2016 IMPACT EVALUATION OF SAN DIEGO GAS & ELECTRIC'S RESIDENTIAL PEAK TIME REBATE AND SMALL CUSTOMER TECHNOLOGY DEPLOYMENT PROGRAMS

Ex Post and Ex Ante Draft Report
CALMAC Study ID: SDG0303

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March 20, 2017

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EXECUTIVE SUMMARY

This report presents the findings of the 2016 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 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.

E.S.1 EX POST EVALUATION SUMMARY

E.S.1.1 PTR Ex Post Evaluation

There was one PTR event during the summer of 2016, occurring on September 26th. The average temperature during event hours was 98.8°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 2016 PTR events, the overall PTR population had an average event hour load reduction of 0.10 kW per participant, representing an average reduction of 10.2% relative to the reference load. The average aggregate load reduction during event hours was 8.13 MW. Large participants delivered 61% of the aggregate load reduction (4.93 MW), while Medium and Small participants delivered the remaining 29% (2.15 MW and 1.00 MW, respectively). Inland customers experienced higher temperatures during events (100.4°F) than Coastal customers (97.2°F) and had a higher average load reduction during event hours (0.13 kW versus 0.08 kW). Low income participants had no load reduction during events, with an average of -0.01 kW (-1.4%). The participants who first enrolled in 2016 saved the most during the 2016 PTR events, with an average of 0.15 kW (14.6%) during event hours. Having both email and text event notification resulted a higher average event hour reduction of 0.11 kW (10.4%). 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 (-9.9%).

TABLE ES-1: PTR EX POST LOAD IMPACT ESTIMATES BY CUSTOMER CATEGORY - AVERAGE 2016 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	78,347	1.10	1.00	0.10	10.2%	8.13	98.8
Large	33,435	1.74	1.60	0.15	8.5%	4.93	99.2
Medium	27,492	0.82	0.74	0.08	10.9%	2.15	98.7
Small	17,419	0.33	0.28	0.06	44.3%	1.00	98.2
Coastal	40,083	1.02	0.94	0.08	8.5%	3.21	97.2
Inland	38,263	1.18	1.05	0.13	11.8%	4.95	100.4
No SCTD	72,852	1.09	1.00	0.09	8.7%	6.22	98.7
No Load Control (SCTD or SS)	68,937	1.09	1.01	0.08	8.3%	5.51	98.7
Low Income*	13,414	0.97	0.99	-0.01	-1.4%	-0.18	98.7
Non-Low Income*	55,522	1.31	1.21	0.10	8.0%	5.66	98.5
Enroll. Year – 2012*	18,627	1.08	1.02	0.07	7.1%	1.21	98.7
Enroll. Year – 2013*	5,676	1.05	1.03	0.02	2.6%	0.11	98.8
Enroll. Year – 2014*	22,510	1.09	1.02	0.07	7.5%	1.66	98.7
Enroll. Year – 2015*	11,038	1.09	1.01	0.08	8.2%	0.88	98.7
Enroll. Year – 2016*	11,086	1.12	0.97	0.15	14.6%	1.65	98.6
Notification – Email Only*	42,827	1.08	0.99	0.09	9.5%	3.87	98.6
Notification – Text Only*	13,058	1.09	1.07	0.02	2.8%	0.29	98.7
Notification – Both*	11,684	1.11	1.00	0.11	10.4%	1.26	98.8
Net Energy Metered	10,607	0.18	-0.05	0.23	-9.9%	2.45	99.4

* 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 0.19 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 2016 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	3,915	1.50	1.31	0.19	12.3%	0.73	100.7
Summer Saver – 50% Cycling	1,408	1.70	1.72	-0.03	-1.4%	-0.04	100.9
Summer Saver – 100% Cycling	2,505	1.38	1.08	0.31	22.0%	0.77	100.6

E.S.1.2 SCTD Ex Post Evaluation

The SCTD event day in 2016 overlapped with the PTR event. Participants received either a 4 degree setback on their thermostats or 50% AC cycling. The average temperature for participants during the SCTD event was 100.5°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 0.51 kW, representing 32.0% of the reference load. The average aggregate load reduction for the dually enrolled group was 2.68 MW. Generally, the participants with 4 degree setbacks had higher event hour load reductions, averaging 0.49 kW in the overall SCTD group, compared to those with 50% AC cycling, who averaged 0.46 kW.

TABLE ES-3: SCTD EX POST LOAD IMPACT ESTIMATES BY CUSTOMER CATEGORY - AVERAGE 2016 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**	9,670	1.79	1.37	0.42	25.1%	4.04	100.5
4 Degree Setback	4,761	1.78	1.28	0.49	29.8%	2.35	100.5
50% Cycling	3,388	1.79	1.33	0.46	27.2%	1.55	100.6
PTR	5,301	1.71	1.20	0.51	32.0%	2.68	100.5
PTR – 4 Deg. Setback	2,602	1.73	1.18	0.56	34.7%	1.45	100.5
PTR – 50% Cycling	1,875	1.69	1.13	0.56	35.4%	1.05	100.6
SCTD Only	4,369	1.89	1.57	0.31	17.9%	1.37	100.5
SCTD Only – 4 Degree Setback	2,159	1.83	1.41	0.43	24.8%	0.92	100.6
SCTD Only – 50% Cycling	1,513	1.91	1.58	0.33	18.3%	0.50	100.6

* Participants excluding Summer Saver load control.

** Cycling strategy is not available for some customers because of confidentiality restraints on the signaling portal.

E.S.2 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 80,000 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 10,000 participants to approximately 15,900 by the end of 2017, with around 55% of that total jointly participating in PTR.

Similar to the previous program year (2015), the event-day weather conditions in 2016 were particularly hot and even exceeded the 1-in-10 weather scenarios used for the *ex ante* analysis. Table ES-4 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 0.33 kW in 1-in-10 scenarios and 0.25 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	0.91	0.86	0.05	5.9%	3.77	87.90
		1-in-2	0.72	0.68	0.04	5.7%	2.87	82.46
PTR/SS	100% Cycle	1-in-10	1.24	1.08	0.16	13.2%	0.31	90.24
		1-in-2	1.05	0.93	0.13	11.9%	0.24	84.33
	50% Cycle	1-in-10	1.59	1.59	0.00	0.1%	0.00	91.60
		1-in-2	1.32	1.32	0.00	0.1%	0.00	85.41
	Overall	1-in-10	1.37	1.26	0.11	7.8%	0.32	90.74
		1-in-2	1.15	1.07	0.08	7.1%	0.25	84.73
PTR/SCTD	4 Degree Setback	1-in-10	1.18	0.82	0.36	30.5%	1.33	89.19
		1-in-2	0.86	0.59	0.27	31.7%	1.01	83.49
	50% Cycle	1-in-10	1.21	0.84	0.37	30.7%	0.99	89.46
		1-in-2	0.88	0.60	0.28	31.9%	0.76	83.71
	Overall	1-in-10	1.17	0.83	0.33	28.7%	2.68	89.31
		1-in-2	0.85	0.60	0.25	29.9%	2.04	83.59
SCTD Only	4 Degree Setback	1-in-10	1.32	1.03	0.29	21.8%	0.87	89.30
		1-in-2	0.99	0.77	0.22	22.2%	0.67	83.58
	50% Cycle	1-in-10	1.26	1.04	0.22	17.6%	0.48	89.40
		1-in-2	0.95	0.78	0.17	17.7%	0.37	83.66
	Overall	1-in-10	1.25	1.04	0.22	17.2%	1.41	89.34
		1-in-2	0.94	0.78	0.17	17.5%	1.08	83.62

1 INTRODUCTION

This report provides estimates of the 2016 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 2016 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 usage 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 80,000 customers had enrolled in PTR as of the singular event day of 2016 (September 26th). Five percent of these participants were dually enrolled in the Summer Saver Program and seven 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 9,700 SCTD participants, only 55% of them also enrolled in PTR.

Approximately 63% of PTR participants enrolled for email notification only, with another 17% enrolled jointly in email and text notifications. Text message-only notifications account for most of the remaining participants at 19%. Only 2% of participants received only telephone notifications.

TABLE 1-1: SUMMARY OF PTR ENROLLMENT BY CUSTOMER CATEGORY[1]

Customer Category	Participants	
	N	%
PTR without Enabling Technology	68,937	88%
Dually enrolled in Summer Saver	3,915	5%
Dually enrolled in SCTD	5,301	7%
SCTD not enrolled in PTR[2]	4,369	N/A
Coastal Climate Zone	40,083	51%
Inland Climate Zone	38,263	49%
Notification Type – Email Only	45,991	59%
Notification Type – Text Only	14,393	18%
Notification Type – Both	12,186	16%
All Participants	**78,347**	**100%**

[1] As of September 26th, 2016

[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 2016 the enabling technology was offered at no cost to qualifying customers through the PTR program. The enabling technology offered in 2016 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 expired 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 Methodology,
- 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 three major participant characteristics: PTR participation, SCTD participation, and having Net Energy Metering (NEM). Each of the six possible participant combinations of these characteristics were also stratified by climate zone (coastal and inland). In total, this provided 12 different strata from which to develop control groups.

TABLE 2-1: PRE-MATCHING PARTICIPANT STRATIFICATION

PTR Participant	Net Energy Metered	SCTD Participant	Climate Zones
✓	✓	×	Inland, Coastal
✓	×	×	Inland, Coastal
✓	✓	✓	Inland, Coastal
✓	×	✓	Inland, Coastal
×	×	✓	Inland, Coastal
×	✓	✓	Inland, Coastal

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 2015 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 and SCTD participants by the stratification detailed above, as well as for the other various participant subgroups, namely 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: seasonal kWh usage, total annual 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, coefficient of variation of annual consumption, usage size category, and dummy variables for Low Income and Summer Saver customers.

The second stage of matching saw the additional inclusion of hourly kWh usage during the event hours for summer hot days[1] and coefficients of variation of kWh usage during event hours.

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 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 the second stage of 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.

[1] For hot days, Itron selected the twelve non-event days in summer 2016 and September 2015 with the highest average peak temperatures across the different weather stations used for the analysis. The dates with these peak temperatures were the 8th, 24th, and 25th of September 2015, 20th of June, 21st, 22nd, 28th of July, 15th of August, 27th, 28th, 29th, and 30th of September 2016. Load profiles by season were also compared to confirm that the groups were sufficiently similar.

FIGURE 2-1: COMPARISON OF ANNUAL MONTHLY LOAD PROFILES FOR CONTROL GROUP WITH ALL AND ONLY MATCHED PARTICIPANTS – PTR STAGE ONE PSM

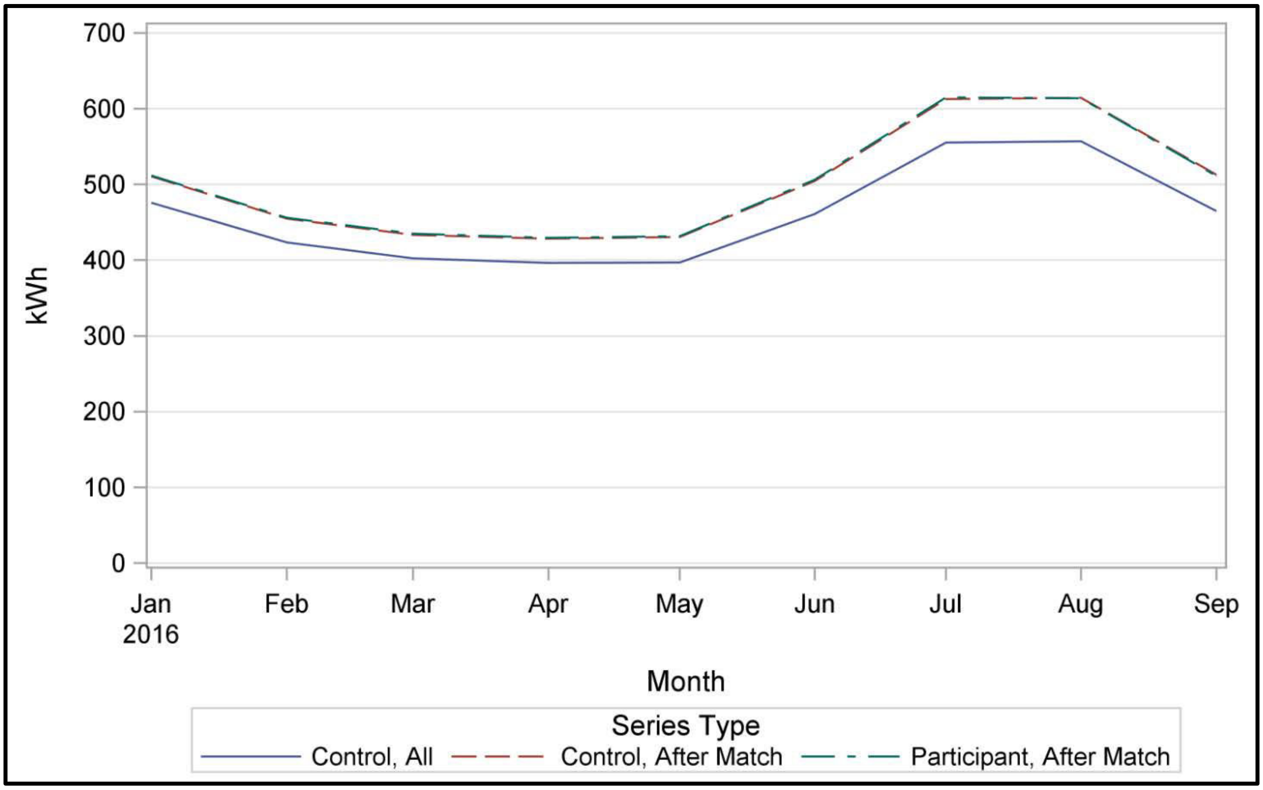
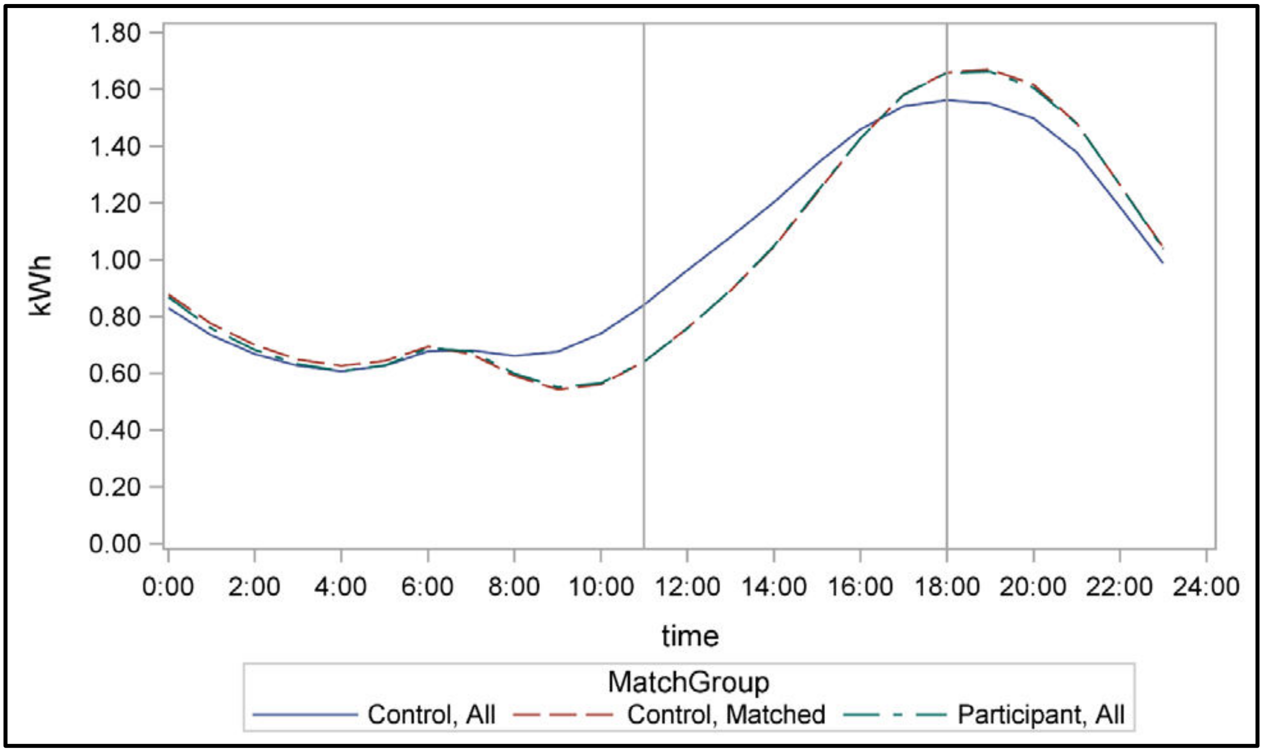


FIGURE 2-2: COMPARISON OF HOURLY HOT DAY LOAD PROFILES FOR CONTROL GROUP WITH ALL AND ONLY MATCHED PARTICIPANTS – PTR STAGE TWO PSM



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:

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

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.). 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 2-2: PTR PARTICIPANT COUNTS BY ANALYSIS STAGE

Participant Group	Initial Counts	After PSM Phase 1	After PSM Phase 2
All PTR	78,347	78,339	74,508
PTR with no Load Control	68,937	68,929	67,282
PTR Dually Enrolled in SCTD*	5,291	5,291	5,125
PTR Dually Enrolled in Summer Saver	3,915	3,915	3,896
SCTD Only*	4,369	4,366	4,296

* 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 2016, SDG&E called a total of one PTR event and one SCTD event. The event was on the same day for both programs: September 26th. 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, and
- PTR customers with Net Energy Metering.

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 the PTR program and not AC cycling. Their incremental impacts are shown in Table 3-2 by cycling strategy. The load reduction from the SS participants was similar (8.2%) to that of the general PTR population with no load control (8.3%).

TABLE 3-1: PTR EX POST LOAD IMPACT ESTIMATES BY CUSTOMER CATEGORY – AVERAGE 2016 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	78,347	1.10	1.00	0.10	10.2%	8.13	98.8
Large	33,435	1.74	1.60	0.15	8.5%	4.93	99.2
Medium	27,492	0.82	0.74	0.08	10.9%	2.15	98.7
Small	17,419	0.33	0.28	0.06	44.3%	1.00	98.2
Coastal	40,083	1.02	0.94	0.08	8.5%	3.21	97.2
Inland	38,263	1.18	1.05	0.13	11.8%	4.95	100.4
No SCTD	72,852	1.09	1.00	0.09	8.7%	6.22	98.7
No Load Control (SCTD or SS)	68,937	1.09	1.01	0.08	8.3%	5.51	98.7
Low Income*	13,414	0.97	0.99	-0.01	-1.4%	-0.18	98.7
Non-Low Income*	55,522	1.31	1.21	0.10	8.0%	5.66	98.5
Enroll. Year – 2012*	18,627	1.08	1.02	0.07	7.1%	1.21	98.7
Enroll. Year – 2013*	5,676	1.05	1.03	0.02	2.6%	0.11	98.8
Enroll. Year – 2014*	22,510	1.09	1.02	0.07	7.5%	1.66	98.7
Enroll. Year – 2015*	11,038	1.09	1.01	0.08	8.2%	0.88	98.7
Enroll. Year – 2016*	11,086	1.12	0.97	0.15	14.6%	1.65	98.6
Notification – Email Only*	42,827	1.08	0.99	0.09	9.5%	3.87	98.6
Notification – Text Only*	13,058	1.09	1.07	0.02	2.8%	0.29	98.7
Notification – Both*	11,684	1.11	1.00	0.11	10.4%	1.26	98.8
Net Energy Metered	10,607	0.18	-0.05	0.23	-9.9%	2.45	99.4

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

TABLE 3-2: PTR DUALLY ENROLLED IN SUMMER SAVER EX POST LOAD IMPACT ESTIMATES – AVERAGE 2016 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	3,915	1.50	1.31	0.19	12.3%	0.73	100.7
Summer Saver – 50% Cycling	1,408	1.70	1.72	-0.03	-1.4%	-0.04	100.9
Summer Saver – 100% Cycling	2,505	1.38	1.08	0.31	22.0%	0.77	100.6

TABLE 3-3: SCTD EX POST LOAD IMPACT ESTIMATES BY CUSTOMER CATEGORY - AVERAGE 2016 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**	9,670	1.79	1.37	0.42	25.1%	4.04	100.5
4 Degree Setback	4,761	1.78	1.28	0.49	29.8%	2.35	100.5
50% Cycling	3,388	1.79	1.33	0.46	27.2%	1.55	100.6
PTR	5,301	1.71	1.20	0.51	32.0%	2.68	100.5
PTR – 4 Deg. Setback	2,602	1.73	1.18	0.56	34.7%	1.45	100.5
PTR – 50% Cycling	1,875	1.69	1.13	0.56	35.4%	1.05	100.6
SCTD Only	4,369	1.89	1.57	0.31	17.9%	1.37	100.5
SCTD Only – 4 Degree Setback	2,159	1.83	1.41	0.43	24.8%	0.92	100.6
SCTD Only – 50% Cycling	1,513	1.91	1.58	0.33	18.3%	0.50	100.6

* Participants excluding Summer Saver load control.

** Cycling strategy is not available for some customers because of confidentiality restraints on the signaling portal.

3.1.1 Peak Time Rebate (PTR) Total

Figure 3-1 and Table 3-4 show the hourly event load impacts for the overall PTR customer population compared with the reference loads. In the 2016 event, there was a definitive load reduction during event hours (11 a.m. to 6 p.m.), averaging 0.10 kW per participant, representing an average reduction of 10.2% relative to the reference load. The hourly load reductions ranged between 0.08 kW and 0.13 kW during event hours. In the hours following events, there are noticeable snapback effects, with an average hourly increase in load of 0.05 kW per customer from 6 p.m. to midnight. The average hourly aggregate load reduction from the 78,347 participants during event hours was 8.13 MW. The average temperature across all the events and the associated event hours was 98.8°F.

