast of enrolled participants to generate the total program impacts. SDG&E forecasts that the PTR, Summer Saver, and SCTD programs will continue to grow. By the end of 2017, the PTR program is expected to grow to over 83,000 participants (including dual enrollments in the other programs), while the SCTD program is expected to grow to over 15,000 participants. These projections are then expected to remain constant throughout the remainder of the *ex ante* forecast period.

While this process was straightforward, there were some nuances to the data that call for additional discussion. First, the enrollment forecasts were based on total participants by participant segment, whereas the weather scenarios and estimated impacts have more detailed information. Consequently, the alignment of these data sources called for making certain assumptions about the allocation of program participants. Total participants from the forecast were allocated to climate zones and, for the SCTD and Summer Saver groups, to the cycling strategies based on the relative shares as of the last event day from 2015. Additionally, since the weather scenarios were provided by climate zone, an average weather scenario was created using an average where the same participant shares were used as weights. Note that this weighting was program segment specific. For example, the overall weather for the SCTD 100% cycling participants was based on the shares by climate zone for that particular group. The shares used for the allocation of the enrollment forecast are presented in Table 4-1.

Table 4-1: Shares for Allocation of Enrollment Forecast

Participant Segment		Coastal	Inland	All
PTR-Only	**All**	54%	46%	100%
PTR Dually Enrolled in Summer Saver	**100% Cycle**	18%	46%	64%
	50% Cycle	5%	31%	36%
	All	23%	77%	100%
PTR Dually Enrolled in SCTD	**4 Degree Setback**	22%	33%	55%
	50% Cycle	16%	29%	45%
	All	37%	63%	100%
SCTD-Only	**4 Degree Setback**	18%	34%	52%
	50% Cycle	17%	31%	48%
	All	35%	65%	100%

4.2 Ex Ante Load Impact Results

4.2.1 PTR-Only

Figure 4-1 and Table 4-2 show the *ex ante* average load impact estimates for the average PTR-only customer on an average weekday, monthly system peak day, and a typical event day based on 1-in-2 and 1-in-10 weather year conditions for 2017. The average weekday and monthly system peak days are presented for June, July, and August, while the typical event day is presented for the month of August. For a 1-in-2 typical event day, the estimated load reduction for the average participant is 0.039 kW during the resource availability hours (1:00pm to 6:00 pm). The average estimated aggregate load reduction under this scenario is 2.67 MW. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.053 kW. The average estimated aggregate reduction is 3.71 MW. These estimates represent approximately 3.3% and 3.8% of the reference load, respectively for each weather scenario.

Figure 4-1: 2017 Ex Ante Hourly Load Profile – PTR Only

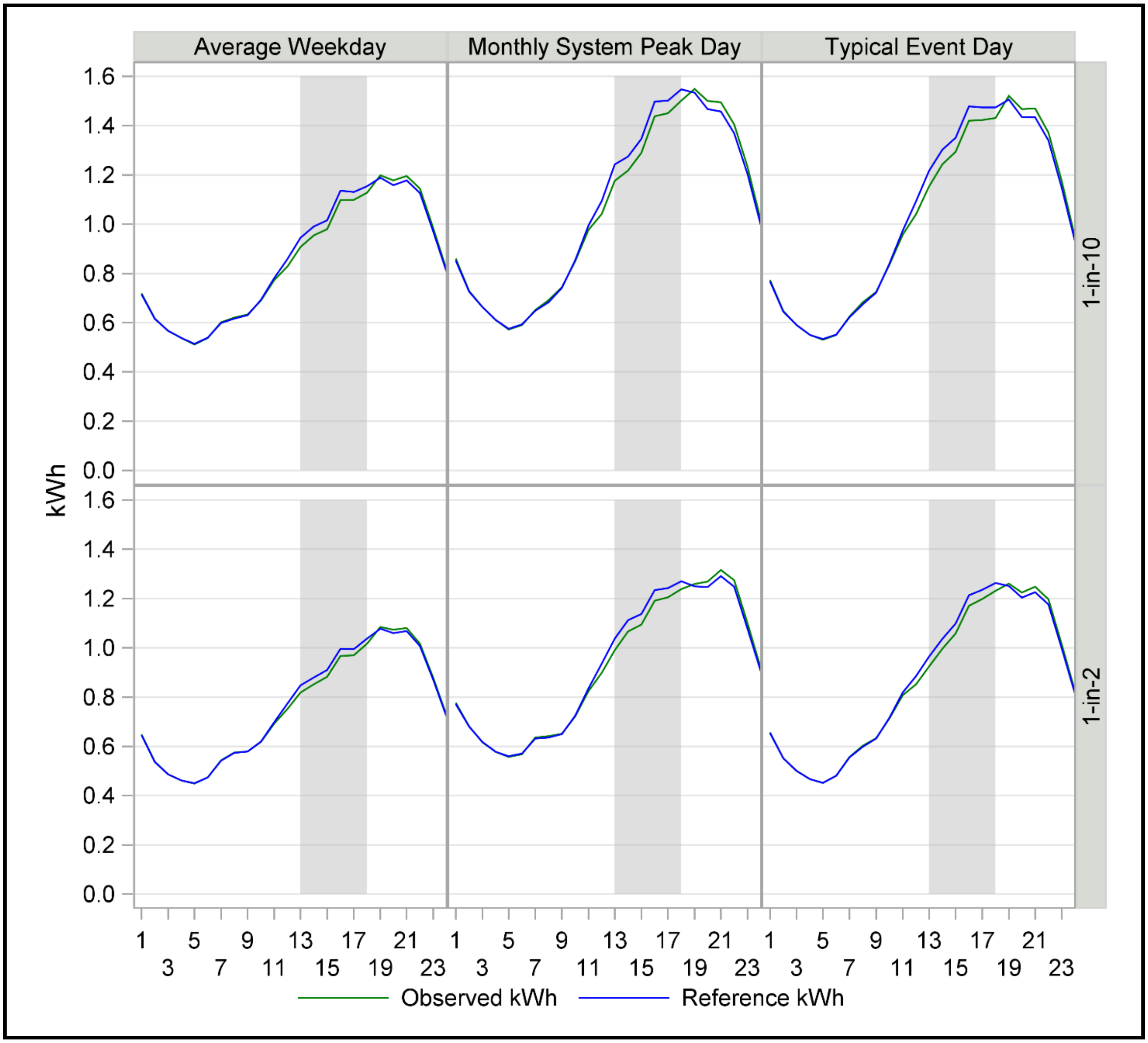


Table 4-2: 2017 Ex Ante Hourly Load Impact Results – PTR-Only

	Day / Type	Month	1-in-10					1-in-2				
			Avg. Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduction	Average Total Hourly Impact (MWh)	Avg. Hourly Reference Load (kWh)	Avg. Hourly Observed Load (kWh)	Avg. Hourly Impact (kWh)	Percent Load Reduction	Avg. Total Hourly Impact (MWh)
ALL	Average Weekday	Jun	0.88	0.86	0.025	2.9%	1.76	0.68	0.66	0.013	2.0%	0.91
		Jul	0.96	0.93	0.029	3.0%	2.02	0.84	0.82	0.022	2.6%	1.54
		Aug	1.09	1.05	0.034	3.1%	2.33	0.96	0.94	0.026	2.7%	1.83
	Monthly System Peak Day	Jun	1.19	1.15	0.044	3.7%	3.03	0.90	0.87	0.027	3.0%	1.83
		Jul	1.32	1.27	0.051	3.9%	3.54	1.07	1.03	0.035	3.3%	2.43
		Aug	1.43	1.38	0.054	3.8%	3.77	1.20	1.16	0.041	3.4%	2.81
	Typical Event Day	Aug	1.42	1.36	0.053	3.8%	3.71	1.17	1.13	0.039	3.3%	2.67

4.2.2 PTR Dually Enrolled in Summer Saver

Figure 4-2 and Table 4-3 show the *ex ante* load impact estimates for the average PTR customer dually enrolled in Summer Saver for the various combinations of day types and weather scenarios for 2017. Just as a reminder, the control group for these dually enrolled participants are Summer Saver participants that are not dually enrolled in PTR, and the forecasted impacts are incremental savings over and above those realized from the Summer Saver program. For a 1-in-2 typical event day, the estimated load reduction for the average participant is 0.16 kW during event hours. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.23 kW. These estimates are higher than the PTR-only group. The average estimated aggregate load reductions are 0.72 MW (11.7%) and 1.02 MW (13.1%), respectively.

