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2014 Impact Evaluation of San Diego Gas & Electric's Residential Peak Time Rebate and Small Customer Technology Deployment Programs

Ex Post and Ex Ante Report

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Executive Summary

ES.1 Executive Summary

This report presents the findings of the 2014 *ex post* and *ex ante* evaluation for San Diego Gas and Electric's (SDG&E) Peak Time Rebate (PTR) Program. SDG&E's PTR Program is marketed as the *Reduce Your Use*^{SM} (RYU) *Rewards*. If customers are able to save electricity between 11 a.m. and 6 p.m. on a RYU Reward days, they earn a credit on their SDG&E bill. To earn rewards, customers must set up an alert (text, email, or both) preference and SDG&E will let them know when to expect an RYU day.

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

ES.2 Ex Post Evaluation Summary

ES.2.1 *PTR Ex Post Evaluation*

There were a total of seven PTR events during 2014. One event occurred in the winter, two in May and the remaining between June and September. The average temperature during event hours was 88.0°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 2014 PTR events, the overall PTR population had an average event hour load reduction of 0.11 kW per participant, representing an average reduction of 6.9% relative to the reference load. The average aggregate load reduction during event hours was 5.92 MW. Large participants delivered over 85% of the aggregate load reduction (5.10 MW), while Medium and Small participants delivered the remaining 15% (1.20 MW and 0.05 MW, respectively). Inland customers experienced higher temperatures during events (89.8°F) than Coastal customers (86.5°F) and had a higher average load reduction during event hours (0.12 kW versus 0.10 kW). The PTR customers who were also enrolled in Summer Saver had higher event hour load reductions due to the AC cycling – the 50% cycling group had an average of 0.18 kW (7.3%), while the 100% cycling group had an average of 0.59 kW (28.1%). Low income participants had very little load reduction during events, with an average of 0.04 kW (2.8%). The participants who first enrolled in 2012 saved the most during the 2014 PTR events, with an average of 0.13 kW (8.4%) during event hours. Having both notification types (email and text) had a higher average event hour reduction of 0.13 kW (8.7%). The net energy metered (NEM) participants 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 is increase in energy export is expressed as a negative load drop (-21.3%).

Table ES-1: PTR Ex Post Load Impact Estimates by Customer Category - Average 2014 Event (11 a.m. to 6 p.m.)

Customer Category	Mean Active Partic-ipants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	56,270	1.52	1.42	0.11	6.9%	5.92	88.0
Large	24,200	2.41	2.20	0.21	8.7%	5.10	88.3
Medium	19,765	1.07	1.01	0.06	5.6%	1.20	87.9
Small	11,435	0.45	0.45	0.00	1.1%	0.05	87.5
Coastal	30,599	1.38	1.29	0.10	7.0%	2.95	86.5
Inland	24,801	1.70	1.58	0.12	6.8%	2.88	89.8
No SCTD	54,757	1.51	1.41	0.11	7.2%	5.95	88.0
No Load Control (SCTD or Summer Saver)	51,855	1.50	1.40	0.10	6.7%	5.14	88.0
Summer Saver – 50% Cycling	871	2.29	2.11	0.18	7.3%	0.16	87.3
Summer Saver – 100% Cycling	2,028	2.02	1.43	0.59	28.1%	1.20	87.0
Low Income	16,199	1.35	1.31	0.04	2.8%	0.60	87.8
Non-Low Income	35,656	1.55	1.44	0.11	7.1%	3.85	88.1
Enroll. Year – 2012	24,224	1.53	1.40	0.13	8.4%	3.08	88.5
Enroll. Year – 2013	8,086	1.51	1.39	0.12	8.0%	0.96	88.5
Enroll. Year – 2014	19,545	1.47	1.40	0.07	4.5%	1.30	87.0
Notification – Email	35,765	1.52	1.41	0.10	7.0%	3.74	88.0
Notification – Text	8,049	1.40	1.34	0.06	4.4%	0.49	88.0
Notification – Both	7,251	1.54	1.41	0.13	8.7%	0.96	88.1
Summer Billing Tier 1	20,499	1.45	1.35	0.10	6.8%	2.01	87.7
Summer Billing Tier 2	4,673	1.42	1.35	0.07	5.0%	0.32	87.5
Summer Billing Tier 3	9,391	1.49	1.38	0.10	7.0%	0.97	87.8
Summer Billing Tier 4	8,700	1.53	1.47	0.06	4.1%	0.53	88.3
Summer Billing Tier 5	8,542	1.64	1.51	0.12	7.6%	1.05	88.6
Net Energy Metered	2,864	0.57	0.14	0.43	-21.3%[1]	1.23	88.4

[1] The data modeled for NEM households represented the net of grid energy used minus PV generation returned to the grid. The negative load reduction in this case reflects an increase in the amount of excess PV generation returned to the grid.

ES.2.2 *SCTD Ex Post Evaluation*

There were four SCTD event days in 2014, during the July and September PTR events. Participants received either a 4 degree setback on their thermostats or 50% AC cycling. The average temperature during SCTD events was 87.0°F. Table ES-2 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 0.66 kW, representing 24.9% of the reference load. The average aggregate load reduction for the dually enrolled group was 0.77 MW. Generally, the participants with 4 degree setbacks had higher event hour load reductions, averaging 0.65 kW in the overall SCTD group, compared to those with 50% AC cycling, who averaged 0.58 kW.

Table ES-2: SCTD Ex Post Load Impact Estimates by Customer Category - Average 2014 Event (2 p.m. to 6 p.m.)

Customer Category	Mean Active Partic-ipants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	1,887	2.70	2.09	0.61	22.9%	1.16	87.0
4 Degree Setback	923	2.58	1.93	0.65	25.6%	0.60	86.2
50% Cycling	964	2.80	2.21	0.58	20.9%	0.56	87.7
PTR	1,162	2.66	2.00	0.66	24.9%	0.77	87.1
PTR – 4 Deg. Setback	556	2.55	1.83	0.72	28.3%	0.40	86.1
PTR – 50% Cycling	606	2.76	2.14	0.62	22.5%	0.37	87.8
SCTD Only	725	2.76	2.22	0.55	20.0%	0.40	87.0
SCTD Only – 4 Degree Setback	366	2.64	2.07	0.57	21.8%	0.21	86.3
SCTD Only – 50% Cycling	359	2.87	2.34	0.53	18.6%	0.19	87.5

ES.3 Ex Ante Evaluation Summary

The ex ante evaluation is based 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 68,500 SDG&E residential customers. Of these, approximately 3,500 are dually enrolled in the Summer Saver Program. While the total is expected to remain constant, around 1,000 are forecast to shift to the dually enrolled in Summer Saver group. SDG&E forecasts that the SCTD program will grow from around 5,300 participants to approximately 8,200 by the end of 2016, with around 60% of that total jointly participating in PTR.

The weather conditions in 2014 were particularly hot and generally fell in line with the 1-in-10 weather scenarios used for the *ex ante* analysis. Table ES-3 shows the average hourly per resource availability hour 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 2014, 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 0.09 kW in 1-in-10 conditions and 0.07 kW in 1-in-2 conditions. The dually enrolled PTR-SCTD participants are estimated to have the highest average event hour load impacts of 0.68 kW in 1-in-10 scenarios and 0.49 kW in 1-in-2 scenarios.

Table ES-3: 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	Mean Temp. °F
PTR Only	**Overall**	**1-in-10**	1.57	1.48	0.09	5.8%	86.52
		1-in-2	1.37	1.30	0.07	4.8%	80.55
PTR/SS	**100% Cycle**	**1-in-10**	2.19	1.40	0.79	36.2%	87.45
		1-in-2	1.82	1.25	0.58	31.7%	81.07
	50% Cycle	**1-in-10**	2.53	2.25	0.27	10.8%	88.05
		1-in-2	2.11	1.91	0.20	9.5%	81.41
	Overall	**1-in-10**	2.30	1.65	0.64	28.0%	87.63
		1-in-2	1.91	1.44	0.47	24.4%	81.17
PTR/SCTD	**4 Degree Setback**	**1-in-10**	2.60	1.92	0.68	26.2%	87.44
		1-in-2	2.03	1.54	0.49	24.2%	81.07
	50% Cycle	**1-in-10**	2.63	2.07	0.55	21.0%	87.26
		1-in-2	2.05	1.65	0.40	19.4%	80.97
	Overall	**1-in-10**	2.62	2.01	0.60	23.1%	87.35
		1-in-2	2.04	1.60	0.43	21.3%	81.02
SCTD Only	**4 Degree Setback**	**1-in-10**	2.64	2.15	0.49	18.7%	87.48
		1-in-2	2.07	1.72	0.36	17.2%	81.09
	50% Cycle	**1-in-10**	2.79	2.35	0.45	15.9%	87.50
		1-in-2	2.18	1.86	0.32	14.7%	81.10
	Overall	**1-in-10**	2.72	2.25	0.46	17.1%	87.49
		1-in-2	2.13	1.79	0.34	15.8%	81.09

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Introduction

This report provides estimates of the 2014 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. PTR is a two-level incentive program, providing a basic incentive level ($0.75/kWh) to customers that reduce energy use through manual means and a premium incentive ($1.25/kWh) to customers that reduce energy use through automated demand response (DR) enabling technologies. The PTR bill credit is calculated based on their event day reduction in electric usage below their established customer-specific reference level (CRL). The program is marketed under the name Reduce Your Use^{SM} (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.

This report also provides estimates of the 2014 ex post and ex ante load impacts for the Small Customer Technology Deployment (SCTD) program. SDG&E is offering 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 Overview of Methods

For the overall opt-in PTR population, 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.

Analysis of the SCTD accounts was conducted in a similar manner to the opt-in PTR population. There was initially concern that the identification of the control group would present some complications, such as ensuring that the control group was composed of accounts with AC. However, extensive diagnostics conducted after selection of the control group were reassuring that the control group is robust enough to minimize the chances of biasing the impact estimates.

1.3 Current Opt-In PTR Enrollment

Table 1-1 summarizes the PTR program enrollment. A total of nearly 68,000 customers had enrolled in PTR as of the last event of 2014 (September 17^{th}). Five percent of these participants were dually enrolled in the Summer Saver Program and four 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 4,000 SCTD participants, only 57% of them also enrolled in PTR despite multiple attempts by SDG&E to encourage them to enroll.

Approximately 68% of PTR participants enrolled for email notification only, with another 14% enrolled jointly in email and some other notification type, principally text. Text message only accounts for most of the remaining participants at 15%. Only two percent of participants received only telephone notifications.

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

Customer Category	Enrollment Year - 2012		Enrollment Year - 2013		Enrollment Year - 2014		All PTR Participants	
	N	%	N	%	N	%	N	%
PTR w/o Enabling Tech.	21,871	91%	7,293	92%	29,053	91%	58,217	91%
Summer Saver	1,640	7%	490	6%	1,257	4%	3,387	5%
SCTD	491	2%	166	2%	1,613	5%	2,270	4%
SCTD not enrolled in PTR[2]	N/A	N/A	N/A	N/A	N/A	N/A	1,702	3%
Coastal Climate Zone	12,940	54%	4,211	53%	16,843	53%	33,994	53%
Inland Climate Zone	10,676	44%	3,638	46%	14,597	46%	28,911	45%
Notification Type – Email	17,649	74%	4,965	63%	20,736	65%	43,350	68%
Notification Type – Text	3,199	13%	1,492	19%	5,125	16%	9,816	15%
Notification Type – Both	3,146	13%	1,487	19%	4,582	14%	9,215	14%
Marketing Segment – 01	4,683	20%	1,487	19%	5,842	18%	12,012	19%
Marketing Segment – 02	6,153	26%	1,981	25%	7,972	25%	16,106	25%
Marketing Segment – 03	2,530	11%	881	11%	3,197	10%	6,608	10%
Marketing Segment – 04	2,997	12%	1,072	13%	4,310	14%	8,379	13%
Marketing Segment – 05	3,969	17%	1,306	16%	5,380	17%	10,655	17%
Marketing Segment – 06	3,640	15%	1,212	15%	5,167	16%	10,019	16%
All Participants	**23,994**	**38%**	**7,944**	**12%**	**31,895**	**50%**	**63,833**	**100%**

[1] As of the end of 2014

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

1.4 Overview of the SCTD Program

The SCTD Program was approved in D-12-04-045 and is new to 2014. The program provides demand response enabling technology to residential customers. In 2014 the enabling technology was offered free of charge and customers received bill credits through the PTR program. The enabling technology offered in 2014 was the Ecobee Smart Si thermostat (http://www.ecobee.com/solutions/home/smart-si). These thermostats are signaled by SDG&E through Wi-Fi. Two cycling strategies were being tested. The first strategy is a four degree thermostat setback and the other is a 50% AC cycling strategy. Customer were randomly assigned to one of the two strategies. Although PTR events are seven hours long SCTD participant's thermostats were curtailed for 4 hours, typically from 2 p.m. – 6 p.m.

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

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

1.5 Enrollment Forecast

The enrollment forecast in the *ex ante* evaluation forecasts that the number of SCTD thermostats installed through the SCTD program will grow from their 2014 year-end level of nearly 4,000 to a total of 10,500 thermostats by the start of the summer of 2015 through the SCTD program. For the purposes of this report, these PCT *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.

1.6 Report Organization

The remainder of this report contains the following sections:

- Ex Post Methods,
- Ex Post Results,
- Ex Ante Methodology and Results, and
- Appendix A – Propensity Score Matching Results.

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 the 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 due to the following conditions: 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, and d) a large population from which to develop a matched control group. To develop control groups for this evaluation, Itron used a Stratified Propensity Score Matching (SPSM) method.

2.1.1 Pre-Matching Stratification and Design

Prior to generating propensity scores, the participant sites were stratified to control for variables that may observationally influence participation. Strata were defined using a combination of climate zone (coastal and inland) and annual usage group (small, medium, large). Net Energy Metering (NEM) customers were placed into their own respective strata, as there were too few premises to include as an additional stratification variable. In total, this provided seven different strata from which to develop control groups. Using these, 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 five control group candidate premises for every participant based on variables calculated using 2013 monthly billing data. After requesting the hourly interval data for these candidate premises, a second stage of PSM selected the final control group using variables developed from interval data. Second-stage matching was done separately for all PTR participants, as well as for the other various participant groups, namely, NEM, SCTD, Summer Saver, Low Income, and Summer Tier.

After experimenting with various combinations, the final set of variables chosen for the first stage's logit model included: monthly kWh usage, average monthly kWh, correlation coefficients between monthly CDD65 and kWh usage for summer and winter months, coefficient of variation of kWh usage, ratio of average monthly usage between summer and winter months, ratio of summer kWh usage to total CDD65, and a dummy variable for Low Income customers. The second stage of matching saw the inclusion of hourly kWh usage during the event hours for summer and hot days[1], as well as monthly event hour kWh usage.

2.1.2 Propensity Score Matching Results

One of the key methods of assessing the effectiveness of the PSM is to conduct t-tests on the independent variables used in the logistic regression for the groups both before and after matching. If the matching is successful, the participant and control groups should not be statistically significantly different for these variables. The results of the t-tests for both stages of the PTR 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 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.

For detailed results of the t-tests and comparison plots for each of the participant subgroupings, please see Appendix A.

1 For hot days, Itron selected the six days with the highest average peak temperatures across the different weather stations used for the analysis. The dates with these peak temperatures were the 13th of May, the 30th of August, and the streak of hot days from the 3rd to the 6th of September. 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

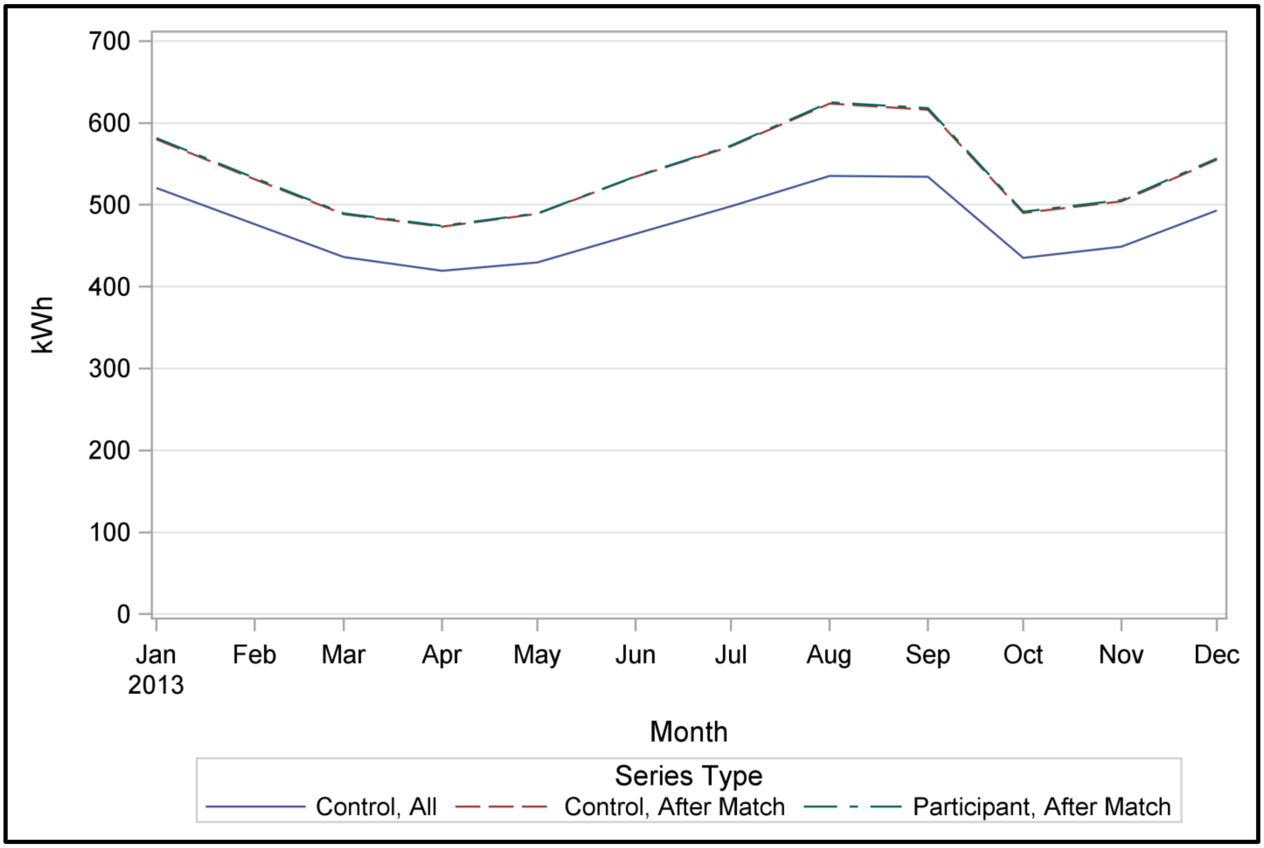
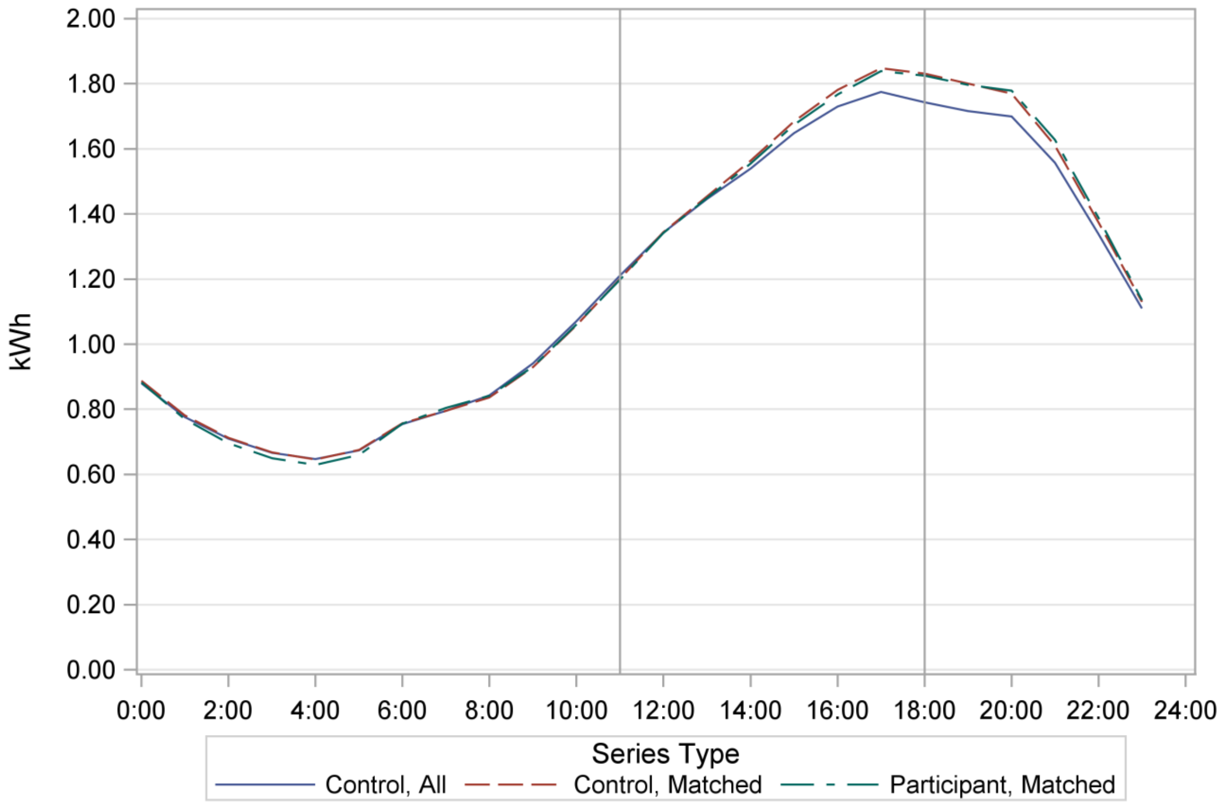


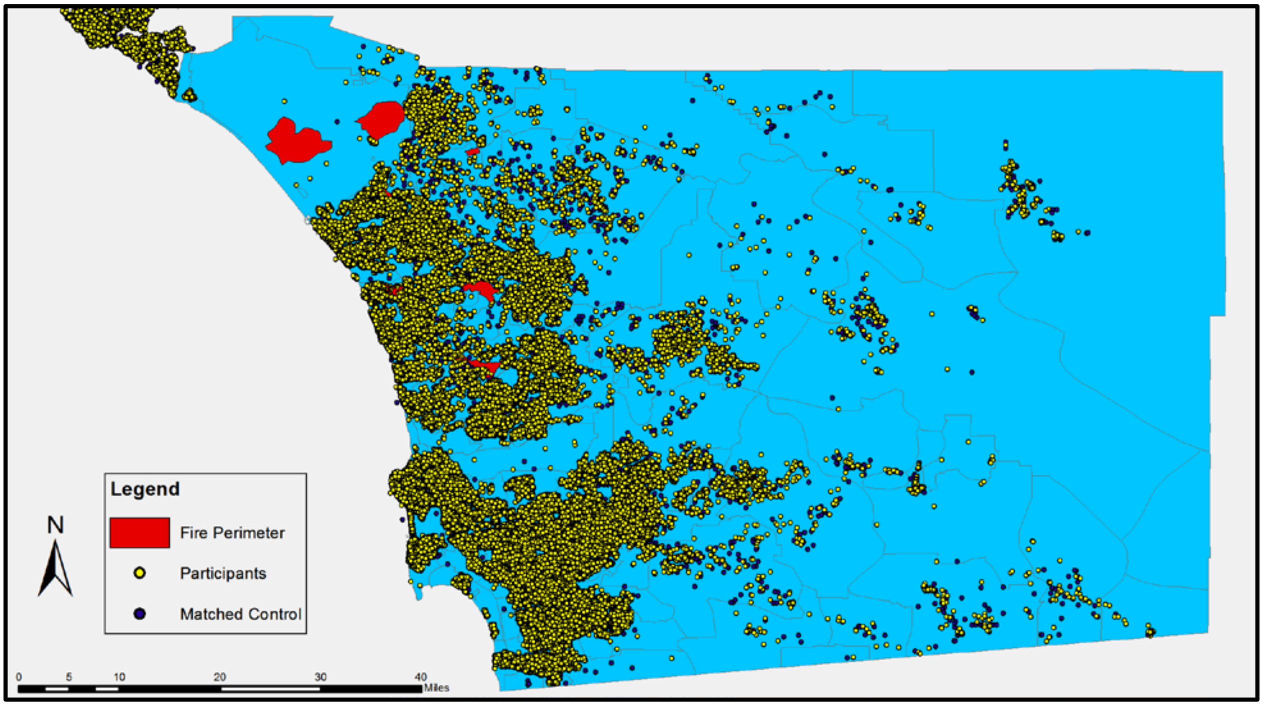
Figure 2-2: Comparison of Hourly Hot Day Load Profiles for Control Group with All and Only Matched Participants – PTR Stage Two PSM



2.2 Assessment of Wildfires during PTR Events

In May 2014, San Diego County experienced a swarm of wildfires that coincided with high temperatures and dry, windy conditions. These overlapped with several RYU, SCTD, and Summer Saver events. As part of its analysis, Itron examined the possible ramifications of the wildfires in estimating impacts. Figure 3-1 shows the map of wildfire perimeters in San Diego County set with the entirety of the PTR participant population and their matched counterparts.

Figure 2-3: Map of Wildfire Perimeters in San Diego County, Including SDG&E PTR Participants and Non-Participants



2.2.1 Methods

The perimeters of the fires were mapped onto San Diego County using GIS software. Then, using latitude and longitude coordinates of each of the participant and control premises, the customer population was mapped as well. By spatially joining these groups with the fire perimeters, a distance was established between each premise and the nearest fire. This allowed for a comparison of average fire distance between the two populations and determining potential influences on customer usage.

Table 3-1 shows count of participants and matched control by strata and distance from fire. The two groups show similar distributions and averages, so any potential fire effects should presumably affect them equally. Histograms of the fire distance for each stratum further corroborated that the control and participant groups were similar.

Table 2-1: Count of Participant and Control Premises and Mean Distance to Nearest Wildfire by Strata and Distance Group

		Group					
		Control			Participant		
Strata and Distance Group		Premises	% of Premises in Strata	Mean Distance	Premises	% of Premises in Strata	Mean Distance
Coastal L	**1. < 5 Miles**	4,103	28.6%	2.9	4,273	29.8%	2.9
	2. 5-10 Mile	1,478	10.3%	6.7	1,479	10.3%	6.8
	3. 10+ Miles	8,781	61.1%	17.0	8,610	59.9%	16.9
Coastal M	**1. < 5 Miles**	3,548	28.7%	3.0	3,730	30.1%	3.0
	2. 5-10 Mile	1,301	10.5%	6.7	1,431	11.6%	6.7
	3. 10+ Miles	7,523	60.8%	16.8	7,211	58.3%	16.6
Coastal S	**1. < 5 Miles**	1,811	23.6%	3.0	1,846	24.0%	3.0
	2. 5-10 Mile	756	9.8%	6.8	910	11.9%	7.0
	3. 10+ Miles	5,112	66.6%	16.5	4,923	64.1%	16.3
Inland L	**1. < 5 Miles**	5,324	39.6%	2.9	5,338	39.7%	2.9
	2. 5-10 Mile	3,444	25.6%	7.0	3,601	26.8%	7.0
	3. 10+ Miles	4,674	34.8%	14.7	4,503	33.5%	14.6
Inland M	**1. < 5 Miles**	3,684	37.1%	3.0	3,799	38.3%	3.0
	2. 5-10 Mile	2,516	25.4%	7.1	2,447	24.7%	7.1
	3. 10+ Miles	3,723	37.5%	14.2	3,677	37.1%	14.2
Inland S	**1. < 5 Miles**	1,801	35.6%	3.0	1,807	35.7%	3.0
	2. 5-10 Mile	1,204	23.8%	7.3	1,258	24.8%	7.3
	3. 10+ Miles	2,060	40.7%	14.1	2,000	39.5%	14.1

In order to determine if proximity to the fires affected household consumption, the load profiles in each stratum were compared by fire distance. Figure 3-2 shows the load profiles during the fires for control and participant customers in the Inland climate zone, the most representative group for the fire effects. These plots show that the group closest to fire (≤4 miles) had substantially lower usage during the period. They also suggest that the effects were approximately the same between the control and participant groups. Figure 3-3 shows the load profiles for the same two groups for a week in late June, when temperatures were similar to the fire week. Here, the separation between the distance groups was not nearly as clear cut.

These comparisons provided sufficient evidence that the wildfires seem to have affected control and participant premises similarly, so they would not affect the *ex post* impact estimations.

However, they did have an influence on a considerable number of premises, and should be accounted for in the *ex ante* impact estimations.