FIGURE 3-1: HOURLY LOAD PROFILE FOR ALL PTR CUSTOMERS – 2016 EVENT AVERAGE

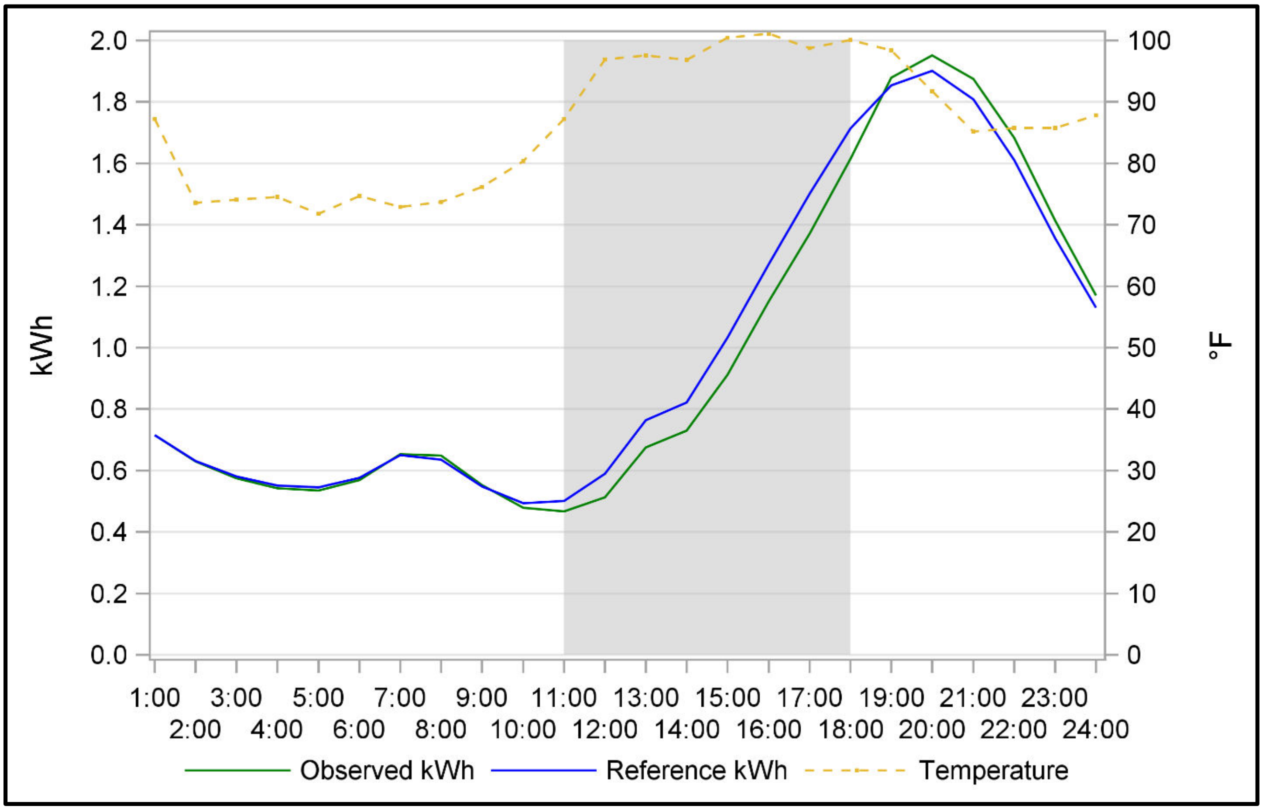


TABLE 3-4: SUMMARY OF EVENT IMPACTS FOR ALL PTR CUSTOMERS – 2016 AVERAGE

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	76.2	0.55	0.55	-0.003	-0.6%	78,347	-266
9:00	10:00	No	80.4	0.49	0.48	0.014	2.9%	78,347	1,122
10:00	11:00	No	87.2	0.50	0.47	0.034	6.8%	78,347	2,688
11:00	12:00	Yes	96.9	0.59	0.51	0.076	12.8%	78,347	5,920
12:00	13:00	Yes	97.6	0.76	0.67	0.089	11.7%	78,347	6,979
13:00	14:00	Yes	96.8	0.82	0.73	0.091	11.1%	78,347	7,135
14:00	15:00	Yes	100.4	1.03	0.91	0.122	11.8%	78,347	9,539
15:00	16:00	Yes	101.1	1.27	1.15	0.120	9.5%	78,347	9,430
16:00	17:00	Yes	98.7	1.50	1.37	0.129	8.6%	78,347	10,132
17:00	18:00	Yes	100.1	1.71	1.62	0.099	5.8%	78,347	7,752
18:00	19:00	No	98.4	1.85	1.88	-0.024	-1.3%	78,347	-1,909
19:00	20:00	No	91.7	1.90	1.95	-0.050	-2.6%	78,347	-3,927
20:00	21:00	No	85.2	1.81	1.88	-0.066	-3.7%	78,347	-5,202
Total - Entire Day			86.3	23.78	23.30	0.481	2.0%	78,347	37,652
Total - Event Hours			98.8	7.69	6.97	0.726	9.4%	78,347	56,886

PTR by Climate Zone

Figure 3-2 and Figure 3-3 show the hourly load profiles during the 2016 event for PTR customers in the Coastal and Inland climate zones, respectively. The average temperature during event hours was 97.2°F for Coastal customers compared to 100.4°F for Inland customers. Perhaps owing to these differences in temperature, Inland participants had a higher average event hour load reduction of 0.13 kW compared to the Coastal participants' load reduction of 0.08 kW. The average aggregate load reduction during event hours was 3.21 MW (8.5%) for Coastal participants and 4.95 MW (11.8%) for Inland participants.

FIGURE 3-2: HOURLY LOAD PROFILE FOR COASTAL PTR CUSTOMERS – 2016 EVENT AVERAGE

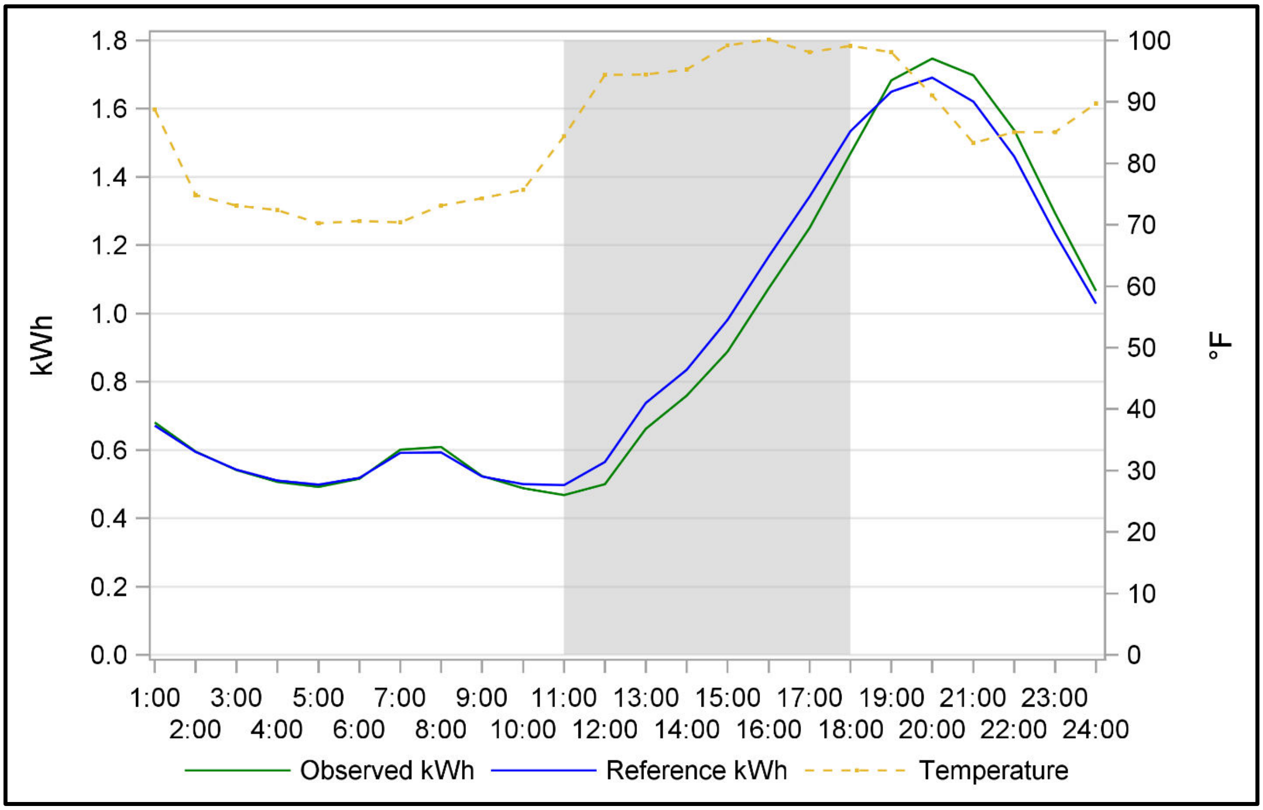
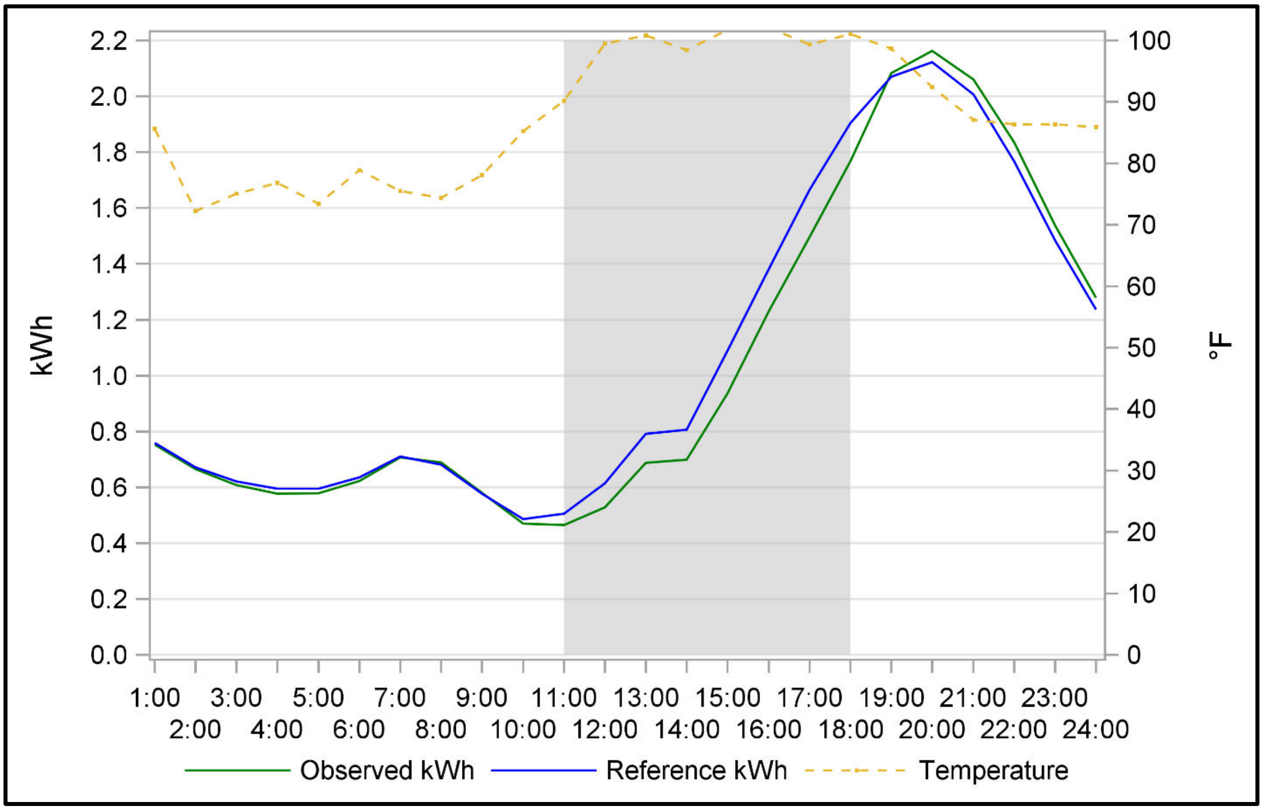


FIGURE 3-3: HOURLY LOAD PROFILE FOR INLAND PTR CUSTOMERS – 2016 EVENT AVERAGE



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 the 2016 event for these three categories of customers. There are marked differences between each of them. Large participants had an average event hour load reduction of 0.15 kW, representing a total reduction of 4.93 MW (8.5%). Medium participants had an average event hour load reduction of 0.08 kW, representing a total reduction of 2.15 MW (10.9%). Lastly, small participants had an average load reduction of 0.06 kW, representing a total reduction of 1.00 MW (44.3%). For the Small subgroup, the rise in usage from 12 p.m. to 1 p.m. is a result of the influence of the Net Energy Metered customers in this segment. See Section 3.1.10 for additional details.

FIGURE 3-4: HOURLY LOAD PROFILE FOR LARGE PTR CUSTOMERS – 2016 EVENT AVERAGE

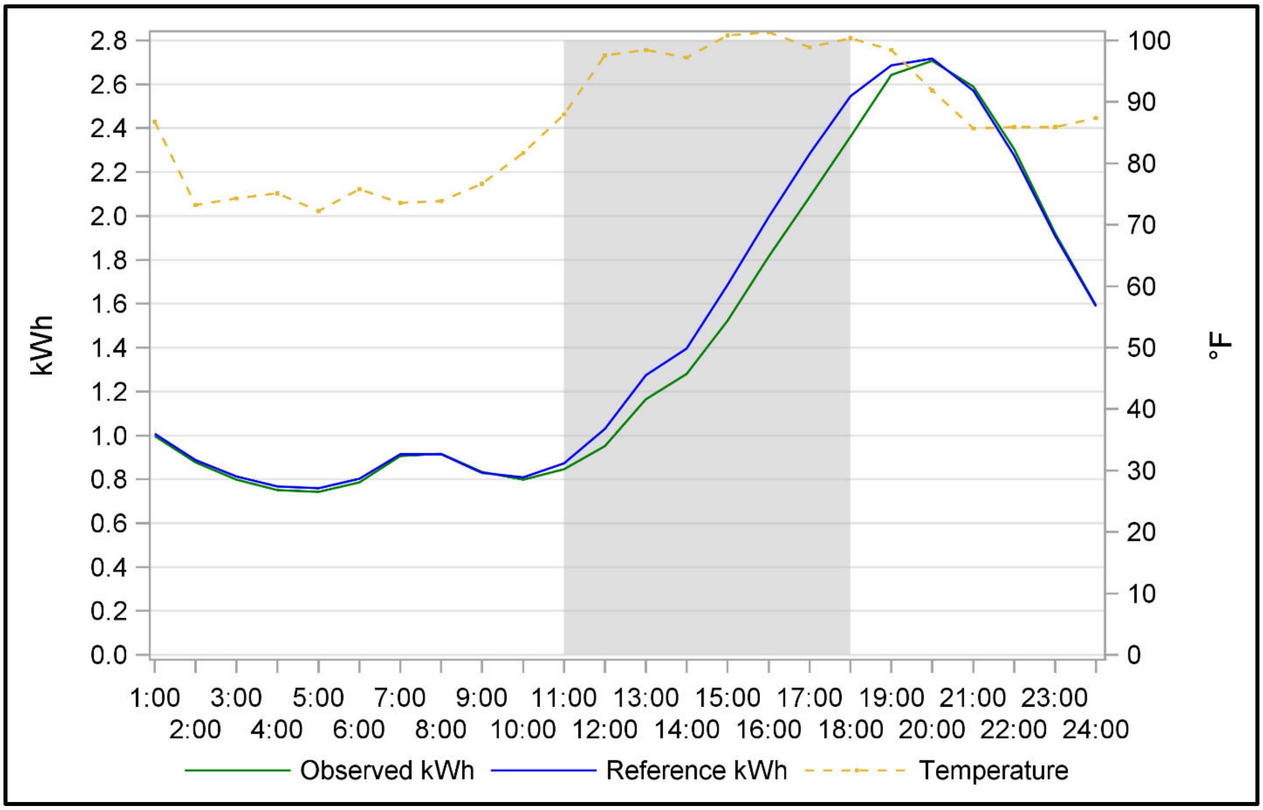


FIGURE 3-5: HOURLY LOAD PROFILE FOR MEDIUM PTR CUSTOMERS – 2016 EVENT AVERAGE

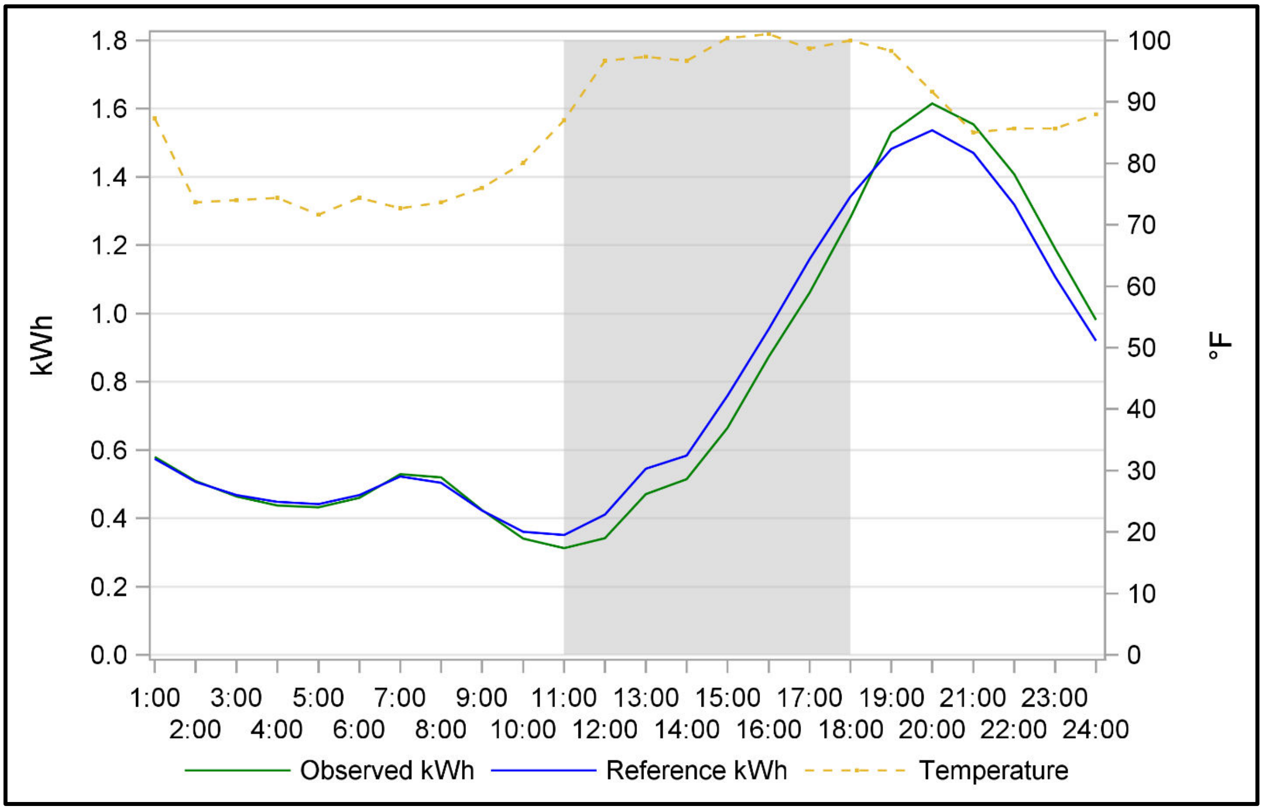
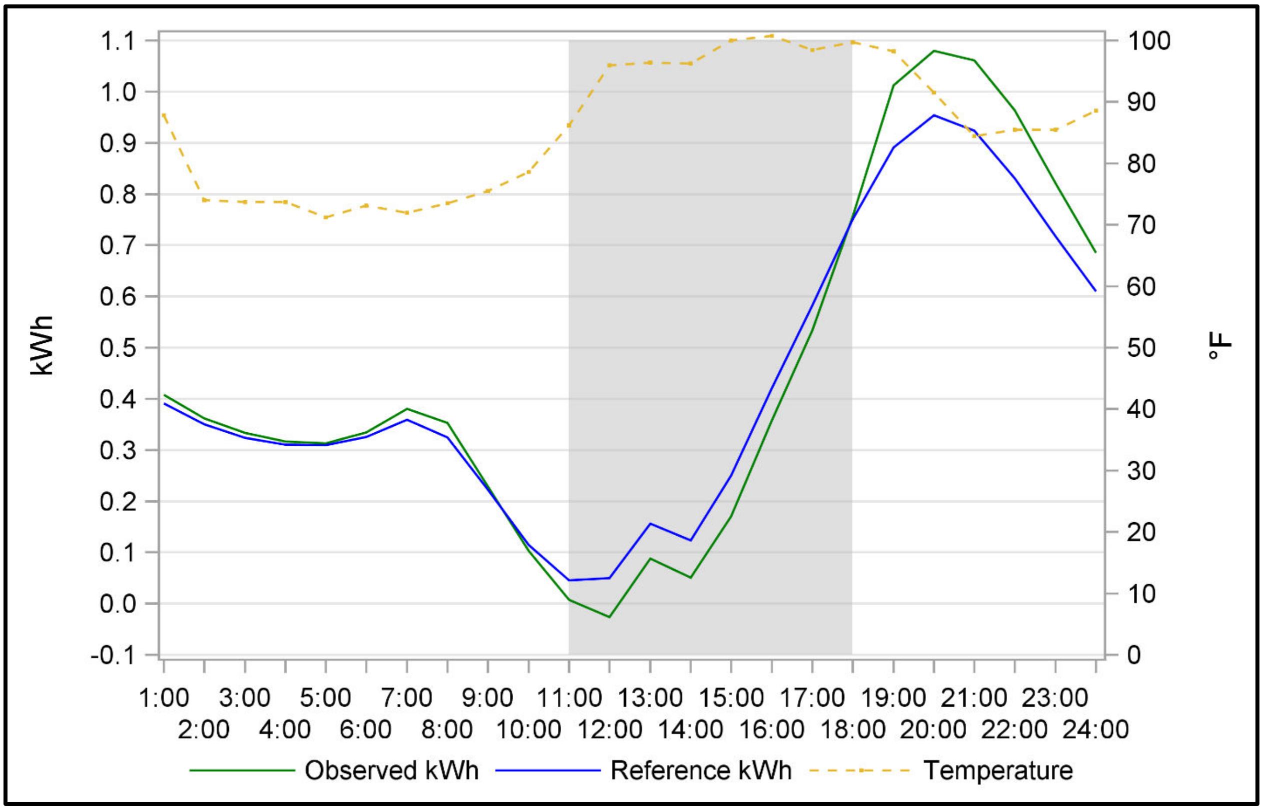


FIGURE 3-6: HOURLY LOAD PROFILE FOR SMALL PTR CUSTOMERS – 2016 EVENT AVERAGE



3.1.2 PTR without SCTD

Figure 3-7 and Table 3-5 show the hourly event load impacts for PTR customers that are not dually enrolled in the SCTD thermostat program. Although the event day was called 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 similar to the overall group at 0.09 kW. However, because of the lower participant count, the PTR without SCTD group had a slightly lower average aggregate event hour reduction with 6.22 MW (8.7%) than the overall PTR group, with 8.13 MW (10.2%).