The 100% cycling group has an estimated load reduction during event hours of 0.23 kW under the 1-in-2 scenario, representing a 17.4% reduction from the reference load. Under the 1-in-10 conditions, this group has an estimated event hour load reduction of 0.32 kW, or 19.6%. The 50% cycling group has much lower estimated load reductions of 0.04 kW (2.6%) and 0.06 kW (3.0%) for the 1-in-2 and 1-in-10 scenarios, respectively.

Figure 4-2: 2017 Ex Ante Hourly Load Profile – PTR Dually Enrolled in Summer Saver

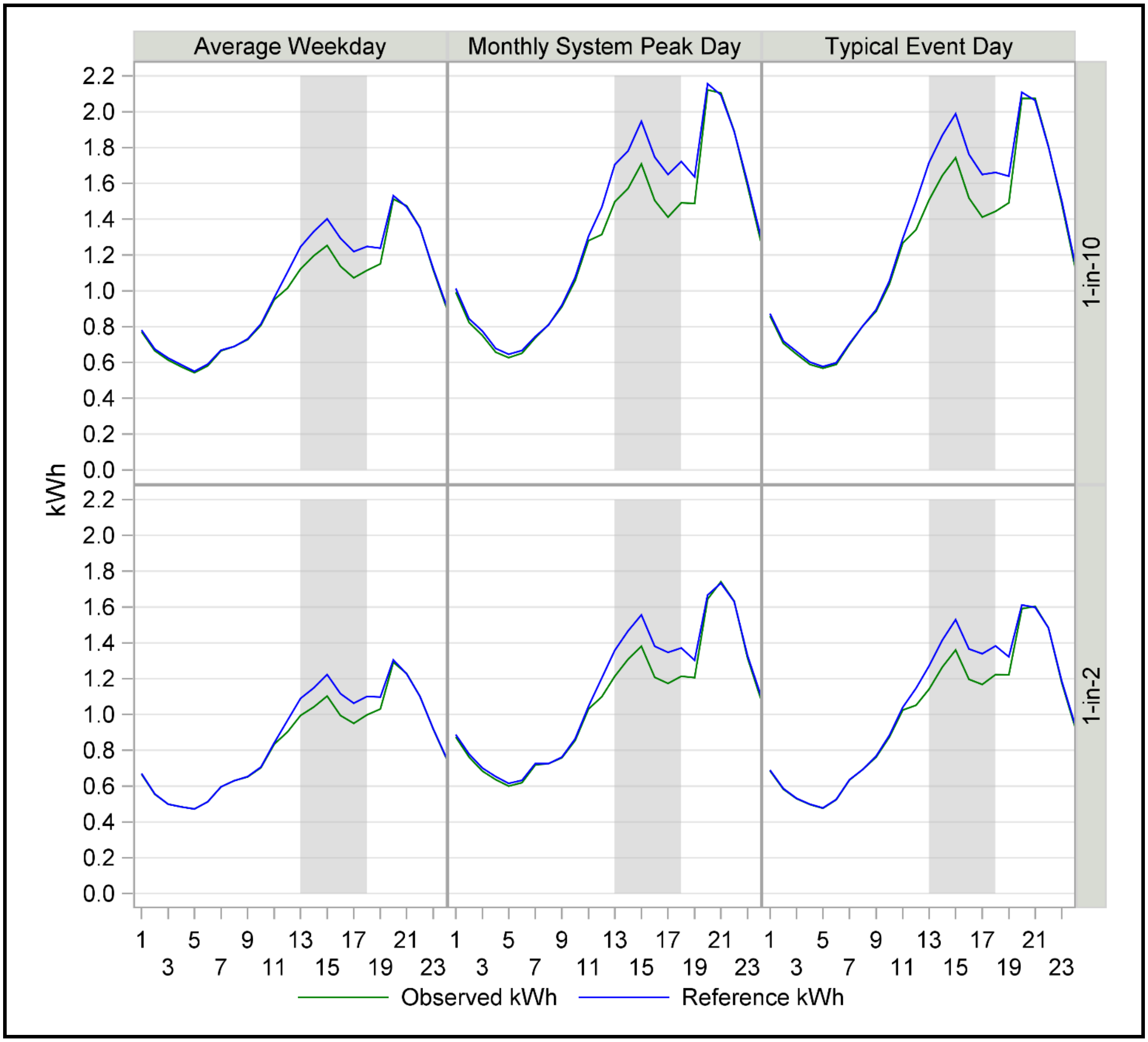


Table 4-3: 2017 Ex Ante Hourly Load Impact Results – PTR Dually Enrolled in Summer Saver

Cycle %	Day / Type	Month	1-in-10					1-in-2				
			Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduc-tion	Average Total Hourly Impact (MWh)	Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduc-tion	Average Total Hourly Impact (MWh)
100	Average Weekday	Jun	0.93	0.78	0.149	16.0%	0.42	0.68	0.60	0.075	11.1%	0.21
		Jul	1.07	0.89	0.178	16.7%	0.50	0.93	0.79	0.137	14.7%	0.38
		Aug	1.21	1.01	0.199	16.4%	0.56	1.07	0.91	0.156	14.6%	0.43
	Monthly System Peak Day	Jun	1.34	1.07	0.267	20.0%	0.75	0.98	0.82	0.161	16.5%	0.45
		Jul	1.50	1.20	0.300	19.9%	0.84	1.17	0.96	0.215	18.3%	0.60
		Aug	1.63	1.31	0.322	19.7%	0.90	1.33	1.10	0.233	17.5%	0.65
	Typical Event Day	Aug	1.64	1.32	0.322	19.6%	0.90	1.31	1.08	0.228	17.4%	0.64
50	Average Weekday	Jun	1.05	1.02	0.029	2.8%	0.05	0.69	0.68	0.015	2.1%	0.02
		Jul	1.26	1.22	0.035	2.7%	0.05	1.06	1.04	0.028	2.6%	0.04
		Aug	1.44	1.41	0.037	2.6%	0.06	1.24	1.21	0.030	2.4%	0.05
	Monthly System Peak Day	Jun	1.63	1.58	0.051	3.1%	0.08	1.12	1.09	0.033	2.9%	0.05
		Jul	1.84	1.78	0.061	3.3%	0.10	1.39	1.35	0.032	2.3%	0.05
		Aug	2.01	1.95	0.057	2.8%	0.09	1.58	1.54	0.042	2.7%	0.07
	Typical Event Day	Aug	2.04	1.98	0.061	3.0%	0.10	1.57	1.53	0.041	2.6%	0.06
ALL	Average Weekday	Jun	0.98	0.87	0.108	11.1%	0.47	0.68	0.63	0.054	7.9%	0.24
		Jul	1.14	1.01	0.130	11.4%	0.57	0.98	0.88	0.100	10.3%	0.44
		Aug	1.30	1.15	0.144	11.1%	0.63	1.13	1.02	0.113	10.0%	0.49
	Monthly System Peak Day	Jun	1.45	1.25	0.195	13.5%	0.85	1.03	0.91	0.118	11.4%	0.51
		Jul	1.63	1.41	0.219	13.5%	0.96	1.25	1.10	0.153	12.2%	0.67
		Aug	1.77	1.54	0.231	13.1%	1.01	1.42	1.26	0.167	11.7%	0.73
	Typical Event Day	Aug	1.79	1.55	0.234	13.1%	1.02	1.41	1.24	0.164	11.7%	0.72

4.2.3 PTR Dually Enrolled in SCTD

Figure 4-3 and Table 4-4 show the *ex ante* load impact estimates for the average PTR customer dually enrolled in SCTD for the various combinations of day types and weather scenarios for 2017. For a 1-in-2 typical event day, the estimated load reduction for the average dual PTR-SCTD participant is 0.36 kW during resource availability hours. For a 1-in-10 typical event day, the estimated load reduction is 0.51 kW. The average estimated aggregate load reductions are 3.05 MW (23.4%) and 4.28 MW (25.3%), respectively.