Figure 2-4: Load Profiles of Control and Participant Inland Customers during May 2014 Wildfires

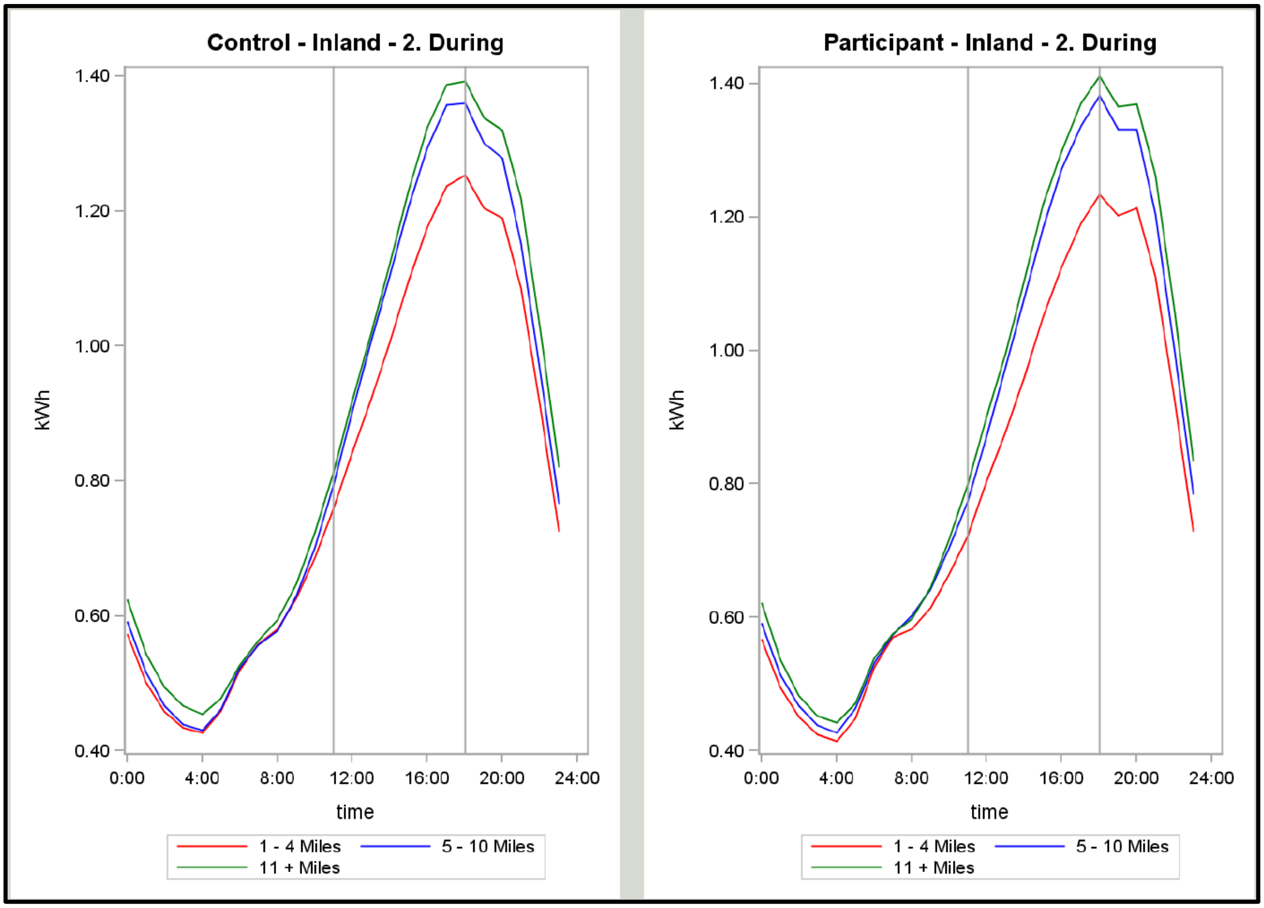
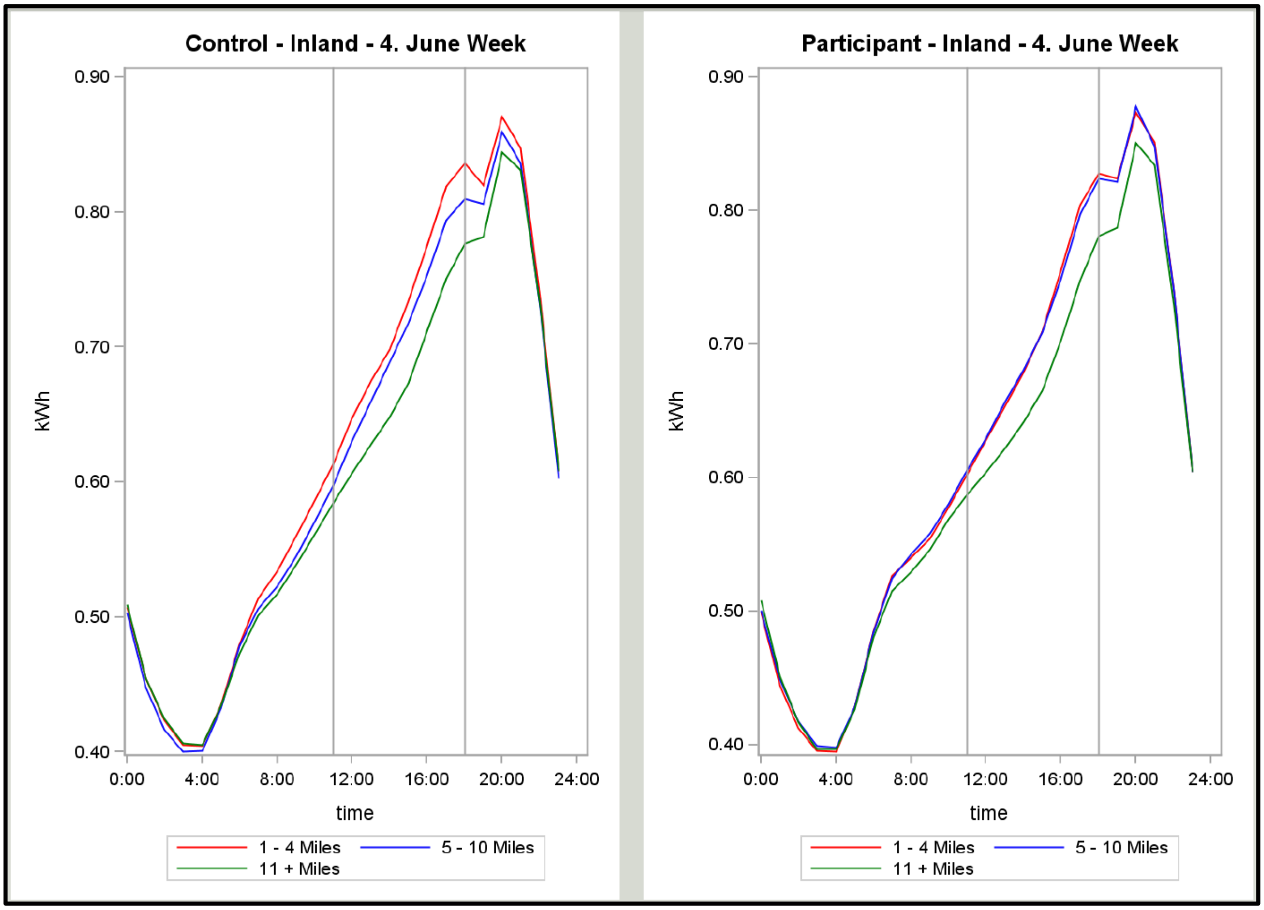


Figure 2-5: Load Profiles of Control and Participant Inland Customers during Hot June Week



2.3 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 difference in differences methodology, controlling for event hours and factors such as weather conditions, day of the week, and month.

2.3.1 PTR Ex Post Estimation

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

Expressed symbolically, the model is as follows:

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

Where

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

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

2.3.2 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.

2.3.3 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 each of the PTR event dates. Net Energy Metered participants are excluded from these counts, as they were analyzed as a separate segment. 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 0.001 and that participants with PV generation that were not identified as NEM were excluded. These counts represent the final set of participants included in the analysis.

Table 2-2: PTR Participant Counts by Analysis Stage

Date	Initial Counts	After PSM Phase 1	After PSM Phase 2
February 7th, 2014	34,169	33,299	33,103
May 14th, 2014	35,968	34,929	34,714
May 15th, 2014	36,094	35,049	34,834
July 31st, 2014	51,104	49,249	48,923
September 15th, 2014	60,404	58,026	57,643
September 16th, 2014	60,930	58,526	58,140
September 17th, 2014	61,290	58,869	58,481
Post-September 17th	64,002	61,404	61,000

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 2014, SDG&E called a total of seven PTR events and four SCTD events. Table 3-1 shows a summary of the events for both of these groups.

Table 3-1: Summary of 2014 PTR and SCTD Events

	PTR				SCTD			
Date	**Total Active Participants**	**Modeled Active Participants***	**Start Time**	**End Time**	**Total Active Participants**	**Modeled Active Participants***	**Start Time**	**End Time**
February 7th, 2014	36,894	33,103	11 a.m.	6 p.m.	-	-	-	-
May 14th, 2014	39,974	34,713	11 a.m.	6 p.m.	-	-	-	-
May 15th, 2014	40,076	34,826	11 a.m.	6 p.m.	-	-	-	-
July 31st, 2014	56,002	48,923	11 a.m.	6 p.m.	1,285	558	2 p.m.	6 p.m.
September 15th, 2014	67,189	57,643	11 a.m.	6 p.m.	2,455	1,028	2 p.m.	6 p.m.
September 16th, 2014	67,189	58,140	11 a.m.	6 p.m.	2,495	2,043	2 p.m.	6 p.m.
September 17th, 2014	67,189	58,139	11 a.m.	6 p.m.	2,554	2,091	2 p.m.	6 p.m.

* Participants included in the analysis that were not excluded due to data attrition.

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 Summer Tier,
- PTR customers without Load Control by Low Income Status,
- PTR customers without Load Control by Year of Enrollment,
- PTR customers without Load Control by Marketing Segment, and
- Net Energy Metered PTR customers without Load Control.

Table 3-2: PTR Ex Post Load Impact Estimates by Customer Category - Average 2014 Event (11 a.m. to 6 p.m.)

Customer Category	Mean Active Partic-ipants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	56,270	1.52	1.42	0.11	6.9%	5.92	88.0
Large	24,200	2.41	2.20	0.21	8.7%	5.10	88.3
Medium	19,765	1.07	1.01	0.06	5.6%	1.20	87.9
Small	11,435	0.45	0.45	0.00	1.1%	0.05	87.5
Coastal	30,599	1.38	1.29	0.10	7.0%	2.95	86.5
Inland	24,801	1.70	1.58	0.12	6.8%	2.88	89.8
No SCTD	54,757	1.51	1.41	0.11	7.2%	5.95	88.0
No Load Control (SCTD or Summer Saver)	51,855	1.50	1.40	0.10	6.7%	5.14	88.0
Summer Saver – 50% Cycling	871	2.29	2.11	0.18	7.3%	0.16	87.3
Summer Saver – 100% Cycling	2,028	2.02	1.43	0.59	28.1%	1.20	87.0
Low Income	16,199	1.35	1.31	0.04	2.8%	0.60	87.8
Non-Low Income	35,656	1.55	1.44	0.11	7.1%	3.85	88.1
Enroll. Year – 2012	24,224	1.53	1.40	0.13	8.4%	3.08	88.5
Enroll. Year – 2013	8,086	1.51	1.39	0.12	8.0%	0.96	88.5
Enroll. Year – 2014	19,545	1.47	1.40	0.07	4.5%	1.30	87.0
Notification – Email	35,765	1.52	1.41	0.10	7.0%	3.74	88.0
Notification – Text	8,049	1.40	1.34	0.06	4.4%	0.49	88.0
Notification – Both	7,251	1.54	1.41	0.13	8.7%	0.96	88.1
Summer Billing Tier 1	20,499	1.45	1.35	0.10	6.8%	2.01	87.7
Summer Billing Tier 2	4,673	1.42	1.35	0.07	5.0%	0.32	87.5
Summer Billing Tier 3	9,391	1.49	1.38	0.10	7.0%	0.97	87.8
Summer Billing Tier 4	8,700	1.53	1.47	0.06	4.1%	0.53	88.3
Summer Billing Tier 5	8,542	1.64	1.51	0.12	7.6%	1.05	88.6
Net Energy Metered	2,864	0.57	0.14	0.43	-21.3%[1]	1.23	88.4

[1] The data modeled for NEM households represented the net of grid energy used minus PV generation returned to the grid. The negative load reduction in this case reflects an increase in the amount of excess PV generation returned to the grid.

Table 3-3: SCTD Ex Post Load Impact Estimates by Customer Category - Average 2014 Event (2 p.m. to 6 p.m.)

Customer Category	Mean Active Partic-ipants	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Mean °F
All	1,887	2.70	2.09	0.61	22.9%	1.16	87.0
4 Degree Setback	923	2.58	1.93	0.65	25.6%	0.60	86.2
50% Cycling	964	2.80	2.21	0.58	20.9%	0.56	87.7
PTR	1,162	2.66	2.00	0.66	24.9%	0.77	87.1
PTR – 4 Deg. Setback	556	2.55	1.83	0.72	28.3%	0.40	86.1
PTR – 50% Cycling	606	2.76	2.14	0.62	22.5%	0.37	87.8
SCTD Only	725	2.76	2.22	0.55	20.0%	0.40	87.0
SCTD Only – 4 Degree Setback	366	2.64	2.07	0.57	21.8%	0.21	86.3
SCTD Only – 50% Cycling	359	2.87	2.34	0.53	18.6%	0.19	87.5

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. Across all 2014 events, there was a definitive load reduction during event hours (11 a.m. to 6 p.m.), averaging 0.11 kW per participant, representing an average reduction of 6.9% relative to the reference load. Average load reductions grew gradually, starting around 10 a.m. with 0.02 kW, peaking around 3-4 p.m. with 0.13 kW. In the hours following events, there are noticeable snapback effects, with an average increase in load of 0.08 kW per customer from 6 p.m. to midnight. The average aggregate load reduction during event hours was 5.92 MW. During event hours, the average temperature was 88.0°F.

Figure 3-1: Hourly Load Profile for All PTR Customers – 2014 Event Average

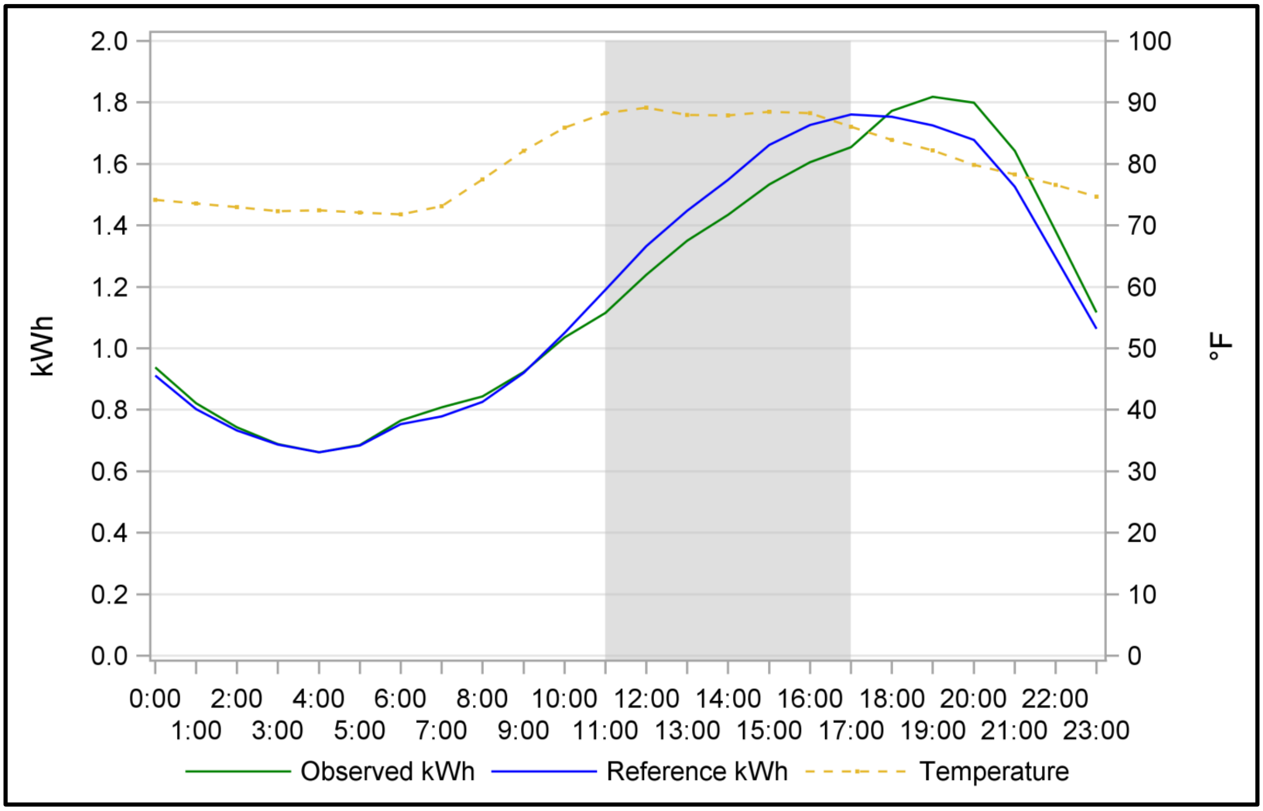


Table 3-4: Summary of Event Impacts for All PTR Customers – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	74.1	0.91	0.94	-0.026	-2.9%	56,270	-1,462
1:00	2:00	No	73.6	0.80	0.82	-0.019	-2.4%	56,270	-1,089
2:00	3:00	No	72.9	0.73	0.74	-0.010	-1.3%	56,270	-547
3:00	4:00	No	72.3	0.69	0.69	-0.002	-0.2%	56,270	-95
4:00	5:00	No	72.4	0.66	0.66	0.001	0.1%	56,270	50
5:00	6:00	No	72.1	0.68	0.69	-0.001	-0.2%	56,270	-83
6:00	7:00	No	71.8	0.75	0.77	-0.012	-1.6%	56,270	-685
7:00	8:00	No	73.1	0.78	0.81	-0.030	-3.9%	56,270	-1,702
8:00	9:00	No	77.5	0.83	0.84	-0.017	-2.1%	56,270	-963
9:00	10:00	No	82.1	0.92	0.92	-0.002	-0.3%	56,270	-133
10:00	11:00	No	85.9	1.05	1.04	0.015	1.4%	56,270	856
11:00	12:00	Yes	88.3	1.19	1.12	0.075	6.3%	56,270	4,233
12:00	13:00	Yes	89.1	1.33	1.24	0.093	7.0%	56,270	5,249
13:00	14:00	Yes	87.9	1.45	1.35	0.098	6.8%	56,270	5,522
14:00	15:00	Yes	87.9	1.55	1.43	0.114	7.4%	56,270	6,423
15:00	16:00	Yes	88.5	1.66	1.53	0.127	7.7%	56,270	7,168
16:00	17:00	Yes	88.2	1.73	1.61	0.122	7.1%	56,270	6,858
17:00	18:00	Yes	86.1	1.76	1.65	0.106	6.0%	56,270	5,961
18:00	19:00	No	83.9	1.75	1.77	-0.019	-1.1%	56,270	-1,084
19:00	20:00	No	82.2	1.73	1.82	-0.093	-5.4%	56,270	-5,206
20:00	21:00	No	79.8	1.68	1.80	-0.122	-7.3%	56,270	-6,872
21:00	22:00	No	78.3	1.53	1.64	-0.116	-7.6%	56,270	-6,554
22:00	23:00	No	76.6	1.30	1.38	-0.085	-6.5%	56,270	-4,761
23:00	24:00	No	74.7	1.06	1.12	-0.053	-5.0%	56,270	-2,998
Total - Entire Day	**-**	**-**	**80.0**	**28.52**	**28.38**	**0.144**	**0.5%**	**56,270**	**8,086**
Total - Event Hours	**-**	**-**	**88.0**	**10.67**	**9.93**	**0.736**	**6.9%**	**56,270**	**41,414**

PTR by Climate Zone

Figure 3-2 and Figure 3-3 show the hourly load profiles during 2014 events for PTR customers in the Coastal and Inland climate zones, respectively. The average temperature during event hours was 86.5°F for Coastal customers compared to 89.8°F for Inland customers. Perhaps owing to these differences in temperature, Inland participants had a higher average event hour load reduction of 0.12 kW compared to the Coastal participants' load reduction of 0.10 kW. However, Coastal participants had a higher aggregate reduction of 2.95 MW (7.0%) relative to the reference load, whereas the Inland participants had an aggregate reduction of 2.88 MW (6.8%), due to there being slightly more participants in the Coastal climate zone.

Figure 3-2: Hourly Load Profile for Coastal PTR Customers – 2014 Event Average

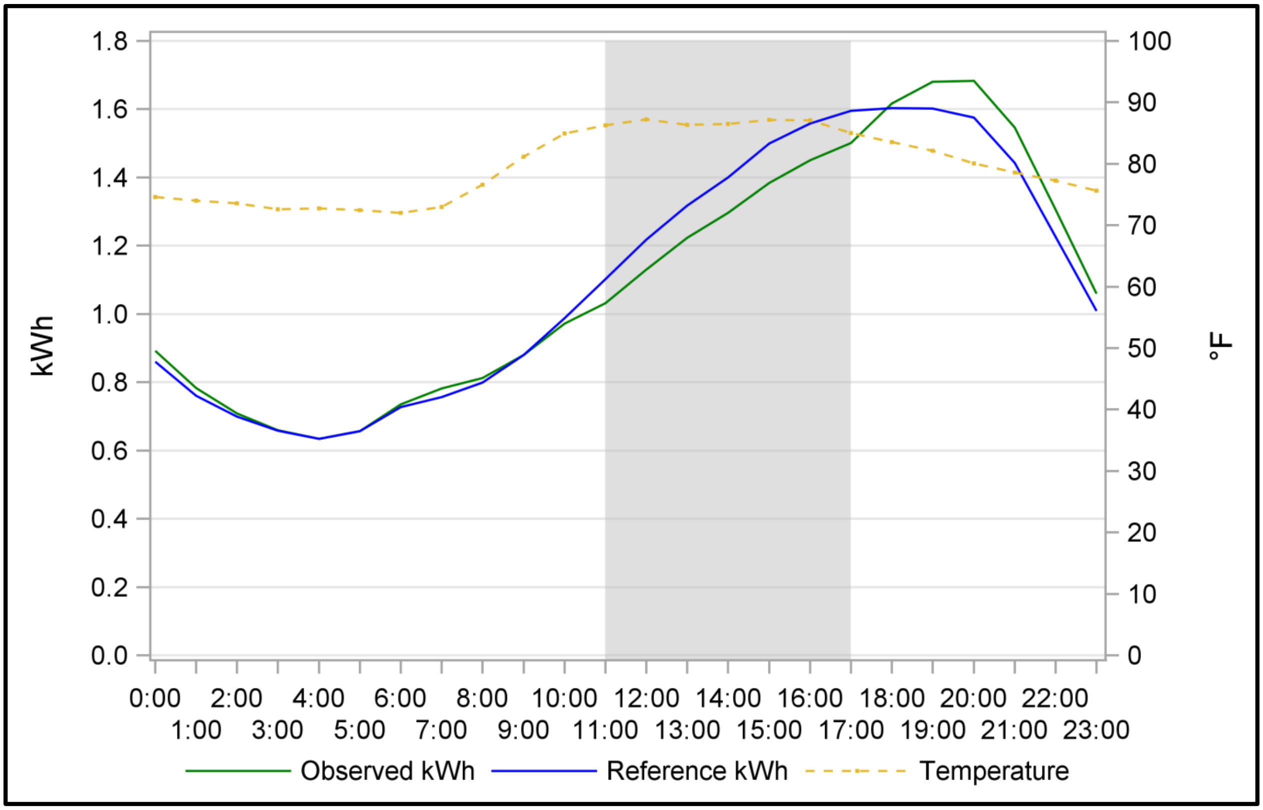
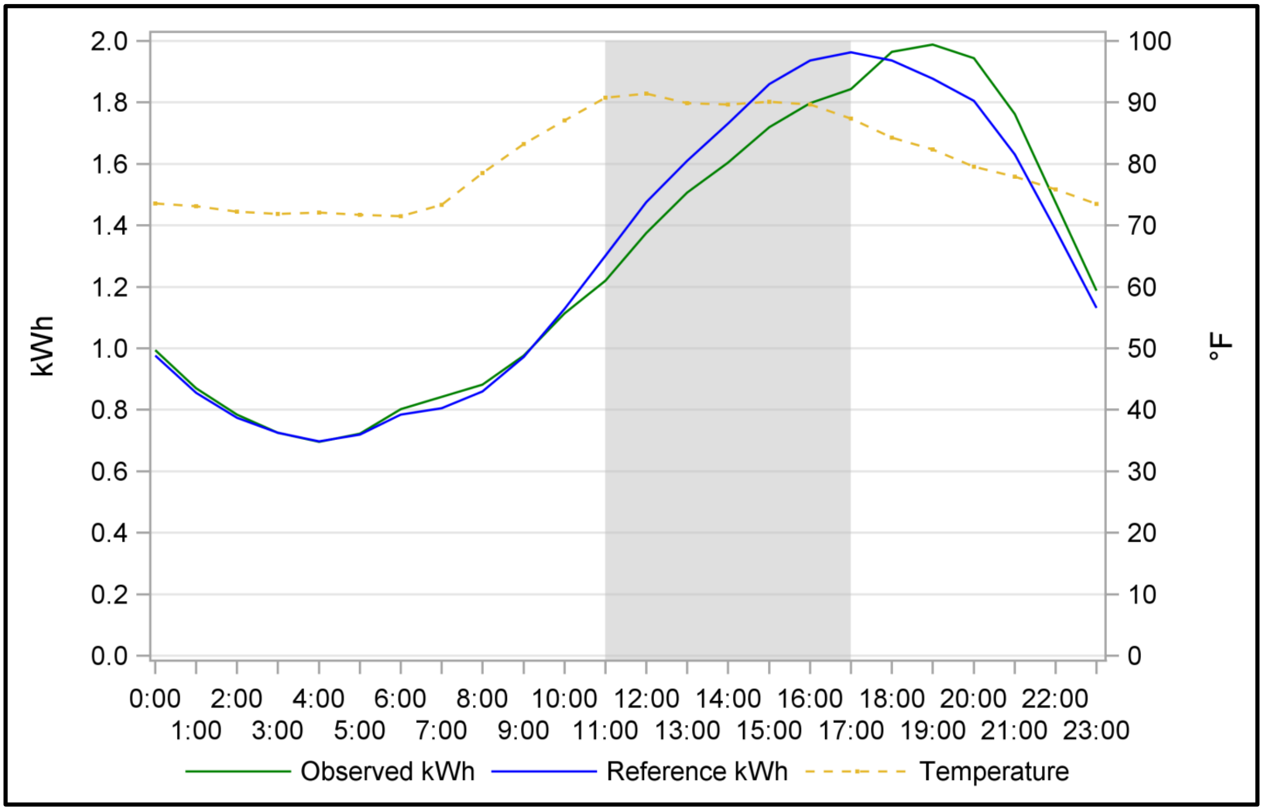


Figure 3-3: Hourly Load Profile for Inland PTR Customers – 2014 Event Average



PTR by Usage Size

There are three size categories defined for SDG&E customers based on their consumption – Small, Medium, and Large. Figure 3-4, Figure 3-5, and Figure 3-6 show the hourly load profiles during 2014 events for these three sets of customers. There are marked differences between each of them. Large participants had an average event hour load reduction of 0.21 kW, representing a total reduction of 5.10 MW (8.8%). Medium participants had an average event hour load reduction of 0.06 kW, representing a total reduction of 1.20 MW (5.7%). Lastly, Small participants had essentially no load reduction during event hours, with an average of 0.005 kW, representing a total reduction of 0.05 MW (1.0%). However, Small customers do show a considerable increase in consumption in the hours after an event, with an average rise of 12.5% in these hours relative to the reference load.