FIGURE 3-7: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT SCTD – 2016 EVENT AVERAGE

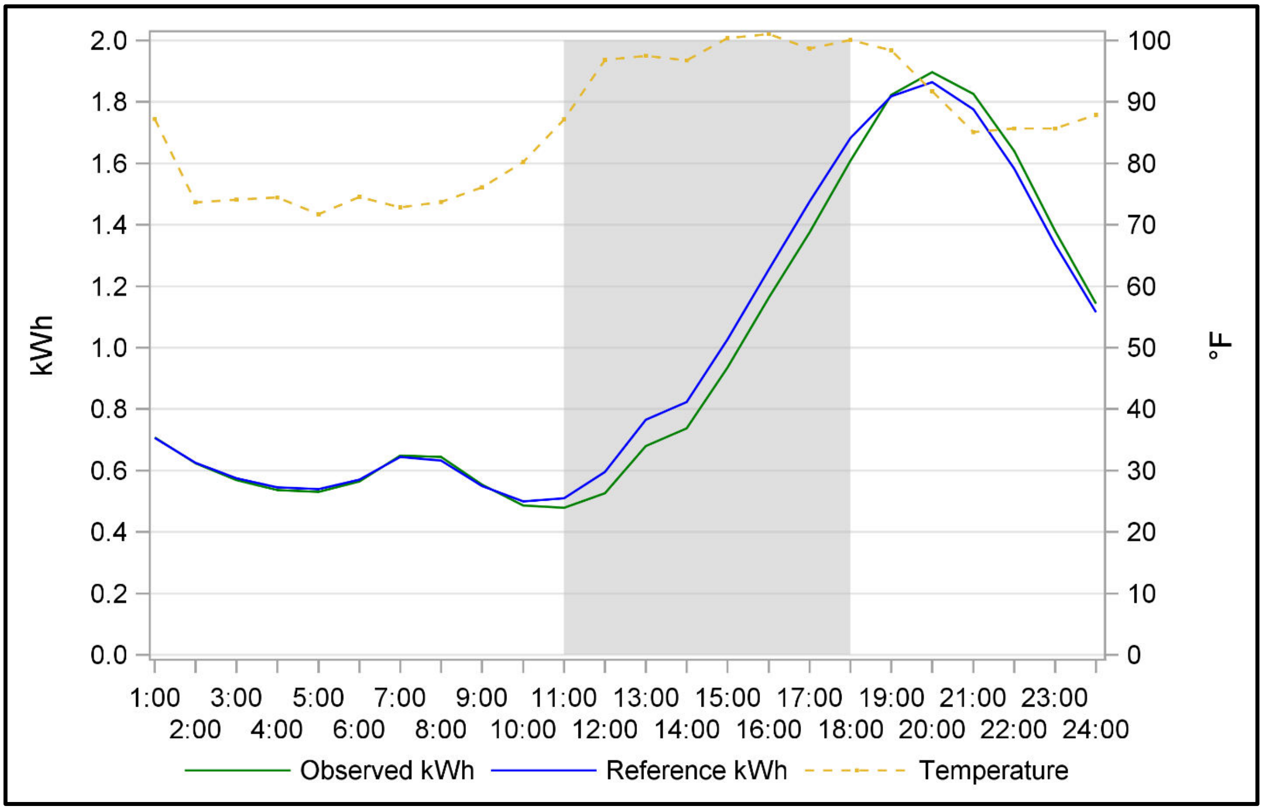


TABLE 3-5: SUMMARY OF EVENT IMPACTS FOR PTR CUSTOMERS WITHOUT SCTD – 2016 AVERAGE

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	76.1	0.55	0.55	-0.005	-0.9%	72,852	-378
9:00	10:00	No	80.2	0.50	0.49	0.013	2.7%	72,852	977
10:00	11:00	No	87.1	0.51	0.48	0.030	6.0%	72,852	2,218
11:00	12:00	Yes	96.8	0.60	0.53	0.069	11.6%	72,852	5,054
12:00	13:00	Yes	97.5	0.77	0.68	0.085	11.1%	72,852	6,186
13:00	14:00	Yes	96.7	0.82	0.74	0.085	10.4%	72,852	6,222
14:00	15:00	Yes	100.4	1.03	0.94	0.092	8.9%	72,852	6,671
15:00	16:00	Yes	101.0	1.25	1.16	0.093	7.4%	72,852	6,740
16:00	17:00	Yes	98.7	1.48	1.38	0.100	6.8%	72,852	7,262
17:00	18:00	Yes	100.0	1.68	1.61	0.074	4.4%	72,852	5,391
18:00	19:00	No	98.3	1.82	1.82	-0.004	-0.2%	72,852	-303
19:00	20:00	No	91.7	1.86	1.90	-0.032	-1.7%	72,852	-2,349
20:00	21:00	No	85.1	1.77	1.83	-0.051	-2.9%	72,852	-3,713
Total - Entire Day			86.3	23.51	23.08	0.430	1.8%	72,852	31,352
Total - Event Hours			98.7	7.62	7.03	0.597	7.8%	72,852	43,528

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 3-6 show the hourly event load impacts for this group. The average event hour load reduction for this group was 0.08 kW, which was slightly lower than the 0.10 kW for the overall PTR group. The average aggregate load reduction during event hours was 5.51 MW (8.3%), 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 – 2016 EVENT AVERAGE

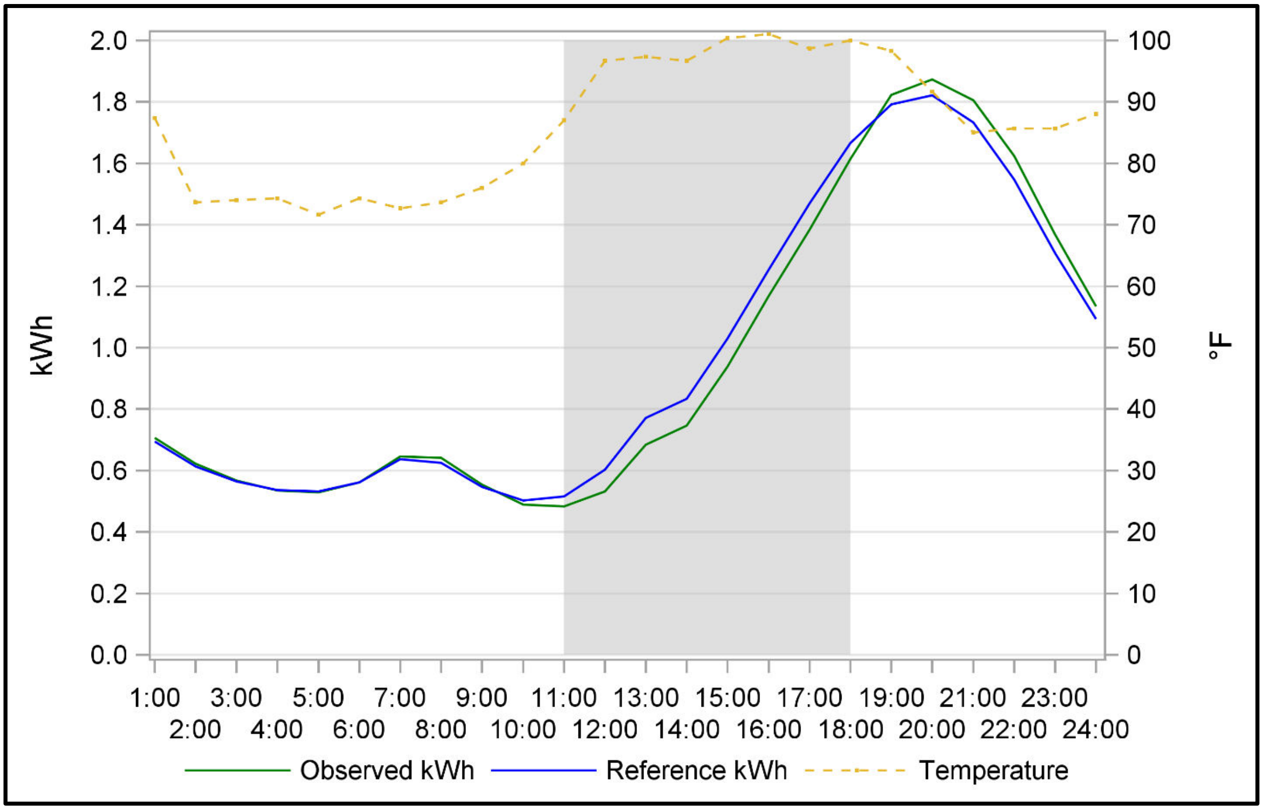


TABLE 3-6: SUMMARY OF EVENT IMPACTS FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2016 AVERAGE

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	76.0	0.55	0.55	-0.007	-1.3%	68,937	-476
9:00	10:00	No	80.0	0.50	0.49	0.015	2.9%	68,937	1,007
10:00	11:00	No	87.0	0.52	0.48	0.033	6.4%	68,937	2,290
11:00	12:00	Yes	96.7	0.60	0.53	0.071	11.9%	68,937	4,927
12:00	13:00	Yes	97.3	0.77	0.68	0.087	11.3%	68,937	6,021
13:00	14:00	Yes	96.7	0.83	0.75	0.088	10.5%	68,937	6,041
14:00	15:00	Yes	100.3	1.03	0.94	0.092	8.9%	68,937	6,345
15:00	16:00	Yes	101.0	1.25	1.17	0.085	6.8%	68,937	5,858
16:00	17:00	Yes	98.7	1.47	1.38	0.085	5.8%	68,937	5,835
17:00	18:00	Yes	100.0	1.67	1.61	0.052	3.1%	68,937	3,560
18:00	19:00	No	98.3	1.79	1.82	-0.031	-1.7%	68,937	-2,159
19:00	20:00	No	91.7	1.82	1.87	-0.052	-2.8%	68,937	-3,563
20:00	21:00	No	85.0	1.73	1.80	-0.072	-4.1%	68,937	-4,943
Total - Entire Day			86.2	23.25	23.03	0.226	1.0%	68,937	15,557
Total - Event Hours			98.7	7.63	7.07	0.560	7.3%	68,937	38,588

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 2016, the PTR event on September 26th was also a Summer Saver event. The Summer Saver event 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. 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 3-7 show the hourly PTR event load impacts for these dually enrolled customers. Their average event hour load reduction (during PTR event hours) was

0.12 kW, which is slightly 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 0.46 MW, representing an 8.2% reduction compared to the reference load.

FIGURE 3-9: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SUMMER SAVER – ALL – 2016 EVENT AVERAGE

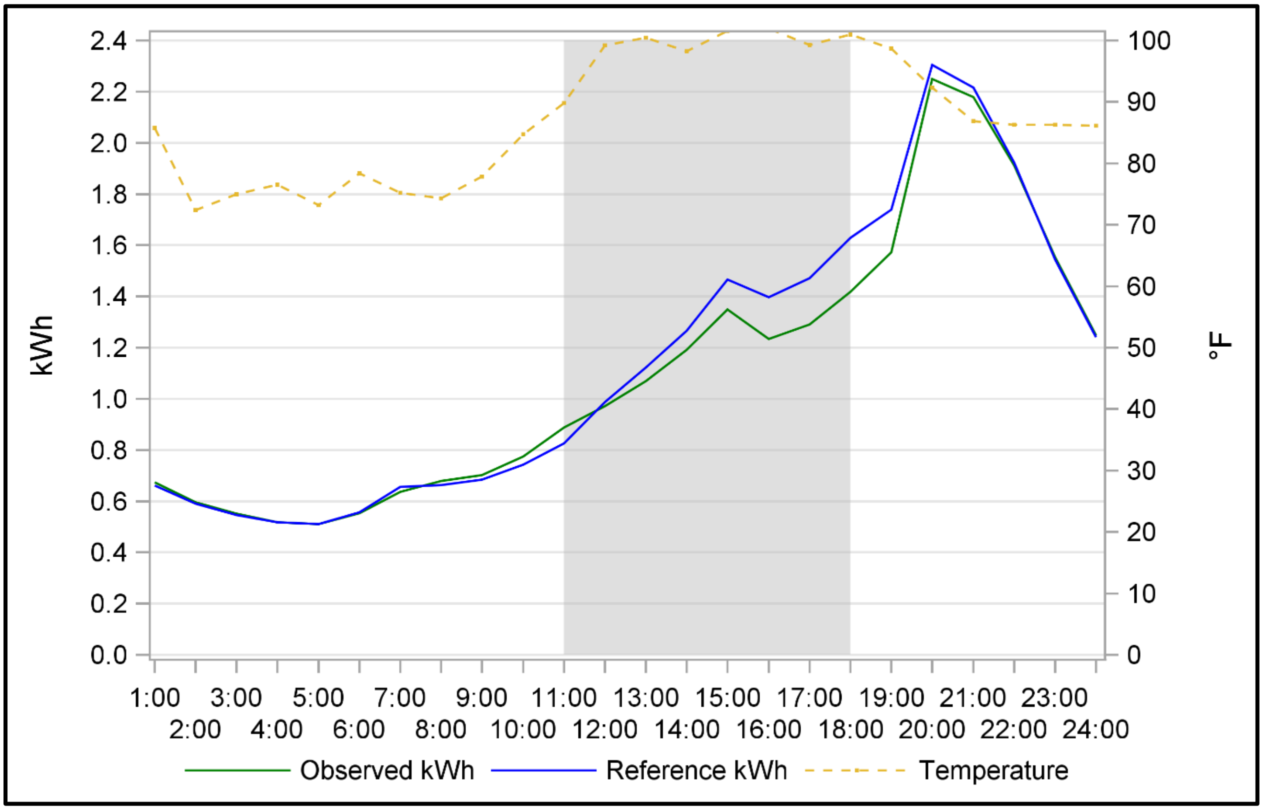


TABLE 3-7: SUMMARY OF PTR EVENT IMPACTS FOR CUSTOMERS DUALLY ENROLLED IN SUMMER SAVER – 2016 AVERAGE

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	77.9	0.68	0.70	-0.018	-2.7%	3,915	-72
9:00	10:00	No	84.7	0.74	0.78	-0.033	-4.4%	3,915	-129
10:00	11:00	No	89.8	0.83	0.89	-0.062	-7.5%	3,915	-242
11:00	12:00	Yes	99.2	0.99	0.97	0.015	1.6%	3,915	60
12:00	13:00	Yes	100.5	1.12	1.07	0.054	4.8%	3,915	209
13:00	14:00	Yes	98.2	1.27	1.19	0.074	5.9%	3,915	291
14:00	15:00	Yes	101.6	1.47	1.35	0.116	7.9%	3,915	453
15:00	16:00	Yes	101.9	1.40	1.23	0.163	11.7%	3,915	639
16:00	17:00	Yes	99.3	1.47	1.29	0.182	12.3%	3,915	711
17:00	18:00	Yes	100.9	1.63	1.42	0.211	13.0%	3,915	826
18:00	19:00	No	98.6	1.74	1.57	0.166	9.5%	3,915	650
19:00	20:00	No	92.3	2.30	2.25	0.054	2.4%	3,915	213
20:00	21:00	No	86.9	2.22	2.18	0.037	1.7%	3,915	143
Total - Entire Day			87.6	27.26	26.32	0.937	3.4%	3,915	3,669
Total - Event Hours			100.2	9.34	8.52	0.815	8.7%	3,915	3,189

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 a modest average load reduction of 0.03 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 0.01 kW. Those with 100% cycling had a significantly larger incremental load reduction of 0.18 kW.

FIGURE 3-10: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SUMMER SAVER – 50% CYCLING – 2016 EVENT AVERAGE

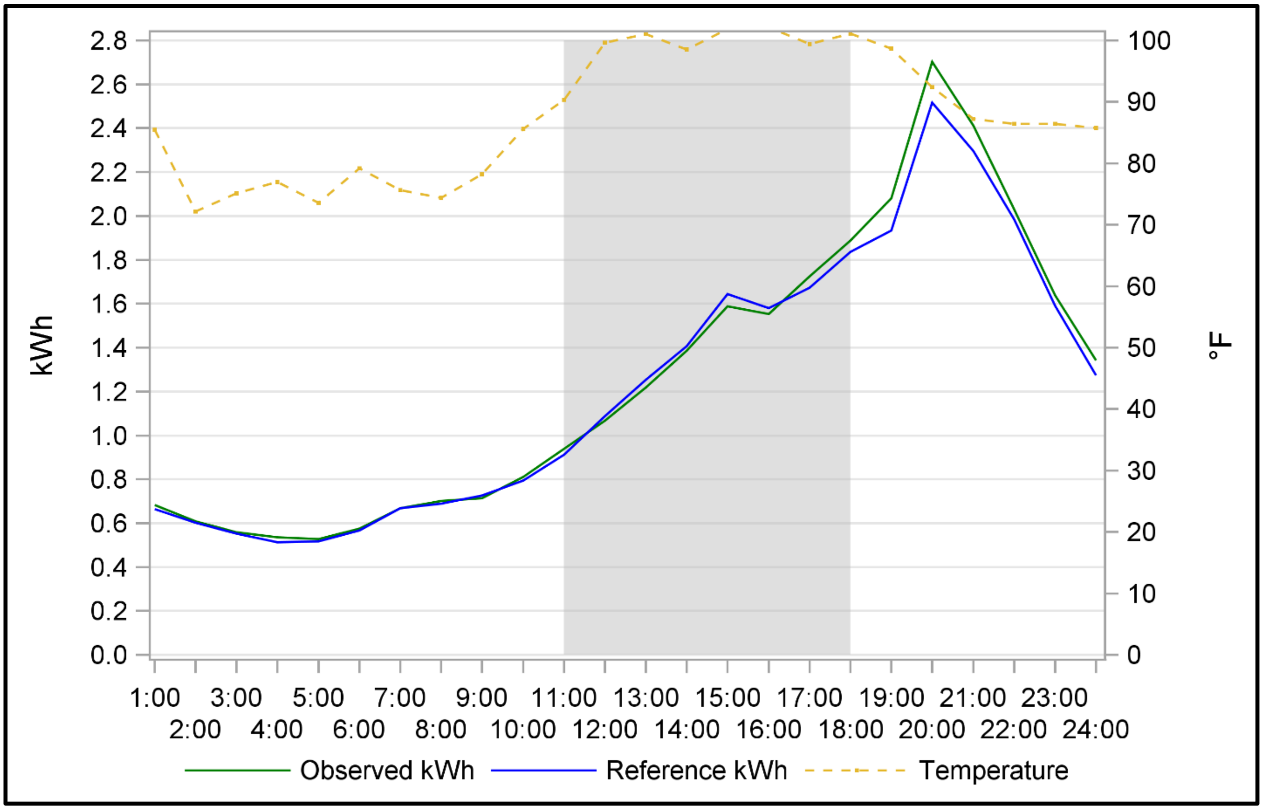
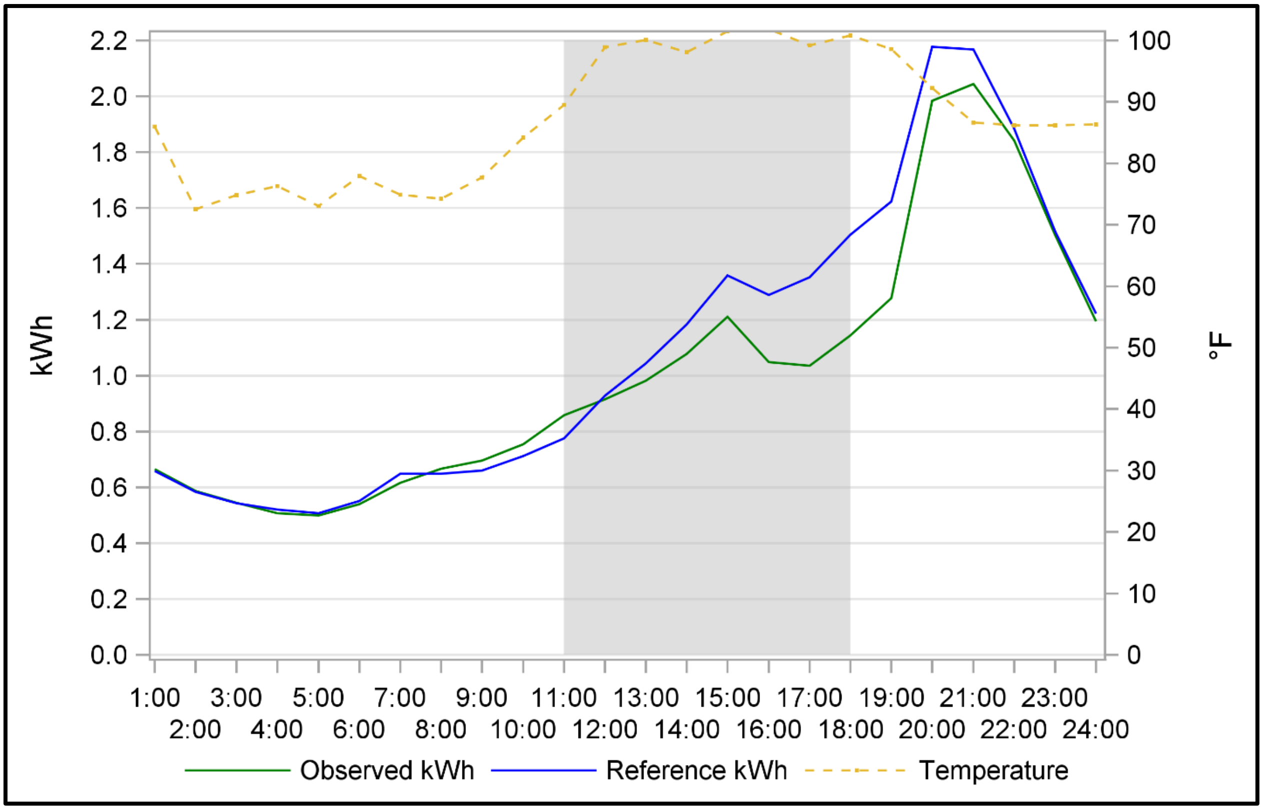


FIGURE 3-11: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SUMMER SAVER – 100% CYCLING – 2016 EVENT AVERAGE



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 are implemented on PTR-SCTD event days – four degree thermostat setback and 50% AC cycling. In 2016, the SCTD event hour window was only 4 hours long, from 2 p.m. to 6 p.m. Figure 3-12 and Table 3-8 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 0.33 kW, which is about three times higher than the overall PTR group. The average load reduction was 0.51 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 0.11 kW, which was similar to the average for PTR participants without any load control devices. The average aggregate load reduction was 1.78 MW during PTR event hours, representing 26.1% of the reference load. The average aggregate reduction during SCTD event hours was 2.68 MW, or 32.0%. Lastly, the average aggregate reduction during the PTR-only hours was 0.57 MW, or 18.2%.

FIGURE 3-12: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SCTD – 2016 EVENT AVERAGE

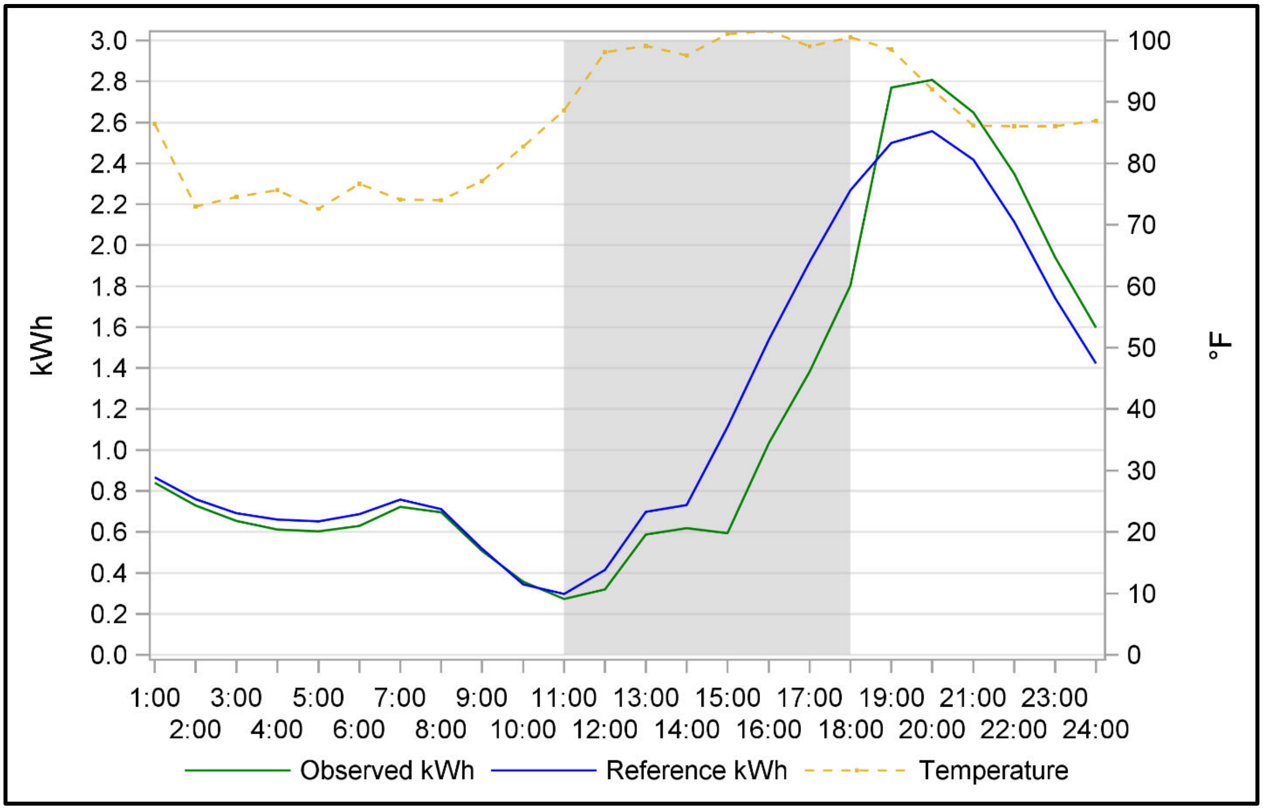


TABLE 3-8: SUMMARY OF PTR EVENT IMPACTS FOR CUSTOMERS DUALLY ENROLLED IN SCTD – 2016 AVERAGE

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	77.1	0.52	0.51	0.010	2.0%	5,301	54
9:00	10:00	No	82.7	0.34	0.36	-0.013	-3.8%	5,301	-70
10:00	11:00	No	88.6	0.30	0.27	0.025	8.5%	5,301	133
11:00	12:00	No	98.1	0.42	0.32	0.097	23.3%	5,301	513
12:00	13:00	No	99.1	0.70	0.59	0.111	15.9%	5,301	589
13:00	14:00	No	97.6	0.73	0.62	0.112	15.4%	5,301	596
14:00	15:00	Yes	101.1	1.11	0.59	0.519	46.6%	5,301	2,749
15:00	16:00	Yes	101.5	1.54	1.03	0.507	32.9%	5,301	2,685
16:00	17:00	Yes	99.0	1.92	1.38	0.535	27.9%	5,301	2,834
17:00	18:00	Yes	100.5	2.27	1.80	0.464	20.5%	5,301	2,462
18:00	19:00	No	98.5	2.50	2.77	-0.271	-10.8%	5,301	-1,436
19:00	20:00	No	92.0	2.56	2.81	-0.250	-9.8%	5,301	-1,325
20:00	21:00	No	86.1	2.42	2.65	-0.230	-9.5%	5,301	-1,220
Total - Entire Day			87.0	28.38	27.07	1.307	4.6%	5,301	6,926
Total - Event Hours			100.5	6.84	4.82	2.024	29.6%	5,301	10,730

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, both the 4 degree setback group and the 50% cycling group had similar average hourly load reductions of 0.56 kW (34.7%) and 0.56 kW (35.4%), respectively. Over the entire event period, the 4 degree setback group had an average hourly load reduction of 0.35 kW (24.9%), while the 50% cycling group had an average of 0.38 kW (31.3%).