The 4 degree setback has a higher load reduction estimate than the 50% cycling group. For example, in the 1 in 2 year on a typical event day, the load reduction is 0.40 kW for the setback group compared to 0.31 for the cycling group, resulting in a percent load reduction of 25.4% compared to 20.5%.

Figure 4-3: 2017 Ex Ante Hourly Load Profile – PTR Dually Enrolled in SCTD

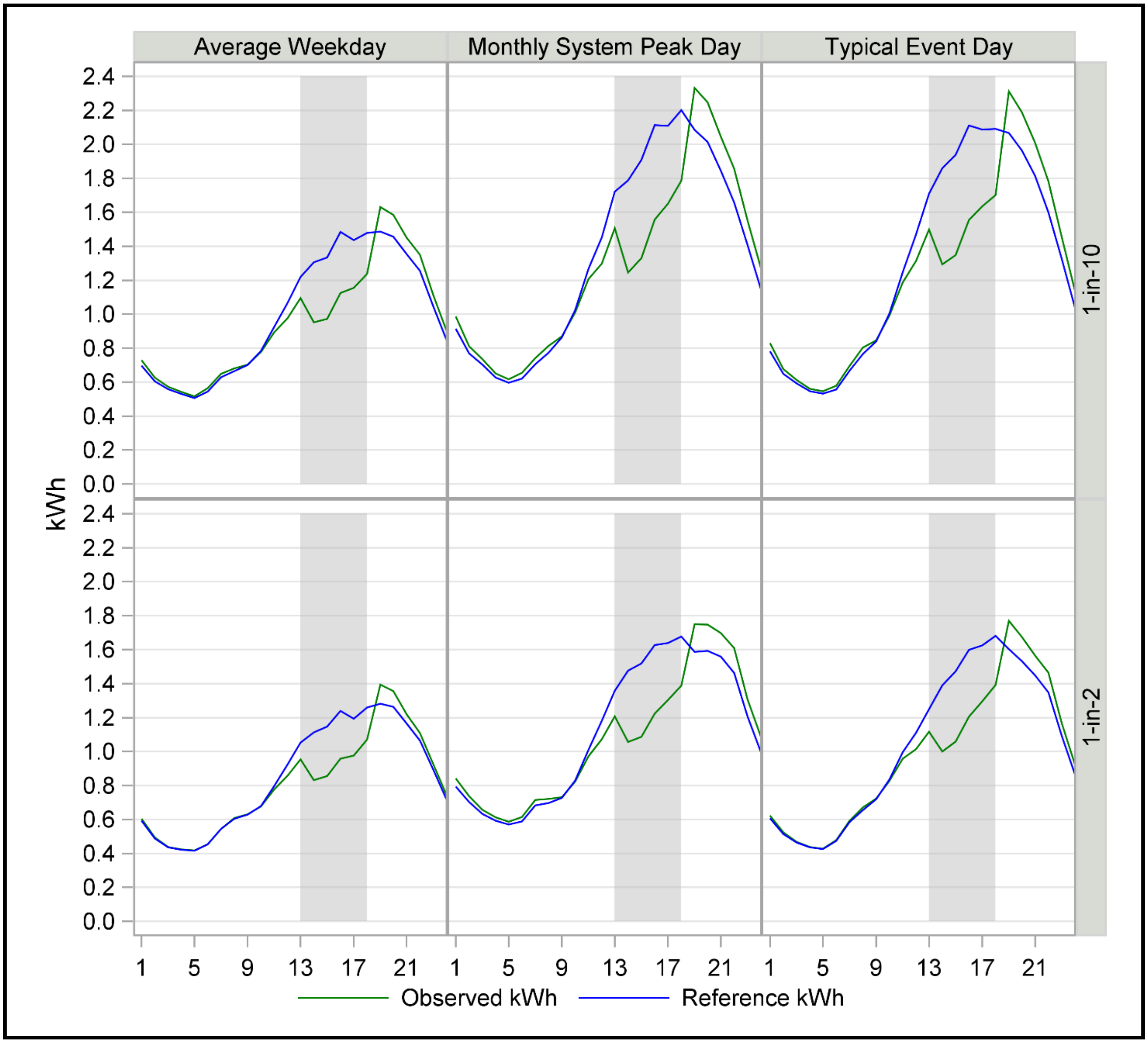


Table 4-4: 2017 Ex Ante Hourly Load Impact Results – PTR Dually Enrolled in SCTD

Control Strategy	Day / Type	Month	1-in-10					1-in-2				
			Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduction	Average Total Hourly Impact (MWh)	Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduction	Average Total Hourly Impact (MWh)
4 Degree Setback	Average Weekday	Jun	1.18	0.91	0.269	22.8%	1.15	0.80	0.66	0.139	17.3%	0.59
		Jul	1.32	1.01	0.315	23.9%	1.38	1.11	0.87	0.244	22.0%	1.06
		Aug	1.44	1.08	0.354	24.6%	1.58	1.22	0.94	0.280	23.0%	1.25
	Monthly System Peak Day	Jun	1.78	1.31	0.468	26.3%	2.00	1.24	0.95	0.288	23.3%	1.23
		Jul	1.96	1.42	0.540	27.5%	2.36	1.51	1.14	0.370	24.6%	1.62
		Aug	2.07	1.50	0.566	27.4%	2.53	1.62	1.21	0.417	25.7%	1.86
	Typical Event Day	Aug	2.06	1.50	0.567	27.5%	2.53	1.59	1.18	0.404	25.4%	1.81
50% Cycle	Average Weekday	Jun	1.13	0.92	0.206	18.3%	0.74	0.77	0.66	0.106	13.8%	0.38
		Jul	1.26	1.02	0.242	19.2%	0.89	1.06	0.87	0.187	17.7%	0.69
		Aug	1.37	1.10	0.272	19.8%	1.02	1.16	0.94	0.214	18.5%	0.81
	Monthly System Peak Day	Jun	1.69	1.33	0.359	21.2%	1.29	1.18	0.96	0.221	18.7%	0.79
		Jul	1.87	1.45	0.413	22.1%	1.52	1.43	1.15	0.285	19.9%	1.05
		Aug	1.97	1.53	0.435	22.1%	1.64	1.54	1.22	0.320	20.7%	1.20
	Typical Event Day	Aug	1.96	1.53	0.435	22.2%	1.64	1.51	1.20	0.310	20.5%	1.17
ALL	Average Weekday	Jun	1.16	0.92	0.242	20.9%	1.94	0.79	0.66	0.125	15.8%	1.00
		Jul	1.29	1.01	0.284	22.0%	2.33	1.09	0.87	0.219	20.2%	1.80
		Aug	1.41	1.09	0.319	22.7%	2.67	1.19	0.94	0.252	21.1%	2.11
	Monthly System Peak Day	Jun	1.74	1.32	0.421	24.2%	3.38	1.21	0.95	0.259	21.4%	2.08
		Jul	1.92	1.43	0.486	25.3%	3.99	1.47	1.14	0.333	22.7%	2.74
		Aug	2.02	1.51	0.510	25.2%	4.28	1.59	1.21	0.375	23.6%	3.15
	Typical Event Day	Aug	2.02	1.51	0.510	25.3%	4.28	1.55	1.19	0.364	23.4%	3.05

4.2.4 SCTD Only

Figure 4-4 and Table 4-5 show the *ex ante* load impact estimates for the average customer only enrolled in the SCTD program for the various combinations of day types and weather scenarios for 2017. For a 1-in-2 typical event day, the estimated load reduction for the average SCTD-only participant is 0.22 kW during the resource availability hour. For a 1-in-10 typical event day, the estimated load reduction is 0.31 kW. The average estimated aggregate load reductions are 1.29 MW (13.7%) and 1.81 MW (14.9%), respectively. As the enrollment in the SCTD programs continues to grow, these aggregate estimates will increase.