Figure 3-4: Hourly Load Profile for Large PTR Customers – 2014 Event Average

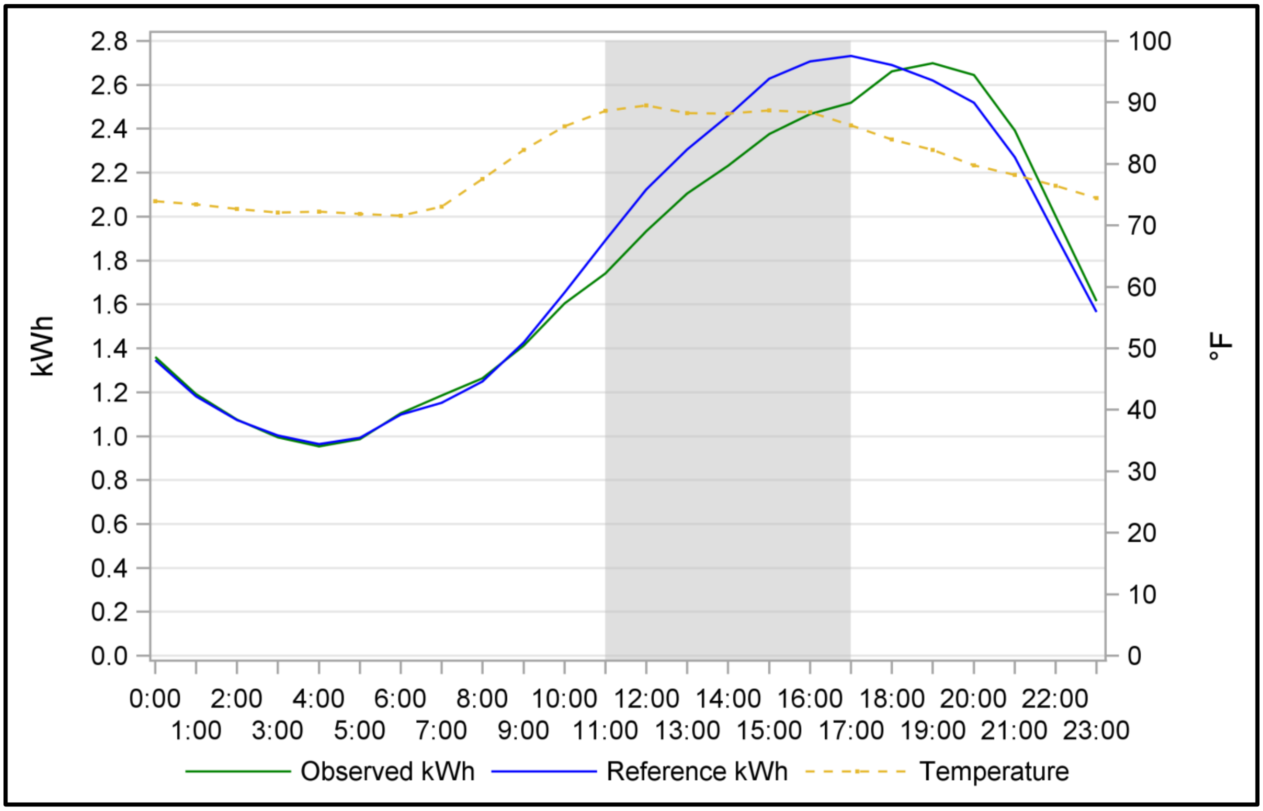


Figure 3-5: Hourly Load Profile for Medium PTR Customers – 2014 Event Average

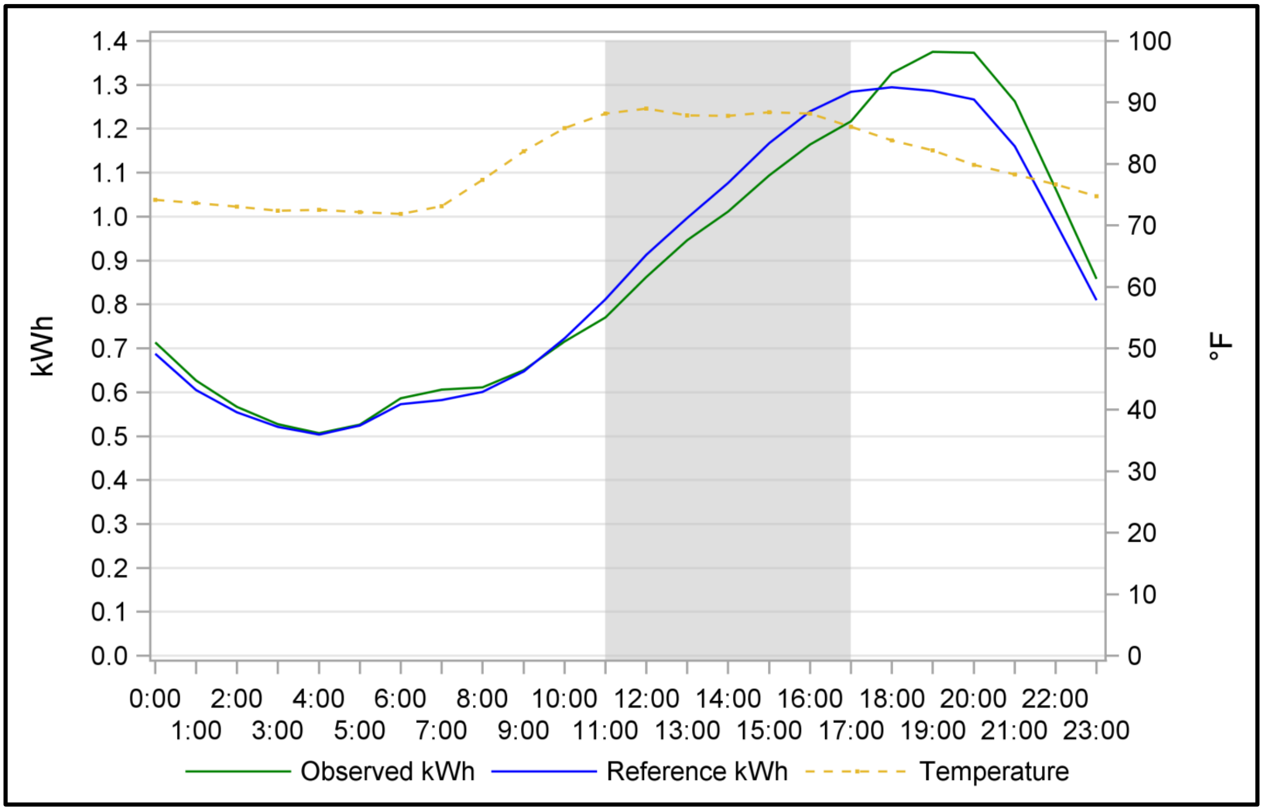
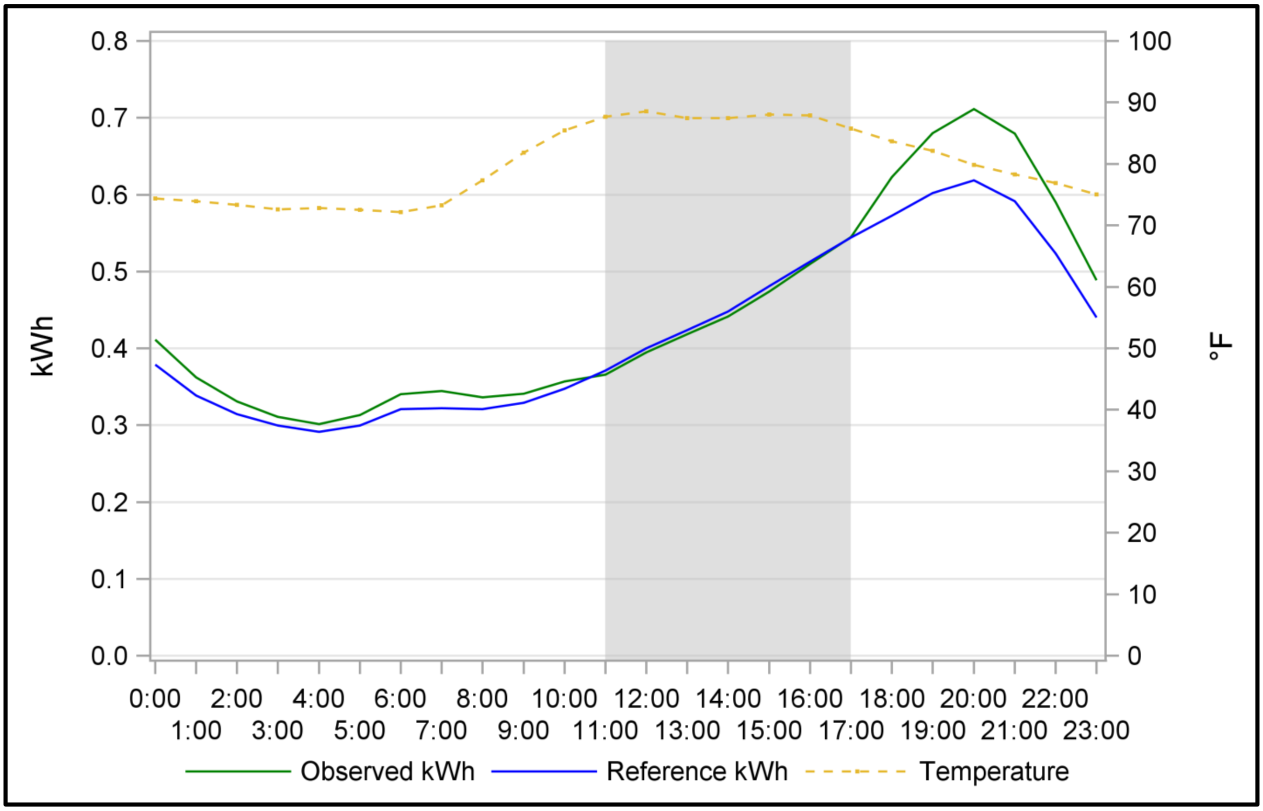


Figure 3-6: Hourly Load Profile for Small PTR Customers – 2014 Event Average



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 also enrolled in the SCTD thermostat program. Although there were overlapping events between the two programs, there were much fewer SCTD participants than PTR participants. Therefore, the differences in load reduction between the overall PTR population and the PTR without SCTD population are relatively small. The average event hour load reduction for this latter group is the same at 0.11 kW. However, compared to their respective reference loads, the PTR without SCTD group had a slightly higher average aggregate event hour reduction with 5.95 MW (7.2%) than the overall PTR group, with 5.92 MW (6.9%).

Figure 3-7: Hourly Load Profile for PTR Customers without SCTD – 2014 Event Average

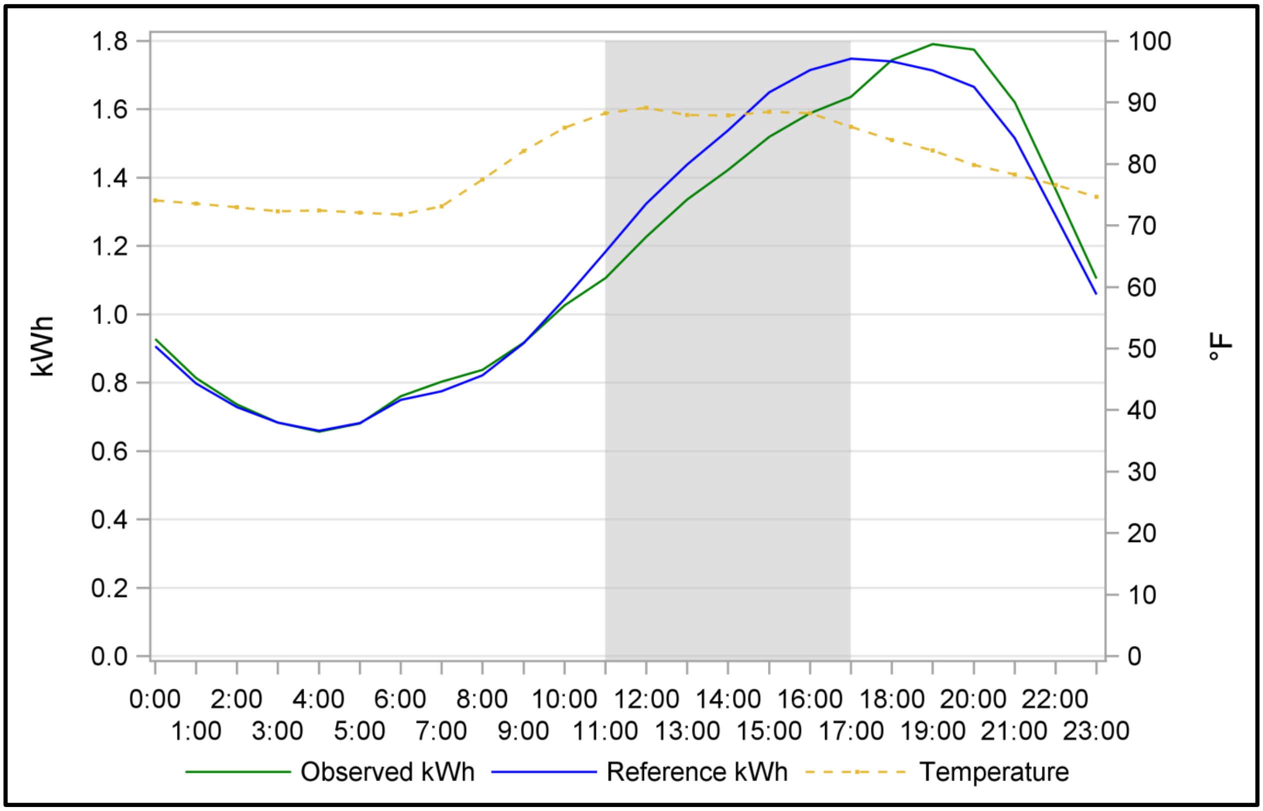


Table 3-5: Summary of Event Impacts for PTR Customers without SCTD – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	74.1	0.91	0.93	-0.022	-2.4%	54,757	-1,197
1:00	2:00	No	73.6	0.80	0.81	-0.015	-1.9%	54,757	-847
2:00	3:00	No	72.9	0.73	0.74	-0.007	-1.0%	54,757	-395
3:00	4:00	No	72.3	0.68	0.68	0.000	0.0%	54,757	1
4:00	5:00	No	72.4	0.66	0.66	0.002	0.3%	54,757	119
5:00	6:00	No	72.1	0.68	0.68	0.001	0.2%	54,757	64
6:00	7:00	No	71.8	0.75	0.76	-0.010	-1.4%	54,757	-563
7:00	8:00	No	73.1	0.78	0.80	-0.028	-3.5%	54,757	-1,507
8:00	9:00	No	77.5	0.82	0.84	-0.016	-1.9%	54,757	-866
9:00	10:00	No	82.1	0.92	0.92	-0.001	-0.1%	54,757	-29
10:00	11:00	No	85.9	1.04	1.03	0.017	1.7%	54,757	951
11:00	12:00	Yes	88.3	1.18	1.11	0.078	6.5%	54,757	4,244
12:00	13:00	Yes	89.1	1.32	1.23	0.096	7.3%	54,757	5,266
13:00	14:00	Yes	87.9	1.44	1.34	0.102	7.1%	54,757	5,610
14:00	15:00	Yes	87.9	1.54	1.42	0.115	7.5%	54,757	6,305
15:00	16:00	Yes	88.5	1.65	1.52	0.131	7.9%	54,757	7,147
16:00	17:00	Yes	88.2	1.72	1.59	0.127	7.4%	54,757	6,929
17:00	18:00	Yes	86.1	1.75	1.64	0.112	6.4%	54,757	6,148
18:00	19:00	No	83.9	1.74	1.74	-0.004	-0.2%	54,757	-209
19:00	20:00	No	82.2	1.71	1.79	-0.078	-4.6%	54,757	-4,269
20:00	21:00	No	79.8	1.67	1.77	-0.109	-6.5%	54,757	-5,949
21:00	22:00	No	78.3	1.52	1.62	-0.105	-6.9%	54,757	-5,729
22:00	23:00	No	76.6	1.29	1.37	-0.078	-6.0%	54,757	-4,251
23:00	24:00	No	74.7	1.06	1.10	-0.047	-4.4%	54,757	-2,569
Total - Entire Day	**-**	**-**	**80.0**	**28.34**	**28.08**	**0.263**	**0.9%**	**54,757**	**14,405**
Total - Event Hours	**-**	**-**	**88.0**	**10.60**	**9.84**	**0.761**	**7.2%**	**54,757**	**41,648**

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 0.10 kW, which was lower than the 0.11 kW for the overall PTR group. The average aggregate load reduction during event hours was 5.14 MW (6.6%), which was also lower than the overall group. This suggests that the load control programs did have an effect on reducing the overall system load, which will be explored in the subsequent sections.

Figure 3-8: Hourly Load Profile for PTR Customers without Any Load Control – 2014 Event Average

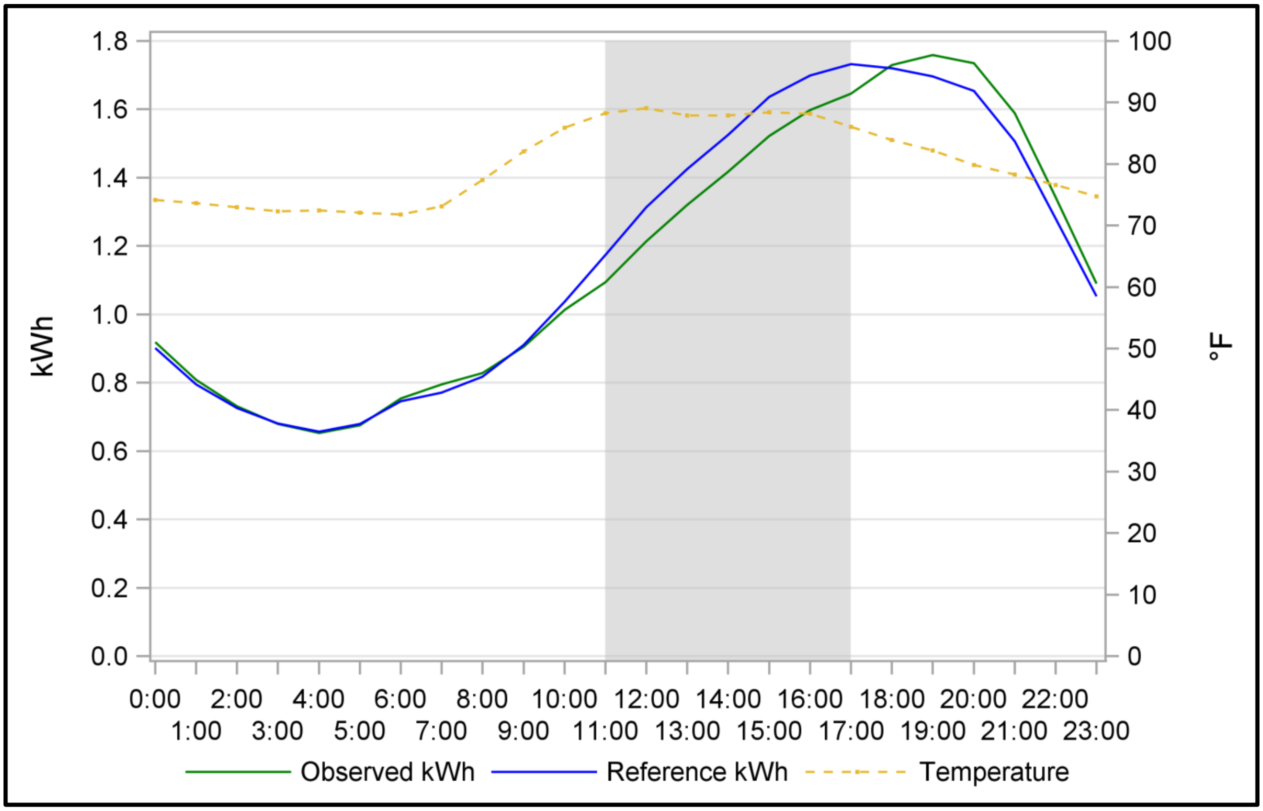


Table 3-6: Summary of Event Impacts for PTR Customers without Any Load Control – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	74.1	0.90	0.92	-0.018	-2.0%	51,855	-951
1:00	2:00	No	73.6	0.80	0.81	-0.013	-1.6%	51,855	-651
2:00	3:00	No	73.0	0.73	0.73	-0.005	-0.7%	51,855	-255
3:00	4:00	No	72.3	0.68	0.68	0.002	0.2%	51,855	82
4:00	5:00	No	72.4	0.66	0.65	0.003	0.5%	51,855	178
5:00	6:00	No	72.1	0.68	0.68	0.003	0.5%	51,855	181
6:00	7:00	No	71.8	0.75	0.75	-0.007	-1.0%	51,855	-385
7:00	8:00	No	73.1	0.77	0.80	-0.024	-3.1%	51,855	-1,249
8:00	9:00	No	77.4	0.82	0.83	-0.010	-1.3%	51,855	-536
9:00	10:00	No	82.1	0.91	0.91	0.005	0.5%	51,855	256
10:00	11:00	No	85.9	1.04	1.01	0.023	2.2%	51,855	1,192
11:00	12:00	Yes	88.2	1.17	1.09	0.081	6.9%	51,855	4,184
12:00	13:00	Yes	89.1	1.31	1.21	0.099	7.6%	51,855	5,149
13:00	14:00	Yes	87.9	1.43	1.32	0.105	7.4%	51,855	5,446
14:00	15:00	Yes	87.9	1.53	1.42	0.109	7.1%	51,855	5,630
15:00	16:00	Yes	88.4	1.64	1.52	0.114	6.9%	51,855	5,888
16:00	17:00	Yes	88.2	1.70	1.60	0.101	5.9%	51,855	5,214
17:00	18:00	Yes	86.0	1.73	1.65	0.086	5.0%	51,855	4,466
18:00	19:00	No	83.9	1.72	1.73	-0.009	-0.5%	51,855	-480
19:00	20:00	No	82.2	1.70	1.76	-0.063	-3.7%	51,855	-3,259
20:00	21:00	No	79.8	1.65	1.74	-0.081	-4.9%	51,855	-4,191
21:00	22:00	No	78.3	1.51	1.59	-0.083	-5.5%	51,855	-4,280
22:00	23:00	No	76.6	1.28	1.34	-0.062	-4.9%	51,855	-3,233
23:00	24:00	No	74.7	1.05	1.09	-0.038	-3.6%	51,855	-1,956
Total - Entire Day	**-**	**-**	**80.0**	**28.14**	**27.82**	**0.317**	**1.1%**	**51,855**	**16,438**
Total - Event Hours	**-**	**-**	**88.0**	**10.51**	**9.81**	**0.694**	**6.6%**	**51,855**	**35,976**

3.1.4 PTR Dually Enrolled in Summer Saver

As referenced previously, 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. Figure 3-9 and Table 3-7 show the hourly event load impacts for these dually enrolled customers. Their average event hour load reduction (during PTR event hours) was 0.47 kW, which is about four times higher than the overall PTR group. This is most likely due to the automatic triggering of the AC cycling technology compared to the optional PTR demand response during events. There was a sharp drop in load when the Summer Saver events began, resulting in an average reduction of 0.71 kW between 2 p.m. and 6 p.m. These larger savings resulted in an average aggregate load reduction during event hours of 1.37 MW, representing a 22.4% reduction compared to the reference load. This group also experienced a large snapback effect in the post-event hours, with an average increase of 20.9% from 6 p.m. to midnight.

Figure 3-9: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – All – 2014 Event Average

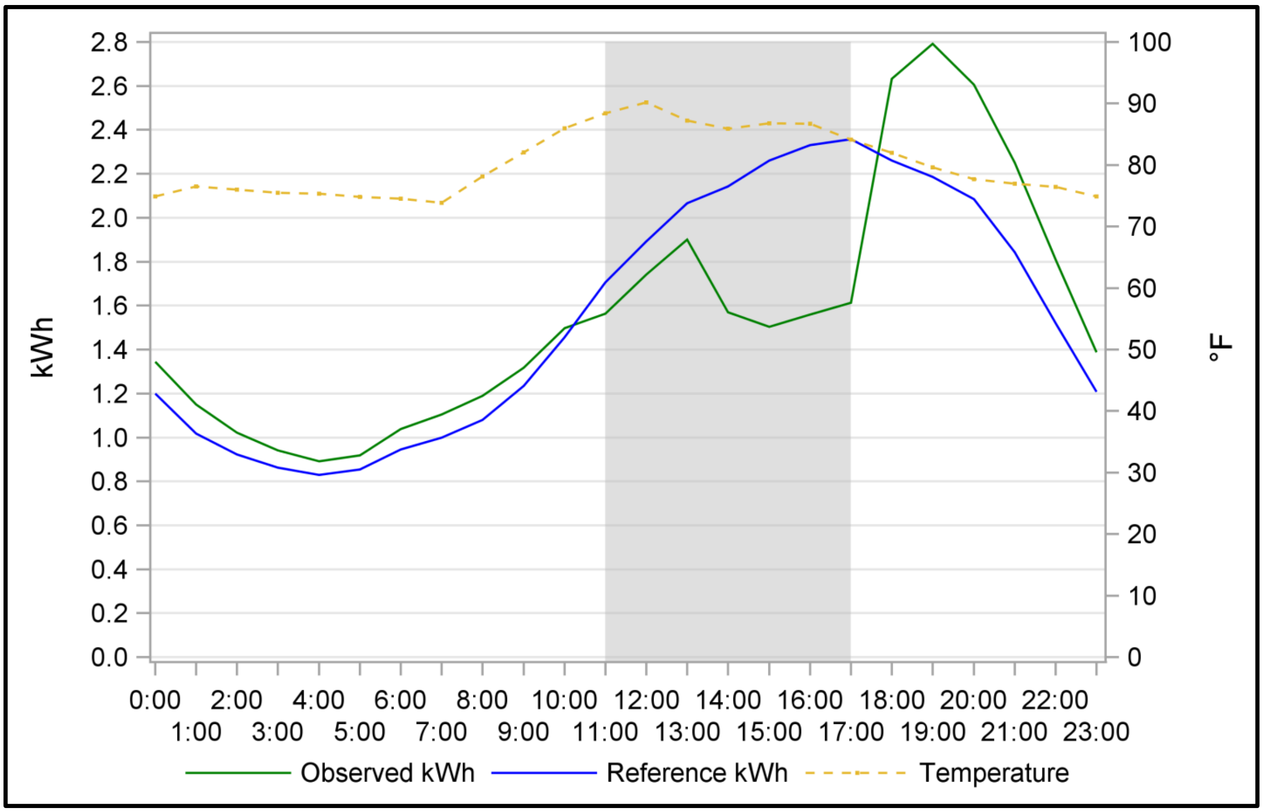


Table 3-7: Summary of Event Impacts for PTR Customers Dually Enrolled in Summer Saver – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	74.9	1.20	1.34	-0.145	-12.1%	2,902	-420
1:00	2:00	No	76.5	1.02	1.15	-0.133	-13.0%	2,902	-385
2:00	3:00	No	76.0	0.92	1.02	-0.100	-10.9%	2,902	-290
3:00	4:00	No	75.5	0.86	0.94	-0.078	-9.0%	2,902	-225
4:00	5:00	No	75.3	0.83	0.89	-0.062	-7.4%	2,902	-179
5:00	6:00	No	74.8	0.85	0.92	-0.064	-7.5%	2,902	-186
6:00	7:00	No	74.5	0.95	1.04	-0.092	-9.8%	2,902	-268
7:00	8:00	No	73.9	1.00	1.10	-0.106	-10.6%	2,902	-308
8:00	9:00	No	78.1	1.08	1.19	-0.111	-10.3%	2,902	-322
9:00	10:00	No	82.1	1.23	1.32	-0.084	-6.8%	2,902	-244
10:00	11:00	No	85.9	1.46	1.50	-0.041	-2.8%	2,902	-120
11:00	12:00	Yes	88.4	1.71	1.56	0.142	8.3%	2,902	413
12:00	13:00	Yes	90.2	1.89	1.74	0.152	8.0%	2,902	441
13:00	14:00	Yes	87.3	2.07	1.90	0.166	8.0%	2,902	483
14:00	15:00	Yes	85.9	2.14	1.57	0.572	26.7%	2,902	1,660
15:00	16:00	Yes	86.8	2.26	1.50	0.756	33.5%	2,902	2,195
16:00	17:00	Yes	86.7	2.33	1.56	0.771	33.1%	2,902	2,237
17:00	18:00	Yes	84.1	2.36	1.61	0.744	31.6%	2,902	2,159
18:00	19:00	No	82.0	2.26	2.63	-0.372	-16.4%	2,902	-1,078
19:00	20:00	No	79.6	2.19	2.79	-0.607	-27.8%	2,902	-1,762
20:00	21:00	No	77.7	2.08	2.61	-0.522	-25.0%	2,902	-1,514
21:00	22:00	No	76.9	1.84	2.25	-0.408	-22.1%	2,902	-1,184
22:00	23:00	No	76.4	1.52	1.81	-0.289	-19.0%	2,902	-838
23:00	24:00	No	74.9	1.21	1.39	-0.181	-15.0%	2,902	-526
Total - Entire Day	**-**	**-**	**80.2**	**37.25**	**37.34**	**-0.090**	**-0.2%**	**2,902**	**-261**
Total - Event Hours	**-**	**-**	**87.0**	**14.75**	**11.45**	**3.304**	**22.4%**	**2,902**	**9,588**

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%. The participants with 50% cycling experienced an average load reduction of 0.18 kW during PTR event hours, while those with 100% cycling had an average of 0.59 kW. The 50% group showed no reduction during the first two hours of the PTR event, only realizing a reduction after the onset of the Summer Saver event.