FIGURE 3-13: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SCTD – 4 DEGREE SETBACK – 2016 EVENT AVERAGE

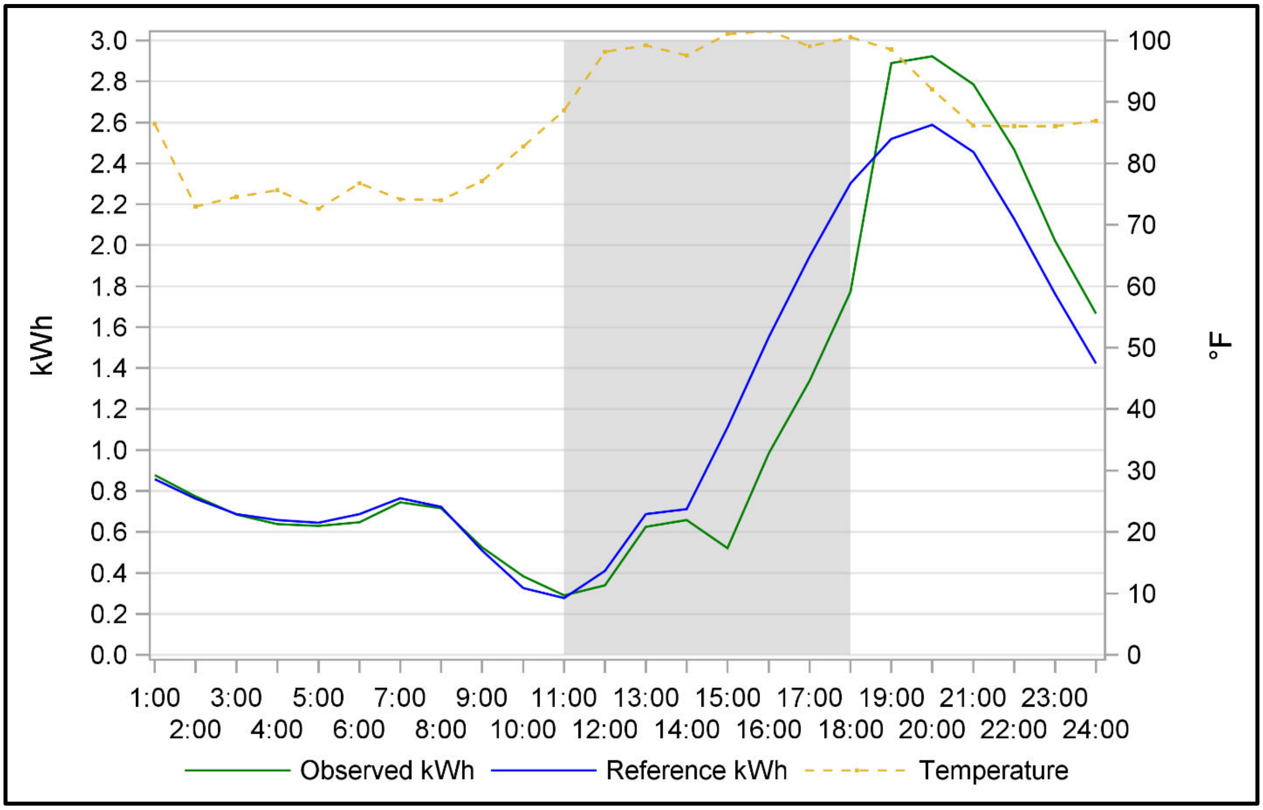
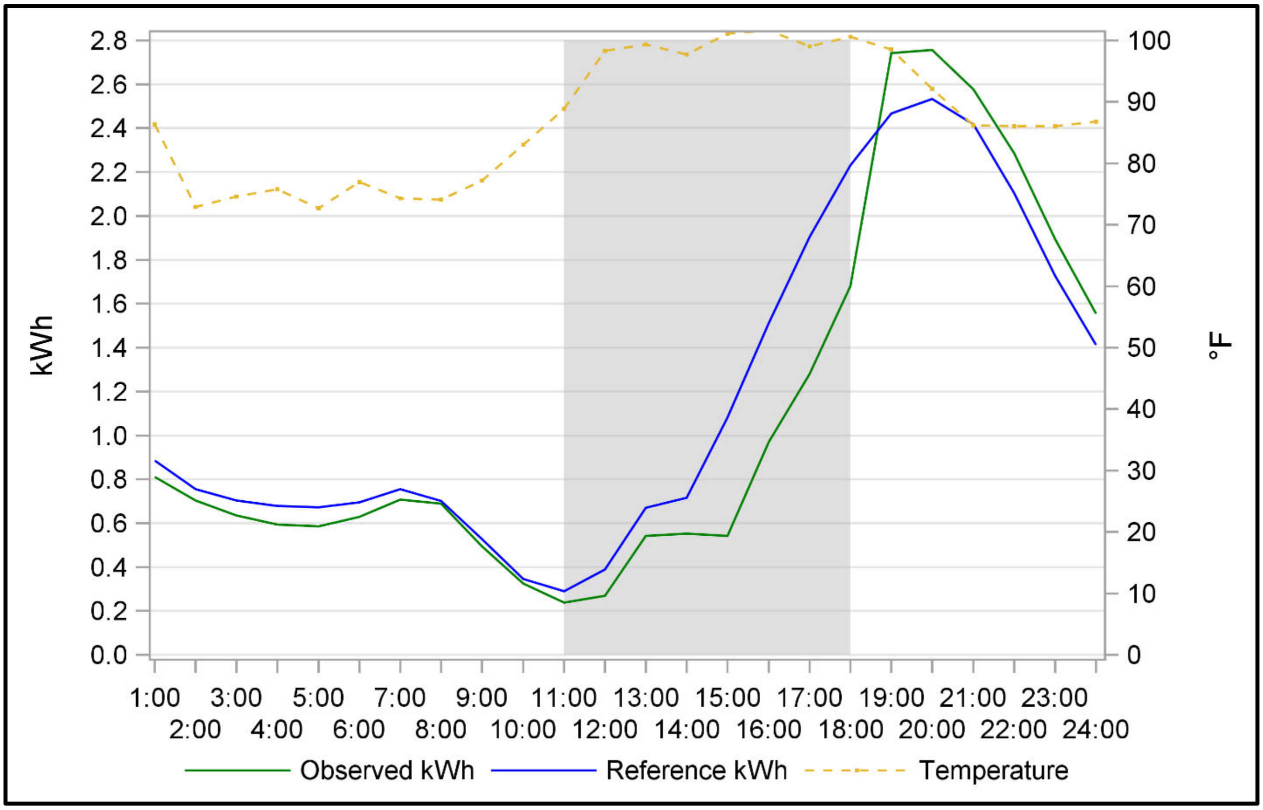


FIGURE 3-14: HOURLY LOAD PROFILE FOR PTR CUSTOMERS DUALLY ENROLLED IN SCTD – 50% CYCLING – 2016 EVENT AVERAGE



3.1.6 SCTD Not Enrolled in PTR

Figure 3-15 and Table 3-9 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 the PTR-SCTD event day. During SCTD event hours, their average load reduction was 0.31 kW, which was lower than that of the dually-enrolled PTR-SCTD participants. The average aggregate impact during the SCTD event hours was 1.37 MW, representing 17.9% of the reference load. The group showed snapback effects averaging 11.1% during the hours following the SCTD event.

FIGURE 3-15: HOURLY LOAD PROFILE FOR SCTD CUSTOMERS NOT ENROLLED IN PTR – 2016 EVENT AVERAGE

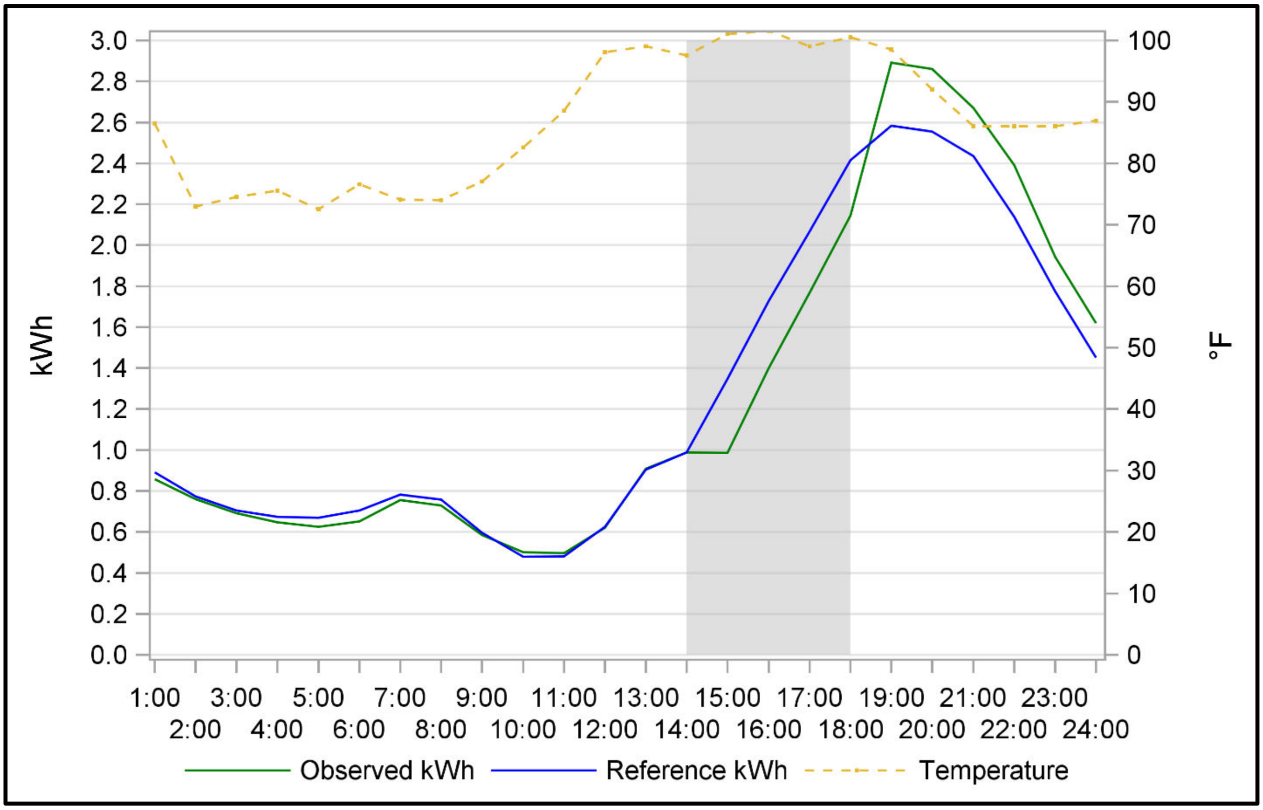


TABLE 3-9: SUMMARY OF EVENT IMPACTS FOR SCTD CUSTOMERS NOT ENROLLED IN PTR – 2016 AVERAGE

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	77.0	0.60	0.58	0.010	1.8%	4,369	46
9:00	10:00	No	82.6	0.48	0.50	-0.021	-4.4%	4,369	-93
10:00	11:00	No	88.6	0.48	0.50	-0.016	-3.4%	4,369	-72
11:00	12:00	No	98.0	0.62	0.62	0.003	0.5%	4,369	13
12:00	13:00	No	99.1	0.90	0.91	-0.006	-0.6%	4,369	-24
13:00	14:00	No	97.5	0.99	0.99	0.001	0.1%	4,369	5
14:00	15:00	Yes	101.0	1.35	0.99	0.361	26.8%	4,369	1,576
15:00	16:00	Yes	101.5	1.73	1.40	0.327	18.9%	4,369	1,429
16:00	17:00	Yes	99.0	2.07	1.77	0.299	14.5%	4,369	1,307
17:00	18:00	Yes	100.5	2.42	2.14	0.271	11.2%	4,369	1,184
18:00	19:00	No	98.5	2.58	2.89	-0.308	-11.9%	4,369	-1,347
19:00	20:00	No	92.0	2.56	2.86	-0.306	-12.0%	4,369	-1,335
20:00	21:00	No	86.0	2.44	2.67	-0.234	-9.6%	4,369	-1,023
Total - Entire Day			87.0	30.53	30.49	0.033	0.1%	4,369	143
Total - Event Hours			100.5	7.56	6.30	1.258	16.6%	4,369	5,497

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 0.33 kW (18.3%) while the latter had an average of 0.43 kW (24.8%).

FIGURE 3-16: HOURLY LOAD PROFILE FOR SCTD CUSTOMERS NOT ENROLLED IN PTR – 4 DEGREE SETBACK – 2016 EVENT AVERAGE

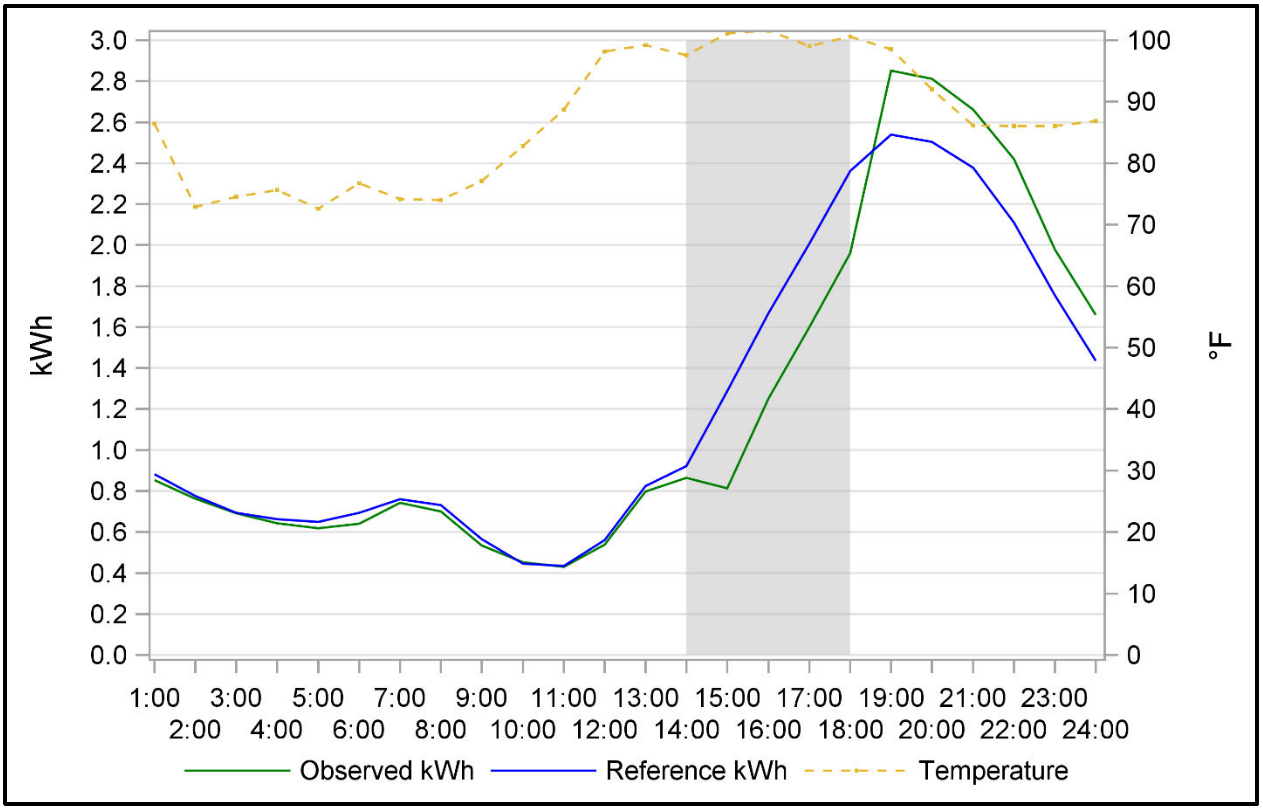
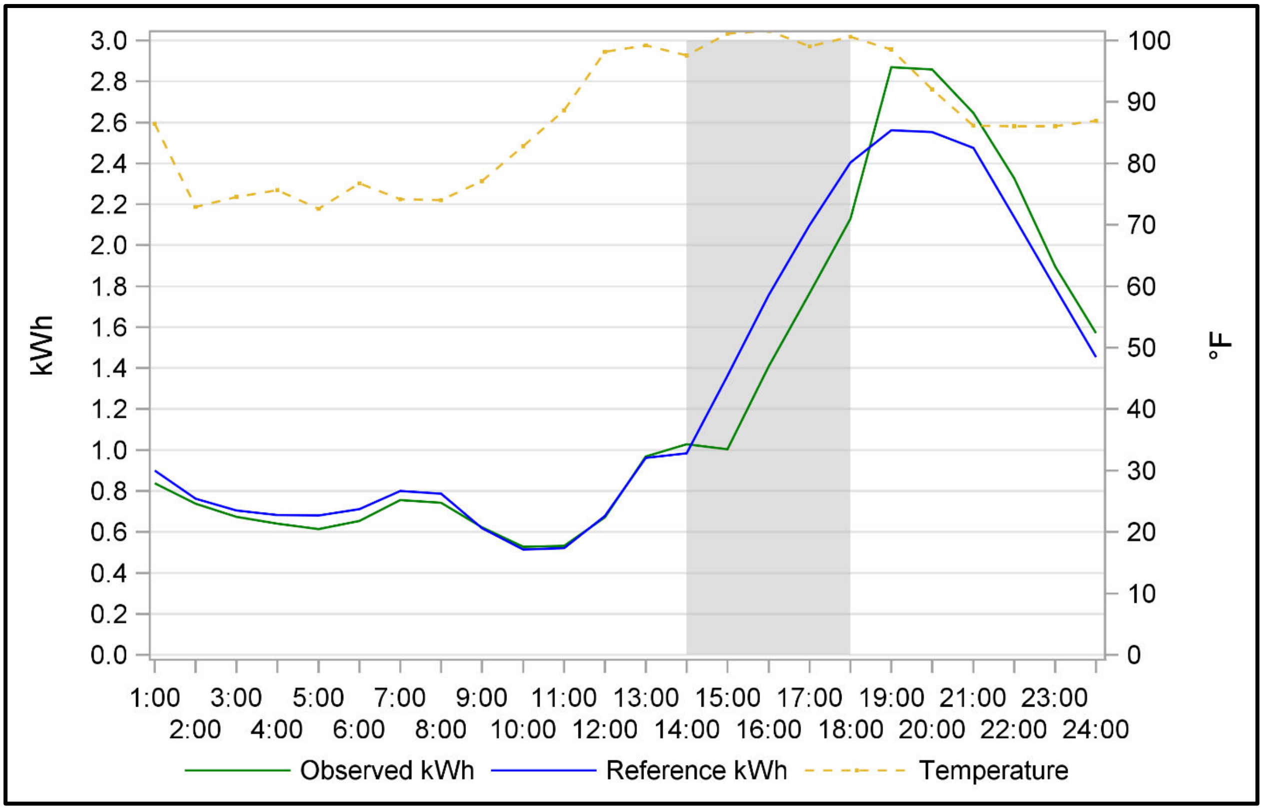


FIGURE 3-17: HOURLY LOAD PROFILE FOR SCTD CUSTOMERS NOT ENROLLED IN PTR – 50% CYCLING – 2016 EVENT AVERAGE



3.1.7 PTR without Load Control by Notification Type

There are three methods of notification for PTR events – email, text message, and phone call. Only about 8% 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 63% of the analysis group opted for email-only notification, about 19% opted for text-only notification, and about 17% 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 0.09 kW (9.5%), which is approximately in line with the general PTR population average. The text message-only group had an average event hour load reduction of 0.02 kW (2.8%), which was below average, and possibly indicative of a signaling error for this type of notification. The group with both types of notifications had the greatest average event hour reduction of 0.11 kW (10.4%), which was slightly above the overall population average. The email-only group also had very little average snapback effects of only 1.7%, compared to the text-only group, which had 7.3% and the group with both types, which had 7.8%.