For the SCTD-only customers, the 4 degree setback group has an average event hour load reduction estimate that is higher than the 50% cycling group. The former has an average event hour load reduction estimate of 0.25 kW and 0.36 for the 1-in-10 and 1-in-2 scenarios, respectively, while the latter has an average estimate of 0.17 kW and 0.24 kW. The aggregate load reduction estimate for the 4 degree setback group is 1.10 MW for the 1-in-10 year, representing a load reduction of 17.0%. The comparative metric for the 50% cycling group is 0.67 MW, which is a 12.1% load reduction.

Figure 4-4: 2017 Ex Ante Hourly Load Profile – SCTD Only

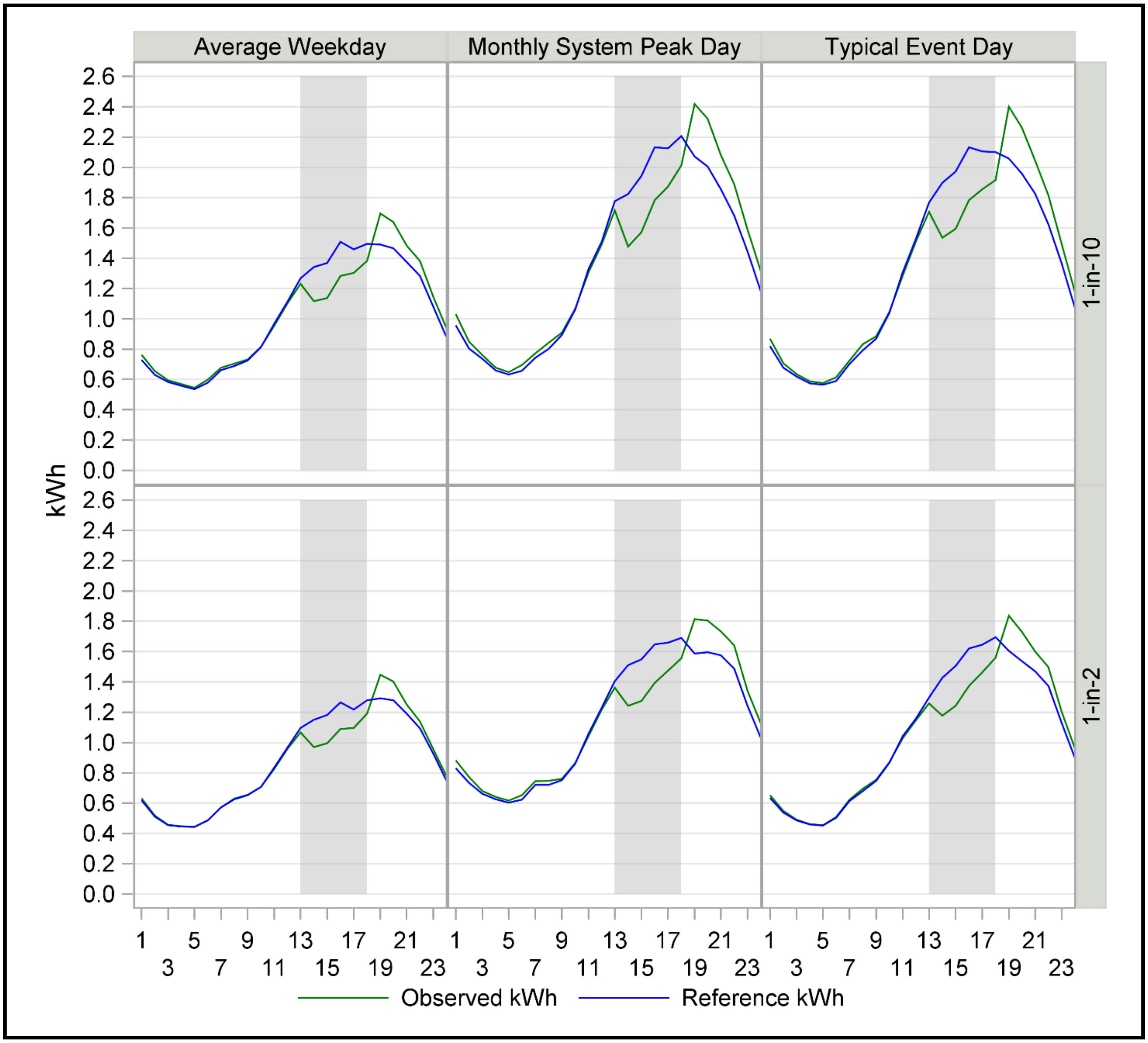


Table 4-5: 2017 Ex Ante Hourly Load Impact Results – SCTD Only

Control Strategy	Day / Type	Month	1-in-10					1-in-2				
			Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduction	Average Total Hourly Impact (MWh)	Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduction	Average Total Hourly Impact (MWh)
4 Degree Setback	**Average Weekday**	**Jun**	1.21	1.04	0.169	13.9%	0.50	0.83	0.75	0.087	10.4%	0.26
		Jul	1.35	1.15	0.198	14.6%	0.60	1.14	0.99	0.153	13.4%	0.46
		Aug	1.47	1.25	0.221	15.1%	0.69	1.25	1.07	0.175	14.0%	0.54
	Monthly System Peak Day	**Jun**	1.81	1.51	0.293	16.2%	0.87	1.27	1.09	0.181	14.3%	0.53
		Jul	1.99	1.65	0.339	17.0%	1.03	1.53	1.30	0.230	15.0%	0.70
		Aug	2.09	1.74	0.353	16.9%	1.09	1.65	1.39	0.260	15.8%	0.80
	Typical Event Day	**Aug**	2.09	1.73	0.355	17.0%	1.10	1.62	1.36	0.252	15.6%	0.78
50% Cycle	**Average Weekday**	**Jun**	1.15	1.04	0.114	9.9%	0.31	0.80	0.74	0.059	7.4%	0.16
		Jul	1.29	1.15	0.134	10.4%	0.37	1.09	0.98	0.104	9.5%	0.28
		Aug	1.39	1.24	0.150	10.7%	0.42	1.19	1.07	0.118	10.0%	0.33
	Monthly System Peak Day	**Jun**	1.71	1.52	0.198	11.5%	0.53	1.21	1.08	0.123	10.2%	0.33
		Jul	1.89	1.66	0.230	12.2%	0.63	1.46	1.30	0.154	10.6%	0.42
		Aug	1.98	1.75	0.238	12.0%	0.67	1.56	1.39	0.176	11.2%	0.49
	Typical Event Day	**Aug**	1.98	1.74	0.240	12.1%	0.67	1.53	1.36	0.170	11.1%	0.48
ALL	**Average Weekday**	**Jun**	1.19	1.04	0.145	12.2%	0.82	0.82	0.74	0.075	9.1%	0.42
		Jul	1.32	1.15	0.170	12.8%	0.99	1.12	0.99	0.132	11.8%	0.76
		Aug	1.43	1.24	0.190	13.3%	1.13	1.22	1.07	0.150	12.3%	0.89
	Monthly System Peak Day	**Jun**	1.77	1.51	0.251	14.2%	1.43	1.24	1.08	0.156	12.5%	0.88
		Jul	1.94	1.65	0.292	15.0%	1.69	1.50	1.30	0.197	13.1%	1.14
		Aug	2.05	1.74	0.303	14.8%	1.80	1.61	1.39	0.223	13.9%	1.33
	Typical Event Day	**Aug**	2.04	1.74	0.305	14.9%	1.81	1.58	1.36	0.216	13.7%	1.29