Figure 3-10: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – 50% Cycling – 2014 Event Average

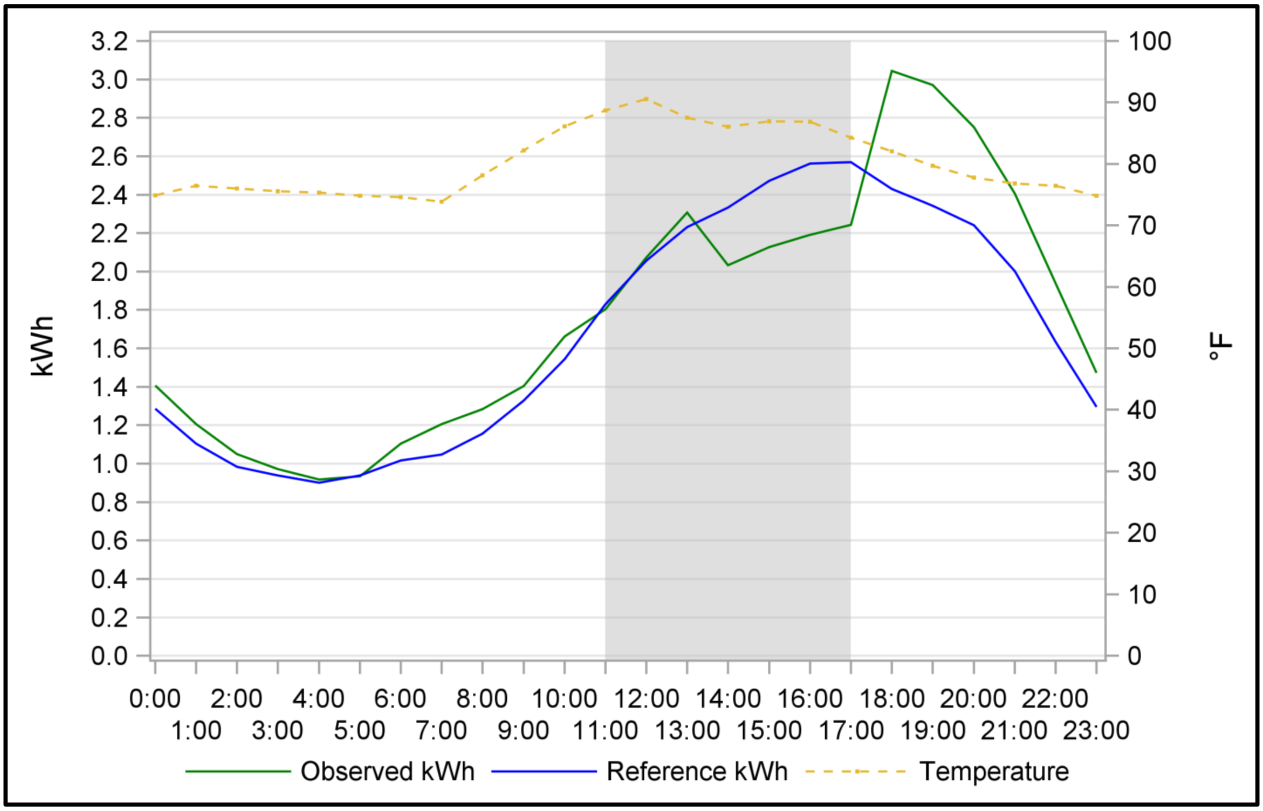
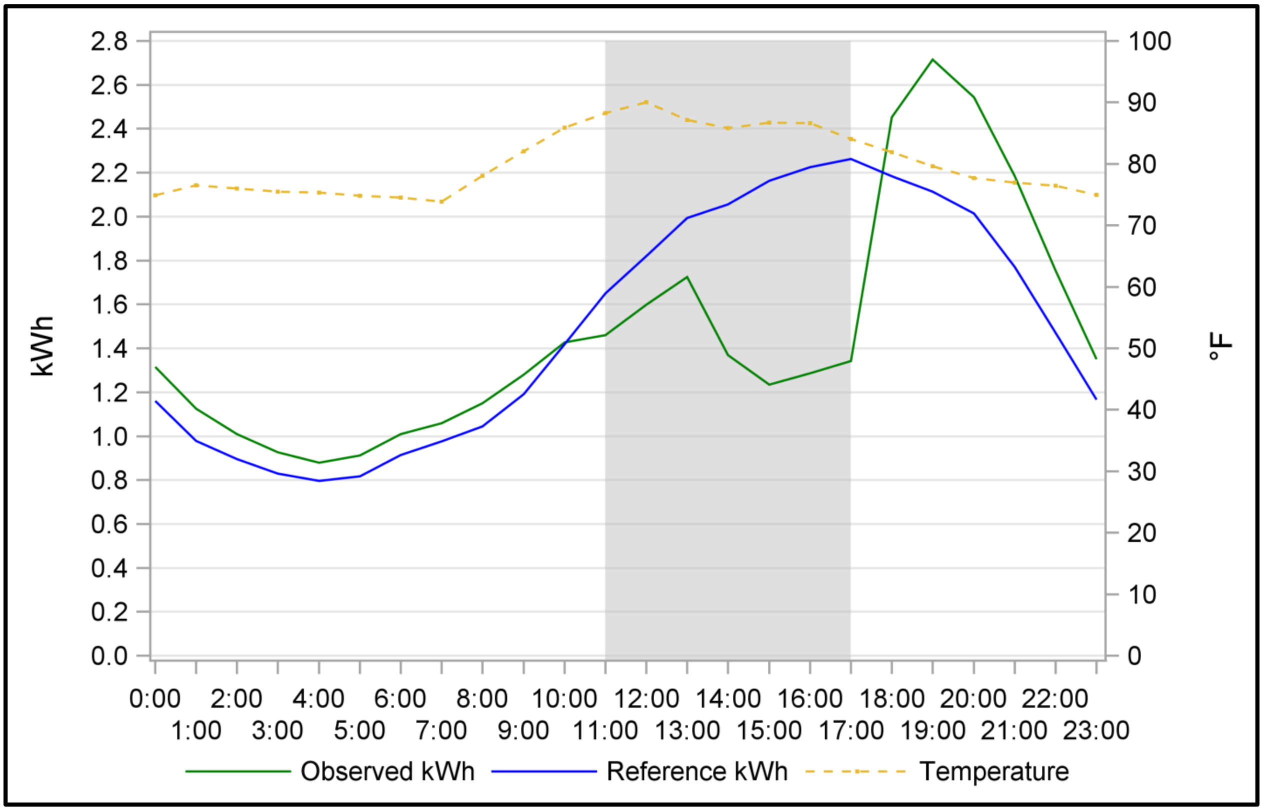


Figure 3-11: Hourly Load Profile for PTR Customers Dually Enrolled in Summer Saver – 100% Cycling – 2014 Event Average



3.1.5 PTR Dually Enrolled in SCTD

SDG&E PTR customers are also eligible to participate in the SCTD program, which involves demand response enabling thermostats signaled through Wi-Fi. Two cycling strategies were tested on PTR-SCTD event days – four degree thermostat setback and 50% AC cycling. The SCTD event hour window was only 4 hours long, from 2 p.m. to 6 p.m. Since the SCTD program was new in 2014, there were a limited number of participants in its first year. 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 hours following. The average event hour load reduction for this group (during PTR event hours) was 0.52 kW, which is about four to five times higher than the overall PTR group, and comparable to the dually enrolled Summer Saver group. The average load reduction was 0.66 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 0.34 kW, which was higher than the average for PTR participants without any load control devices. The average aggregate load reduction was 0.61 MW during PTR event hours, representing 20.9% of the reference load. The average aggregate reduction during SCTD event hours was 0.77 MW, or

24.7%. Lastly, the average aggregate reduction during the PTR-only hours was 0.40 MW, or 15.7%.

Figure 3-12: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 2014 Event Average

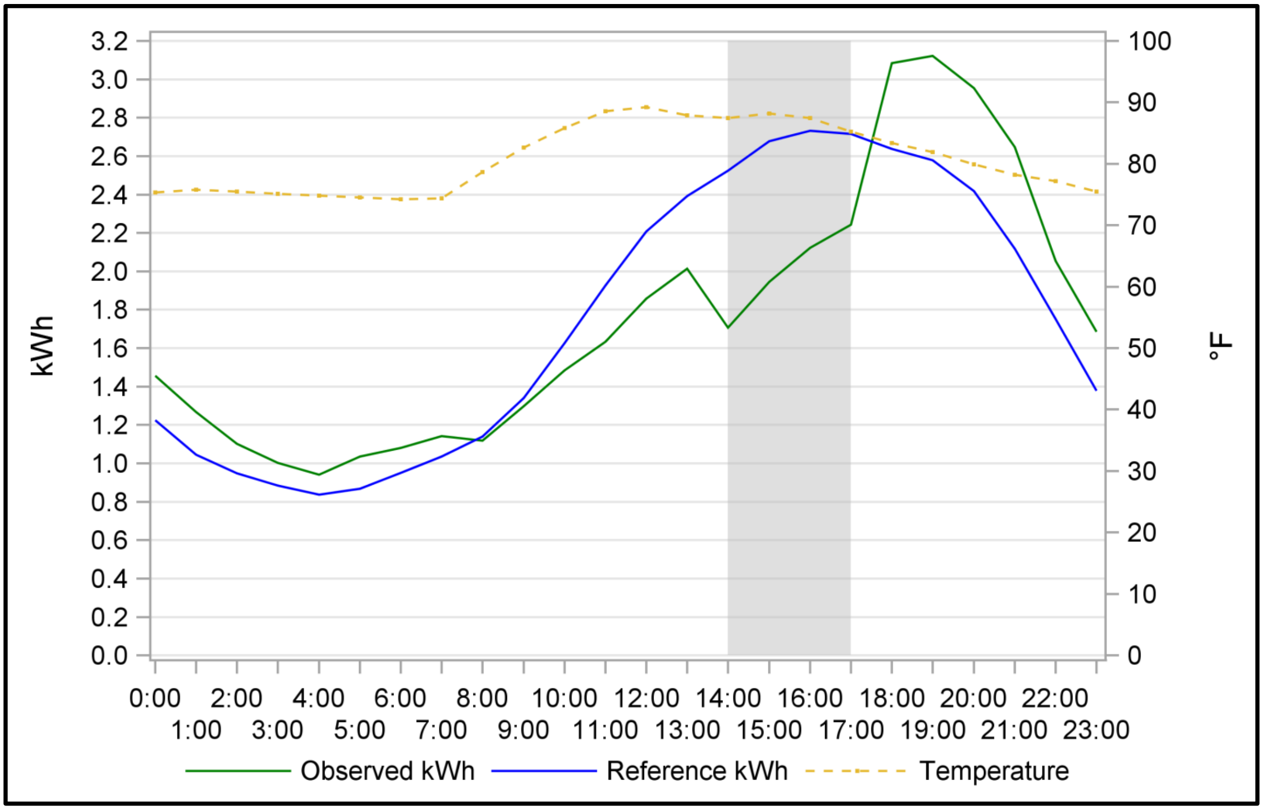


Table 3-8: Summary of Event Impacts for PTR Customers Dually Enrolled in SCTD – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	75.3	1.22	1.46	-0.233	-19.0%	1,162	-271
1:00	2:00	No	75.8	1.05	1.27	-0.220	-21.0%	1,162	-255
2:00	3:00	No	75.5	0.95	1.10	-0.156	-16.5%	1,162	-181
3:00	4:00	No	75.1	0.88	1.00	-0.119	-13.4%	1,162	-138
4:00	5:00	No	74.8	0.84	0.94	-0.104	-12.4%	1,162	-120
5:00	6:00	No	74.6	0.87	1.04	-0.168	-19.4%	1,162	-195
6:00	7:00	No	74.2	0.95	1.08	-0.130	-13.7%	1,162	-151
7:00	8:00	No	74.4	1.04	1.14	-0.106	-10.2%	1,162	-123
8:00	9:00	No	78.6	1.14	1.12	0.021	1.8%	1,162	24
9:00	10:00	No	82.6	1.34	1.30	0.042	3.2%	1,162	49
10:00	11:00	No	85.8	1.63	1.48	0.142	8.7%	1,162	165
11:00	12:00	No	88.6	1.93	1.63	0.293	15.2%	1,162	340
12:00	13:00	No	89.2	2.21	1.86	0.351	15.9%	1,162	408
13:00	14:00	No	87.9	2.39	2.01	0.378	15.8%	1,162	439
14:00	15:00	Yes	87.4	2.52	1.71	0.818	32.4%	1,162	950
15:00	16:00	Yes	88.2	2.68	1.95	0.732	27.3%	1,162	850
16:00	17:00	Yes	87.5	2.73	2.12	0.611	22.3%	1,162	709
17:00	18:00	Yes	85.2	2.72	2.24	0.475	17.5%	1,162	551
18:00	19:00	No	83.4	2.64	3.08	-0.447	-17.0%	1,162	-519
19:00	20:00	No	81.9	2.58	3.12	-0.543	-21.1%	1,162	-631
20:00	21:00	No	79.9	2.42	2.95	-0.536	-22.2%	1,162	-623
21:00	22:00	No	78.2	2.12	2.65	-0.530	-25.0%	1,162	-616
22:00	23:00	No	77.2	1.75	2.05	-0.301	-17.2%	1,162	-350
23:00	24:00	No	75.5	1.38	1.69	-0.308	-22.4%	1,162	-358
Total - Entire Day	**-**	**-**	**80.7**	**41.95**	**41.99**	**-0.039**	**-0.1%**	**1,162**	**-45**
Total - Event Hours	**-**	**-**	**87.1**	**10.65**	**8.02**	**2.635**	**24.7%**	**1,162**	**3,061**

PTR Dually Enrolled in SCTD, by Cycling Strategy

Figure 3-13 and Figure 3-14 show the hourly event load impacts for dually enrolled PTR and SCTD participants, by cycling strategy. During SCTD event hours, the 4 degree setback group had a higher average hourly load reduction of 0.72 kW (28.1%) compared to the 50% cycling group, which had an average of 0.62 kW (22.4%).

Figure 3-13: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 4 Degree Setback – 2014 Event Average

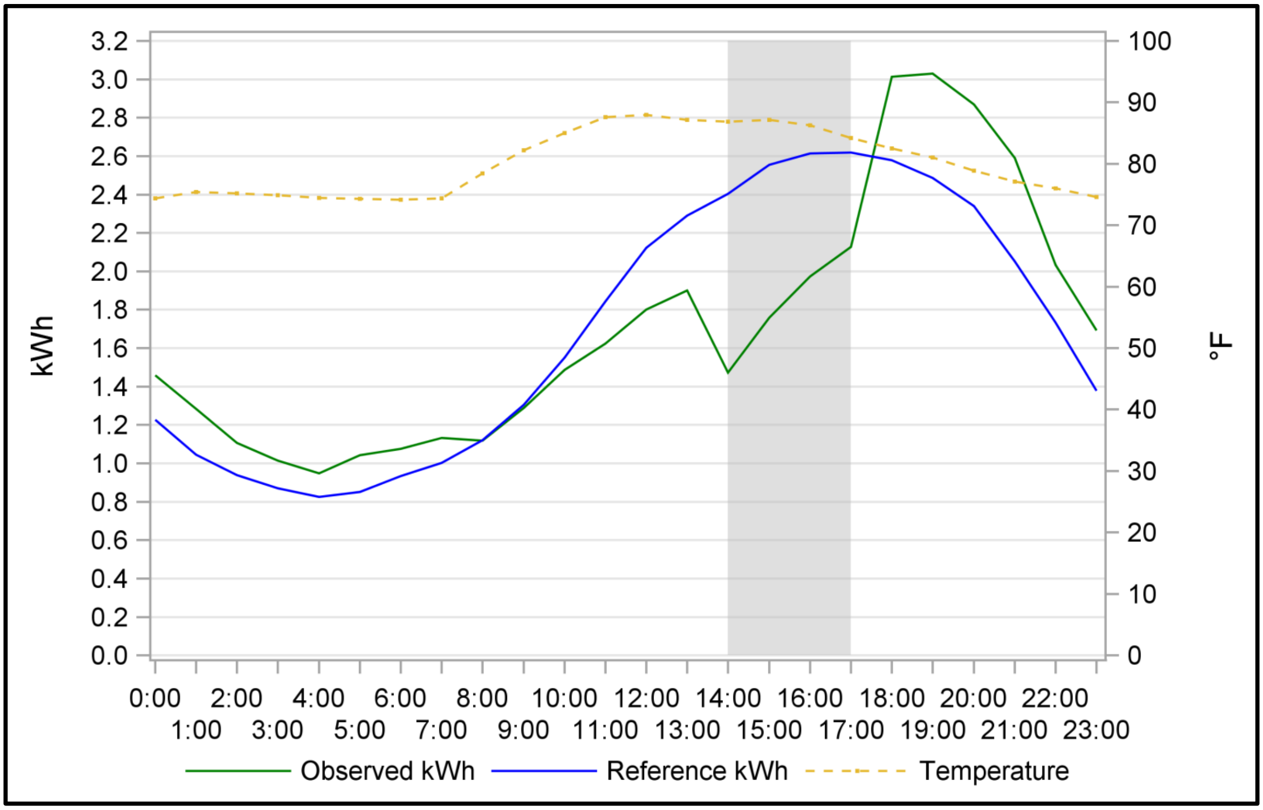
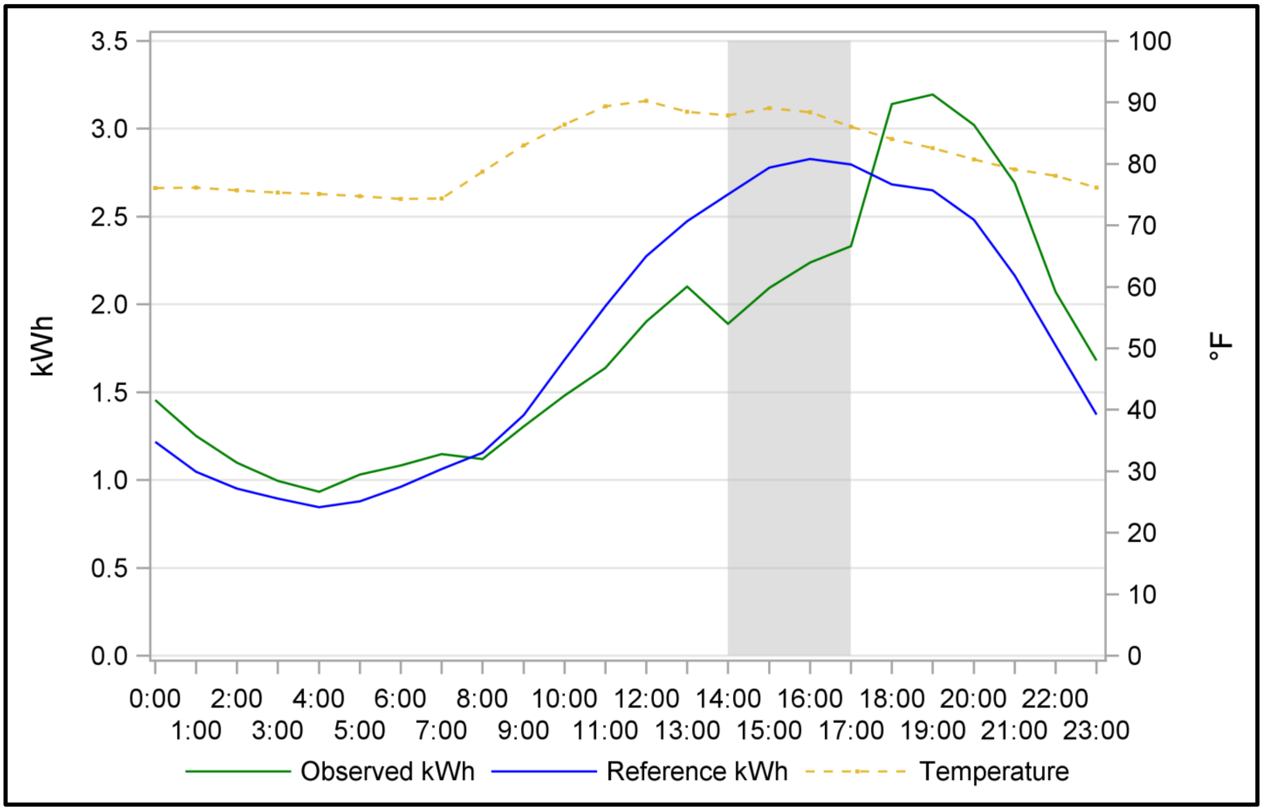


Figure 3-14: Hourly Load Profile for PTR Customers Dually Enrolled in SCTD – 50% Cycling – 2014 Event Average



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 few participants in this group, as it was comprised of those customers that received a thermostat but did not opt-in to the PTR program. These participants still had a 4 degree setback or 50% AC cycling on PTR-SCTD event days. During SCTD event hours, their average load reduction was 0.55 kW, which is in line with the dually-enrolled PTR-SCTD participants. The average aggregate impact during the event hours was 0.40 MW, representing 19.8% of the reference load. The group showed snapback effects averaging 16.9% during the hours following the SCTD event.

Figure 3-15: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 2014 Event Average

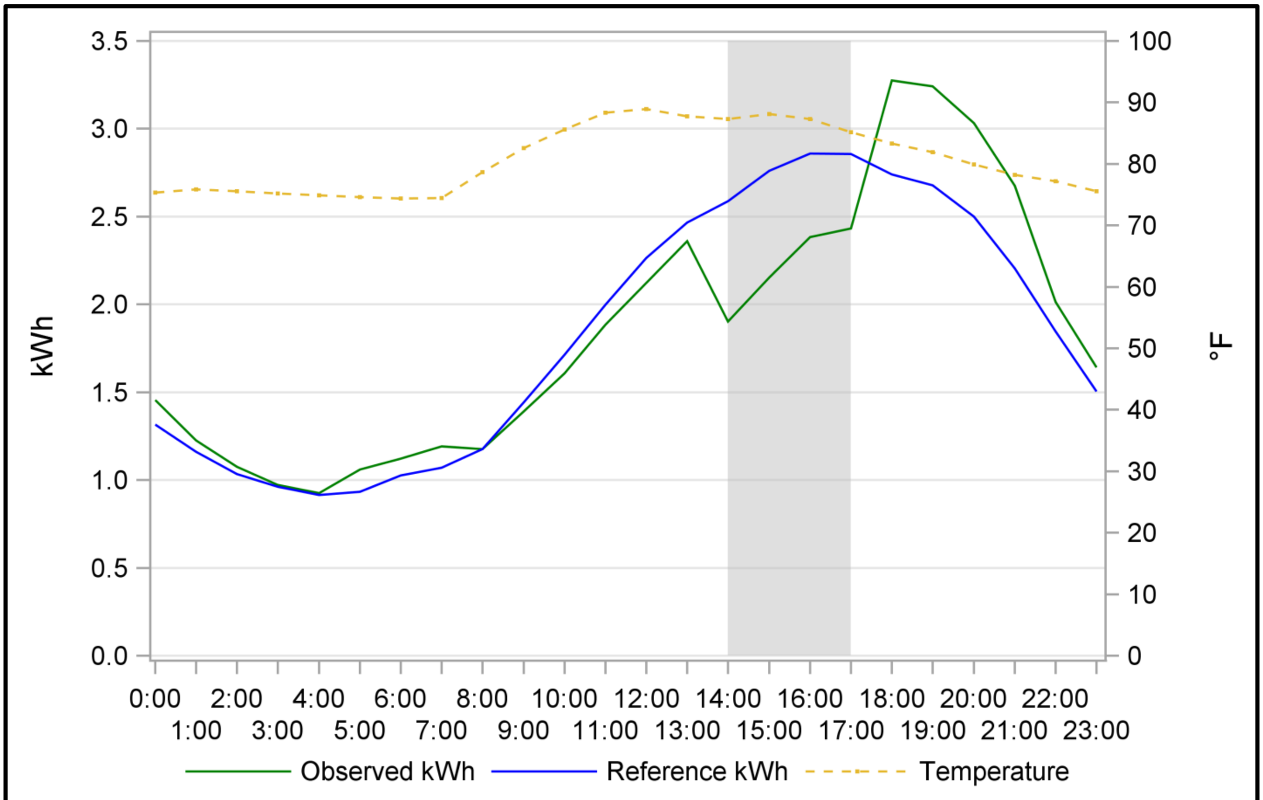


Table 3-9: Summary of Event Impacts for SCTD Customers Not Enrolled in PTR – 2014 Average

Hour Beg.	Hour End.	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	75.3	1.32	1.45	-0.140	-10.6%	725	-101
1:00	2:00	No	75.9	1.16	1.23	-0.065	-5.6%	725	-47
2:00	3:00	No	75.6	1.03	1.07	-0.040	-3.9%	725	-29
3:00	4:00	No	75.2	0.96	0.97	-0.010	-1.1%	725	-7
4:00	5:00	No	74.9	0.91	0.93	-0.012	-1.3%	725	-9
5:00	6:00	No	74.6	0.93	1.06	-0.127	-13.6%	725	-92
6:00	7:00	No	74.4	1.03	1.12	-0.098	-9.5%	725	-71
7:00	8:00	No	74.5	1.07	1.19	-0.121	-11.3%	725	-88
8:00	9:00	No	78.6	1.18	1.18	-0.002	-0.2%	725	-2
9:00	10:00	No	82.5	1.44	1.39	0.053	3.7%	725	39
10:00	11:00	No	85.6	1.71	1.61	0.106	6.2%	725	77
11:00	12:00	No	88.3	2.00	1.88	0.116	5.8%	725	84
12:00	13:00	No	88.9	2.26	2.12	0.141	6.2%	725	102
13:00	14:00	No	87.7	2.46	2.36	0.104	4.2%	725	76
14:00	15:00	Yes	87.3	2.59	1.90	0.683	26.4%	725	495
15:00	16:00	Yes	88.1	2.76	2.15	0.606	22.0%	725	439
16:00	17:00	Yes	87.3	2.86	2.38	0.475	16.6%	725	344
17:00	18:00	Yes	85.2	2.86	2.43	0.424	14.8%	725	307
18:00	19:00	No	83.3	2.74	3.27	-0.534	-19.5%	725	-387
19:00	20:00	No	81.9	2.68	3.24	-0.563	-21.0%	725	-408
20:00	21:00	No	79.9	2.50	3.03	-0.532	-21.3%	725	-386
21:00	22:00	No	78.2	2.21	2.68	-0.471	-21.3%	725	-341
22:00	23:00	No	77.2	1.85	2.01	-0.167	-9.1%	725	-121
23:00	24:00	No	75.6	1.50	1.64	-0.136	-9.1%	725	-99
Total - Entire Day	**-**	**-**	**80.7**	**44.01**	**44.32**	**-0.308**	**-0.7%**	**725**	**-223**
Total - Event Hours	**-**	**-**	**87.0**	**11.06**	**8.87**	**2.189**	**19.8%**	**725**	**1,586**

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 0.53 kW (18.5%) while the latter had an average of 0.57 kW (21.5%).