FIGURE 3-18: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – EMAIL-ONLY NOTIFICATION – 2016 EVENT AVERAGE

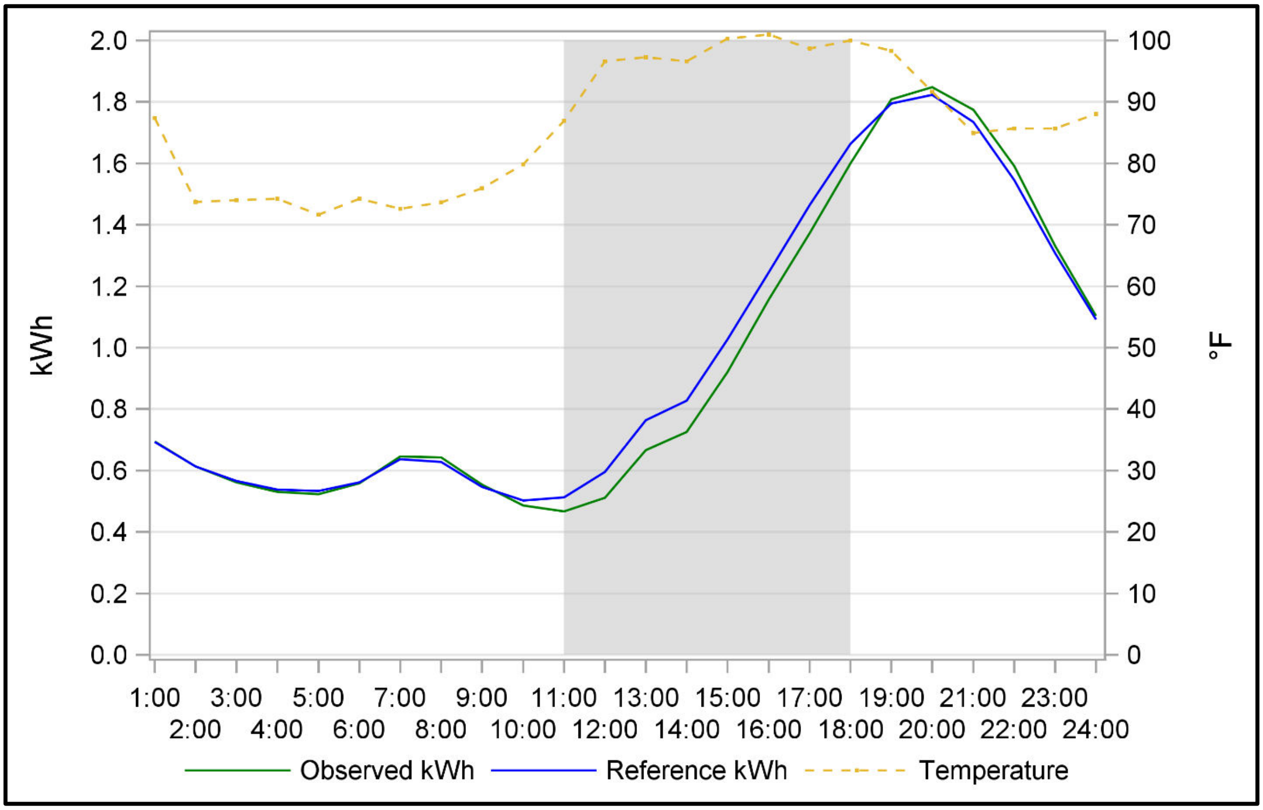


FIGURE 3-19: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – TEXT-ONLY NOTIFICATION – 2016 EVENT AVERAGE

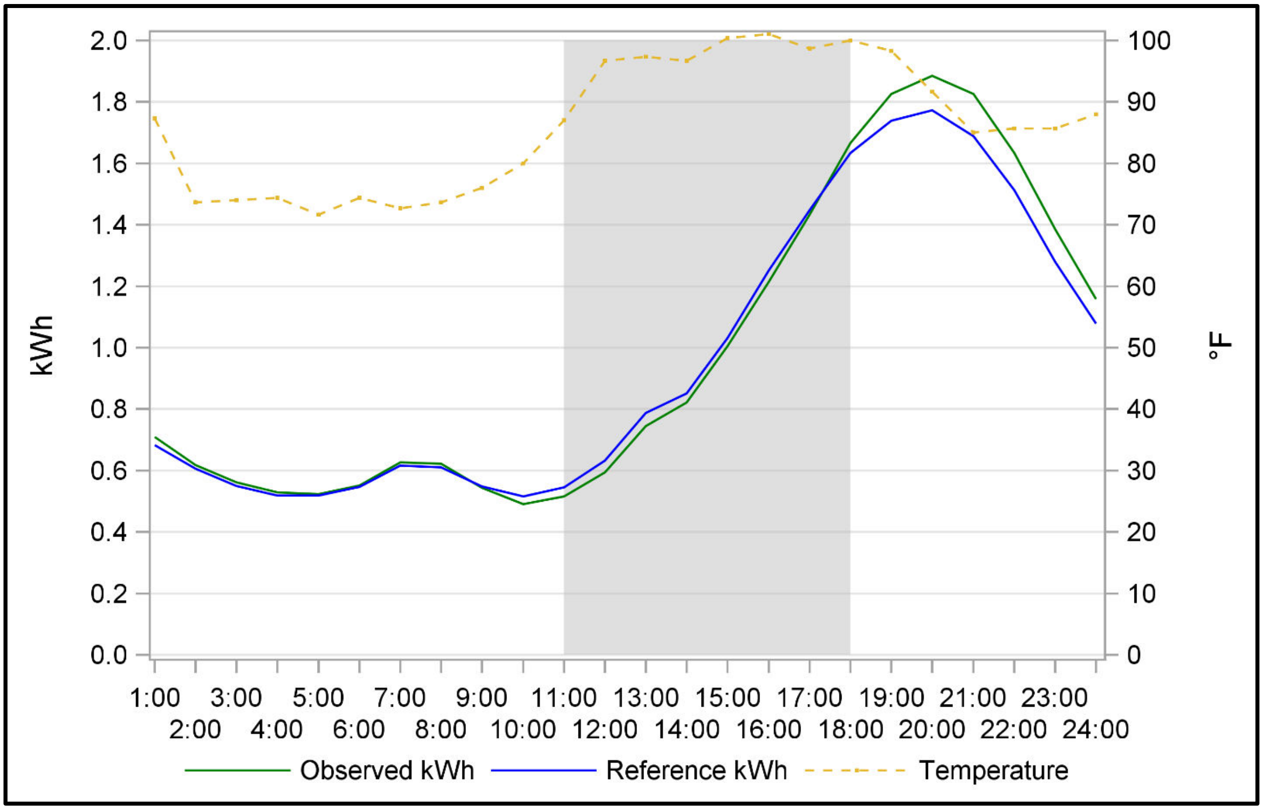
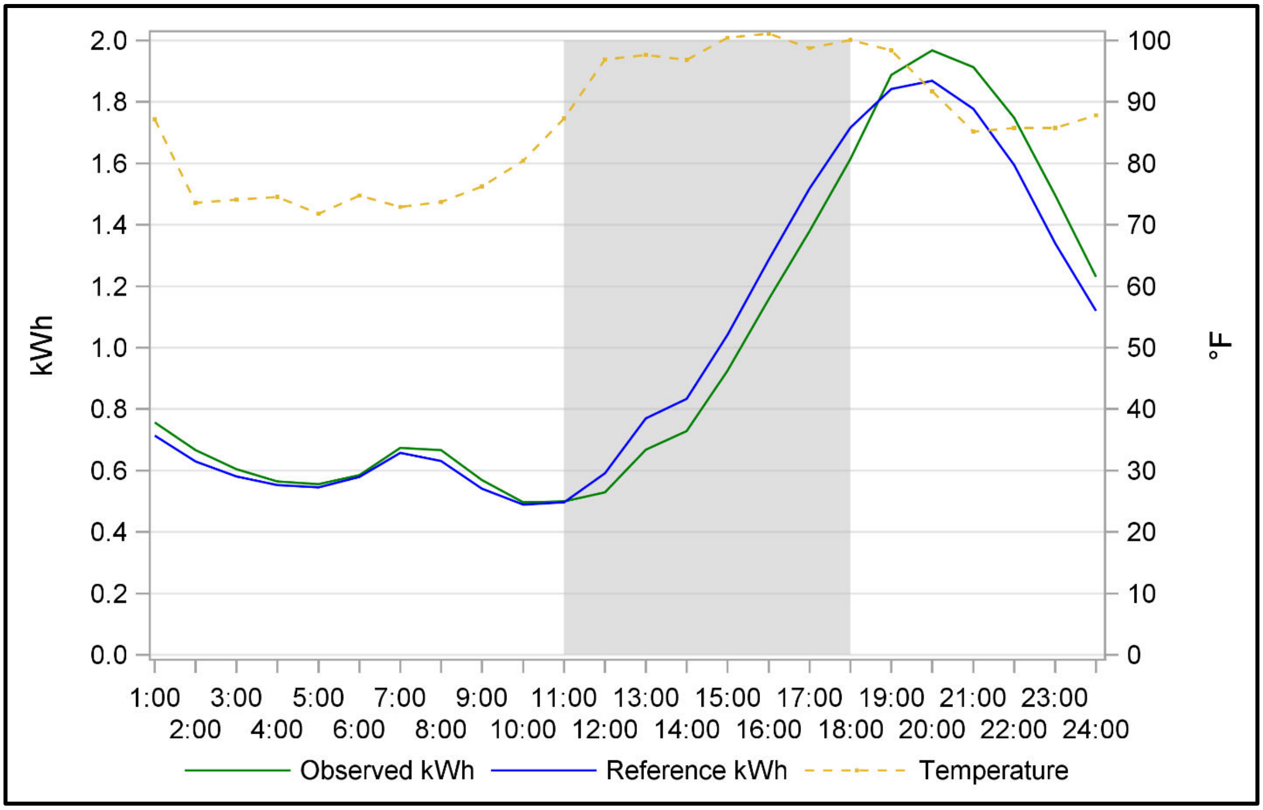


FIGURE 3-20: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – BOTH EMAIL AND TEXT NOTIFICATIONS – 2016 EVENT AVERAGE



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. Almost 20% of PTR participants had a low income billing rate. The non-low income participants had an average event hour load reduction that was in line with the overall PTR population, saving 0.10 kW (8.0%). The low income participants showed no load reduction during the event hours, with an average of -0.01 kW (-1.4%). However, this group showed snapback effects after the event, with an average increase of 0.07 kW over the reference load in the hours of 6 p.m. to midnight.

FIGURE 3-21: HOURLY LOAD PROFILE FOR NON-LOW INCOME PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2016 EVENT AVERAGE

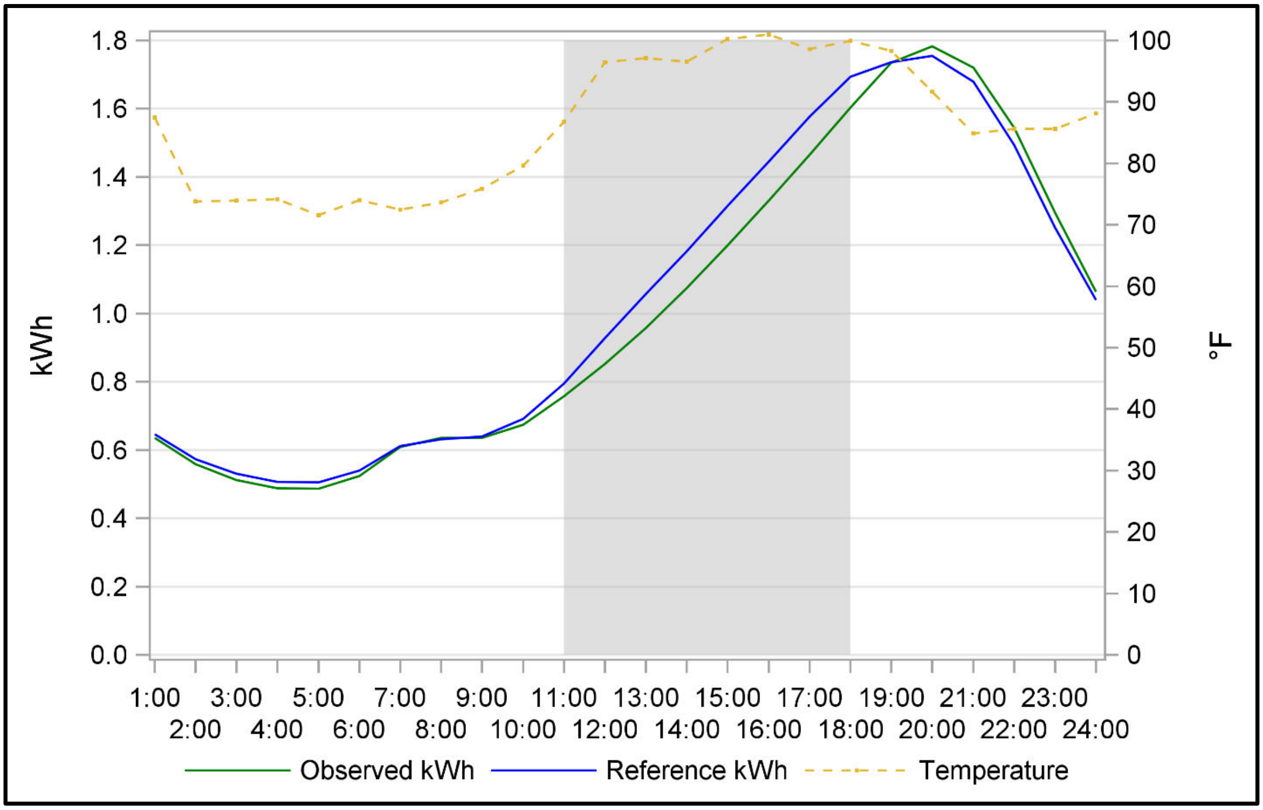
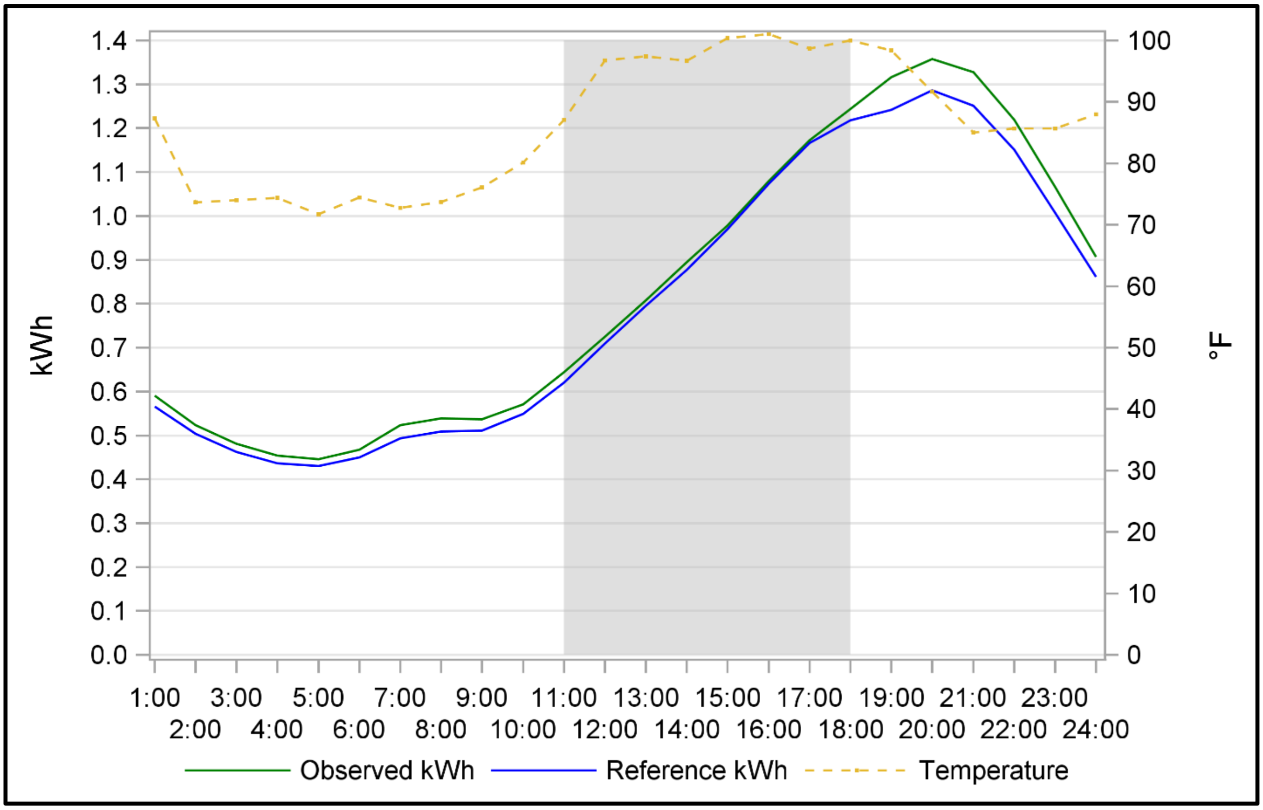


FIGURE 3-22: HOURLY LOAD PROFILE FOR LOW INCOME PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2016 EVENT AVERAGE



3.1.9 PTR without Load Control by First Year of Enrollment

Figure 3-23 through Figure 3-27 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 2016. The participants who first enrolled in 2016 (the "newest" group) saved the most during the 2016 PTR event, with an average of 0.15 kW (14.6%) during event hours. This group also showed the most snapback effects, with an average increase of 6.4% from 6 p.m. to midnight. The "oldest" group of participants who first enrolled in 2012 had an average event hour load reduction of 0.07 kW (7.1%), and an average post-event snapback of 2.2%. Lastly, the 2013 enrollees had very little reduction during event hours of 0.02 kW (2.6%), and an average post-event snapback of 5.3%.