4.2.5 Comparison of 2015 and 2014 Ex Ante Estimates

Table 4-7 and Figure 4-5 through Figure 4-8 show the comparisons between the *ex ante* estimates in the current evaluation and those reported in the previous evaluation for the forecast year 2017. The current *ex ante* estimates are lower for the PTR-only group – the current estimates are 0.04 kW for a 1-in-2 event day and 0.05 kW for a 1-in-10 event day, while the previous estimates were 0.07 kW and 0.09 kW, respectively. The percentage load reductions are also lower, from approximately 6% in the previous analysis to approximately 4% in the current analysis for a 1-in-10 year. This is largely due to the lower modeled impacts for the PTR events in the current evaluation cycle.

The estimates for the group dually enrolled in Summer Saver are not comparable because the current evaluation focused on quantifying the incremental impact of the PTR program for those dually enrolled in Summer Saver over and above those enrolled in Summer Saver alone. This ensures that there is no double counting of the Summer Saver impacts as they are covered by a separate evaluation. Subsequent evaluations will use this incremental approach, which will allow for a more meaningful comparison of PTR *ex ante* estimates.

The estimates for the SCTD participants in the current analysis are similar to the previous analysis, but slightly lower in absolute terms. For the dually enrolled participants, the previous analysis found estimates of 0.43 kW on 1-in-2 event days and 0.60 kW on 1-in-10 event days. The current analysis projects 0.36 kW on 1-in-2 event days and 0.51 kW on 1-in-10 event days. The percentage load reduction estimates under the current analysis are higher. For example, in the 1-in-2 year, the previous results had load reductions of 21.3%, while the current estimates are 23.4%. For the SCTD-only participants, the current forecasts are lower in both absolute and percentage terms. The previous analysis found estimates of 0.34 kW (15.8%) on 1-in-2 event days and 0.46 kW (17.1%) on 1-in-10 event days. The current analysis projects 0.22 kW (13.7%) on 1-in-2 event days and 0.30 kW (14.9%) on 1-in-10 event days.

Table 4-6: Comparison of 2015 and 2014 Ex Ante Estimates Per Customer – Forecast Year 2017 1-in-2 August System Peak Days, 1 p.m. to 6 p.m.

			Current				Previous			
Participant Segment	Weather Year	Day / Type	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction
PTR Only	**1-in-2**	**August System Peak Day**	1.20	1.16	0.04	3.4%	1.39	1.32	0.07	5.0%
PTR/SS	**1-in-2**	**August System Peak Day**	1.42	1.26	0.17	11.7%	1.94	1.47	0.48	24.5%
PTR/SCTD	**1-in-2**	**August System Peak Day**	1.59	1.21	0.38	23.6%	2.09	1.64	0.45	21.5%
SCTD Only	**1-in-2**	**August System Peak Day**	1.61	1.39	0.22	13.9%	2.19	1.84	0.35	15.8%

Table 4-7: Comparison of 2015 and 2014 Ex Ante Estimates Per Customer – Forecast Year 2017, 1 p.m. to 6 p.m.

			Current				Previous			
Participant Segment	Weather Year	Day / Type	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction
PTR Only	1-in-10	August System Peak Day	1.43	1.38	0.05	3.8%	1.59	1.50	0.09	5.8%
		Typical Event Day	1.42	1.36	0.05	3.8%	1.57	1.48	0.09	5.8%
	1-in-2	August System Peak Day	1.20	1.16	0.04	3.4%	1.39	1.32	0.07	5.0%
		Typical Event Day	1.17	1.13	0.04	3.3%	1.37	1.30	0.07	4.8%
PTR/SS	1-in-10	August System Peak Day	1.77	1.54	0.23	13.1%	2.31	1.66	0.66	28.4%
		Typical Event Day	1.79	1.55	0.23	13.1%	2.30	1.65	0.64	28.0%
	1-in-2	August System Peak Day	1.42	1.26	0.17	11.7%	1.94	1.47	0.48	24.5%
		Typical Event Day	1.41	1.24	0.16	11.7%	1.91	1.44	0.47	24.4%
PTR/SCTD	1-in-10	August System Peak Day	2.02	1.51	0.51	25.2%	2.64	2.03	0.61	23.1%
		Typical Event Day	2.02	1.51	0.51	25.3%	2.62	2.01	0.60	23.1%
	1-in-2	August System Peak Day	1.59	1.21	0.38	23.6%	2.09	1.64	0.45	21.5%
		Typical Event Day	1.55	1.19	0.36	23.4%	2.04	1.60	0.43	21.3%
SCTD Only	1-in-10	August System Peak Day	2.05	1.74	0.30	14.8%	2.74	2.27	0.47	17.2%
		Typical Event Day	2.04	1.74	0.30	14.9%	2.72	2.25	0.46	17.1%
	1-in-2	August System Peak Day	1.61	1.39	0.22	13.9%	2.19	1.84	0.35	15.8%
		Typical Event Day	1.58	1.36	0.22	13.7%	2.13	1.79	0.34	15.8%

Figure 4-5: Comparison of 2015 and 2014 Ex Ante Hourly Load Profiles – PTR-Only – Typical Event Day