Figure 3-16: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 4 Degree Setback – 2014 Event Average

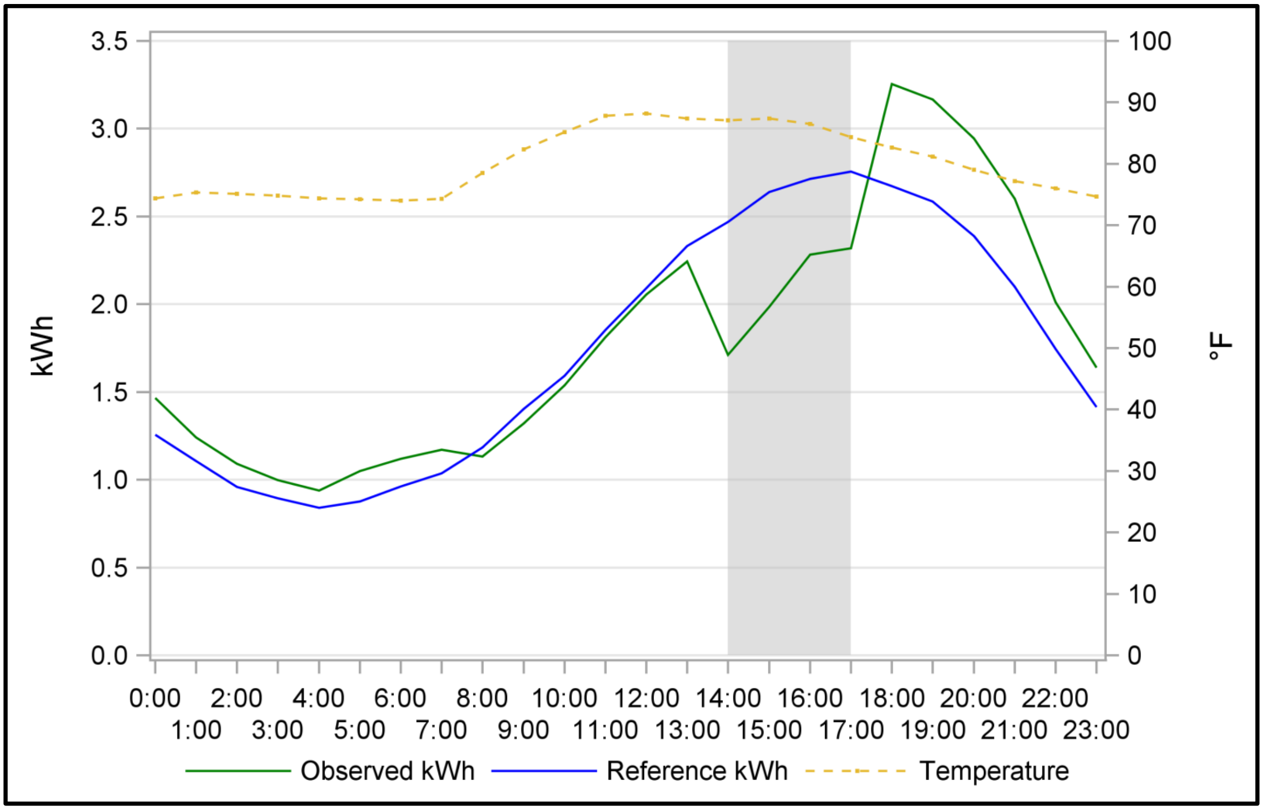
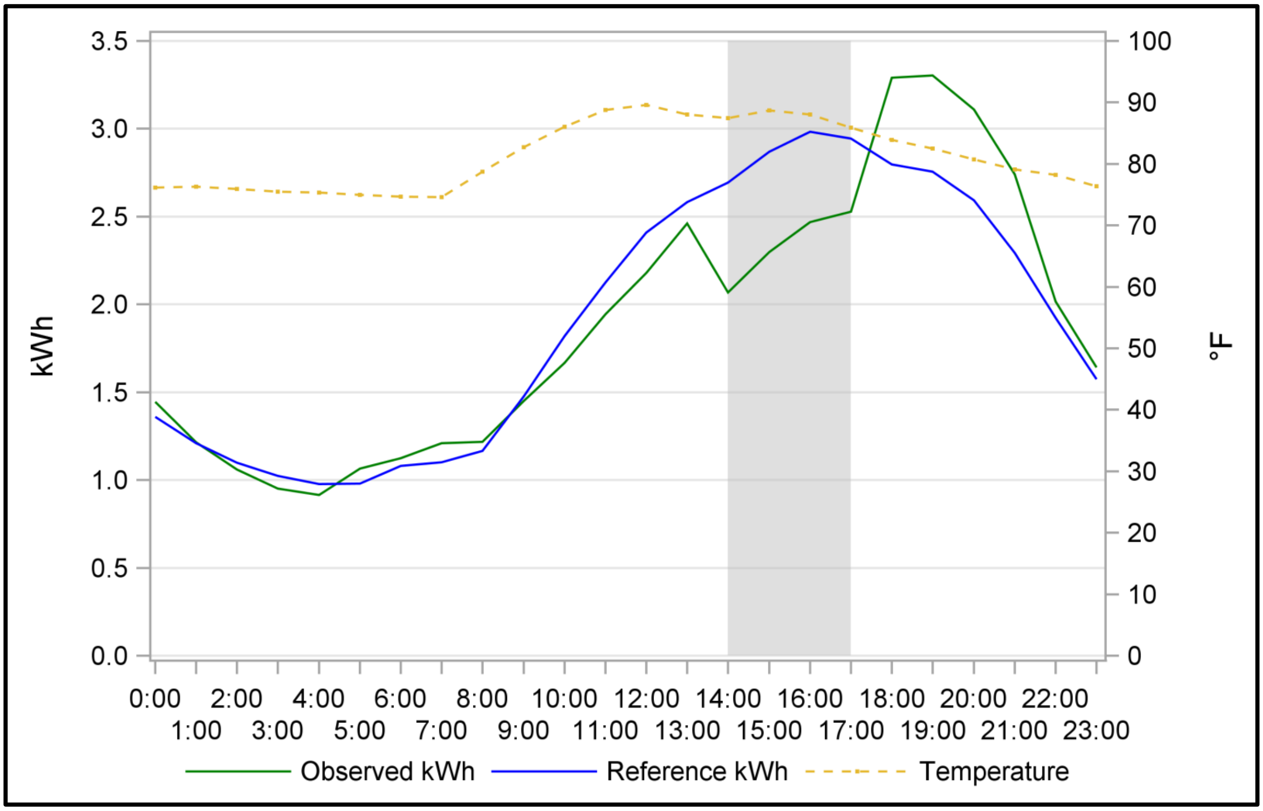


Figure 3-17: Hourly Load Profile for SCTD Customers Not Enrolled in PTR – 50% Cycling – 2014 Event Average



3.1.7 PTR without Load Control by Notification Type

There were three methods of notification for 2014 PTR event days – email, text message, and phone call. Less than 7% of the final participant group had opted for phone notification, so this sub-group analysis focused on the email and text message notifications. Over 70% of the analysis group opted for email-only notification, about 16% opted for text-only notification, and about 14% 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 0.10 kW (6.9%), which is approximately in line with the general PTR population average. The text message-only group had an average event hour load reduction of 0.06 kW (4.4%), which was below average. The group with both types of notifications had the greatest average event hour reduction of 0.13 kW (8.6%), which was above the overall population average. The email-only group also had very little snapback effects of only 1.8%, compared to the text-only group, which had 8.5% and the group with both types, which had 7.9%.

Figure 3-18: Hourly Load Profile for PTR Customers without Any Load Control – Email-Only Notification – 2014 Event Average

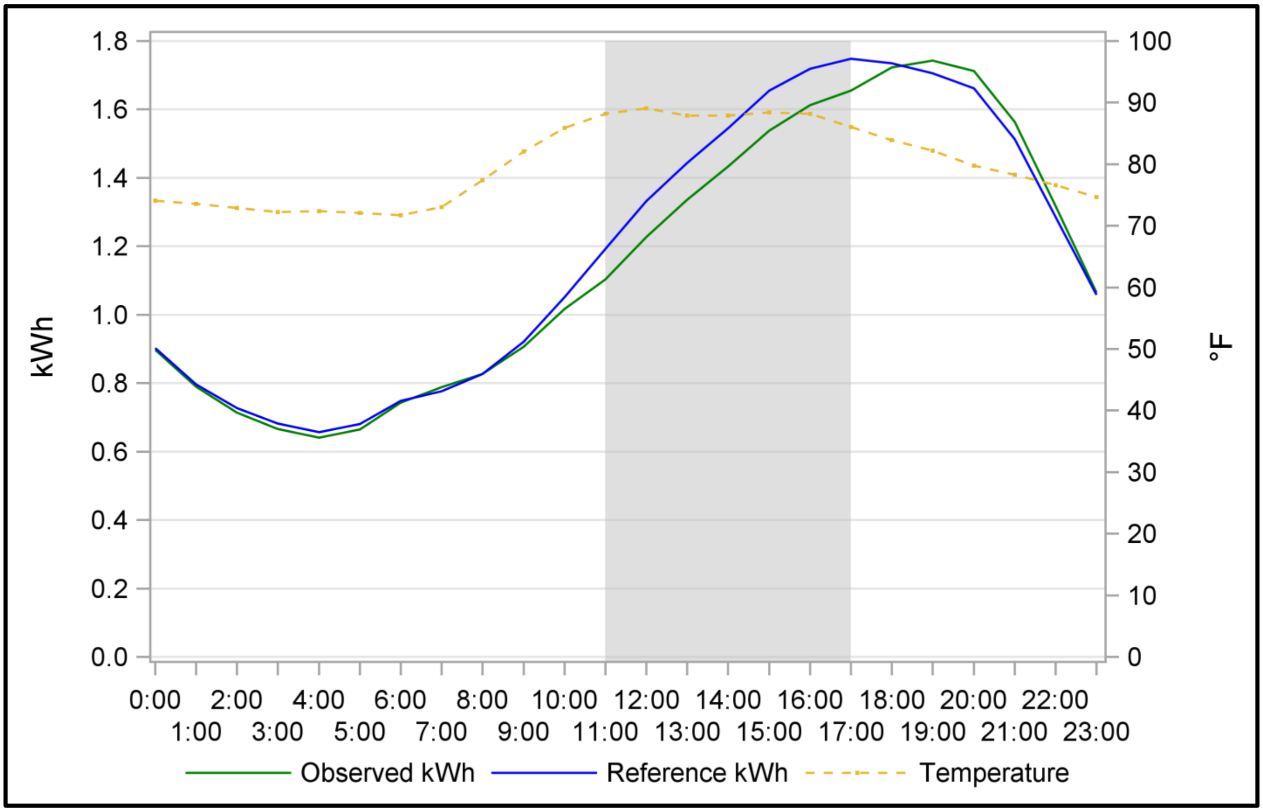


Figure 3-19: Hourly Load Profile for PTR Customers without Any Load Control – Text-Only Notification – 2014 Event Average

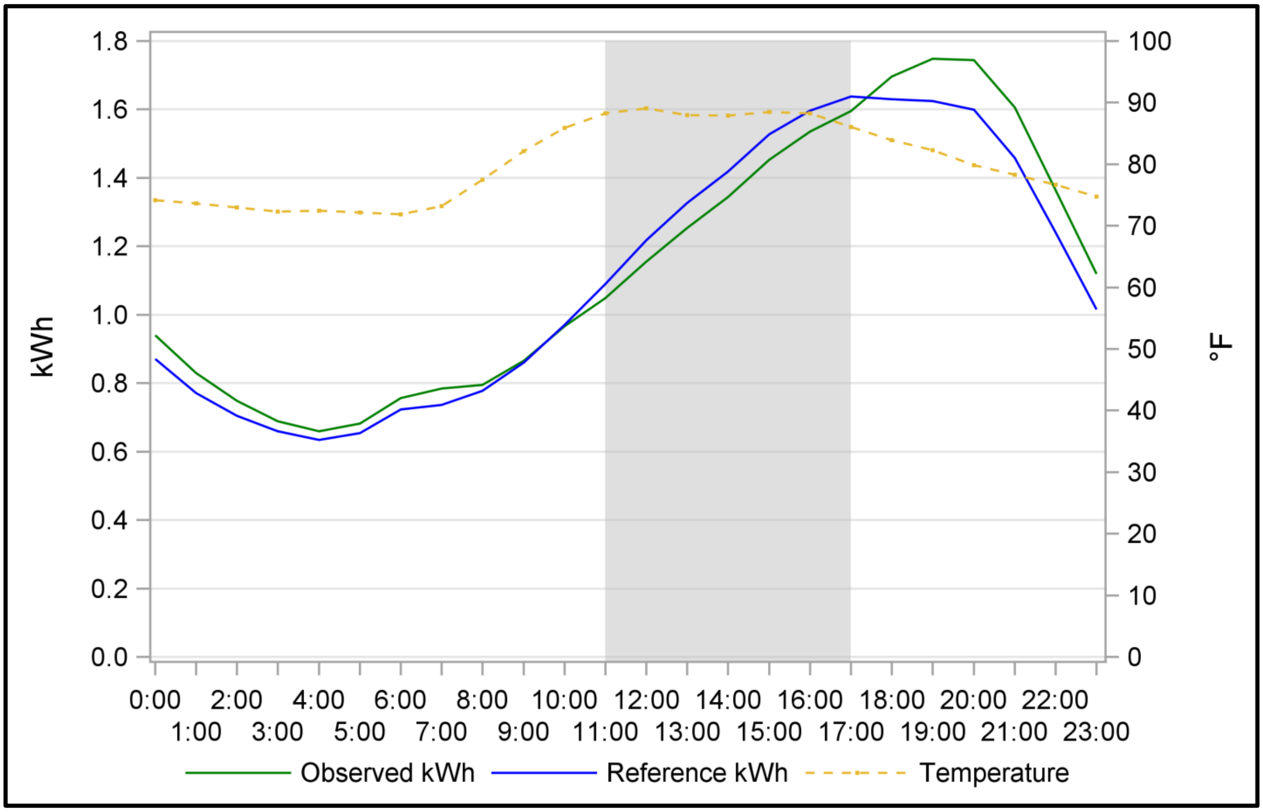
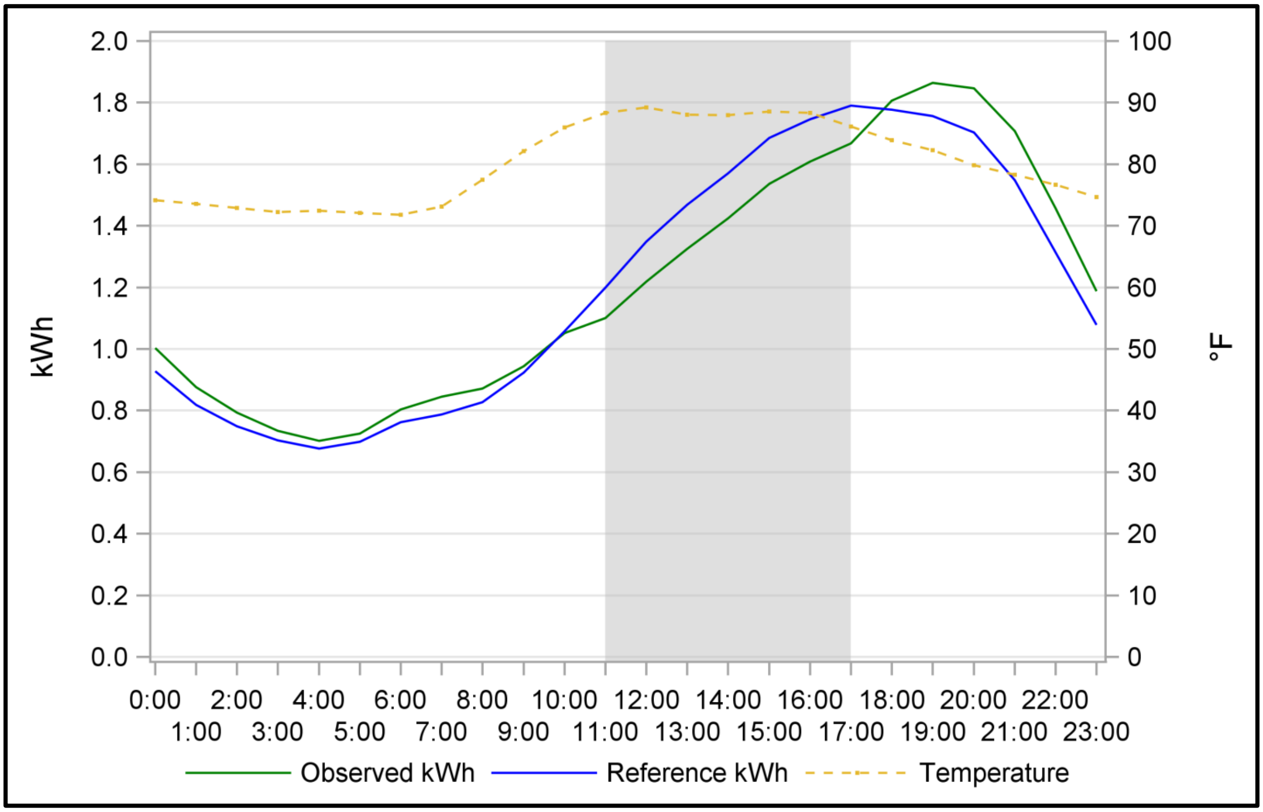


Figure 3-20: Hourly Load Profile for PTR Customers without Any Load Control – Both Email and Text Notifications – 2014 Event Average



3.1.8 PTR without Load Control by Summer Billing Tier

Figure 3-21 through Figure 3-25 show the hourly event load impacts for PTR customers with no load control by summer billing tier. These tiers are determined by consumption, and translate to increasing monthly rates. The tiers in this section represent the maximum tier a household reached during the summer months in 2014. Most accounts stayed in Summer Tier 1 for these months. There was no substantial difference between the hourly event load reductions between these tiers, which ranged from 0.06 kW (4.0%) for Summer Tier 4 to 0.12 kW (7.5%) for Summer Tier 5. Summer Tier 1 had an average of 0.10 kW (6.8%), Summer Tier 2 had an average of 0.07 kW (4.9%), and Summer Tier 3 had an average of 0.10 kW (6.9%).

Figure 3-21: Hourly Load Profile for PTR Customers without Any Load Control – Summer Tier 1 – 2014 Event Average

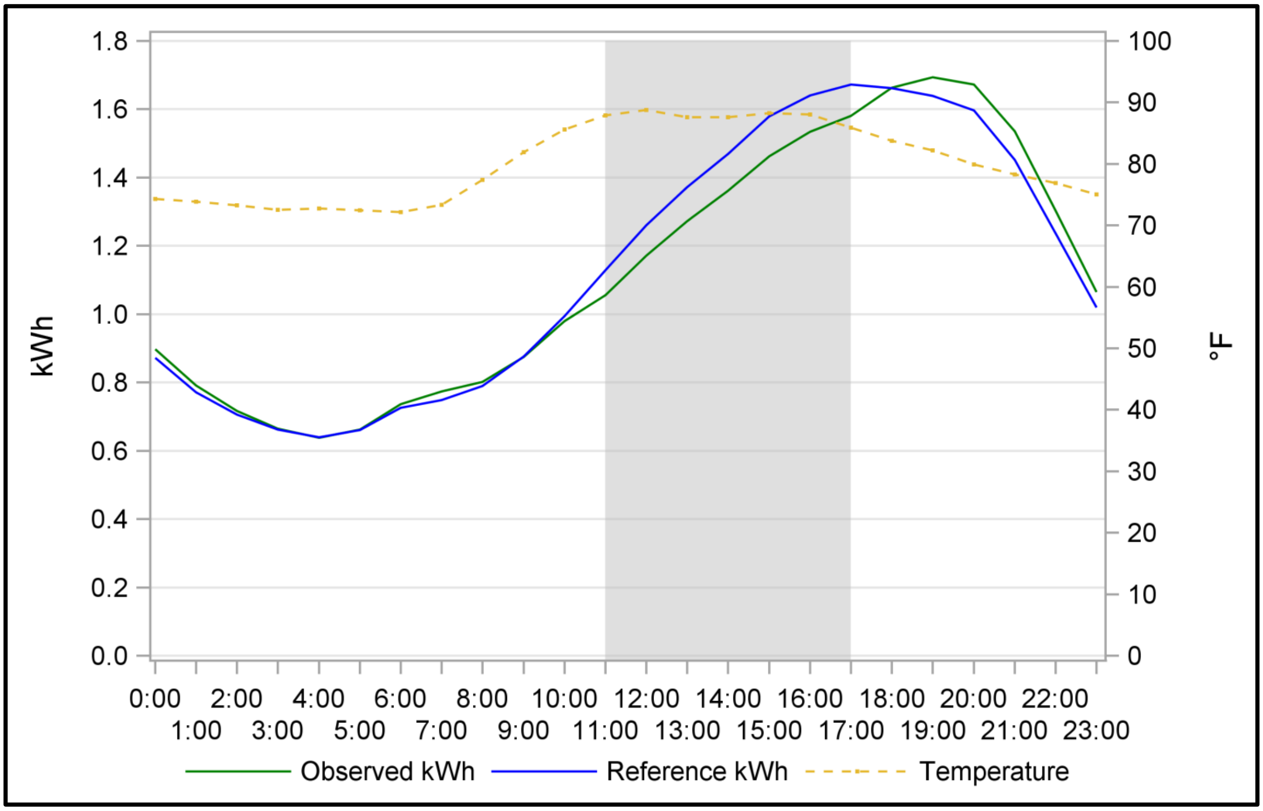


Figure 3-22: Hourly Load Profile for PTR Customers without Any Load Control – Summer Tier 2 – 2014 Event Average

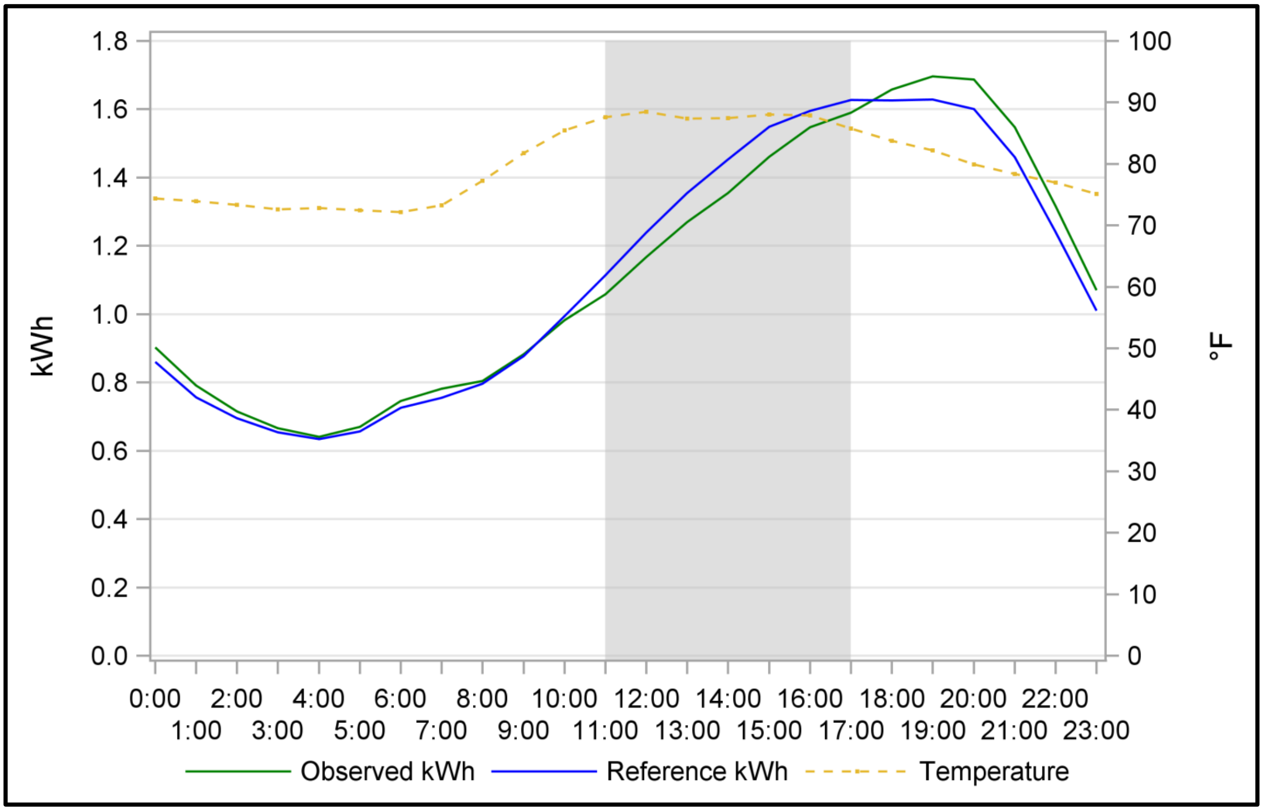


Figure 3-23: Hourly Load Profile for PTR Customers without Any Load Control – Summer Tier 3 – 2014 Event Average

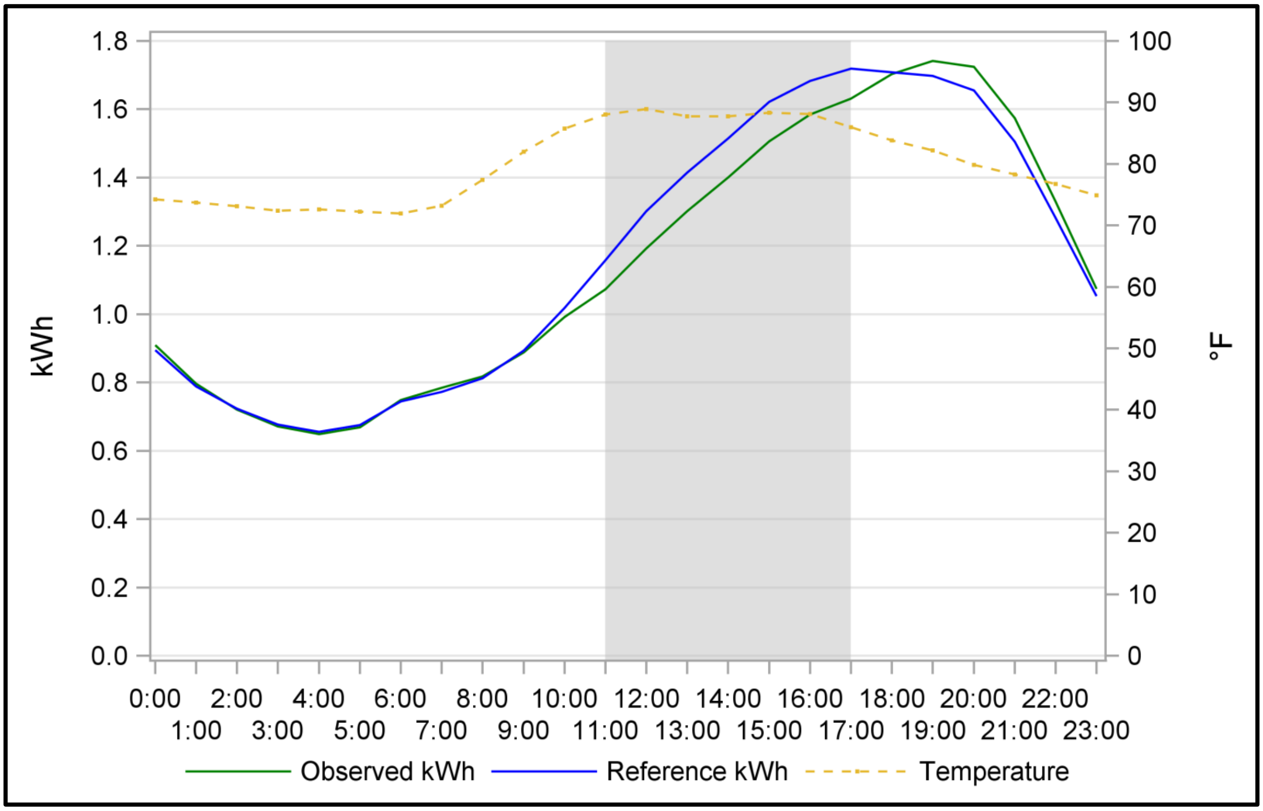


Figure 3-24: Hourly Load Profile for PTR Customers without Any Load Control – Summer Tier 4 – 2014 Event Average

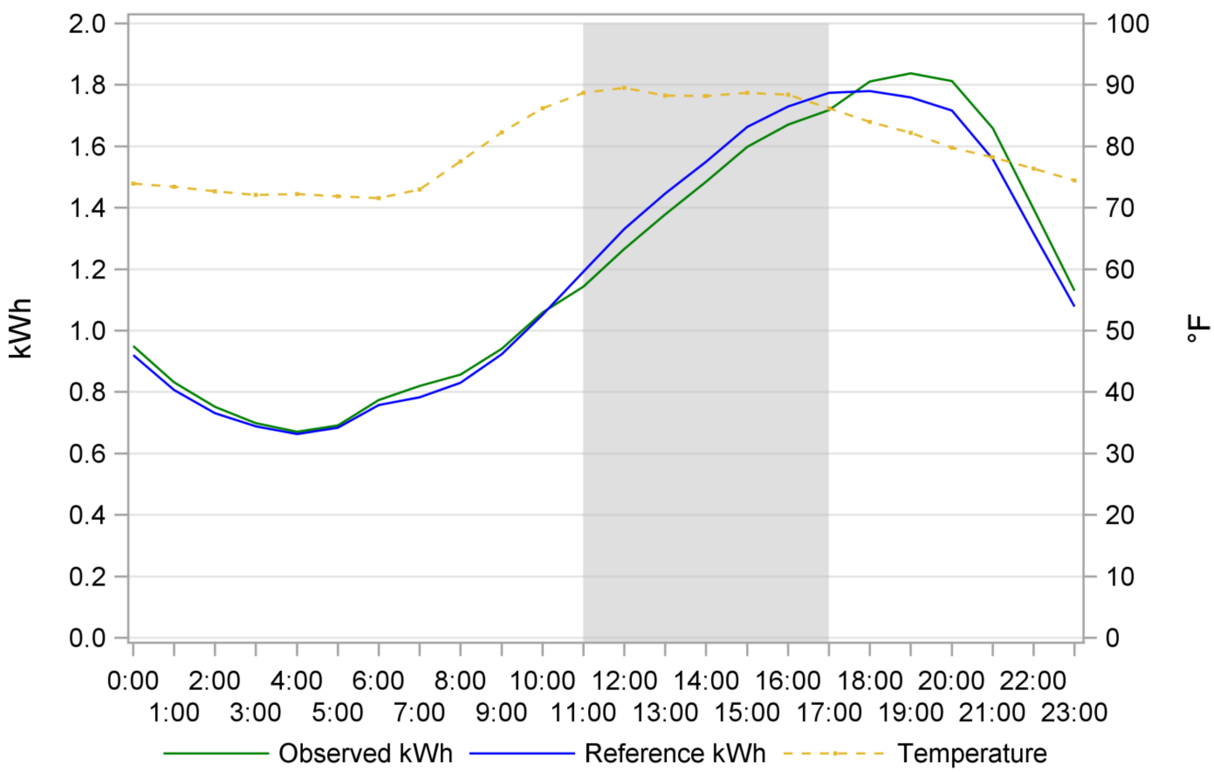
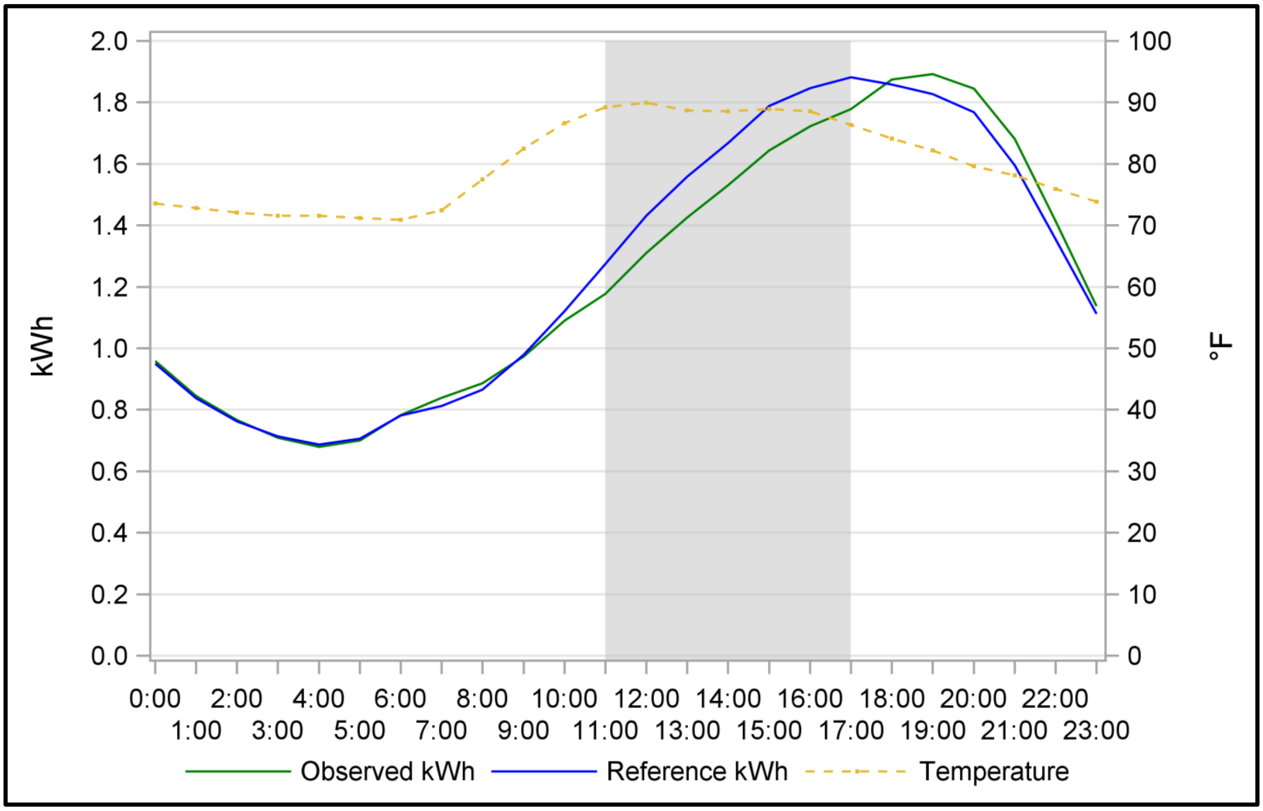


Figure 3-25: Hourly Load Profile for PTR Customers without Any Load Control – Summer Tier 5 – 2014 Event Average



3.1.9 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 3-26 and Figure 3-27 show the hourly event load impacts for both non-low income and low income PTR participants with no load control. About one-third of this subset of PTR participants had a low income billing rate. The non-low income participants had an average event hour load reduction that was very similar to the overall PTR population, saving 0.11 kW (7.0%). The low income participants had very little load reduction during events, with an average of 0.04 kW (2.8%).