FIGURE 3-23: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2012 FIRST ENROLLMENT YEAR – 2016 EVENT AVERAGE

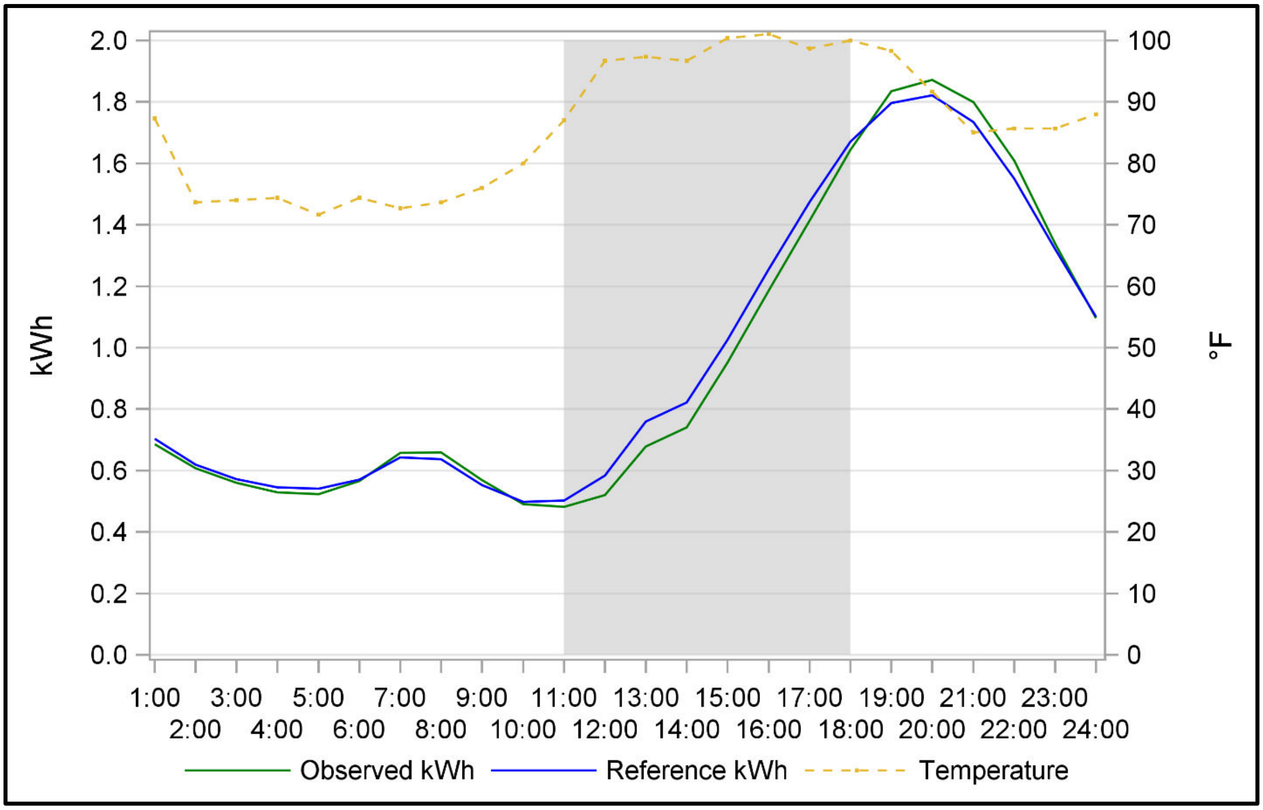


FIGURE 3-24: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2013 FIRST ENROLLMENT YEAR – 2016 EVENT AVERAGE

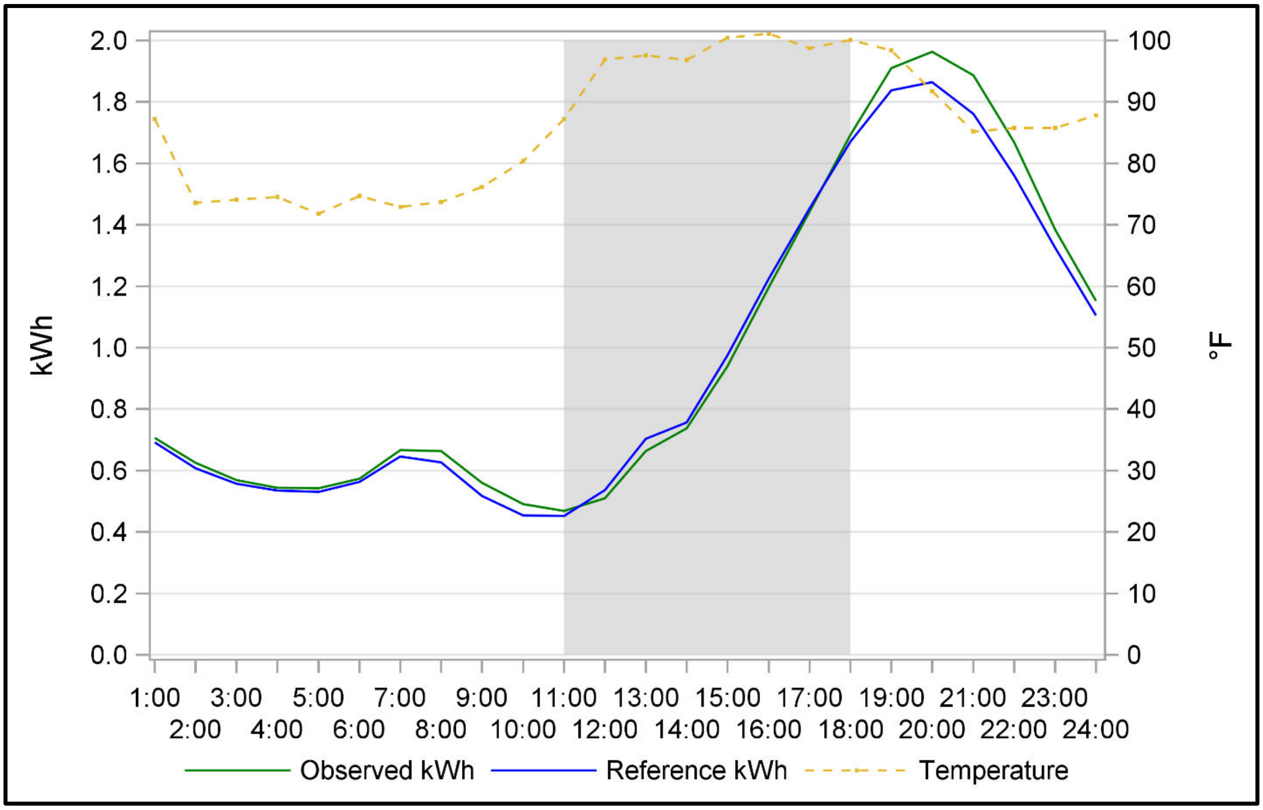


FIGURE 3-25: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2014 FIRST ENROLLMENT YEAR OF – 2016 EVENT AVERAGE

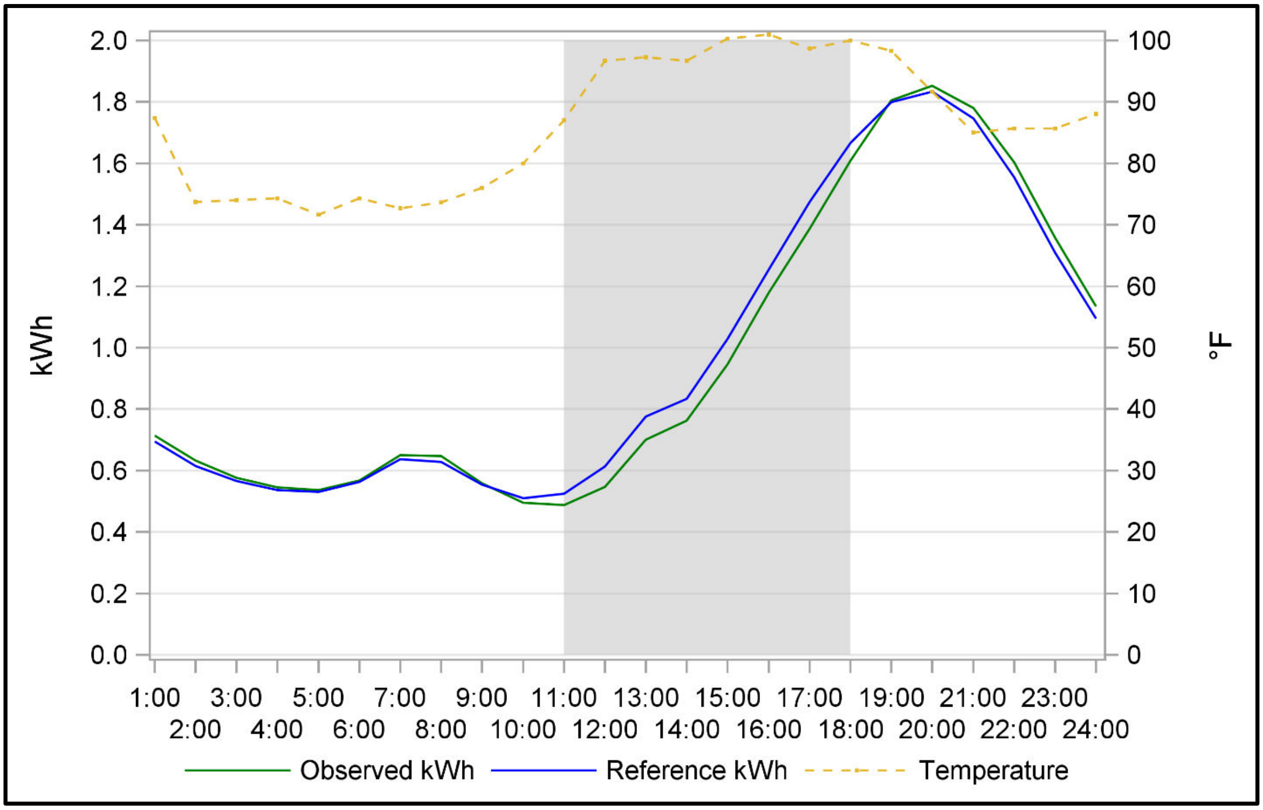


FIGURE 3-26: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2015 FIRST ENROLLMENT YEAR – 2016 EVENT AVERAGE

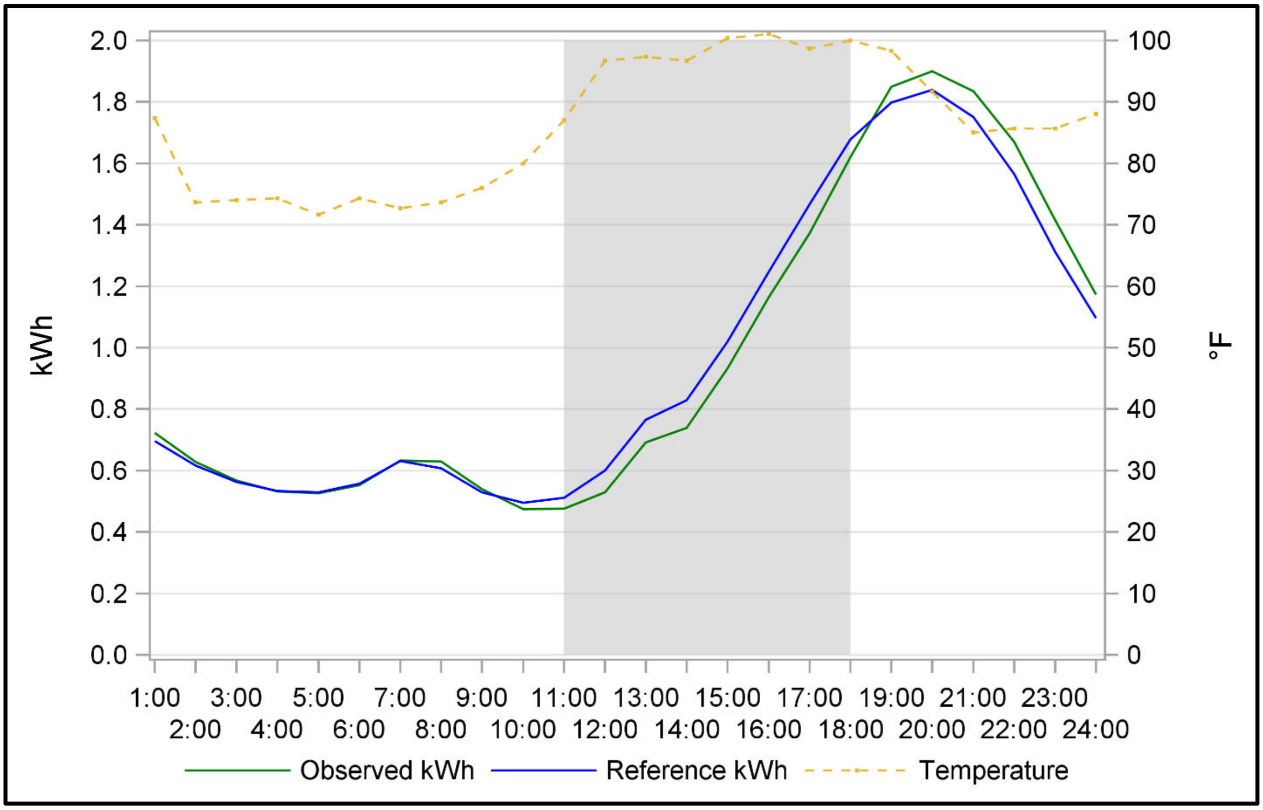
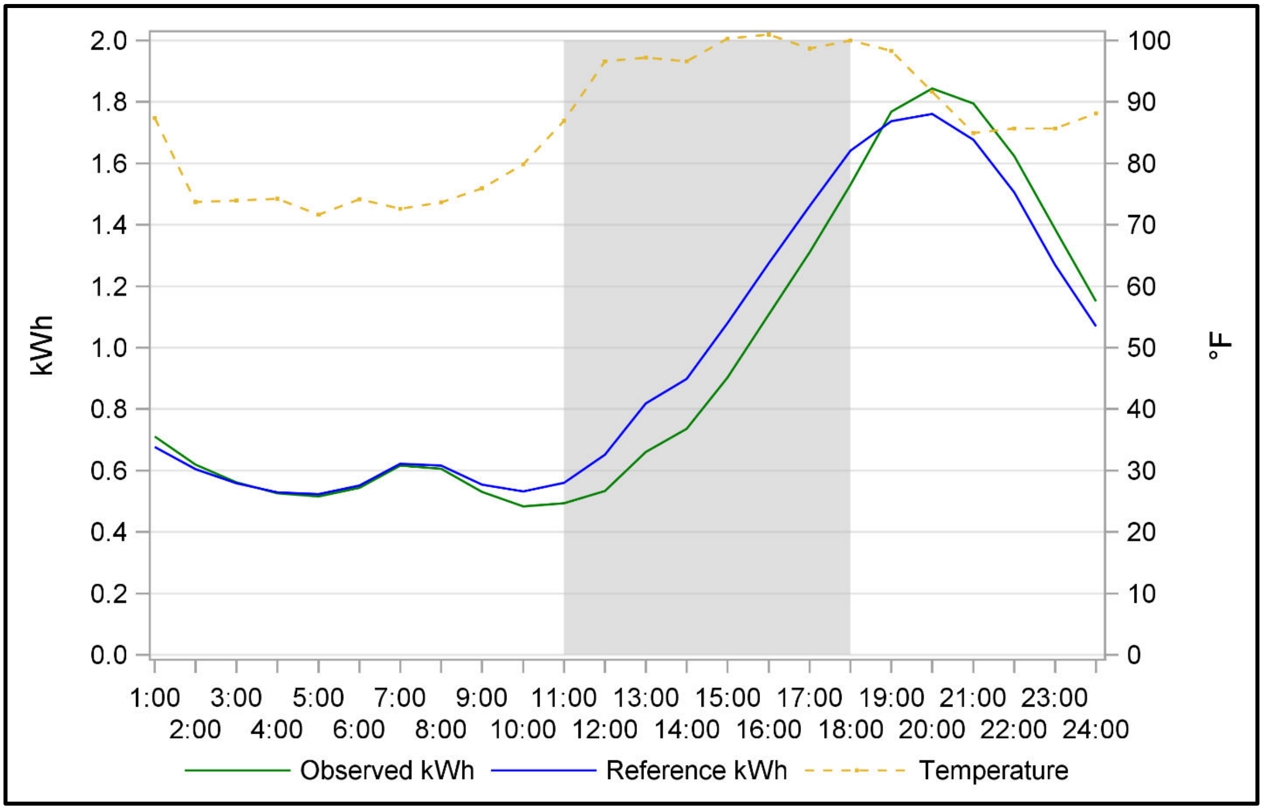


FIGURE 3-27: HOURLY LOAD PROFILE FOR PTR CUSTOMERS WITHOUT ANY LOAD CONTROL – 2016 FIRST ENROLLMENT YEAR – 2016 EVENT AVERAGE



3.1.10 Net Energy Metered Ex Post Load Impacts

As part of its analysis, Itron modeled the impacts of 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 3-28 and Table 3-10 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 0.23 kW. The average aggregate event-induced load impact for these NEM customers was 2.45 MW, which is a considerable amount given that they comprise 13.5% of the overall PTR population.

The majority of PTR participants with NEM do not have load control. However, there are approximately 2,600 participants that have load control out of the total 10,607 NEM participants; either SCTD or Summer Saver. This incidence (24.3%) of load control is higher than for the general PTR population (11.9%). As can be seen in Figure 3-28, 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.

For the ex post NEM PTR participants in 2016, there is a noticeable increase in usage in the hour ending 1 p.m. that does not follow the expected load shape. This affected both program participants and non-participants, and is concentrated in the Inland climate zone. After confirming that the anomaly is not the result of an underlying data issue, this spike suggests that the cloud cover of the Inland areas of San Diego service territory was significant enough to decrease PV production in this hour.

FIGURE 3-28: HOURLY LOAD PROFILE FOR PTR NEM CUSTOMERS – 2016 EVENT AVERAGE

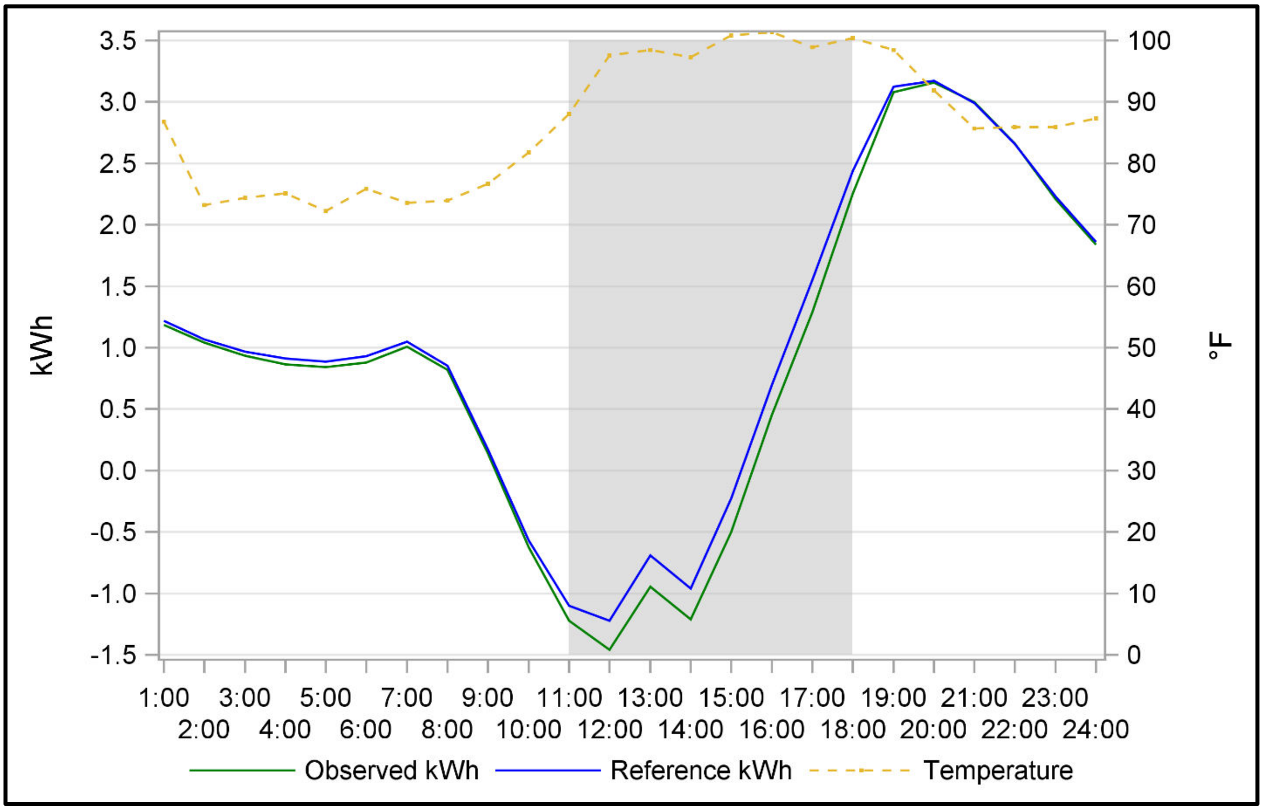


TABLE 3-10: SUMMARY OF PTR EVENT IMPACTS FOR NEM CUSTOMERS – 2016 AVERAGE

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	76.7	0.17	0.14	0.034	19.7%	8,640	294
9:00	10:00	No	81.7	-0.57	-0.62	0.054	-9.4%	8,640	465
10:00	11:00	No	88.0	-1.10	-1.22	0.122	-11.1%	8,640	1,052
11:00	12:00	Yes	97.6	-1.22	-1.46	0.235	-19.2%	8,640	2,033
12:00	13:00	Yes	98.5	-0.69	-0.94	0.255	-36.9%	8,640	2,200
13:00	14:00	Yes	97.2	-0.96	-1.21	0.249	-25.9%	8,640	2,153
14:00	15:00	Yes	100.8	-0.23	-0.50	0.273	-118.2%	8,640	2,359
15:00	16:00	Yes	101.3	0.70	0.45	0.242	34.8%	8,640	2,095
16:00	17:00	Yes	98.9	1.55	1.29	0.261	16.8%	8,640	2,256
17:00	18:00	Yes	100.3	2.44	2.25	0.185	7.6%	8,640	1,599
18:00	19:00	No	98.4	3.12	3.08	0.044	1.4%	8,640	378
19:00	20:00	No	91.9	3.17	3.16	0.015	0.5%	8,640	129
20:00	21:00	No	85.7	2.99	3.00	-0.006	-0.2%	8,640	-54
Total - Entire Day			86.7	24.00	21.68	2.318	9.7%	8,640	20,031
Total - Event Hours			99.2	1.58	-0.12	1.701	107.7%	8,640	14,695

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 5-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 these 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-only enrollments will stay constant and that the SCTD program will continue to grow. By the end of 2017, the PTR program is expected to grow to over 81,000 participants (driven by dual enrollments from SCTD), and the SCTD program is expected to grow to over 15,000 participants. By the end of 2022, the PTR program is forecasted to grow to almost 90,000 participants, while the SCTD program is forecasted to grow to over 30,000 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 event day from 2016. 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	17%	46%	63%
	50% Cycle	4%	33%	37%
	All	21%	79%	100%
PTR Dually Enrolled in SCTD	4 Degree Setback	22%	35%	57%
	50% Cycle	16%	28%	43%
	All	38%	62%	100%
SCTD-Only	4 Degree Setback	22%	36%	57%
	50% Cycle	16%	27%	43%
	All	37%	63%	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 2018. 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 0.041 kW during the resource availability hours (1:00pm to 6:00 pm). The average estimated aggregate load reduction under this scenario is 2.87 MW. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.054 kW. The average estimated aggregate reduction is 3.77 MW. These estimates represent approximately 5.7% and 5.9% of the reference load, respectively for each weather scenario.

FIGURE 4-1: 2018 EX ANTE HOURLY LOAD PROFILE – PTR ONLY

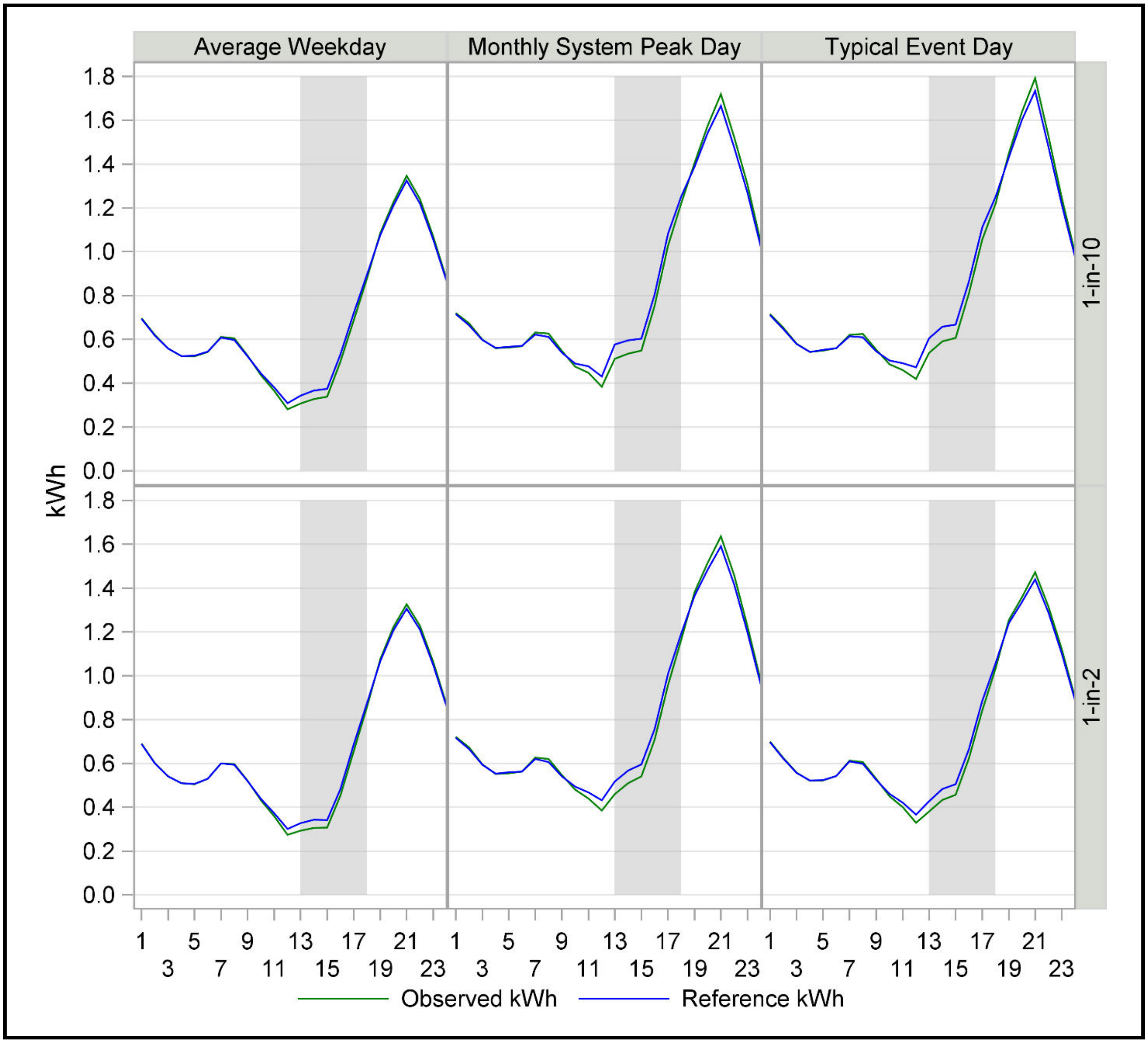


TABLE 4-2: 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – PTR-ONLY

	Day / Type	Month	1-in-10 Avg. Hourly Reference Load (kWh)	1-in-10 Avg. Hourly Observed Load (kWh)	1-in-10 Avg. Hourly Impact (kWh)	1-in-10 Percent Load Reduc-tion	1-in-10 Avg. Total Hourly Impact (MWh)	1-in-2 Avg. Hourly Reference Load (kWh)	1-in-2 Avg. Hourly Observed Load (kWh)	1-in-2 Avg. Hourly Impact (kWh)	1-in-2 Percent Load Reduc-tion	1-in-2 Avg. Total Hourly Impact (MWh)
ALL	Average Weekday	Jun	0.23	0.22	0.015	6.3%	1.04	0.21	0.20	0.014	6.4%	0.95
		Jul	0.51	0.49	0.025	5.0%	1.77	0.46	0.44	0.022	4.7%	1.51
		Aug	0.58	0.55	0.032	5.5%	2.22	0.55	0.52	0.030	5.4%	2.07
	Monthly System Peak Day	Jun	0.75	0.70	0.050	6.6%	3.47	0.36	0.33	0.023	6.6%	1.63
		Jul	0.85	0.80	0.049	5.7%	3.39	0.67	0.63	0.036	5.4%	2.51
		Aug	0.87	0.82	0.051	5.8%	3.54	0.82	0.78	0.048	5.8%	3.35
	Typical Event Day	Aug	0.91	0.86	0.054	5.9%	3.77	0.72	0.68	0.041	5.7%	2.87

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 2018. 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 incremental load reduction for the average participant is 0.081 kW during event hours. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.106 kW. These estimates are higher than the PTR-only group. The average incremental estimated aggregate load reductions are 0.25 MW (11.7%) and 0.32 MW (13.1%), respectively.

The 100% cycling group has an estimated load reduction during event hours of 0.13 kW under the 1-in-2 scenario, representing an 11.9% reduction from the reference load. Under the 1-in-10 conditions, this group has an estimated event hour load reduction of 0.16 kW, or 13.2%. The 50% cycling group has much lower estimated load reductions of 0.001 kW (0.1%) for both the 1-in-2 and 1-in-10 scenarios.

FIGURE 4-2: 2018 EX ANTE HOURLY LOAD PROFILE – PTR DUALLY ENROLLED IN SUMMER SAVER

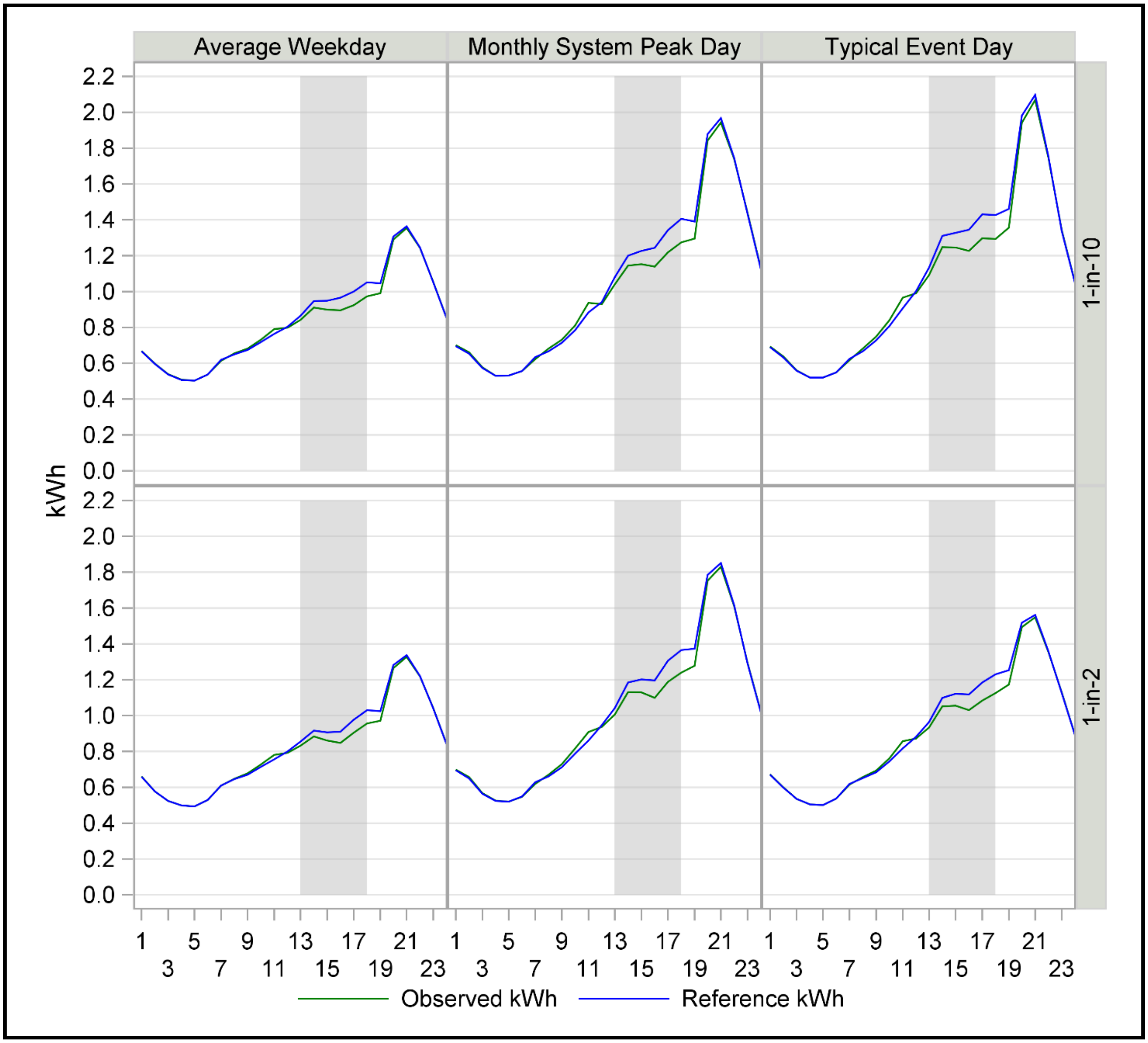


TABLE 4-3: 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – PTR DUALLY ENROLLED IN SUMMER SAVER