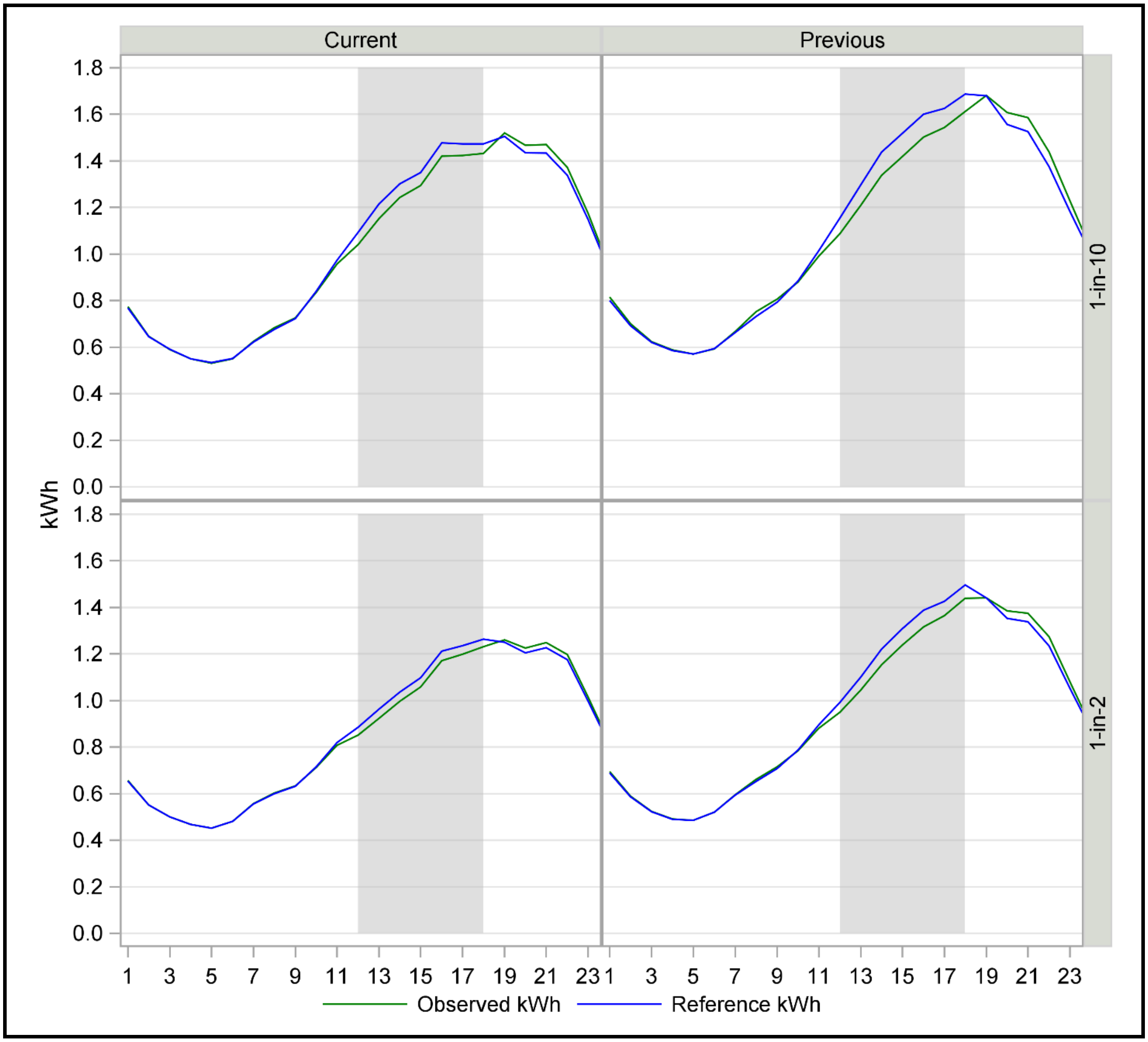


Figure 4-6: Comparison of 2015 and 2014 Ex Ante Hourly Load Profiles – PTR Dually Enrolled in Summer Saver – Typical Event Day

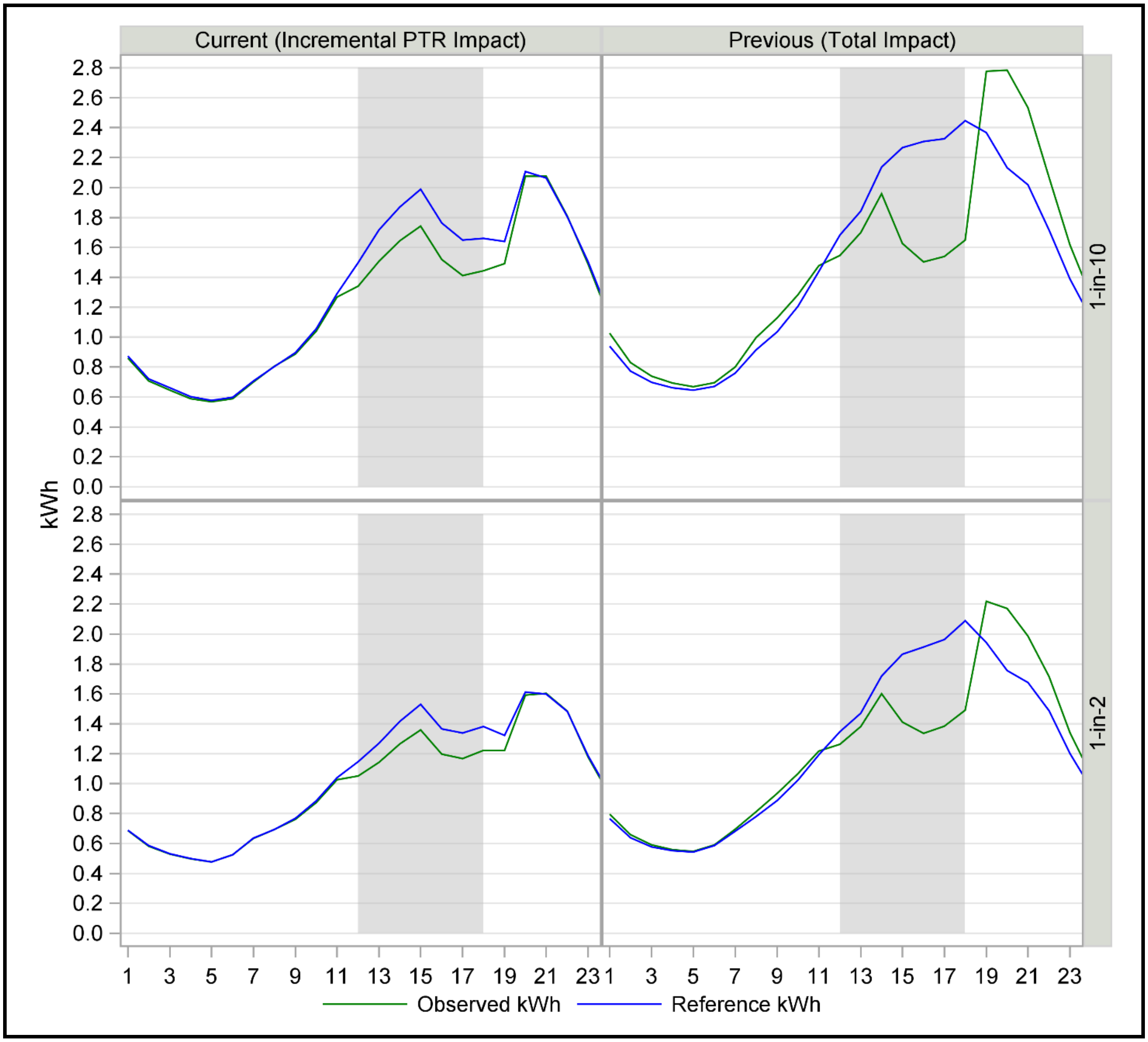


Figure 4-7: Comparison of 2015 and 2014 Ex Ante Hourly Load Profiles – PTR Dually Enrolled in SCTD – Typical Event Day