Figure 3-26: Hourly Load Profile for Non-Low Income PTR Customers without Any Load Control – 2014 Event Average

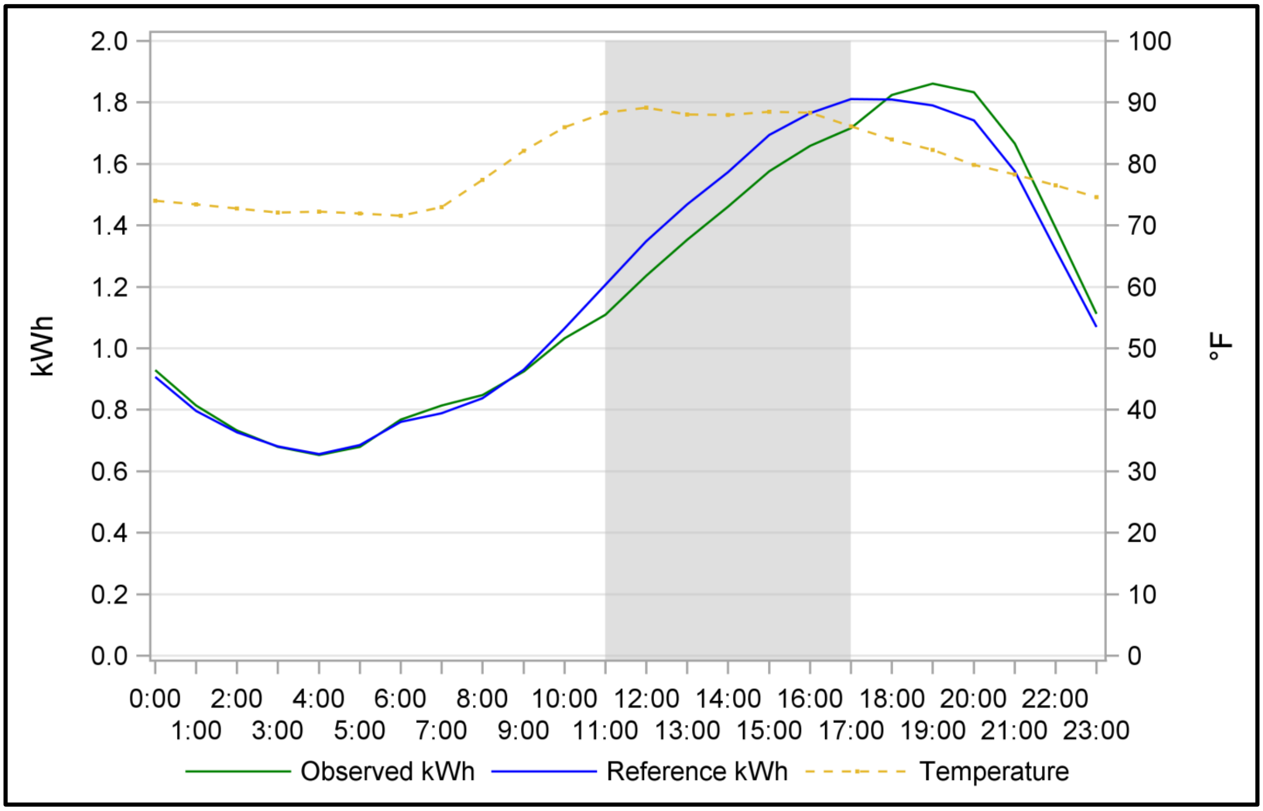
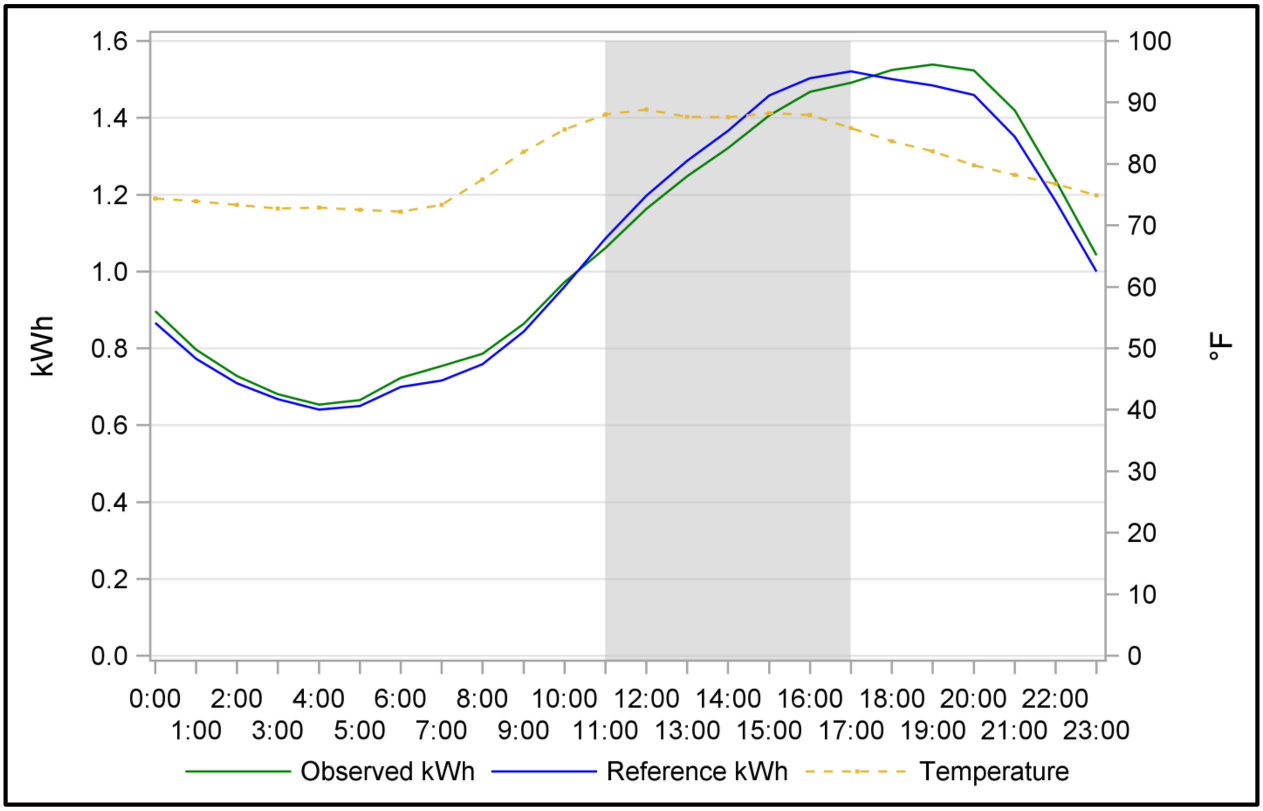


Figure 3-27: Hourly Load Profile for Low Income PTR Customers without Any Load Control – 2014 Event Average



3.1.10 PTR without Load Control by First Year of Enrollment

Figure 3-28 through Figure 3-30 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 2014. The participants who first enrolled in 2012 saved the most during the 2014 PTR events, with an average of 0.13 kW (8.3%) during event hours. This group also showed the least snapback effects, with an average increase of only 0.1% from 6 p.m. to midnight. The participants who first enrolled in 2013 had an average event hour load reduction of 0.12 kW (7.9%), and an average post-event snapback of 3.4%. Lastly, the 2014 enrollees had an average event hour load reduction of 0.07 kW (4.5%), and an average post-event snapback of 7.6%.

Figure 3-28: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2012 – 2014 Event Average

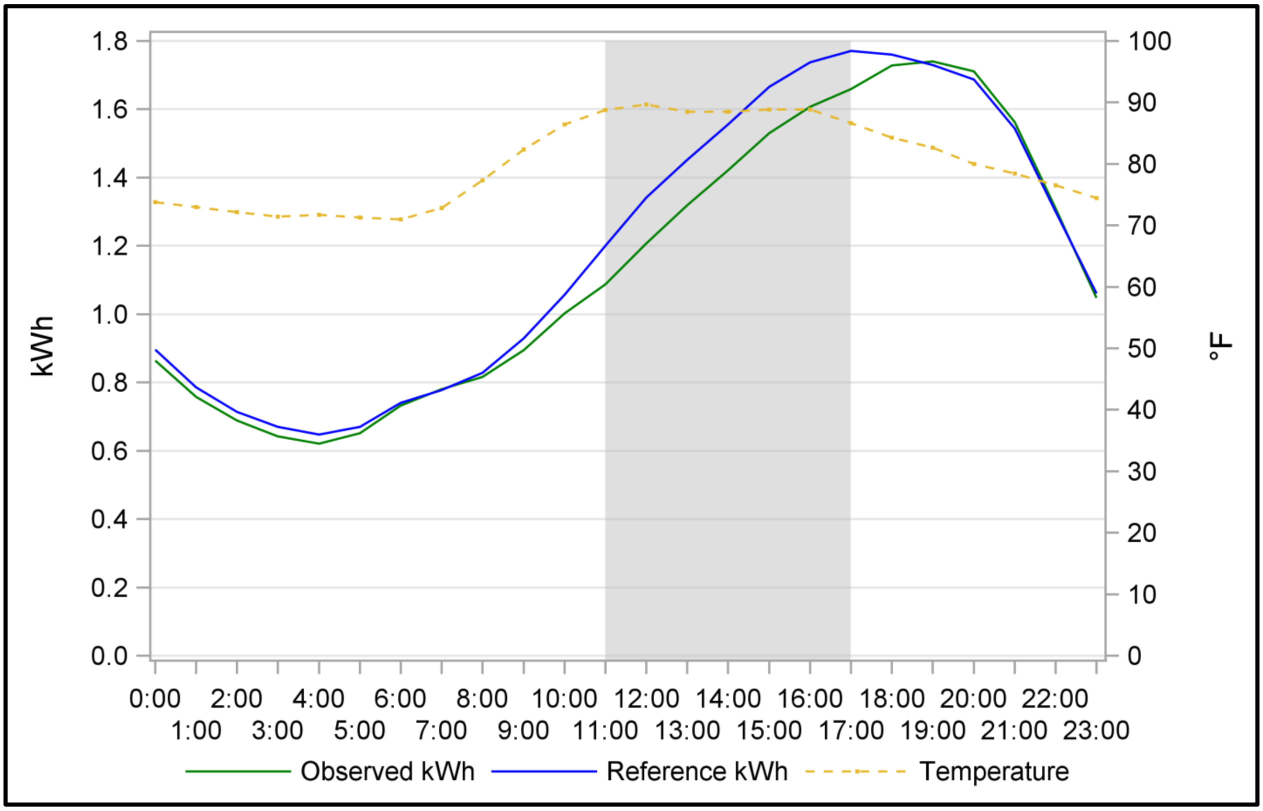


Figure 3-29: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2013 – 2014 Event Average

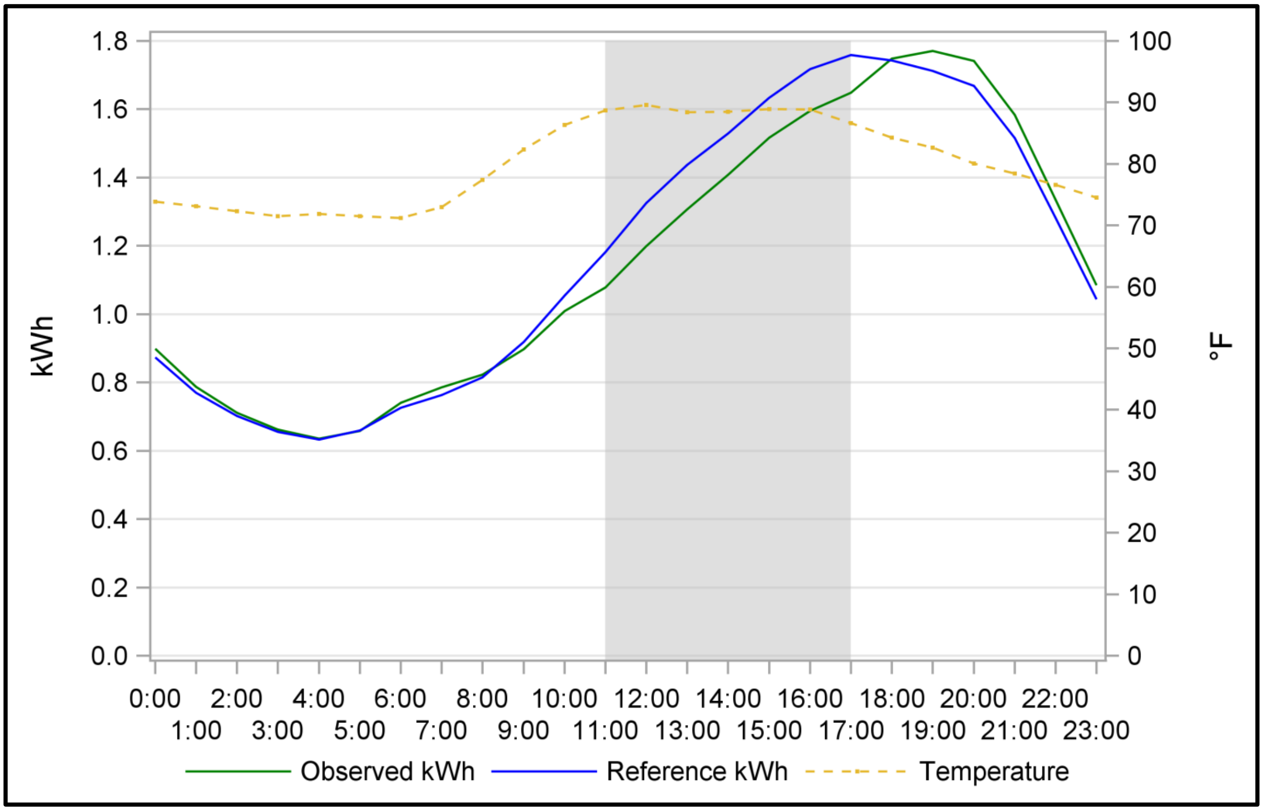
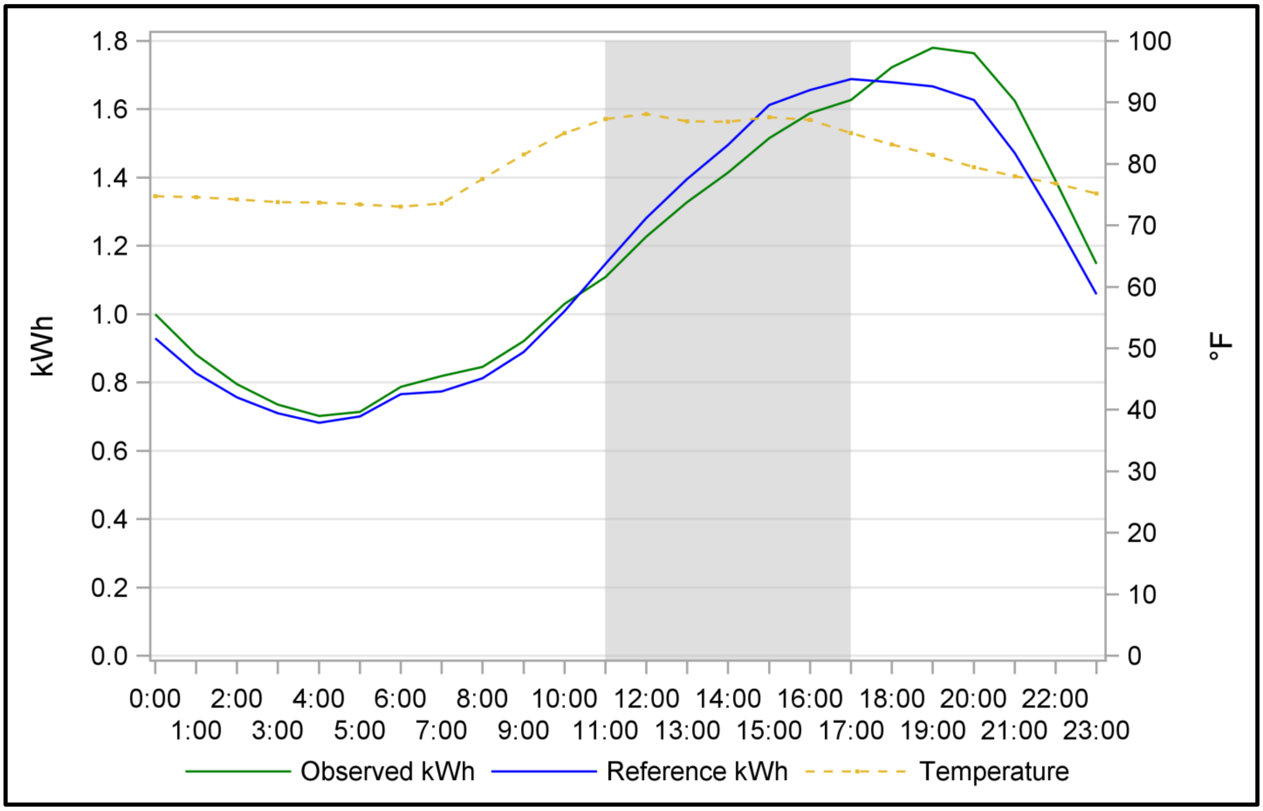


Figure 3-30: Hourly Load Profile for PTR Customers without Any Load Control – First Enrollment Year of 2014 – 2014 Event Average



3.1.11 PTR without Load Control by Marketing Segment

SDG&E has identified six marketing segments for its customers. Figure 3-31 through Figure 3-36 show the hourly event load impacts for PTR customers without any load control by these segments. There were no substantial differences between each of these marketing segments in terms of load reduction during the 2014 PTR events. Marketing Segment 01 had an average event hour load reduction of 0.11 kW (6.8%), Marketing Segment 02 had an average of 0.09 kW (5.7%), Marketing Segment 03 had an average of 0.11 kW (7.5%), Marketing Segment 04 had an average of 0.09 kW (6.9%), Marketing Segment 05 had an average of 0.12 kW (7.9%), and Marketing Segment 06 had an average of 0.09 kW (5.9%).

Figure 3-31: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 01 – 2014 Event Average

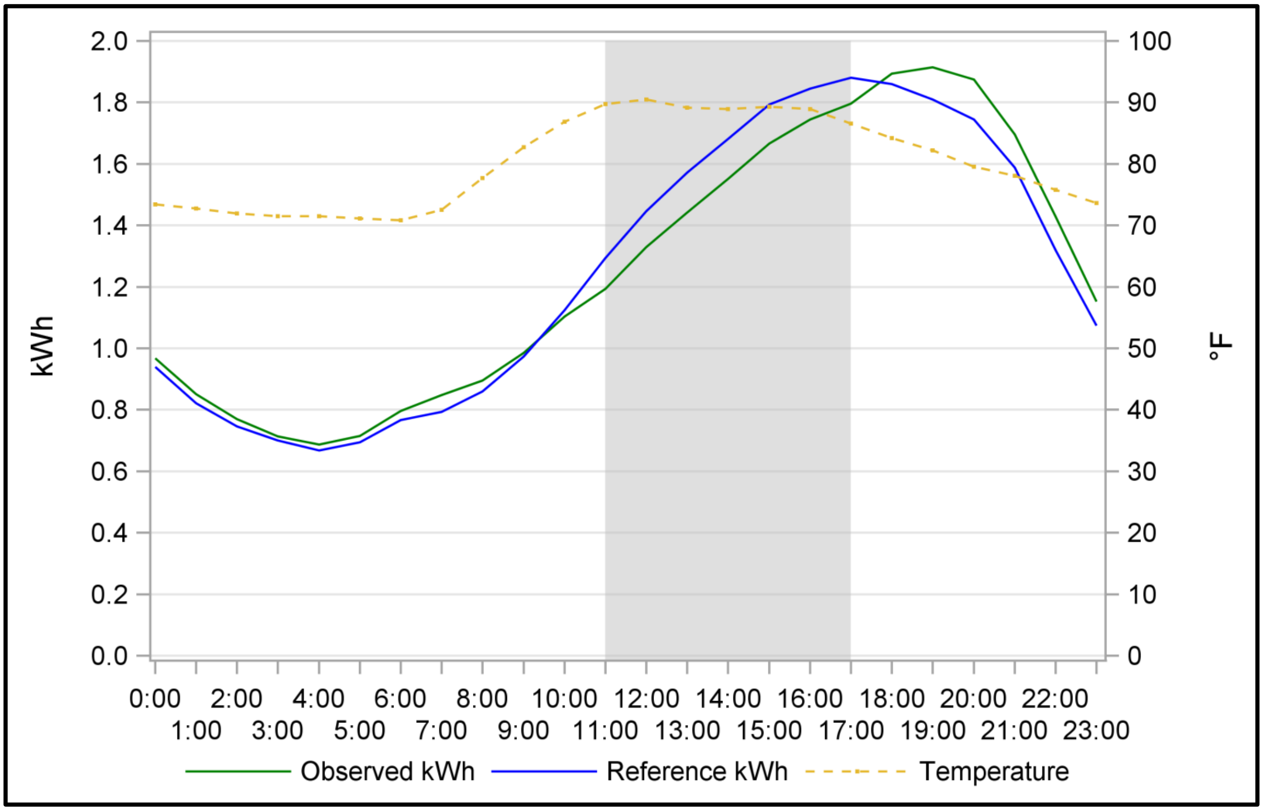


Figure 3-32: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 02 – 2014 Event Average

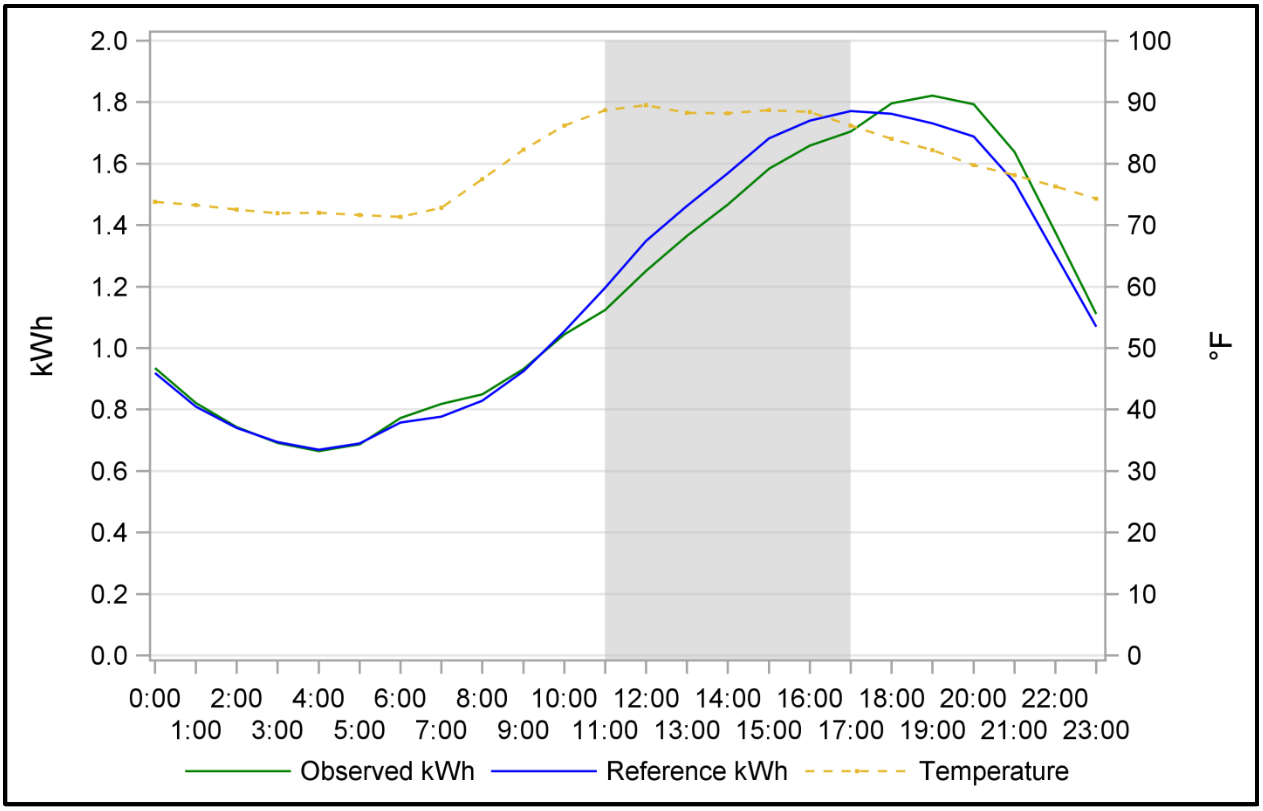


Figure 3-33: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 03 – 2014 Event Average

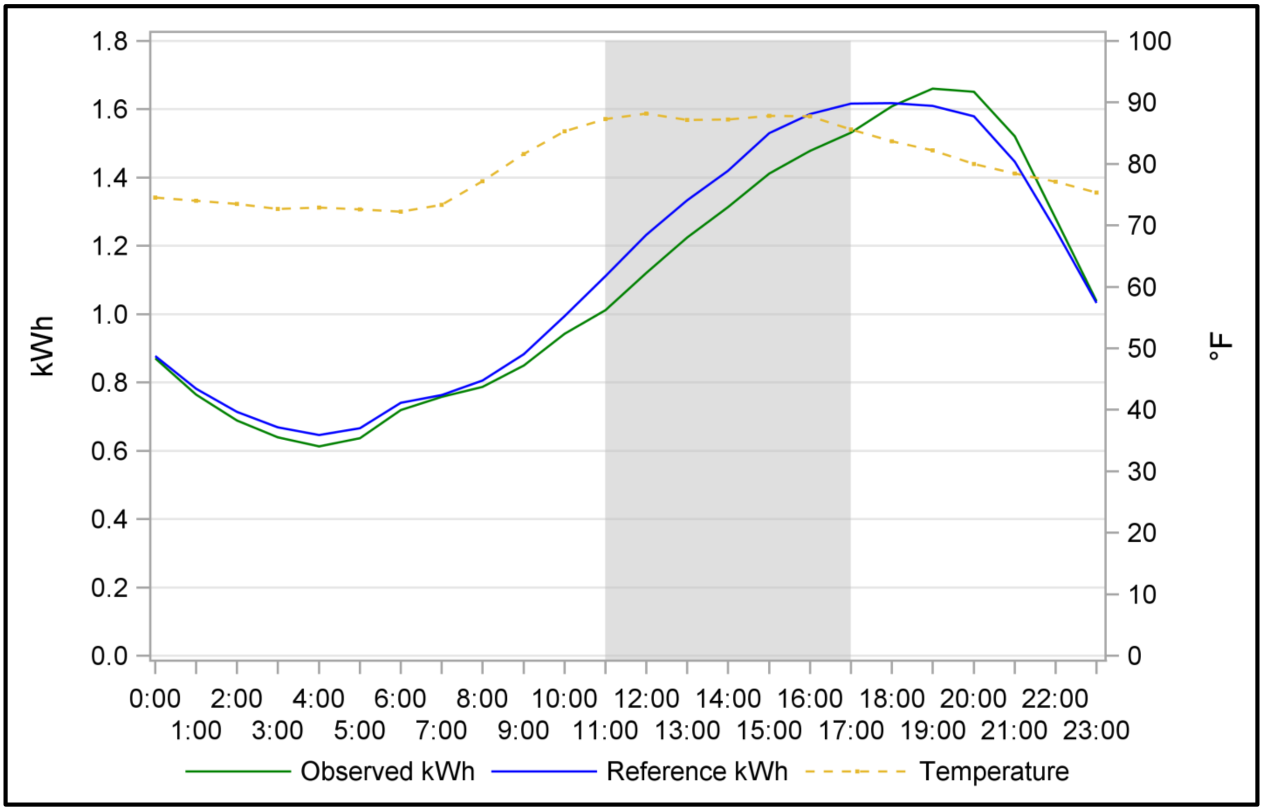


Figure 3-34: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 04 – 2014 Event Average