Cycle %	Day / Type	Month	1-in-10 Average Hourly Reference Load (kWh)	1-in-10 Average Hourly Observed Load (kWh)	1-in-10 Average Hourly Impact (kWh)	1-in-10 Percent Load Reduc-tion	1-in-10 Average Total Hourly Impact (MWh)	1-in-2 Average Hourly Referenc e Load (kWh)	1-in-2 Average Hourly Observed Load (kWh)	1-in-2 Average Hourly Impact (kWh)	1-in-2 Percent Load Reduc-tion	1-in-2 Average Total Hourly Impact (MWh)
100	Average Weekday	Jun	0.58	0.53	0.047	8.0%	0.09	0.57	0.53	0.045	7.8%	0.09
		Jul	0.87	0.80	0.078	8.9%	0.15	0.81	0.74	0.065	8.0%	0.12
		Aug	0.91	0.82	0.096	10.5%	0.18	0.88	0.79	0.090	10.2%	0.17
	Monthly System Peak Day	Jun	1.11	0.95	0.154	14.0%	0.29	0.70	0.63	0.069	9.9%	0.13
		Jul	1.22	1.08	0.147	12.0%	0.28	1.02	0.91	0.107	10.5%	0.20
		Aug	1.17	1.02	0.151	12.9%	0.29	1.14	1.00	0.144	12.6%	0.28
	Typical Event Day	Aug	1.24	1.08	0.163	13.2%	0.31	1.05	0.93	0.125	11.9%	0.24
50	Average Weekday	Jun	0.60	0.60	0.001	0.1%	0.00	0.59	0.59	0.001	0.2%	0.00
		Jul	1.04	1.04	0.001	0.1%	0.00	0.93	0.93	0.001	0.1%	0.00
		Aug	1.11	1.11	0.001	0.1%	0.00	1.07	1.06	0.001	0.1%	0.00
	Monthly System Peak Day	Jun	1.38	1.38	0.001	0.1%	0.00	0.76	0.76	0.002	0.2%	0.00
		Jul	1.56	1.56	0.003	0.2%	0.00	1.23	1.23	0.001	0.1%	0.00
		Aug	1.47	1.47	0.000	0.0%	0.00	1.44	1.44	0.000	0.0%	0.00
	Typical Event Day	Aug	1.59	1.59	0.001	0.1%	0.00	1.32	1.32	0.001	0.1%	0.00
ALL	Average Weekday	Jun	0.59	0.56	0.031	5.2%	0.09	0.58	0.55	0.030	5.1%	0.09
		Jul	0.93	0.88	0.051	5.5%	0.15	0.85	0.81	0.042	4.9%	0.13
		Aug	0.98	0.92	0.062	6.3%	0.19	0.95	0.89	0.058	6.2%	0.18
	Monthly System Peak Day	Jun	1.20	1.10	0.101	8.4%	0.31	0.72	0.68	0.045	6.3%	0.14
		Jul	1.35	1.25	0.097	7.2%	0.29	1.10	1.03	0.069	6.3%	0.21
		Aug	1.28	1.19	0.097	7.6%	0.29	1.25	1.16	0.093	7.5%	0.28
	Typical Event Day	Aug	1.37	1.26	0.106	7.8%	0.32	1.15	1.07	0.081	7.1%	0.25

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 2018. For a 1-in-2 typical event day, the estimated load reduction for the average dual PTR-SCTD participant is 0.26 kW during resource availability hours. For a 1-in-10 typical event day, the estimated load reduction is 0.34 kW. The average estimated aggregate load reductions are 2.04 MW (28.7%) and 2.68 MW (29.9%), respectively.

The 4 degree setback has a similar load reduction estimate to the 50% cycling group. For example, in the 1-in-2 year on a typical event day, the load reduction is 0.27 kW for the setback group compared to 0.28 for the cycling group, resulting in a percent load reduction of 31.7% compared to 31.9%.

FIGURE 4-3: 2018 EX ANTE HOURLY LOAD PROFILE – PTR DUALLY ENROLLED IN SCTD

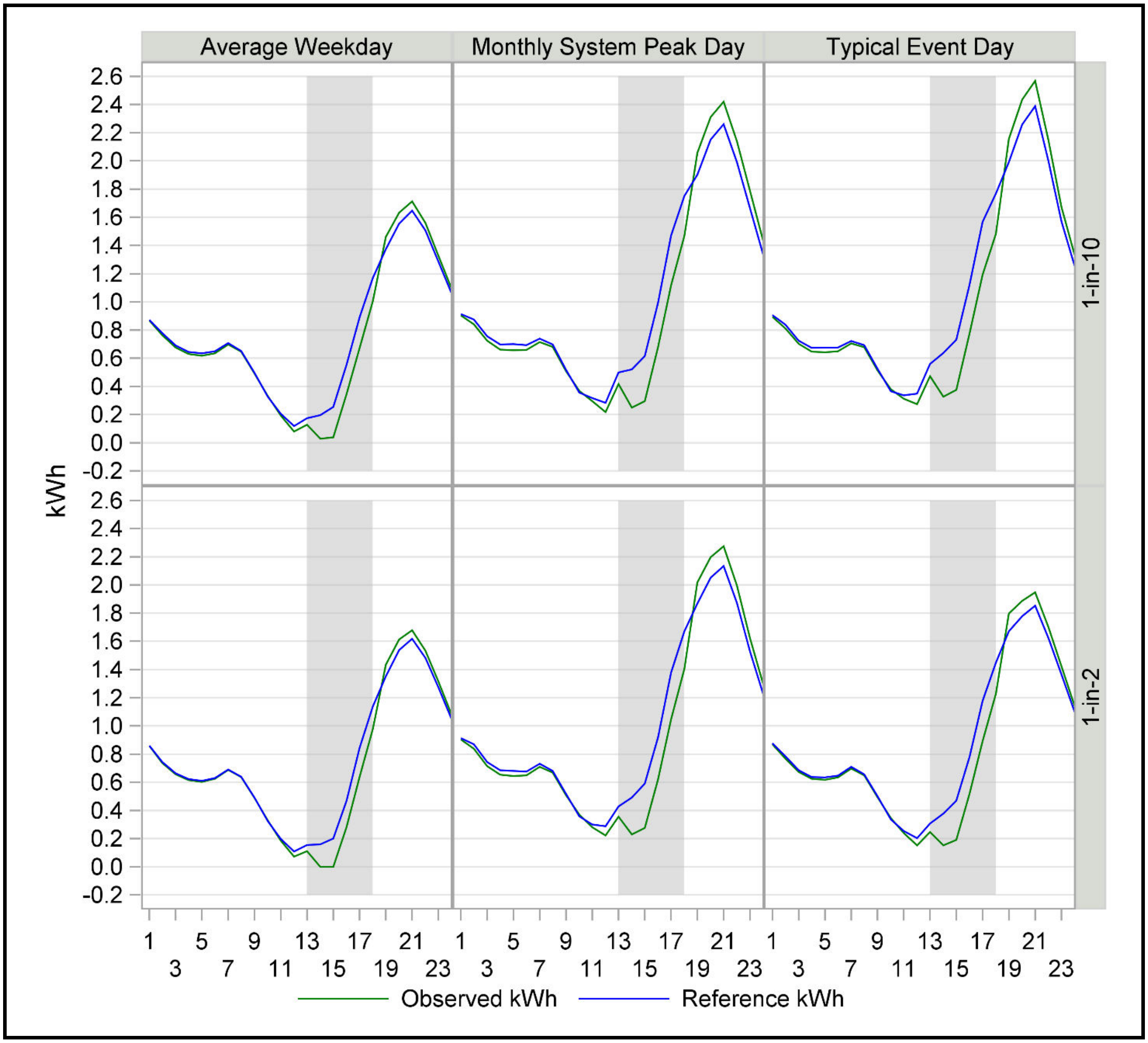


TABLE 4-4: 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – PTR DUALLY ENROLLED IN SCTD

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	0.01	-0.09	0.106	911.9%	0.38	-0.01	-0.11	0.101	-920.1%	0.36
		Jul	0.50	0.33	0.172	34.4%	0.63	0.40	0.25	0.148	37.1%	0.54
		Aug	0.62	0.41	0.208	33.5%	0.76	0.57	0.38	0.194	34.1%	0.71
	Monthly System Peak Day	Jun	0.90	0.55	0.345	38.4%	1.24	0.21	-0.03	0.242	114.8%	0.87
		Jul	1.08	0.75	0.330	30.5%	1.20	0.75	0.51	0.242	32.2%	0.88
		Aug	1.09	0.76	0.334	30.6%	1.23	1.03	0.71	0.317	30.9%	1.17
	Typical Event Day	Aug	1.18	0.82	0.361	30.5%	1.33	0.86	0.59	0.274	31.7%	1.01
50% Cycle	Average Weekday	Jun	0.02	-0.08	0.105	442.5%	0.28	0.00	-0.10	0.101	2936%	0.27
		Jul	0.51	0.33	0.178	35.1%	0.47	0.40	0.25	0.154	38.4%	0.41
		Aug	0.64	0.42	0.216	33.8%	0.58	0.59	0.38	0.203	34.5%	0.54
	Monthly System Peak Day	Jun	0.92	0.57	0.358	38.7%	0.94	0.22	-0.01	0.238	106.0%	0.63
		Jul	1.10	0.76	0.337	30.7%	0.90	0.76	0.51	0.248	32.7%	0.66
		Aug	1.11	0.76	0.341	30.9%	0.92	1.05	0.72	0.325	31.1%	0.87
	Typical Event Day	Aug	1.21	0.84	0.370	30.7%	0.99	0.88	0.60	0.282	31.9%	0.76

TABLE 4-4 (CONT'D): 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – PTR DUALLY ENROLLED IN SCTD

			1-in-10					1-in-2				
Control Strategy	Day / Type	Month	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)
ALL	Average Weekday	Jun	0.01	-0.09	0.096	1053%	0.75	-0.01	-0.10	0.092	-762.3%	0.72
		Jul	0.49	0.33	0.162	32.9%	1.28	0.39	0.25	0.141	36.3%	1.11
		Aug	0.61	0.42	0.195	31.8%	1.56	0.56	0.38	0.183	32.5%	1.46
	Monthly System Peak Day	Jun	0.88	0.56	0.323	36.6%	2.53	0.20	0.02	0.189	92.1%	1.48
		Jul	1.06	0.76	0.306	28.8%	2.42	0.74	0.51	0.225	30.6%	1.78
		Aug	1.07	0.76	0.309	28.9%	2.47	1.01	0.72	0.295	29.1%	2.35
	Typical Event Day	Aug	1.17	0.83	0.335	28.7%	2.68	0.85	0.60	0.255	29.9%	2.04

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 2018. For a 1-in-2 typical event day, the estimated load reduction for the average SCTD-only participant is 0.17 kW during the resource availability hours. For a 1-in-10 typical event day, the estimated load reduction is 0.22 kW. The average estimated aggregate load reductions are 1.08 MW (17.5%) and 1.41 MW (17.2%), 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 0.22 kW and 0.29 kW for the 1-in-2 and 1-in-10 scenarios, respectively, while the latter has an average estimate of 0.17 kW and 0.22 kW. The aggregate load reduction estimate for the 4 degree setback group is 0.87 MW for the 1-in-10 year, representing a load reduction of 21.8%. The comparative metric for the 50% cycling group is 0.48 MW, which is a 17.6% load reduction.

FIGURE 4-4: 2018 EX ANTE HOURLY LOAD PROFILE – SCTD ONLY

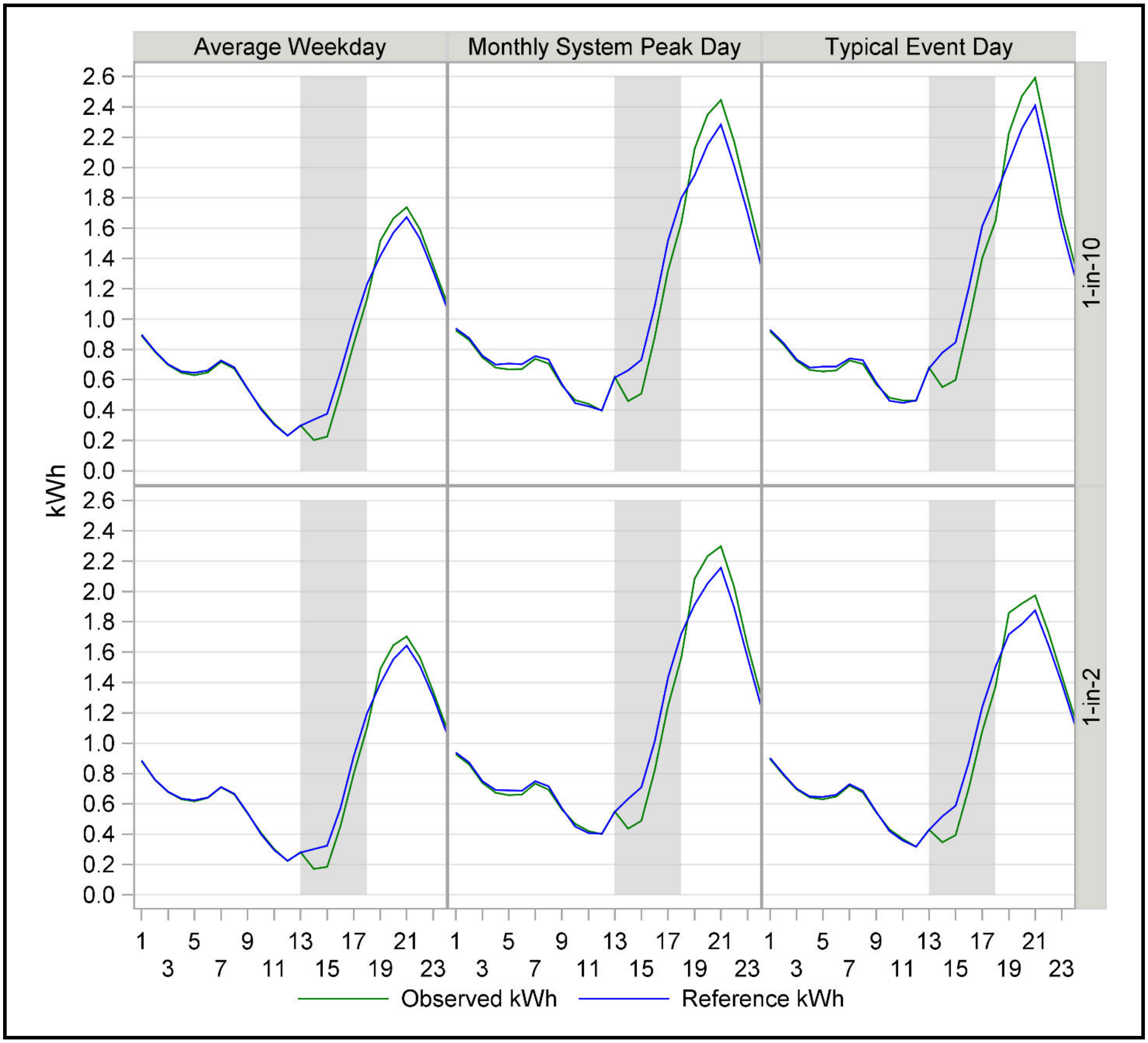


TABLE 4-5: 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – SCTD ONLY

Control Strategy	Day / Type	Month	1-in-10 Average Hourly Reference Load (kWh)	1-in-10 Average Hourly Observed Load (kWh)	1-in-10 Average Hourly Impact (kWh)	1-in-10 Percent Load Reduction	1-in-10 Average Total Hourly Impact (MWh)	1-in-2 Average Hourly Reference Load (kWh)	1-in-2 Average Hourly Observed Load (kWh)	1-in-2 Average Hourly Impact (kWh)	1-in-2 Percent Load Reduction	1-in-2 Average Total Hourly Impact (MWh)
4 Degree Setback	Average Weekday	Jun	0.12	0.04	0.079	65.0%	0.24	0.10	0.02	0.076	75.9%	0.23
		Jul	0.63	0.49	0.140	22.1%	0.42	0.53	0.41	0.119	22.7%	0.36
		Aug	0.74	0.57	0.169	22.8%	0.51	0.69	0.53	0.159	23.0%	0.48
	Monthly System Peak Day	Jun	1.03	0.75	0.275	26.8%	0.82	0.32	0.21	0.118	36.3%	0.35
		Jul	1.22	0.96	0.263	21.5%	0.79	0.89	0.69	0.193	21.8%	0.58
		Aug	1.22	0.95	0.265	21.8%	0.81	1.16	0.90	0.253	21.9%	0.77
	Typical Event Day	Aug	1.32	1.03	0.287	21.8%	0.87	0.99	0.77	0.220	22.2%	0.67
50% Cycle	Average Weekday	Jun	0.13	0.06	0.062	49.1%	0.13	0.11	0.05	0.059	56.0%	0.13
		Jul	0.62	0.51	0.107	17.4%	0.23	0.51	0.42	0.091	17.6%	0.20
		Aug	0.72	0.59	0.130	18.1%	0.29	0.67	0.55	0.122	18.2%	0.27
	Monthly System Peak Day	Jun	0.98	0.77	0.211	21.6%	0.45	0.32	0.23	0.090	28.5%	0.19
		Jul	1.17	0.97	0.203	17.3%	0.44	0.86	0.71	0.148	17.3%	0.32
		Aug	1.16	0.96	0.204	17.5%	0.45	1.11	0.91	0.194	17.6%	0.43
	Typical Event Day	Aug	1.26	1.04	0.221	17.6%	0.48	0.95	0.78	0.169	17.7%	0.37

TABLE 4-5 (CONT'D): 2018 EX ANTE HOURLY LOAD IMPACT RESULTS – SCTD ONLY

Control Strategy	Day / Type	Month	1-in-10 Average Hourly Reference Load (kWh)	1-in-10 Average Hourly Observed Load (kWh)	1-in-10 Average Hourly Impact (kWh)	1-in-10 Percent Load Reduction	1-in-10 Average Total Hourly Impact (MWh)	1-in-2 Average Hourly Reference Load (kWh)	1-in-2 Average Hourly Observed Load (kWh)	1-in-2 Average Hourly Impact (kWh)	1-in-2 Percent Load Reduction	1-in-2 Average Total Hourly Impact (MWh)
ALL	Average Weekday	Jun	0.11	0.05	0.059	52.2%	0.38	0.09	0.04	0.056	61.1%	0.36
		Jul	0.61	0.50	0.105	17.4%	0.68	0.51	0.42	0.090	17.8%	0.58
		Aug	0.71	0.58	0.128	18.0%	0.84	0.66	0.54	0.120	18.1%	0.78
	Monthly System Peak Day	Jun	0.97	0.76	0.207	21.4%	1.33	0.30	0.21	0.090	29.6%	0.58
		Jul	1.17	0.97	0.198	17.0%	1.29	0.85	0.70	0.145	17.1%	0.94
		Aug	1.16	0.96	0.199	17.2%	1.30	1.10	0.91	0.190	17.2%	1.24
	Typical Event Day	Aug	1.25	1.04	0.216	17.2%	1.41	0.94	0.78	0.165	17.5%	1.08

4.2.5 Comparison of 2016 and 2015 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* impact estimates are the same for the PTR-only group – both the current and previous estimates are 0.04 kW for a 1-in-2 event day and 0.05 kW for a 1-in-10 event day. The percentage load reductions are higher in the current estimates, from approximately 4% in the previous analysis to approximately 6% in the current analysis for a 1-in-10 year.

The estimates for the group dually enrolled in Summer Saver are lower in the current evaluation. The current estimates for incremental Summer Saver impacts are 0.08 kW for a 1-in-2 event day and 0.11 kW for a 1-in-10 event day, compared to 0.16 kW and 0.23 kW in the previous evaluation. The percentage load reductions are also lower in the current estimates, from approximately 13% in the previous analysis to approximately 8% in the current analysis for a 1-in-10 year. The current *ex ante* event day estimates for the incremental PTR effects on dually enrolled Summer Saver participants are still higher than the PTR-only group.

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 0.36 kW on 1-in-2 event days and 0.51 kW on 1-in-10 event days. The current analysis projects 0.25 kW on 1-in-2 event days and 0.33 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 23.4%, while the current estimates are 29.9%. For the SCTD-only participants, the current forecasts are lower in absolute impacts, but higher in terms of percentage impacts. The previous analysis found estimates of 0.22 kW (13.7%) on 1-in-2 event days and 0.30 kW (14.9%) on 1-in-10 event days. The current analysis projects 0.17 kW (17.5%) on 1-in-2 event days and 0.22 kW (17.2%) on 1-in-10 event days.

Shown in Figure 4-5 through Figure 4-8, the hourly load shapes for each of the groups are noticeably different between evaluation years. The current evaluation's shapes are based on the one event on September 26th, 2016. This results in a less smooth load shape than the previous evaluation, which was based on four separate events. This year's event also happened to be an extremely hot day, leading to the steep ramp-up in usage during the event hours. Lastly, the incidence of Net Energy Metered customers is higher than ever before, so their reducing effect on the overall load shapes is very pronounced.

TABLE 4-6: COMPARISON OF 2016 AND 2015 EX ANTE ESTIMATES PER CUSTOMER – FORECAST YEAR 2018 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**	0.82	0.78	0.05	5.8%	1.20	1.16	0.04	3.4%
PTR/SS	**1-in-2**	**August System Peak Day**	1.25	1.16	0.09	7.5%	1.42	1.26	0.17	11.7%
PTR/SCTD	**1-in-2**	**August System Peak Day**	1.01	0.72	0.29	29.1%	1.59	1.21	0.38	23.6%
SCTD Only	**1-in-2**	**August System Peak Day**	1.10	0.91	0.19	17.2%	1.61	1.39	0.22	13.9%

TABLE 4-7: COMPARISON OF 2016 AND 2015 EX ANTE ESTIMATES PER CUSTOMER – FORECAST YEAR 2018, 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**	0.87	0.82	0.05	5.8%	1.43	1.38	0.05	3.8%
		Typical Event Day	0.91	0.86	0.05	5.9%	1.42	1.36	0.05	3.8%
	1-in-2	**August System Peak Day**	0.82	0.78	0.05	5.8%	1.20	1.16	0.04	3.4%
		Typical Event Day	0.72	0.68	0.04	5.7%	1.17	1.13	0.04	3.3%

TABLE 4-7 (CONT'D): COMPARISON OF 2016 AND 2015 EX ANTE ESTIMATES PER CUSTOMER – FORECAST YEAR 2018, 1 P.M. TO 6 P.M.