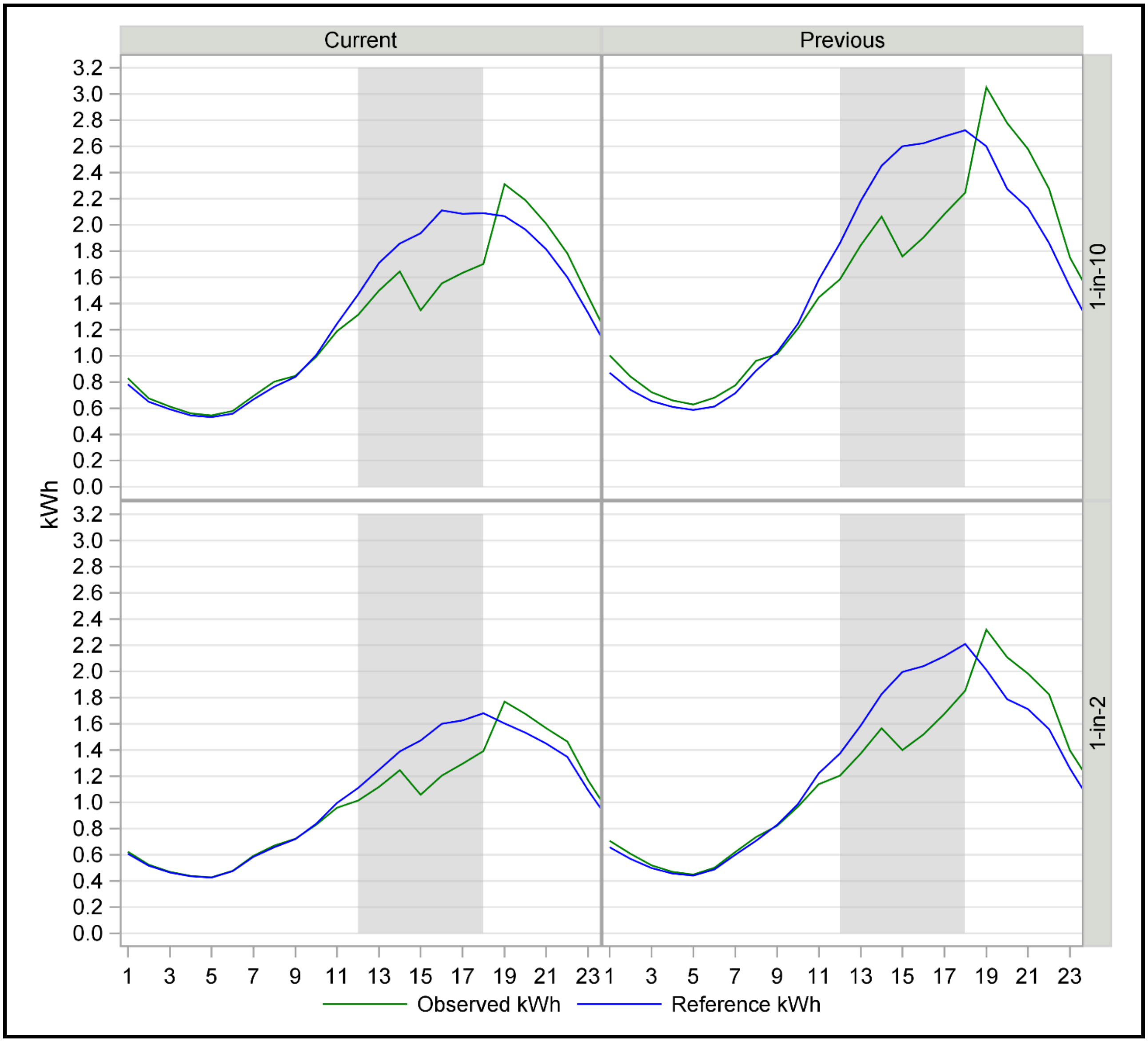
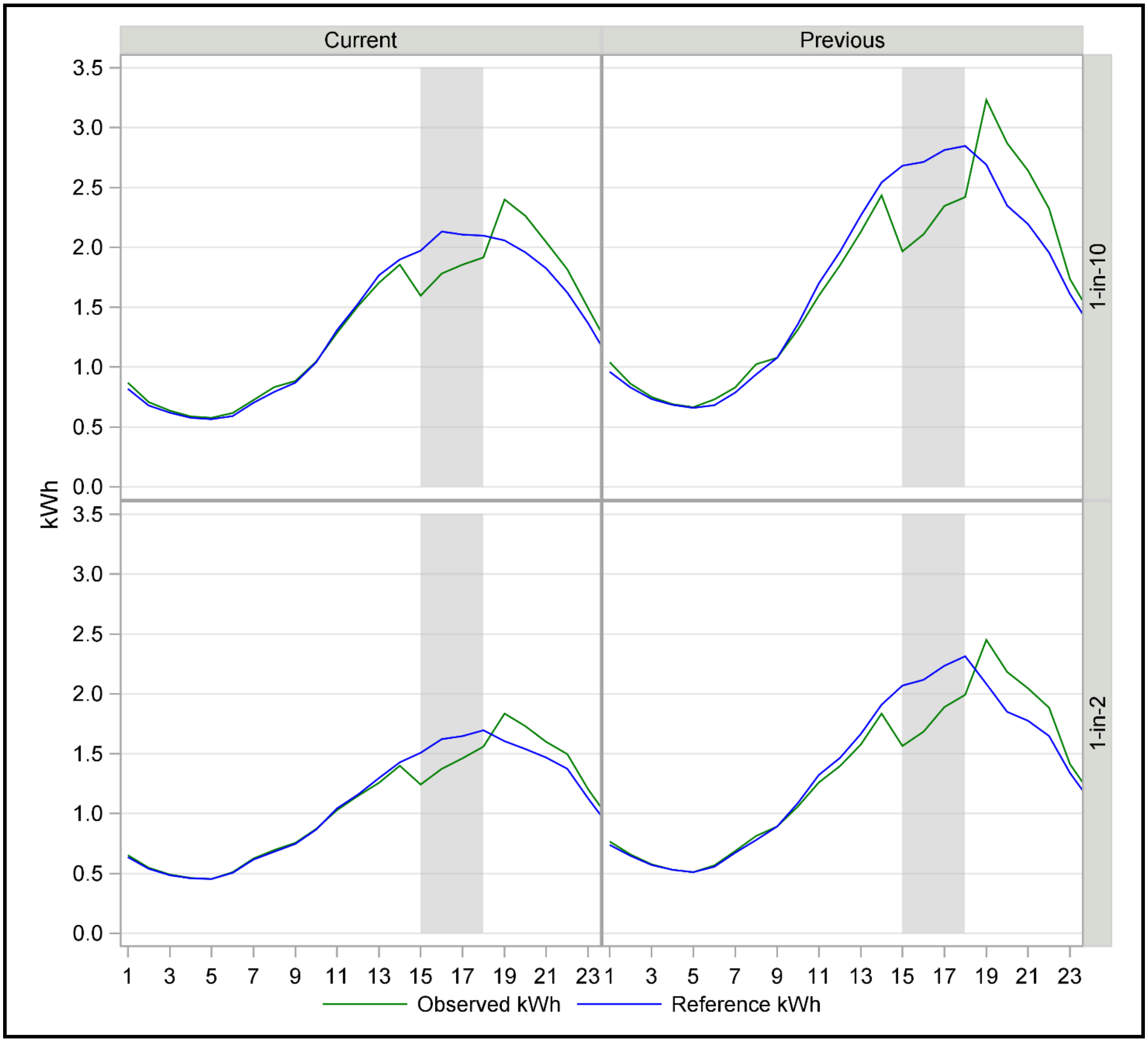


Figure 4-8: Comparison of 2015 and 2014 Ex Ante Hourly Load Profiles – SCTD-Only – Typical Event Day



4.2.6 Relationship between Ex Post and Ex Ante Estimates

Table 4-8 and Table 4-9 show comparisons between the *ex ante* and *ex post* estimates from this evaluation. For all of the groups, and similar to the previous evaluation, it seems that the weather in 2015 was particularly hot, and thus the results are more aligned with 1-in-10 weather conditions.

For the overall PTR-only group, the *ex post* results show an average event hour load reduction of 0.06 kW, while the 1-in-10 *ex ante* estimates show average event hour load reductions of 0.05 kW, both around 4% of the reference load. The predicted 1-in-10 average event hour load reductions for the overall PTR-Summer Saver dually enrolled group (0.27 kW, or 13.8%) are very similar, but slightly higher than the *ex post* impacts (0.23 kW, or 13.1%). The same relationship exists for the 50% and 100% cycling sub-groups. For the dually enrolled PTR-SCTD group, the *ex post* and 1-in-10 *ex ante* estimates are essentially identical, at 0.52 and 0.51 kW, respectively. These represent approximately 22% and 25% of the reference load. The estimates for the load control sub-groups are also similar. The 4 degree setback group's 1-in-10 *ex ante* estimate 0.01 kW lower than the *ex post* estimate, while the 50% cycling group's is the same. As with the other groups, the SCTD-only *ex post* estimates are similar to the 1-in-10 *ex ante* estimates. The overall event hour load reduction estimate is 0.28 kW (11.9%) for the *ex post* and 0.30 kW (14.9%) for the 1-in-10 *ex ante*. The 50% cycling sub-group has lower *ex post* estimates, with averages of 0.20 kW (8.9%) for *ex post* and 0.24 (12.1%) for the 1-in-10 *ex ante* estimate. The 4 degree setback has *ex post* estimate of 0.34 kW, compared to the *ex ante* average of 0.35 for the 1-in-10 typical event day.

Table 4-8: Comparison of Ex Ante 1-in-2 August System Peak Day and Ex Post Average Event Day Estimates per Customer, 1 p.m. to 6 p.m.