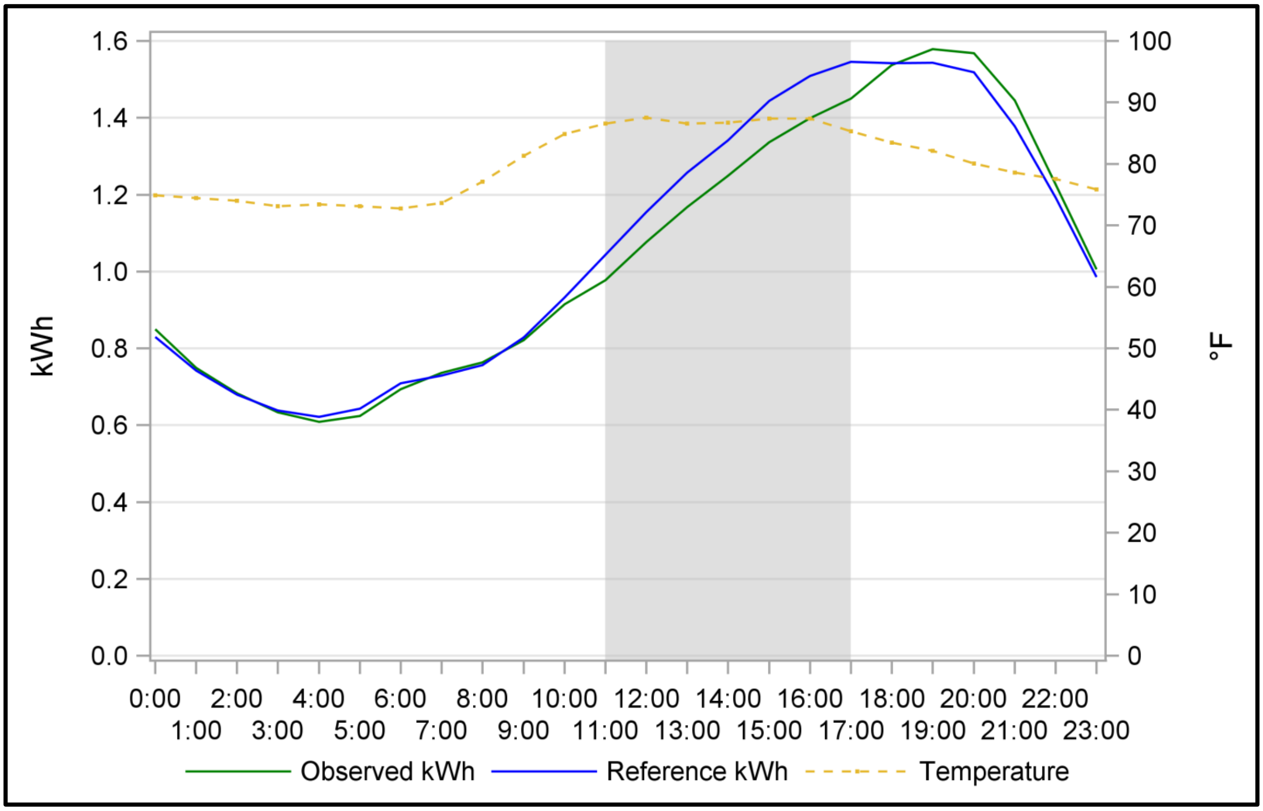


Figure 3-35: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 05 – 2014 Event Average

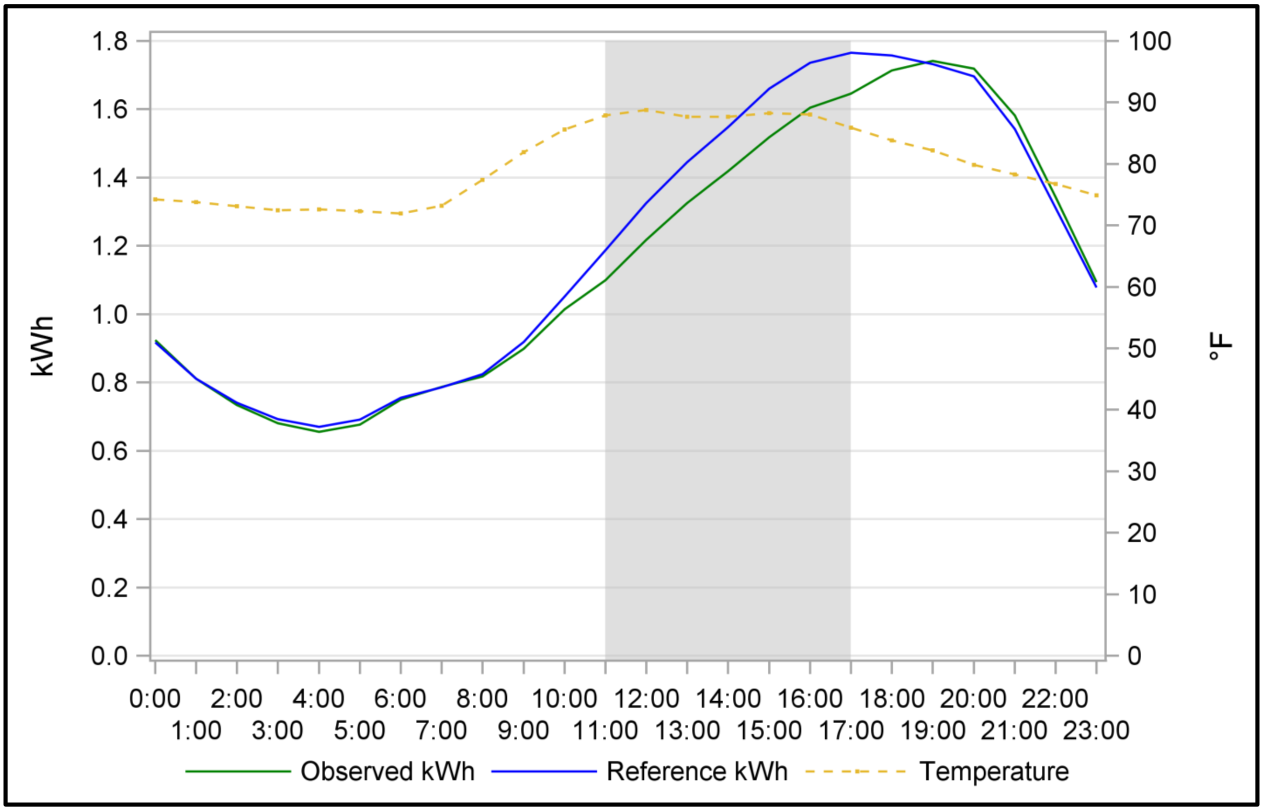
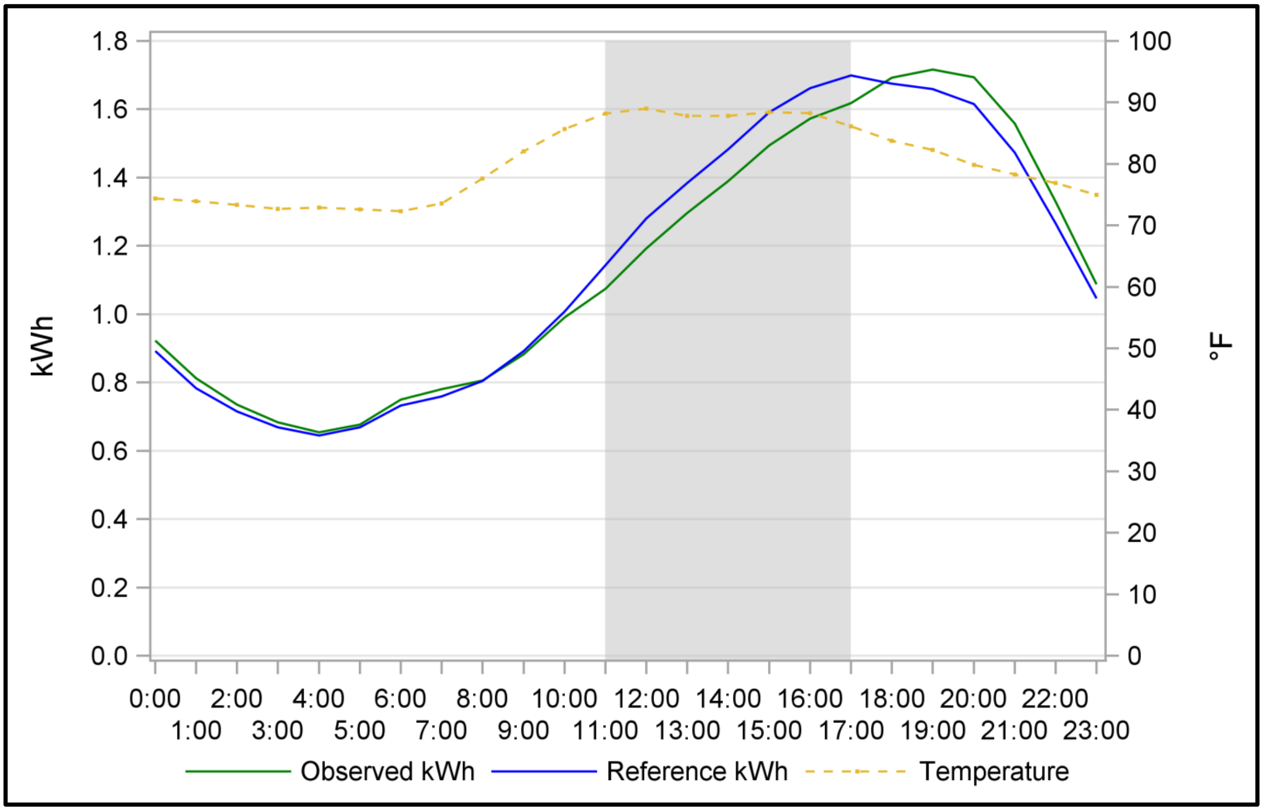


Figure 3-36: Hourly Load Profile for PTR Customers without Any Load Control – Marketing Segment 06 – 2014 Event Average



3.1.12 Net Energy Metered Ex Post Load Impacts

As part of its analysis, Itron separated out the set of PTR participants with photovoltaic (PV) generation, or Net Energy Metering (NEM). These customers, in addition to standard consumption, are able to export excess PV generation back to the grid. Figure 3-37 and Table 3-10 show the hourly PTR event load impacts for these NEM participants. The values reported reflect these customers' net consumption of energy consumed minus energy exported. The average event hour load reduction for these customers is substantial, at 0.43 kW. The average aggregate event-induced load impact for these NEM customers was 1.23 MW, which is a considerable amount given their relatively small population.

Figure 3-37: Hourly Load Profile for PTR NEM Customers without Any Load Control – 2014 Event Average

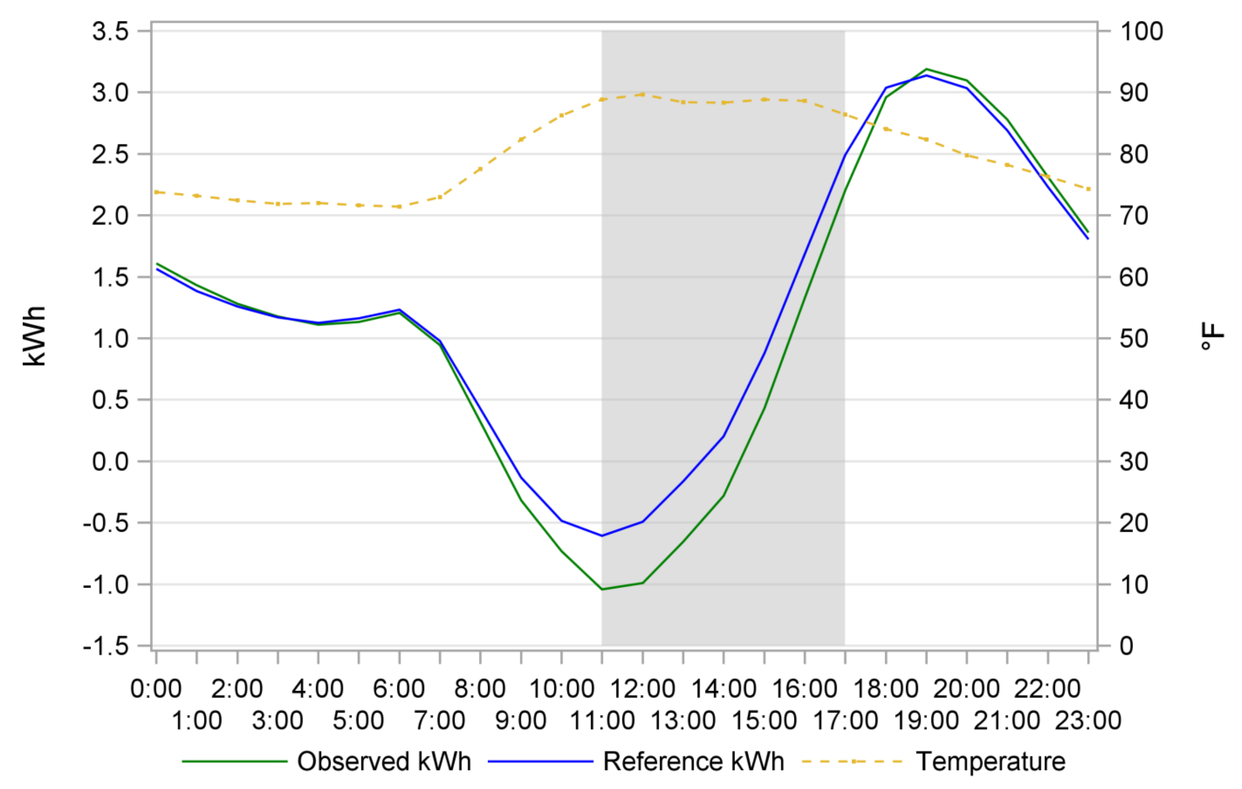


Table 3-10: Summary of Event Impacts for PTR NEM Customers without Any Load Control – 2014 Average

Hour Beg.	Hour End	Event Hour	Mean °F	Mean Reference Load (kW)	Mean Observed Load (kW)	Mean Impact (kW)	% Load Reduction	Mean Active Partic-ipants	Total Net Impact (kW)
0:00	1:00	No	73.8	1.56	1.61	-0.047	-3.0%	2,864	-135
1:00	2:00	No	73.2	1.38	1.43	-0.048	-3.5%	2,864	-137
2:00	3:00	No	72.5	1.26	1.28	-0.021	-1.6%	2,864	-59
3:00	4:00	No	71.8	1.17	1.18	-0.008	-0.7%	2,864	-24
4:00	5:00	No	72.0	1.13	1.11	0.017	1.5%	2,864	48
5:00	6:00	No	71.7	1.16	1.13	0.030	2.6%	2,864	86
6:00	7:00	No	71.4	1.23	1.21	0.025	2.0%	2,864	71
7:00	8:00	No	73.0	0.98	0.94	0.032	3.3%	2,864	92
8:00	9:00	No	77.6	0.43	0.32	0.105	24.7%	2,864	301
9:00	10:00	No	82.4	-0.13	-0.32	0.186	-139.7%	2,864	532
10:00	11:00	No	86.3	-0.48	-0.73	0.250	-51.8%	2,864	716
11:00	12:00	Yes	88.8	-0.61	-1.04	0.434	-71.5%	2,864	1,244
12:00	13:00	Yes	89.6	-0.49	-0.99	0.499	-101.5%	2,864	1,430
13:00	14:00	Yes	88.4	-0.16	-0.65	0.490	-298.7%	2,864	1,405
14:00	15:00	Yes	88.4	0.20	-0.28	0.482	238.8%	2,864	1,380
15:00	16:00	Yes	88.8	0.88	0.43	0.445	50.7%	2,864	1,274
16:00	17:00	Yes	88.6	1.69	1.33	0.361	21.4%	2,864	1,033
17:00	18:00	Yes	86.4	2.49	2.21	0.286	11.5%	2,864	820
18:00	19:00	No	84.1	3.04	2.96	0.077	2.5%	2,864	221
19:00	20:00	No	82.3	3.14	3.19	-0.052	-1.7%	2,864	-149
20:00	21:00	No	79.7	3.03	3.10	-0.064	-2.1%	2,864	-183
21:00	22:00	No	78.2	2.69	2.78	-0.088	-3.3%	2,864	-253
22:00	23:00	No	76.3	2.23	2.31	-0.081	-3.6%	2,864	-231
23:00	24:00	No	74.3	1.80	1.86	-0.057	-3.2%	2,864	-164
Total - Entire Day	**-**	**-**	**80.0**	**29.62**	**26.37**	**3.253**	**11.0%**	**2,864**	**9,316**
Total - Event Hours	**-**	**-**	**88.4**	**4.00**	**1.00**	**2.998**	**75.0%**	**2,864**	**8,586**

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 20-year forecast of enrollment for four separate participant segments. The second data source was two separate versions of weather scenarios containing hourly weather for different types of weather years and day types for each month of the year, one from SDG&E and the second from CAISO. The results presented in this section use the weather conditions based on SDG&E estimates.

The *ex ante* estimation process was relatively straightforward, involving two main steps. The first step required taking the model parameters from the *ex post* regression model and combining them with the weather scenarios to calculate per participant average reference loads, observed loads, and load impacts. Because the impacts were based on variables that were interacted with temperature variables, they can be applied to the weather data from the various year and day types to generated estimated savings for those scenarios. The standard errors from the impact variable parameters from the ex post model were used to calculate the uncertainty estimates. The second step was to combine estimated per-participant impacts for the different weather scenarios and multiply them by the forecast of enrolled participants to generate the total program impacts. SDG&E forecasts that the PTR, Summer Saver, and SCTD programs will continue to grow. By the end of 2016, the PTR program is expected to grow to over 73,000 participants (including dual enrollments in the other programs), while the SCTD program is expected to grow to over 8,000 participants. These projections are then expected to remain constant throughout the remainder of the *ex ante* forecast period.

While this process was straightforward, there were some nuances to the data that call for additional discussion. First, the enrollment forecasts were based on total participants by participant segment, whereas the weather scenarios and estimated impacts have more detailed information. Consequently, the alignment of these data sources called for making certain assumptions about the allocation of program participants. Total participants from the forecast were allocated to climate zones and, for the SCTD and Summer Saver groups, to the cycling strategies based on the relative shares as of the last event day from 2014. 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**	56%	44%	100%
PTR Dually Enrolled in Summer Saver	**100% Cycle**	32%	38%	70%
	50% Cycle	12%	18%	30%
	All	44%	56%	100%
PTR Dually Enrolled in SCTD	**4 Degree Setback**	22%	26%	48%
	50% Cycle	24%	28%	52%
	All	46%	54%	100%
SCTD-Only	**4 Degree Setback**	23%	27%	50%
	50% Cycle	22%	27%	50%
	All	45%	55%	100%

The second area related to the data has to do with the effects of the fires. For the ex post impacts, while these effects represent a caveat on the interpretation of the results, they are a reality and there is no reason to attempt to account for them. For the *ex ante* impacts, however, unless fires of this nature are going to be annual occurrence, which is extremely unlikely, it makes sense to try, where possible, to remove their influence. To this end, for the PTR-Only participants, a separate set of ex post impacts was estimated where those premises that were within five miles of the fire were removed, and the parameter estimates from his model were used in the calculation of the *ex ante* forecast. This was not done for the other participant segments because the data attrition would have been too great to ensure a sufficient sample size.

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 2016. 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 0.066 kW during the resource availability hours (1:00pm to 6:00 pm). The average estimated aggregate load reduction under this scenario is 4.2 MW. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.09 kW. The average estimated aggregate reduction is 5.80 MW. These estimates represent approximately 4.8% and 5.8% of the reference load, respectively for each weather scenario.

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

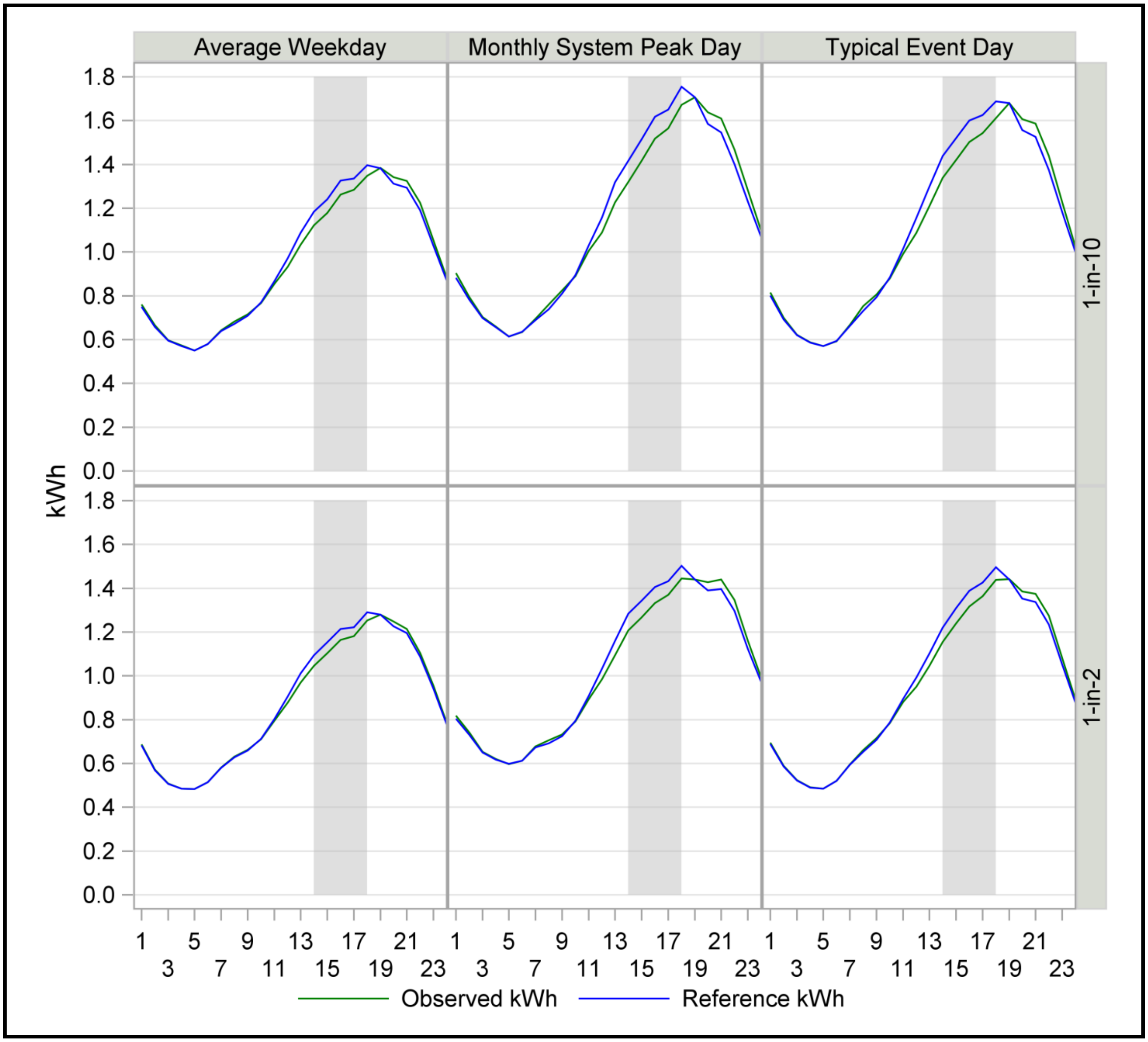


Table 4-2: Ex Ante Hourly Load Impact Results – PTR-Only

			1-in-10					1-in-2				
	Day / Type	Month	Avg. Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load Reduc-tion	Average Total Hourly Impact (MWh)	Avg. Hourly Reference Load (kWh)	Avg. Hourly Observed Load (kWh)	Avg. Hourly Impact (kWh)	Percent Load Reduc-tion	Avg. Total Hourly Impact (MWh)
_NA_	Average Weekday	Jun	0.96	0.92	0.043	4.5%	2.78	0.79	0.77	0.023	2.9%	1.44
		Jul	1.18	1.13	0.050	4.2%	3.18	1.09	1.05	0.038	3.5%	2.43
		Aug	1.30	1.24	0.057	4.4%	3.67	1.19	1.15	0.045	3.8%	2.88
	Monthly System Peak Day	Jun	1.22	1.15	0.075	6.1%	4.78	0.98	0.93	0.045	4.6%	2.90
		Jul	1.49	1.40	0.087	5.9%	5.58	1.28	1.22	0.060	4.7%	3.83
		Aug	1.59	1.50	0.093	5.8%	5.93	1.39	1.32	0.069	5.0%	4.43
	Typical Event Day	Aug	1.57	1.48	0.091	5.8%	5.83	1.37	1.30	0.066	4.8%	4.21

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 2016. For a 1-in-2 typical event day, the estimated load reduction for the average participant is 0.47 kW during event hours. For a 1-in-10 typical event day, the estimated load reduction is higher, at 0.64 kW. These estimates are much higher than the PTR-only group due to the additional effects of automatic cycling of ACs during events. The average estimated aggregate load reductions are 2.1 MW (24.4%) and 2.9 MW (28%), respectively.

The 100% cycling group has an estimated load reduction during event hours of 0.58 kW under the 1-in-2 scenario, representing a 31.7% reduction from the reference load. Under the 1-in-10 conditions, this group has an estimated event hour load reduction of 0.8 kW, or 36.2%. The 50% cycling group has much lower estimated load reductions of 0.19 kW (9.5%) and 0.27 kW (10.8%) for the 1-in-2 and 1-in-10 scenarios, respectively. These estimates are less than a third of the 100% cycling group.