Participant Segment	Weather Year	Day / Type	Current				Previous			
			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/SS	1-in-10	August System Peak Day	1.28	1.19	0.10	7.6%	1.77	1.54	0.23	13.1%
		Typical Event Day	1.37	1.26	0.11	7.8%	1.79	1.55	0.23	13.1%
	1-in-2	August System Peak Day	1.25	1.16	0.09	7.5%	1.42	1.26	0.17	11.7%
		Typical Event Day	1.15	1.07	0.08	7.1%	1.41	1.24	0.16	11.7%
PTR/SCTD	1-in-10	August System Peak Day	1.07	0.76	0.31	28.9%	2.02	1.51	0.51	25.2%
		Typical Event Day	1.17	0.83	0.33	28.7%	2.02	1.51	0.51	25.3%
	1-in-2	August System Peak Day	1.01	0.72	0.29	29.1%	1.59	1.21	0.38	23.6%
		Typical Event Day	0.85	0.60	0.25	29.9%	1.55	1.19	0.36	23.4%
SCTD Only	1-in-10	August System Peak Day	1.16	0.96	0.20	17.2%	2.05	1.74	0.30	14.8%
		Typical Event Day	1.25	1.04	0.22	17.2%	2.04	1.74	0.30	14.9%
	1-in-2	August System Peak Day	1.10	0.91	0.19	17.2%	1.61	1.39	0.22	13.9%
		Typical Event Day	0.94	0.78	0.17	17.5%	1.58	1.36	0.22	13.7%

FIGURE 4-5: COMPARISON OF 2016 AND 2015 EX ANTE HOURLY LOAD PROFILES – PTR-ONLY – TYPICAL EVENT DAY

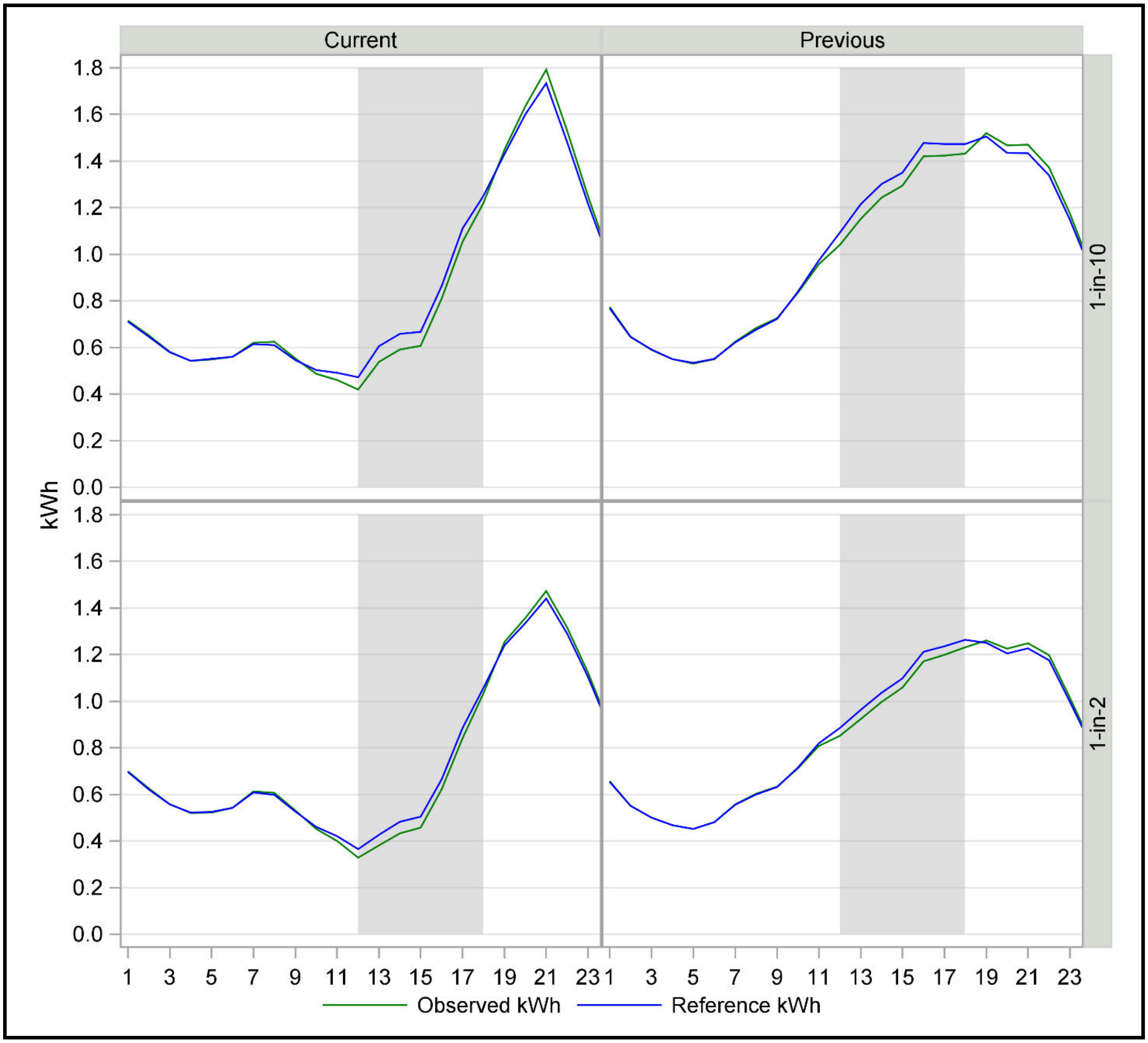


FIGURE 4-6: COMPARISON OF 2016 AND 2015 EX ANTE HOURLY LOAD PROFILES – PTR DUALLY ENROLLED IN SUMMER SAVER – TYPICAL EVENT DAY

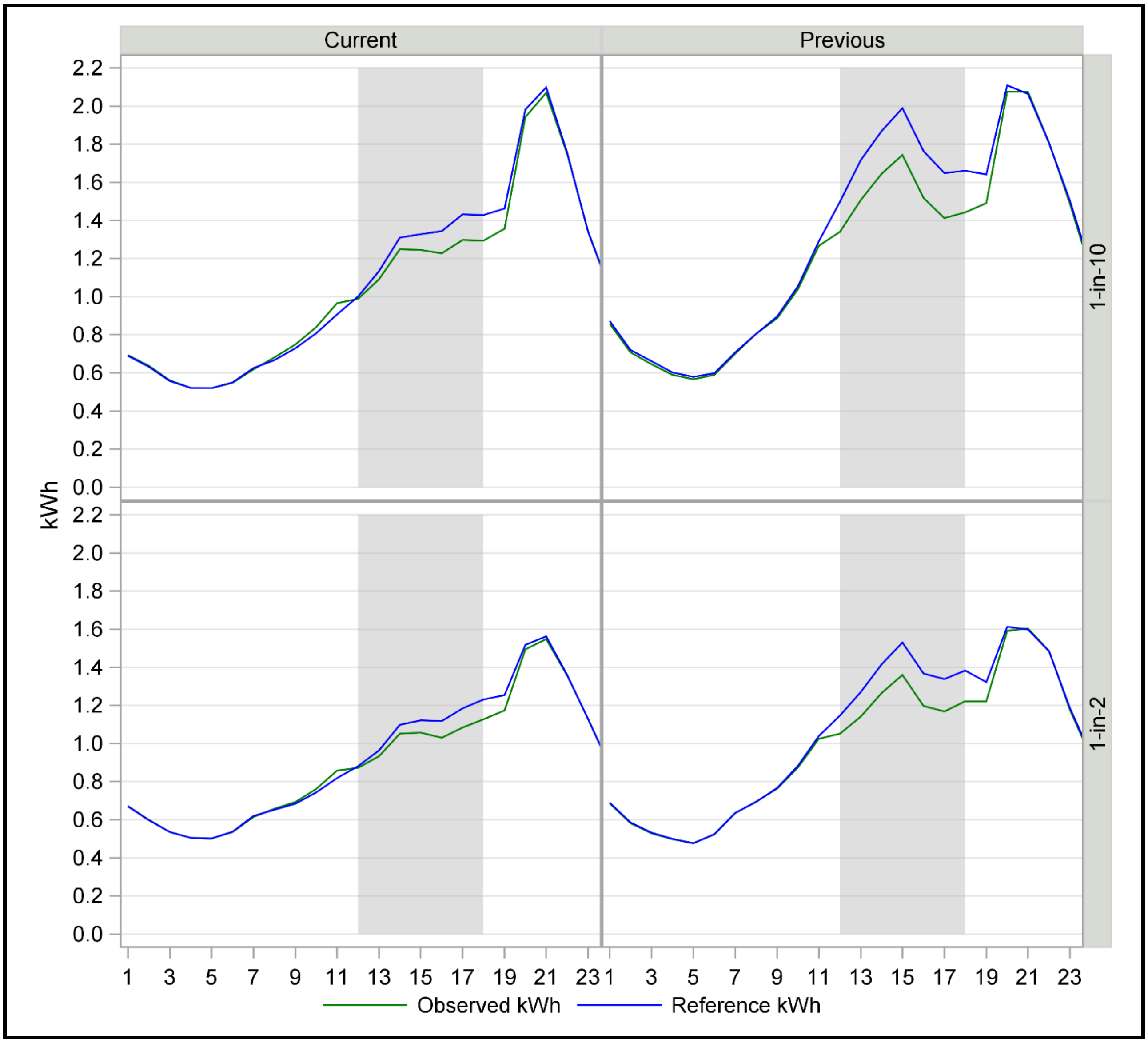


FIGURE 4-7: COMPARISON OF 2016 AND 2015 EX ANTE HOURLY LOAD PROFILES – PTR DUALLY ENROLLED IN SCTD – TYPICAL EVENT DAY

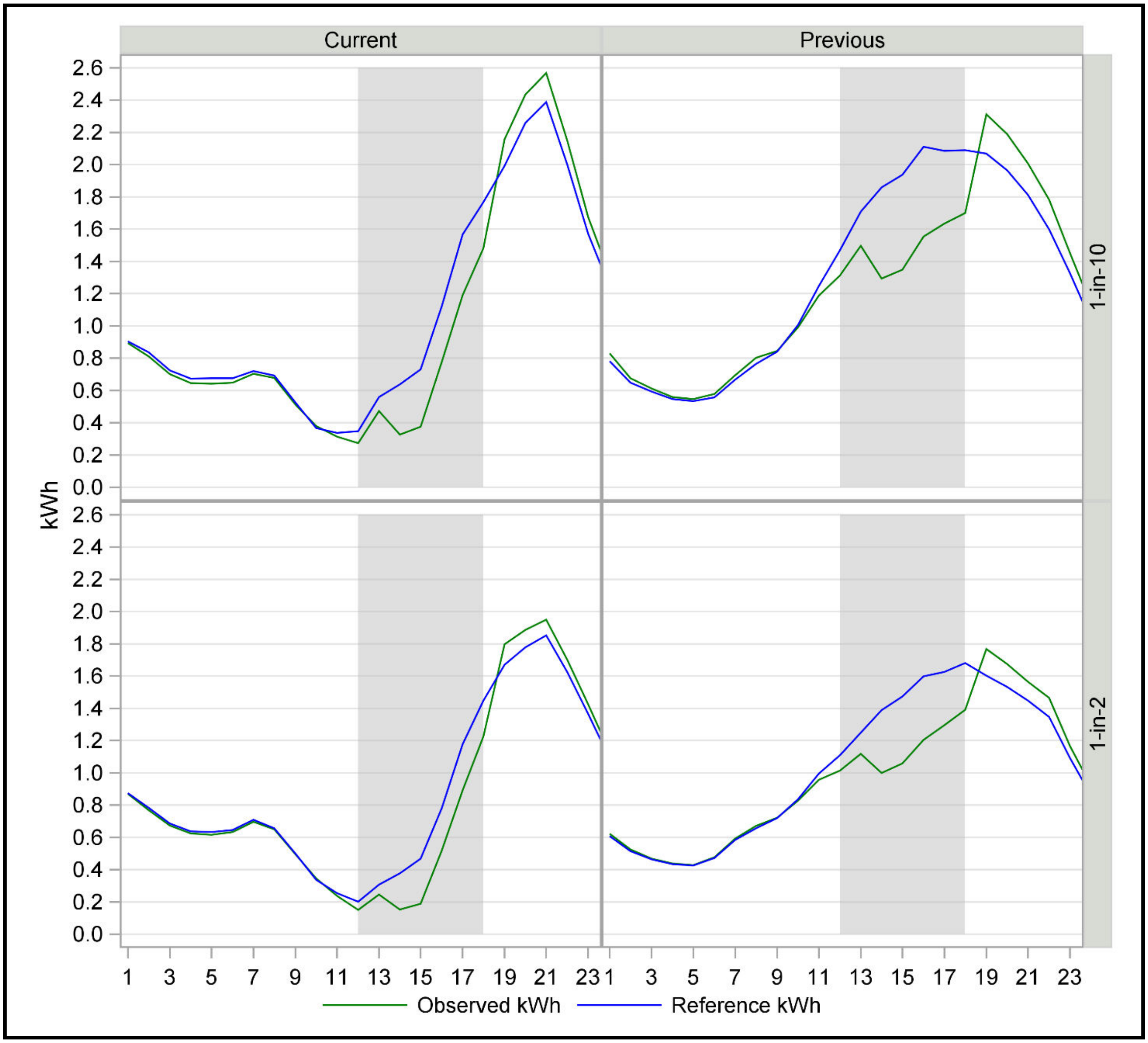
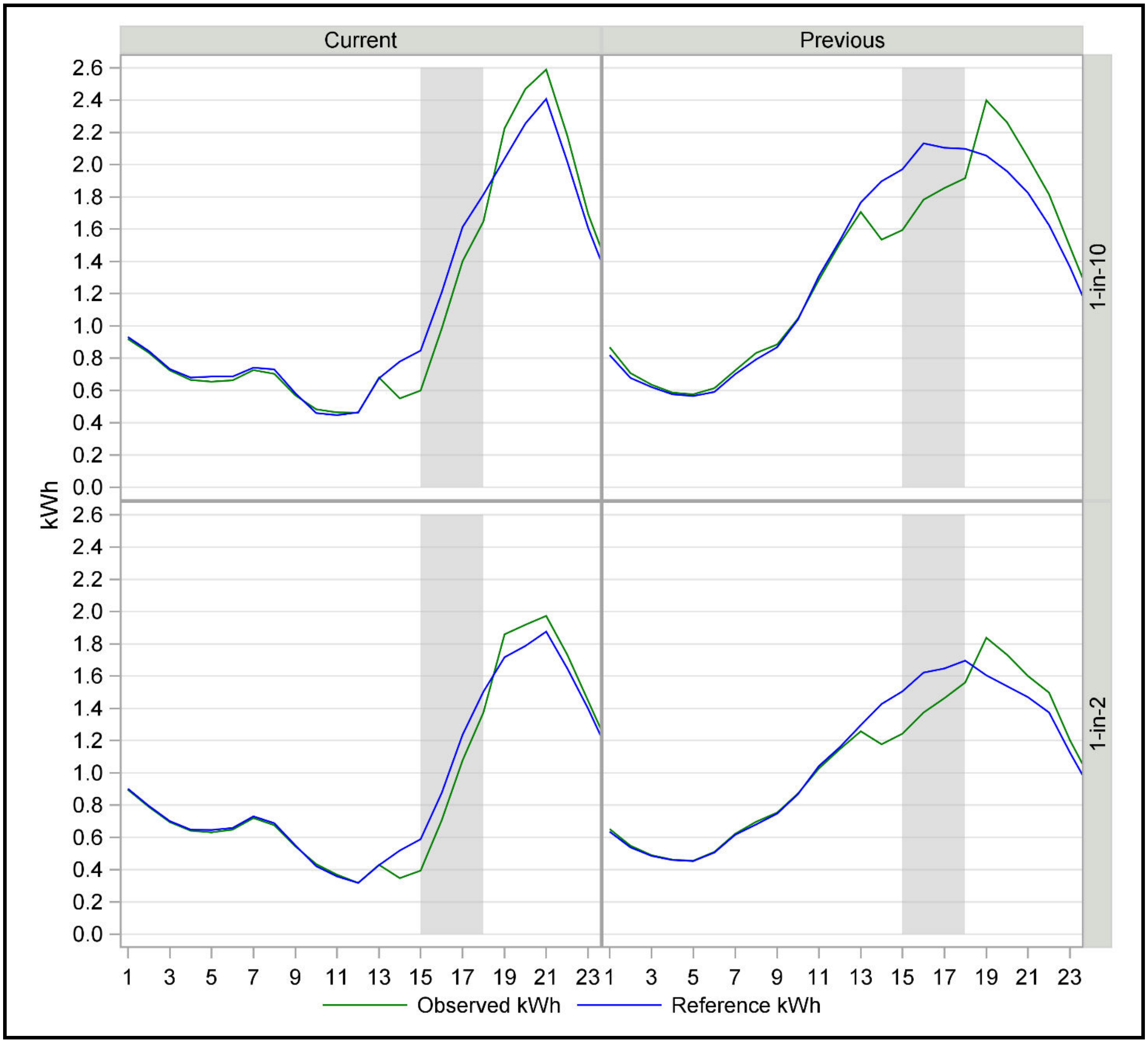


FIGURE 4-8: COMPARISON OF 2016 AND 2015 EX ANTE HOURLY LOAD PROFILES – SCTD-ONLY – TYPICAL EVENT DAY



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 for the 2016 event was extremely hot, and thus the results are higher than those associated with 1-in-10 weather conditions.

For the overall PTR-only group, the *ex post* results show an average event hour load reduction of 0.08 kW, while the 1-in-10 *ex ante* estimates show average event hour load reductions of 0.05 kW, both around 6% of the reference load. The predicted 1-in-10 average event hour load reductions for the overall PTR-Summer Saver dually enrolled group (0.11 kW, or 7.8%) are similar, but slightly lower than the *ex post* impacts (0.15 kW, or 10.3%). The same relationship exists for the 100% cycling sub-group. Since the 50% cycling sub-group had minimal *ex post* impacts, this is reflected in its *ex ante* estimate. For the dually enrolled PTR-SCTD group, the *ex post* and 1-in-10 *ex ante* estimates are essentially identical in terms of percentage impacts, at 28.2% and 28.7%, respectively. The absolute *ex post* impacts are higher, at 0.43 kW, compared to the 1-in-10 *ex ante* estimate of 0.33 kW. The estimates for the load control sub-groups are also similar. The 4 degree setback group's 1-in-10 *ex ante* estimate is 0.10 kW lower (both approximately 30% reduction) than the *ex post* estimate, while the 50% cycling group's is 0.12 kW lower (31% and 32%, respectively). The SCTD-only *ex post* estimates are more similar to the 1-in-10 *ex ante* estimates. The overall event hour load reduction estimate is 0.25 kW (14.7%) for the *ex post* and 0.22 kW (17.2%) for the 1-in-10 *ex ante*. The 50% cycling sub-group has averages of 0.25 kW (14.7%) for *ex post* and 0.22 (17.6%) for the 1-in-10 *ex ante* estimate. The 4 degree setback has an *ex post* estimate of 0.35 kW (21.3%), compared to the *ex ante* average of 0.29 (21.8%) 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	0.82	0.78	0.05	5.8%	85.43
		Ex Post	Ex Post Average Event Day	1.25	1.17	0.08	6.4%	99.33
PTR/SS	100%	1-In-2	August System Peak Day	1.14	1.00	0.14	12.6%	87.10
		Ex Post	Ex Post Average Event Day	1.34	1.10	0.23	17.5%	100.28
	50%	1-In-2	August System Peak Day	1.44	1.44	0.00	0.0%	88.07
		Ex Post	Ex Post Average Event Day	1.63	1.63	0.00	0.0%	100.60
	ALL	1-In-2	August System Peak Day	1.25	1.16	0.09	7.5%	87.46
		Ex Post	Ex Post Average Event Day	1.45	1.30	0.15	10.3%	100.40
PTR/SCTD	4 Degree Setback	1-In-2	August System Peak Day	1.03	0.71	0.32	30.9%	86.35
		Ex Post	Ex Post Average Event Day	1.53	1.08	0.46	29.8%	99.94
	50% Cycle	1-In-2	August System Peak Day	1.05	0.72	0.33	31.1%	86.55
		Ex Post	Ex Post Average Event Day	1.50	1.01	0.49	32.4%	100.03
	ALL	1-In-2	August System Peak Day	1.01	0.72	0.29	29.1%	86.44
		Ex Post	Ex Post Average Event Day	1.51	1.09	0.43	28.2%	99.95
SCTD Only	4 Degree Setback	1-In-2	August System Peak Day	1.16	0.90	0.25	21.9%	86.43
		Ex Post	Ex Post Average Event Day	1.65	1.30	0.35	21.3%	99.96
	50% Cycle	1-In-2	August System Peak Day	1.11	0.91	0.19	17.6%	86.50
		Ex Post	Ex Post Average Event Day	1.72	1.47	0.25	14.7%	99.96
	ALL	1-In-2	August System Peak Day	1.10	0.91	0.19	17.2%	86.46
		Ex Post	Ex Post Average Event Day	1.71	1.46	0.25	14.7%	99.92

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	0.87	0.82	0.05	5.8%	86.60
			Typical Event Day	0.91	0.86	0.05	5.9%	87.90
		1-In-2	Monthly System Peak Day	0.82	0.78	0.05	5.8%	85.43
			Typical Event Day	0.72	0.68	0.04	5.7%	82.46
		Ex Post	Ex Post Average Event Day	1.25	1.17	0.08	6.4%	99.33
PTR/SS	100%	1-In-10	Monthly System Peak Day	1.17	1.02	0.15	12.9%	88.03
			Typical Event Day	1.24	1.08	0.16	13.2%	90.24
		1-In-2	Monthly System Peak Day	1.14	1.00	0.14	12.6%	87.10
			Typical Event Day	1.05	0.93	0.13	11.9%	84.33
		Ex Post	Ex Post Average Event Day	1.34	1.10	0.23	17.5%	100.28
	50%	1-In-10	Monthly System Peak Day	1.47	1.47	0.00	0.0%	88.87
			Typical Event Day	1.59	1.59	0.00	0.1%	91.60
		1-In-2	Monthly System Peak Day	1.44	1.44	0.00	0.0%	88.07
			Typical Event Day	1.32	1.32	0.00	0.1%	85.41
		Ex Post	Ex Post Average Event Day	1.63	1.63	0.00	0.0%	100.60
	ALL	1-In-10	Monthly System Peak Day	1.28	1.19	0.10	7.6%	88.34
			Typical Event Day	1.37	1.26	0.11	7.8%	90.74
		1-In-2	Monthly System Peak Day	1.25	1.16	0.09	7.5%	87.46
			Typical Event Day	1.15	1.07	0.08	7.1%	84.73
		Ex Post	Ex Post Average Event Day	1.45	1.30	0.15	10.3%	100.40

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	4 Degree Setback	1-In-10	Monthly System Peak Day	1.09	0.76	0.33	30.6%	87.39
			Typical Event Day	1.18	0.82	0.36	30.5%	89.19
		1-In-2	Monthly System Peak Day	1.03	0.71	0.32	30.9%	86.35
			Typical Event Day	0.86	0.59	0.27	31.7%	83.49
		Ex Post	Ex Post Average Event Day	1.53	1.08	0.46	29.8%	99.94
PTR/SCTD	50% Cycle	1-In-10	Monthly System Peak Day	1.11	0.76	0.34	30.9%	87.56
			Typical Event Day	1.21	0.84	0.37	30.7%	89.46
		1-In-2	Monthly System Peak Day	1.05	0.72	0.33	31.1%	86.55
			Typical Event Day	0.88	0.60	0.28	31.9%	83.71
		Ex Post	Ex Post Average Event Day	1.50	1.01	0.49	32.4%	100.03
	ALL	1-In-10	Monthly System Peak Day	1.07	0.76	0.31	28.9%	87.46
			Typical Event Day	1.17	0.83	0.33	28.7%	89.31
		1-In-2	Monthly System Peak Day	1.01	0.72	0.29	29.1%	86.44
			Typical Event Day	0.85	0.60	0.25	29.9%	83.59
		Ex Post	Ex Post Average Event Day	1.51	1.09	0.43	28.2%	99.95

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
SCTD Only	4 Degree Setback	1-In-10	Monthly System Peak Day	1.22	0.95	0.27	21.8%	87.46
			Typical Event Day	1.32	1.03	0.29	21.8%	89.30
		1-In-2	Monthly System Peak Day	1.16	0.90	0.25	21.9%	86.43
			Typical Event Day	0.99	0.77	0.22	22.2%	83.58
		Ex Post	Ex Post Average Event Day	1.65	1.30	0.35	21.3%	99.96
	50% Cycle	1-In-10	Monthly System Peak Day	1.16	0.96	0.20	17.5%	87.52
			Typical Event Day	1.26	1.04	0.22	17.6%	89.40
		1-In-2	Monthly System Peak Day	1.11	0.91	0.19	17.6%	86.50
			Typical Event Day	0.95	0.78	0.17	17.7%	83.66
		Ex Post	Ex Post Average Event Day	1.72	1.47	0.25	14.7%	99.96
	ALL	1-In-10	Monthly System Peak Day	1.16	0.96	0.20	17.2%	87.49
			Typical Event Day	1.25	1.04	0.22	17.2%	89.34
		1-In-2	Monthly System Peak Day	1.10	0.91	0.19	17.2%	86.46
			Typical Event Day	0.94	0.78	0.17	17.5%	83.62
		Ex Post	Ex Post Average Event Day	1.71	1.46	0.25	14.7%	99.92