Participant Segment	Control Strategy	Weather Year	Day / Type	Average Hourly Reference Load (kW)	Average Hourly Observed Load (kW)	Average Hourly Impact (kW)	Percent Load Reduction	Average °F
PTR Only	ALL	1-In-2	August System Peak Day	1.20	1.16	0.04	3.4%	81.37
		Ex Post	Ex Post Average Event Day	1.59	1.52	0.06	4.0%	90.94
PTR/SS	100%	1-In-2	August System Peak Day	1.33	1.10	0.23	17.5%	82.45
		Ex Post	Ex Post Average Event Day	1.80	1.42	0.37	20.9%	93.06
	50%	1-In-2	August System Peak Day	1.58	1.54	0.04	2.7%	83.03
		Ex Post	Ex Post Average Event Day	2.20	2.14	0.07	3.0%	93.80
	ALL	1-In-2	August System Peak Day	1.42	1.26	0.17	11.7%	82.66
		Ex Post	Ex Post Average Event Day	1.95	1.68	0.27	13.8%	93.33
PTR/SCTD	4 Degree Setback	1-In-2	August System Peak Day	1.62	1.21	0.42	25.7%	82.06
		Ex Post	Ex Post Average Event Day	2.40	1.82	0.58	24.0%	92.34
	50% Cycle	1-In-2	August System Peak Day	1.54	1.22	0.32	20.7%	82.10
		Ex Post	Ex Post Average Event Day	2.29	1.85	0.44	19.2%	92.49
	ALL	1-In-2	August System Peak Day	1.59	1.21	0.38	23.6%	82.07
		Ex Post	Ex Post Average Event Day	2.35	1.83	0.52	22.0%	92.40
SCTD Only	4 Degree Setback	1-In-2	August System Peak Day	1.65	1.39	0.26	15.8%	82.12
		Ex Post	Ex Post Average Event Day	2.42	2.08	0.34	14.0%	92.38
	50% Cycle	1-In-2	August System Peak Day	1.56	1.39	0.18	11.2%	82.13
		Ex Post	Ex Post Average Event Day	2.29	2.08	0.20	8.9%	92.27
	ALL	1-In-2	August System Peak Day	1.61	1.39	0.22	13.9%	82.13
		Ex Post	Ex Post Average Event Day	2.36	2.08	0.28	11.9%	92.34

Table 4-9: Detailed Comparison of Ex Ante and Ex Post Estimates per Customer, 1 p.m. to 6 p.m.

Participant Segment	Control Strategy	Weather Year	Day / Type	Average Hourly Reference Load (kW)	Average Hourly Observed Load (kW)	Average Hourly Impact (kW)	Percent Load Reduction	Average °F
PTR Only	**ALL**	**1-In-10**	**Monthly System Peak Day**	1.43	1.38	0.05	3.8%	86.97
			Typical Event Day	1.42	1.36	0.05	3.8%	86.59
		1-In-2	**Monthly System Peak Day**	1.20	1.16	0.04	3.4%	81.37
			Typical Event Day	1.17	1.13	0.04	3.3%	80.59
		Ex Post	**Ex Post Average Event Day**	1.59	1.52	0.06	4.0%	90.94
PTR/SS	**100%**	**1-In-10**	**Monthly System Peak Day**	1.63	1.31	0.32	19.7%	89.01
			Typical Event Day	1.64	1.32	0.32	19.6%	89.18
		1-In-2	**Monthly System Peak Day**	1.33	1.10	0.23	17.5%	82.45
			Typical Event Day	1.31	1.08	0.23	17.4%	82.05
		Ex Post	**Ex Post Average Event Day**	1.80	1.42	0.37	20.9%	93.06
	50%	**1-In-10**	**Monthly System Peak Day**	2.01	1.95	0.06	2.8%	90.10
			Typical Event Day	2.04	1.98	0.06	3.0%	90.57
		1-In-2	**Monthly System Peak Day**	1.58	1.54	0.04	2.7%	83.03
			Typical Event Day	1.57	1.53	0.04	2.6%	82.83
		Ex Post	**Ex Post Average Event Day**	2.20	2.14	0.07	3.0%	93.80
	ALL	**1-In-10**	**Monthly System Peak Day**	1.77	1.54	0.23	13.1%	89.40
			Typical Event Day	1.79	1.55	0.23	13.1%	89.69
		1-In-2	**Monthly System Peak Day**	1.42	1.26	0.17	11.7%	82.66
			Typical Event Day	1.41	1.24	0.16	11.7%	82.33
		Ex Post	**Ex Post Average Event Day**	1.95	1.68	0.27	13.8%	93.33
PTR/SCTD	**4 Degree Setback**	**1-In-10**	**Monthly System Peak Day**	2.07	1.50	0.57	27.4%	88.27
			Typical Event Day	2.06	1.50	0.57	27.5%	88.24
		1-In-2	**Monthly System Peak Day**	1.62	1.21	0.42	25.7%	82.06
			Typical Event Day	1.59	1.18	0.40	25.4%	81.52
		Ex Post	**Ex Post Average Event Day**	2.40	1.82	0.58	24.0%	92.34

Table 4-9 (Cont'd): Detailed Comparison of Ex Ante and Ex Post Estimates per Customer, 1 p.m. to 6 p.m.

Participant Segment	Control Strategy	Weather Year	Day / Type	Average Hourly Reference Load (kW)	Average Hourly Observed Load (kW)	Average Hourly Impact (kW)	Percent Load Reduction	Average °F
PTR/SCTD	50% Cycle	1-In-10	Monthly System Peak Day	1.97	1.53	0.44	22.1%	88.35
			Typical Event Day	1.96	1.53	0.44	22.2%	88.35
		1-In-2	Monthly System Peak Day	1.54	1.22	0.32	20.7%	82.10
			Typical Event Day	1.51	1.20	0.31	20.5%	81.58
		Ex Post	Ex Post Average Event Day	2.29	1.85	0.44	19.2%	92.49
	ALL	1-In-10	Monthly System Peak Day	2.02	1.51	0.51	25.2%	88.30
			Typical Event Day	2.02	1.51	0.51	25.3%	88.28
		1-In-2	Monthly System Peak Day	1.59	1.21	0.38	23.6%	82.07
			Typical Event Day	1.55	1.19	0.36	23.4%	81.54
		Ex Post	Ex Post Average Event Day	2.35	1.83	0.52	22.0%	92.40
SCTD Only	4 Degree Setback	1-In-10	Monthly System Peak Day	2.09	1.74	0.35	16.9%	88.39
			Typical Event Day	2.09	1.73	0.35	17.0%	88.39
		1-In-2	Monthly System Peak Day	1.65	1.39	0.26	15.8%	82.12
			Typical Event Day	1.62	1.36	0.25	15.6%	81.60
		Ex Post	Ex Post Average Event Day	2.42	2.08	0.34	14.0%	92.38
	50% Cycle	1-In-10	Monthly System Peak Day	1.98	1.75	0.24	12.0%	88.41
			Typical Event Day	1.98	1.74	0.24	12.1%	88.43
		1-In-2	Monthly System Peak Day	1.56	1.39	0.18	11.2%	82.13
			Typical Event Day	1.53	1.36	0.17	11.1%	81.62
		Ex Post	Ex Post Average Event Day	2.29	2.08	0.20	8.9%	92.27
	ALL	1-In-10	Monthly System Peak Day	2.05	1.74	0.30	14.8%	88.40
			Typical Event Day	2.04	1.74	0.30	14.9%	88.42
		1-In-2	Monthly System Peak Day	1.61	1.39	0.22	13.9%	82.13
			Typical Event Day	1.58	1.36	0.22	13.7%	81.62
		Ex Post	Ex Post Average Event Day	2.36	2.08	0.28	11.9%	92.34