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

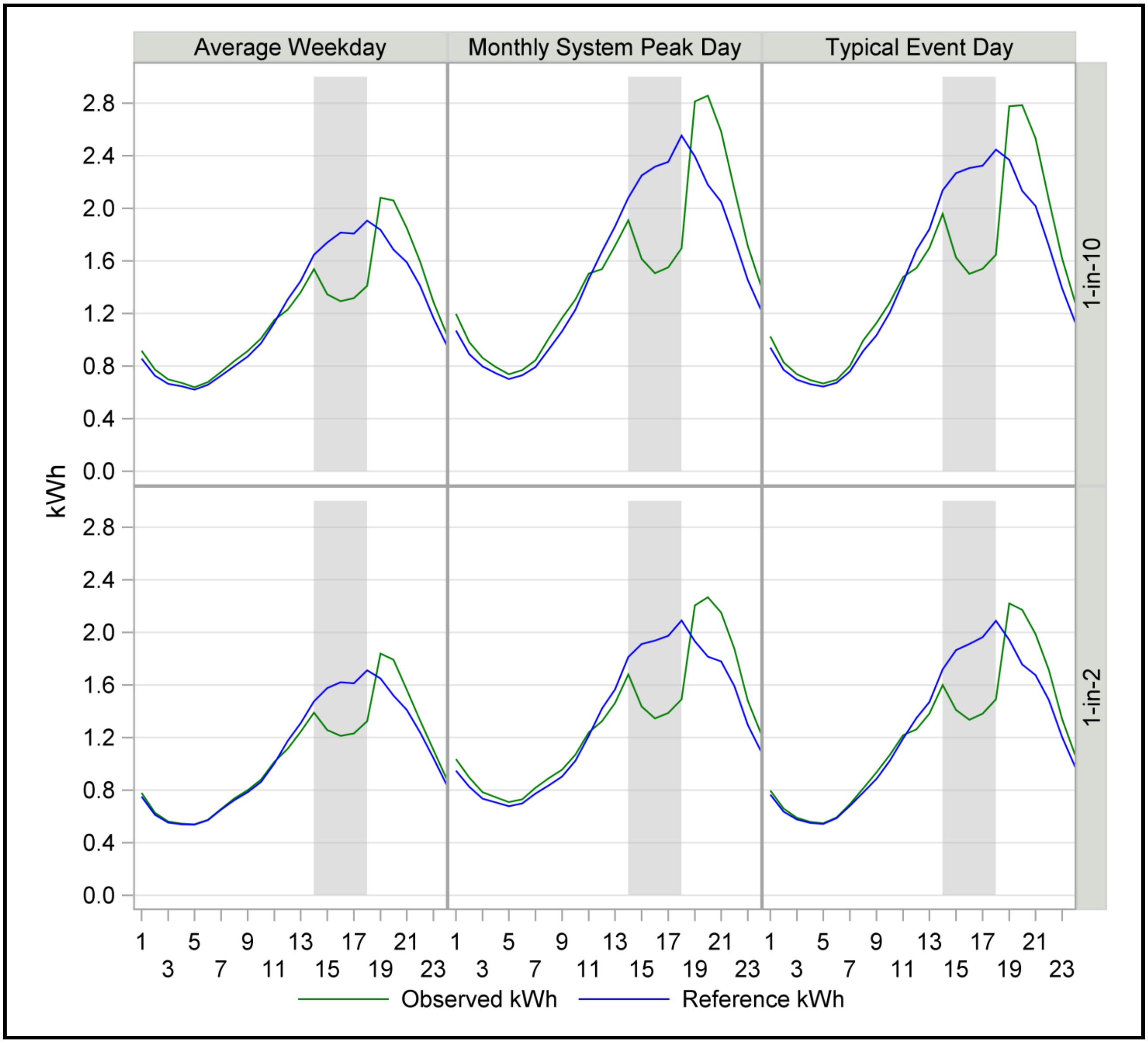


Table 4-3: Ex Ante Hourly Load Impact Results – PTR Dually Enrolled in Summer Saver

Cycle %	Day / Type	Month	1-in-10					1-in-2				
			Average Hourly Reference Load (kWh)	Average Hourly Observed Load (kWh)	Average Hourly Impact (kWh)	Percent Load 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)
100	Average Weekday	Jun	1.23	0.86	0.373	30.3%	1.18	0.93	0.74	0.192	20.6%	0.61
		Jul	1.54	1.10	0.434	28.3%	1.37	1.37	1.03	0.331	24.2%	1.05
		Aug	1.70	1.20	0.499	29.4%	1.57	1.52	1.13	0.391	25.7%	1.24
	Monthly System Peak Day	Jun	1.70	1.05	0.653	38.4%	2.06	1.27	0.87	0.395	31.1%	1.25
		Jul	2.06	1.32	0.740	36.0%	2.34	1.69	1.15	0.541	32.0%	1.71
		Aug	2.21	1.40	0.812	36.7%	2.56	1.86	1.27	0.592	31.9%	1.87
	Typical Event Day	Aug	2.19	1.40	0.795	36.2%	2.51	1.82	1.25	0.577	31.7%	1.82
50	Average Weekday	Jun	1.39	1.26	0.128	9.2%	0.17	1.05	0.99	0.065	6.2%	0.09
		Jul	1.77	1.62	0.150	8.5%	0.20	1.58	1.47	0.115	7.2%	0.16
		Aug	1.97	1.80	0.172	8.7%	0.23	1.78	1.64	0.135	7.6%	0.18
	Monthly System Peak Day	Jun	1.91	1.69	0.224	11.7%	0.31	1.43	1.30	0.136	9.5%	0.19
		Jul	2.34	2.09	0.254	10.8%	0.34	1.94	1.75	0.189	9.8%	0.26
		Aug	2.53	2.25	0.280	11.1%	0.38	2.14	1.94	0.202	9.4%	0.27
	Typical Event Day	Aug	2.53	2.25	0.274	10.8%	0.37	2.11	1.91	0.199	9.5%	0.27
ALL	Average Weekday	Jun	1.28	0.98	0.301	23.5%	1.36	0.97	0.81	0.154	16.0%	0.70
		Jul	1.61	1.26	0.351	21.8%	1.59	1.43	1.16	0.268	18.7%	1.21
		Aug	1.78	1.38	0.403	22.6%	1.82	1.60	1.28	0.316	19.7%	1.43
	Monthly System Peak Day	Jun	1.77	1.24	0.528	29.9%	2.38	1.32	1.00	0.319	24.2%	1.44
		Jul	2.15	1.55	0.597	27.8%	2.70	1.77	1.33	0.438	24.8%	1.98
		Aug	2.31	1.66	0.655	28.4%	2.96	1.94	1.47	0.477	24.5%	2.16
	Typical Event Day	Aug	2.30	1.65	0.642	28.0%	2.90	1.91	1.44	0.466	24.4%	2.10

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 2016. For a 1-in-2 typical event day, the estimated load reduction for the average dual PTR-SCTD participant is 0.43 kW during resource availability hours. For a 1-in-10 typical event day, the estimated load reduction is 0.6 kW. The average estimated aggregate load reductions are 2.06 MW (21.3%) and 2.86 MW (23.1%), respectively.

The 4 degree setback has a higher load reduction estimate than the 50% cycling group. For example, in the 1 in 2 year on a typical event day, the load reduction is .49 for the setback group compared .4 for the cycling group, resulting in a percent load reduction of 24% compared to 19%.

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

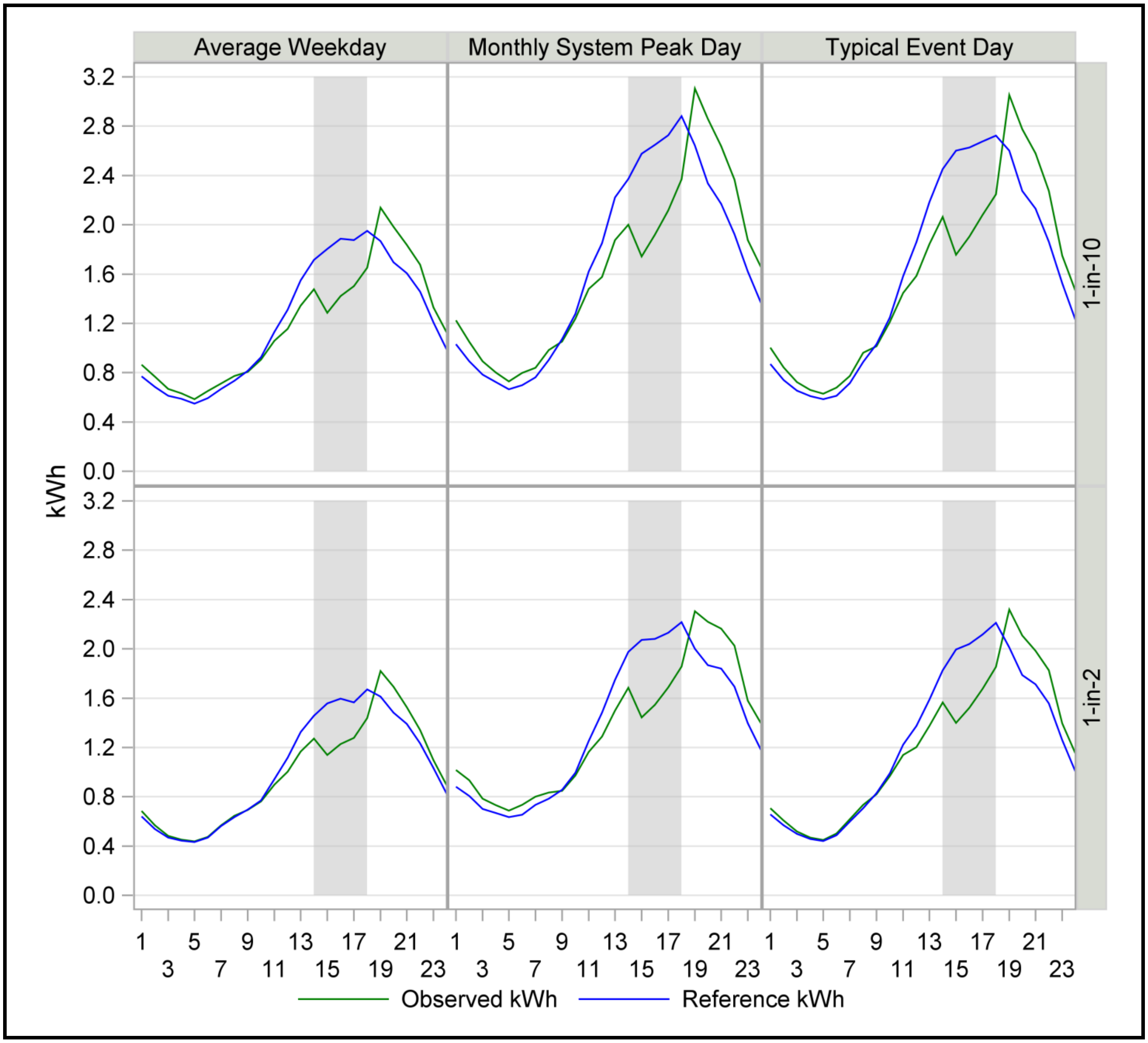


Table 4-4: Ex Ante Hourly Load Impact Results – PTR Dually Enrolled in SCTD

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	1.41	1.08	0.324	23.0%	0.72	0.94	0.77	0.166	17.7%	0.37
		Jul	1.64	1.27	0.375	22.8%	0.84	1.38	1.09	0.287	20.8%	0.64
		Aug	1.84	1.41	0.428	23.2%	0.96	1.56	1.23	0.337	21.5%	0.76
	Monthly System Peak Day	Jun	2.13	1.57	0.560	26.3%	1.24	1.46	1.12	0.343	23.5%	0.76
		Jul	2.45	1.80	0.652	26.6%	1.45	1.88	1.43	0.450	23.9%	1.00
		Aug	2.63	1.94	0.690	26.2%	1.55	2.08	1.58	0.509	24.4%	1.14
	Typical Event Day	Aug	2.60	1.92	0.683	26.2%	1.54	2.03	1.54	0.491	24.2%	1.10
50% Cycle	Average Weekday	Jun	1.41	1.15	0.262	18.5%	0.64	0.94	0.80	0.135	14.4%	0.33
		Jul	1.68	1.37	0.303	18.0%	0.75	1.41	1.18	0.232	16.4%	0.57
		Aug	1.85	1.51	0.346	18.7%	0.86	1.57	1.30	0.272	17.3%	0.68
	Monthly System Peak Day	Jun	2.14	1.69	0.453	21.2%	1.11	1.47	1.19	0.276	18.8%	0.67
		Jul	2.50	1.98	0.526	21.0%	1.29	1.92	1.55	0.365	19.0%	0.90
		Aug	2.65	2.10	0.559	21.0%	1.39	2.11	1.69	0.412	19.6%	1.02
	Typical Event Day	Aug	2.63	2.07	0.552	21.0%	1.37	2.05	1.65	0.397	19.4%	0.99
ALL	Average Weekday	Jun	1.41	1.12	0.287	20.3%	1.33	0.94	0.79	0.148	15.7%	0.69
		Jul	1.66	1.33	0.332	20.0%	1.56	1.40	1.14	0.254	18.2%	1.19
		Aug	1.85	1.47	0.379	20.5%	1.79	1.57	1.27	0.298	19.0%	1.41
	Monthly System Peak Day	Jun	2.13	1.64	0.496	23.3%	2.31	1.46	1.16	0.303	20.7%	1.41
		Jul	2.48	1.90	0.576	23.3%	2.70	1.90	1.50	0.399	21.0%	1.87
		Aug	2.64	2.03	0.611	23.1%	2.89	2.09	1.64	0.451	21.5%	2.13
	Typical Event Day	Aug	2.62	2.01	0.605	23.1%	2.86	2.04	1.60	0.435	21.3%	2.06

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 2016. For a 1-in-2 typical event day, the estimated load reduction for the average SCTD-only participant is 0.336 kW during the resource availability hour. For a 1-in-10 typical event day, the estimated load reduction is 0.465 kW. The average estimated aggregate load reductions are 1.09 MW (15.8%) and 1.5 MW (17.1%), 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 slightly higher than the 50% cycling group. The former has an average event hour load reduction estimate of 0.36 kW and 0.49 for the 1 in 10 and 1 in 2 scenarios, respectively, while the latter has an average estimate of 0.32 kW and .45 kW. The aggregate load reduction estimate for the 4 degree setback group is 0.79 MW for the 1 in 10 year, representing a load reduction of 18.7%. The comparative metric for the 50% cycling group is 0.72 MW, which is a 15.9% load reduction.

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

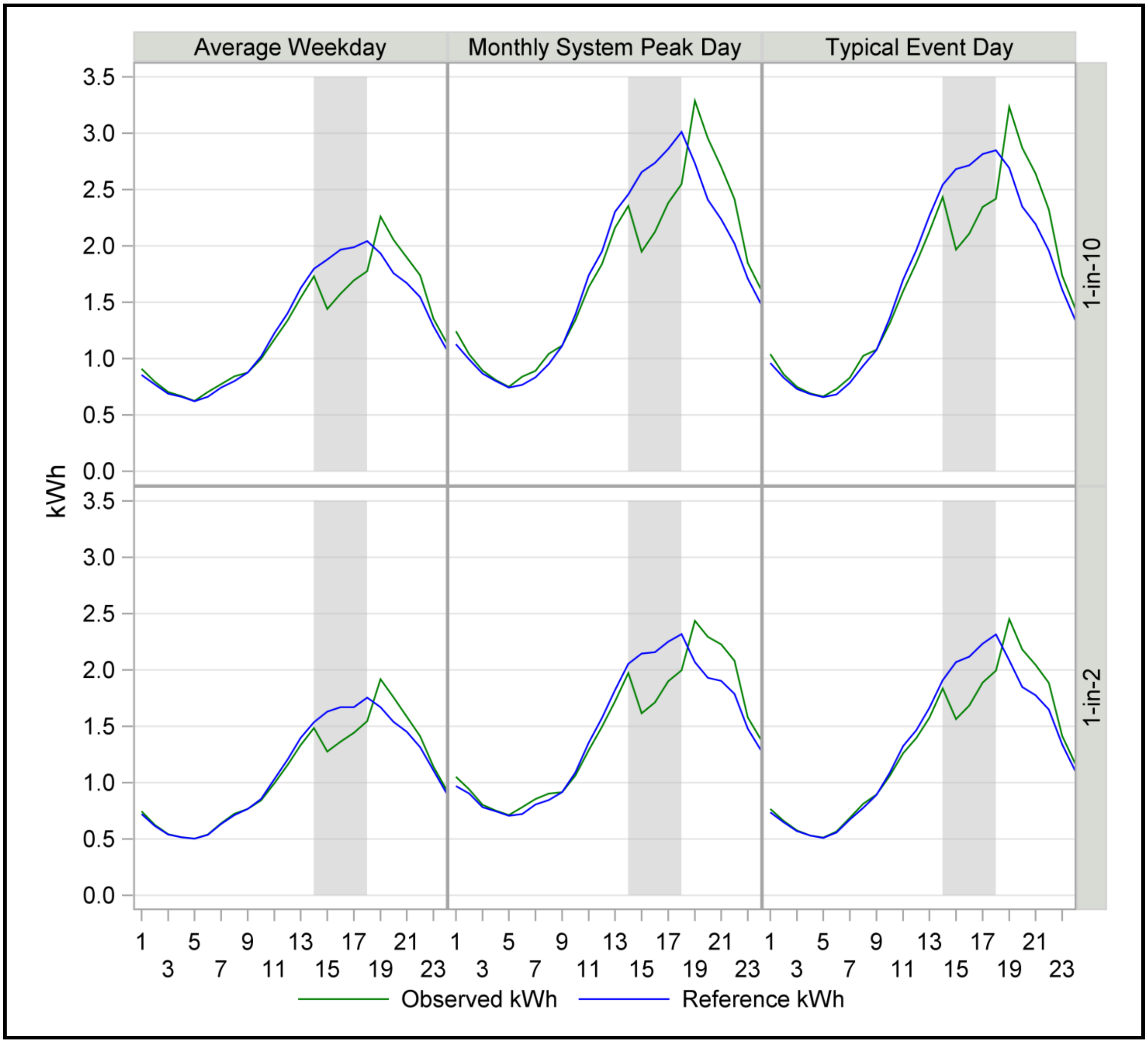


Table 4-5: Ex Ante Hourly Load Impact Results – SCTD Only

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	1.43	1.20	0.234	16.3%	0.37	0.97	0.85	0.120	12.4%	0.19
		Jul	1.70	1.43	0.271	16.0%	0.43	1.44	1.23	0.207	14.4%	0.33
		Aug	1.88	1.57	0.309	16.4%	0.50	1.61	1.37	0.244	15.2%	0.39
	Monthly System Peak Day	Jun	2.15	1.75	0.403	18.7%	0.64	1.49	1.24	0.248	16.6%	0.39
		Jul	2.50	2.03	0.469	18.8%	0.75	1.94	1.61	0.329	17.0%	0.52
		Aug	2.67	2.17	0.501	18.8%	0.80	2.12	1.76	0.367	17.3%	0.59
	Typical Event Day	Aug	2.64	2.15	0.493	18.7%	0.79	2.07	1.72	0.356	17.2%	0.57
50% Cycle	Average Weekday	Jun	1.53	1.32	0.210	13.8%	0.34	1.03	0.92	0.108	10.5%	0.17
		Jul	1.80	1.56	0.244	13.6%	0.39	1.52	1.34	0.187	12.3%	0.30
		Aug	1.98	1.70	0.279	14.1%	0.45	1.69	1.47	0.220	13.0%	0.36
	Monthly System Peak Day	Jun	2.29	1.93	0.365	15.9%	0.58	1.59	1.36	0.223	14.1%	0.36
		Jul	2.65	2.23	0.421	15.9%	0.68	2.05	1.75	0.298	14.6%	0.48
		Aug	2.82	2.37	0.452	16.0%	0.73	2.24	1.91	0.331	14.8%	0.54
	Typical Event Day	Aug	2.79	2.35	0.445	15.9%	0.72	2.18	1.86	0.322	14.7%	0.52
ALL	Average Weekday	Jun	1.48	1.26	0.220	14.8%	0.70	1.00	0.89	0.113	11.3%	0.36
		Jul	1.75	1.49	0.255	14.6%	0.82	1.48	1.29	0.195	13.2%	0.63
		Aug	1.93	1.64	0.292	15.1%	0.94	1.65	1.42	0.230	13.9%	0.74
	Monthly System Peak Day	Jun	2.22	1.84	0.380	17.1%	1.21	1.54	1.31	0.233	15.2%	0.74
		Jul	2.58	2.14	0.441	17.1%	1.41	1.99	1.68	0.311	15.6%	1.00
		Aug	2.74	2.27	0.472	17.2%	1.52	2.19	1.84	0.346	15.8%	1.12
	Typical Event Day	Aug	2.72	2.25	0.465	17.1%	1.50	2.13	1.79	0.336	15.8%	1.09

4.2.5 Comparison of 2013 and 2014 Ex Ante Estimates

Table 4-6 and Figure 4-5 through Figure 4-7 show the comparisons between the *ex ante* estimates in the current evaluation and those reported in the previous evaluation for the forecast year 2015. The current *ex ante* estimates are slightly lower for the PTR-only group – the current estimates are 0.07 kW for a 1-in-2 event day and 0.09 kW for a 1-in-10 event day, while the previous estimates are 0.11 kW and 0.13 kW, respectively. This is largely a function of a lower forecasted temperature between the two evaluation cycles – the current average temperature forecast is 80°F during event hours under the 1-in-2 scenario, whereas the previous analysis had a forecasted average temperature of 84°F. The percentage load reductions are also lower, from approximately 9% 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 substantially higher in the current evaluation. This is mainly a result of the fact that the model for the previous analysis was adapted from the opt-in PTR-only group due to small sample size and few historical events. The current analysis was able to capture the effects of the dual enrollment and thus delivers impact estimates of 0.47 kW (24%) and 0.64 kW (28%) for 1-in-2 and 1-in-10 conditions on typical event days. The previous analysis had estimates of 0.17 kW (11.4%) and 0.19 kW (10.8%), which are more akin to the PTR-only numbers.

The estimates for the SCTD participants in the current analysis are similar to the previous analysis. The previous analysis found estimates of 0.45 kW on 1-in-2 event days and 0.55 kW on 1-in-10 event days. The current analysis projects 0.43 kW on 1-in-2 event days and 0.6 kW on 1-in-10 event days. The percentage load reduction estimates under the previous analysis were higher. For example, in the 1-in-2 year, the previous results had load reductions of nearly 25%, while the current estimates are 21.3%. One minor caveat in comparing these results is that the underlying composition of cycling vs. setback is unknown for the previous ex ante numbers.

Table 4-6: Comparison of 2013 and 2014 Ex Ante Estimates – Forecast Year 2016

Participant Segment	Weather Year	Day / Type	Current: Average Hourly Reference Load	Current: Average Hourly Observed Load	Current: Average Hourly Impact	Current: Percent Load Reduction	Previous: Average Hourly Reference Load	Previous: Average Hourly Observed Load	Previous: Average Hourly Impact	Previous: Percent Load Reduction
PTR Only	1-in-10	Monthly System Peak Day	1.59	1.50	0.09	5.8%	1.50	1.37	0.13	8.7%
		Typical Event Day	1.57	1.48	0.09	5.8%	1.45	1.32	0.13	8.9%
	1-in-2	Monthly System Peak Day	1.39	1.32	0.07	5.0%	1.22	1.11	0.11	9.3%
		Typical Event Day	1.37	1.30	0.07	4.8%	1.27	1.16	0.12	9.2%
PTR/SS	1-in-10	Monthly System Peak Day	2.31	1.66	0.66	28.4%	1.82	1.63	0.19	10.4%
		Typical Event Day	2.30	1.65	0.64	28.0%	1.74	1.56	0.19	10.8%
	1-in-2	Monthly System Peak Day	1.94	1.47	0.48	24.5%	1.46	1.29	0.17	11.5%
		Typical Event Day	1.91	1.44	0.47	24.4%	1.51	1.34	0.17	11.4%
PTR/SCTD	1-in-10	Monthly System Peak Day	2.64	2.03	0.61	23.1%	2.10	1.58	0.53	25.1%
		Typical Event Day	2.62	2.01	0.60	23.1%	2.18	1.63	0.55	25.2%
	1-in-2	Monthly System Peak Day	2.09	1.64	0.45	21.5%	1.83	1.38	0.45	24.5%
		Typical Event Day	2.04	1.60	0.43	21.3%	1.84	1.39	0.45	24.5%

Figure 4-5: Comparison of 2013 and 2014 Ex Ante Hourly Load Profiles – PTR-Only – Typical Event Day

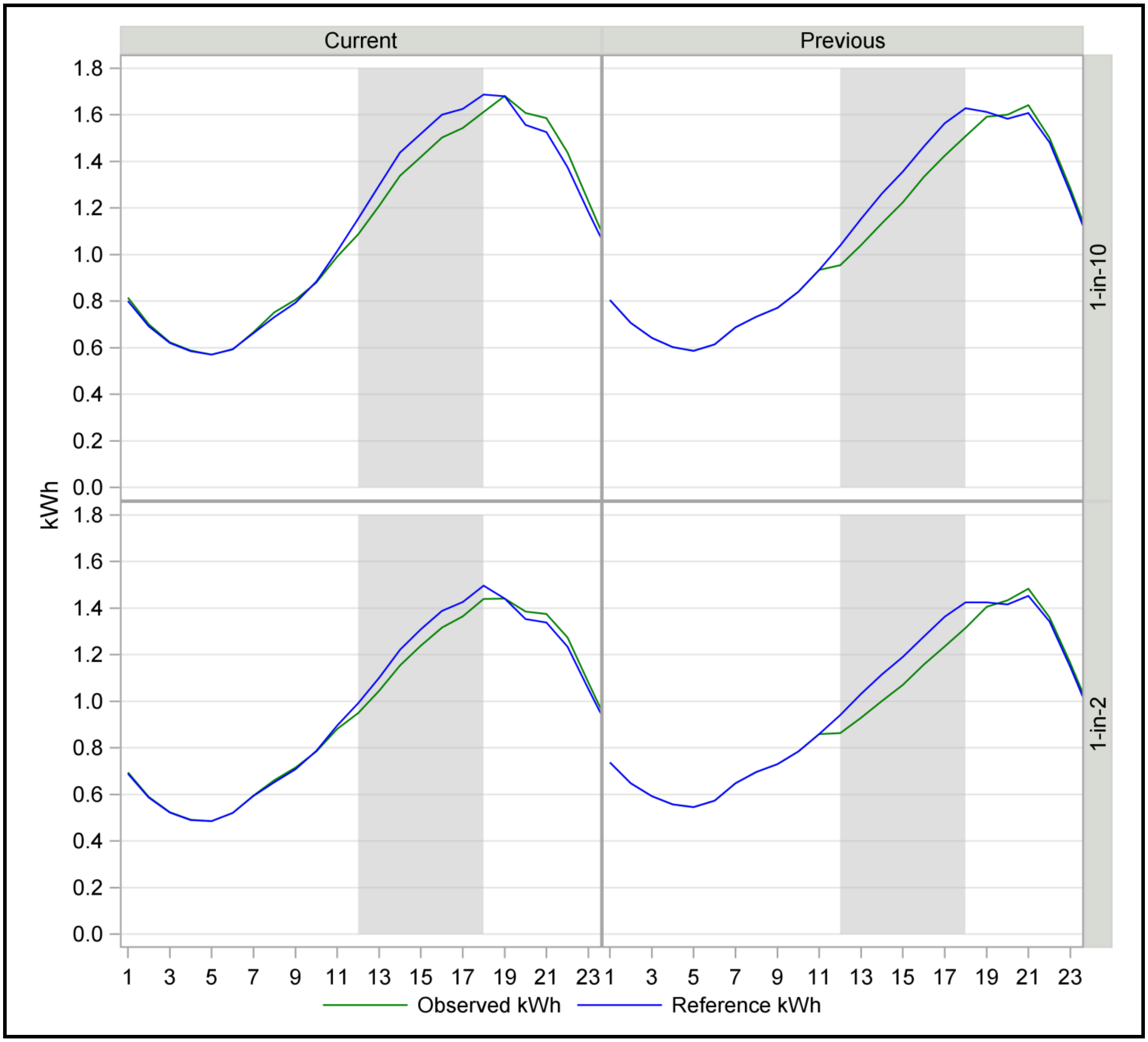


Figure 4-6: Comparison of 2013 and 2014 Ex Ante Hourly Load Profiles – PTR Dually Enrolled in Summer Saver – Typical Event Day

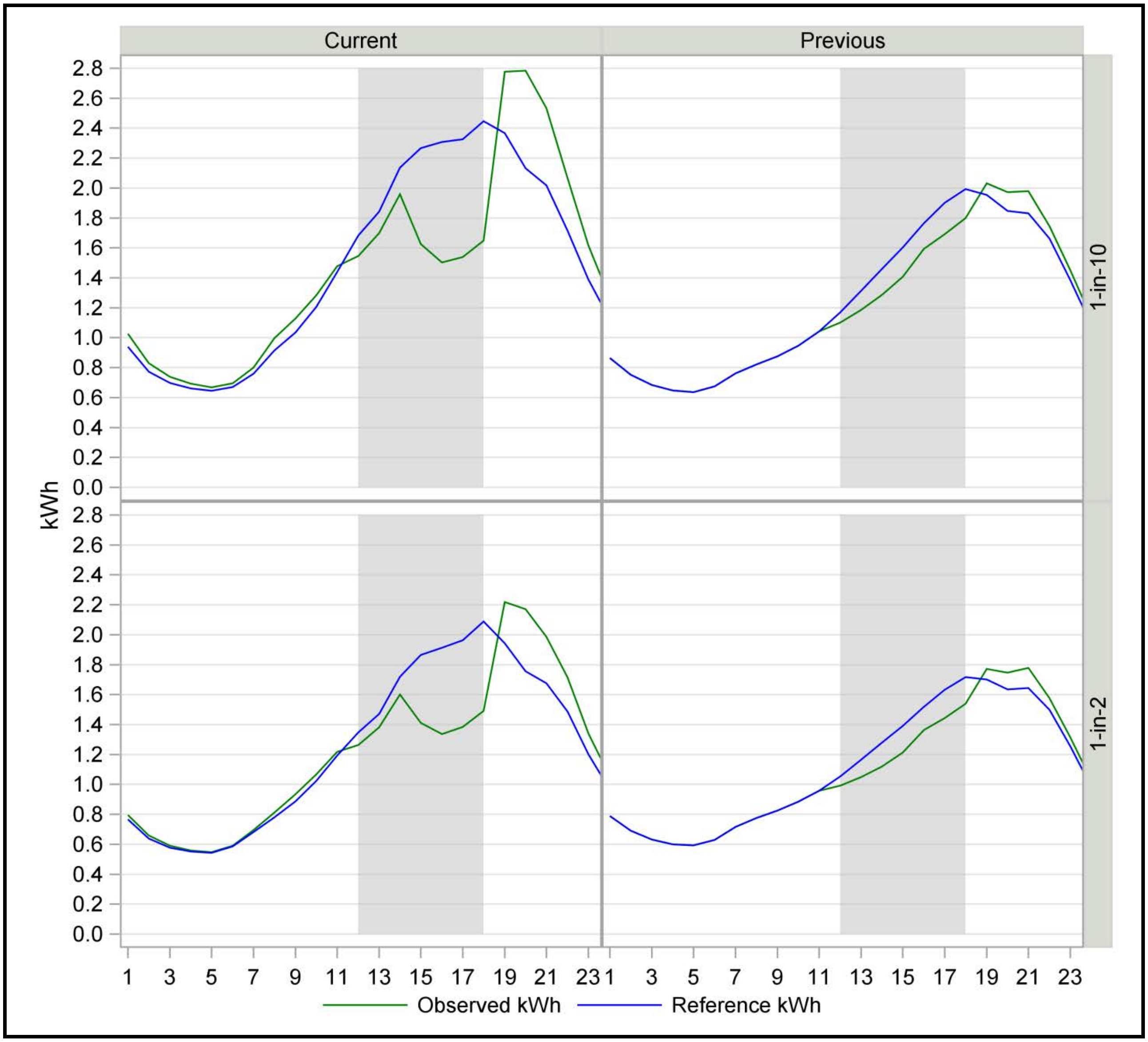
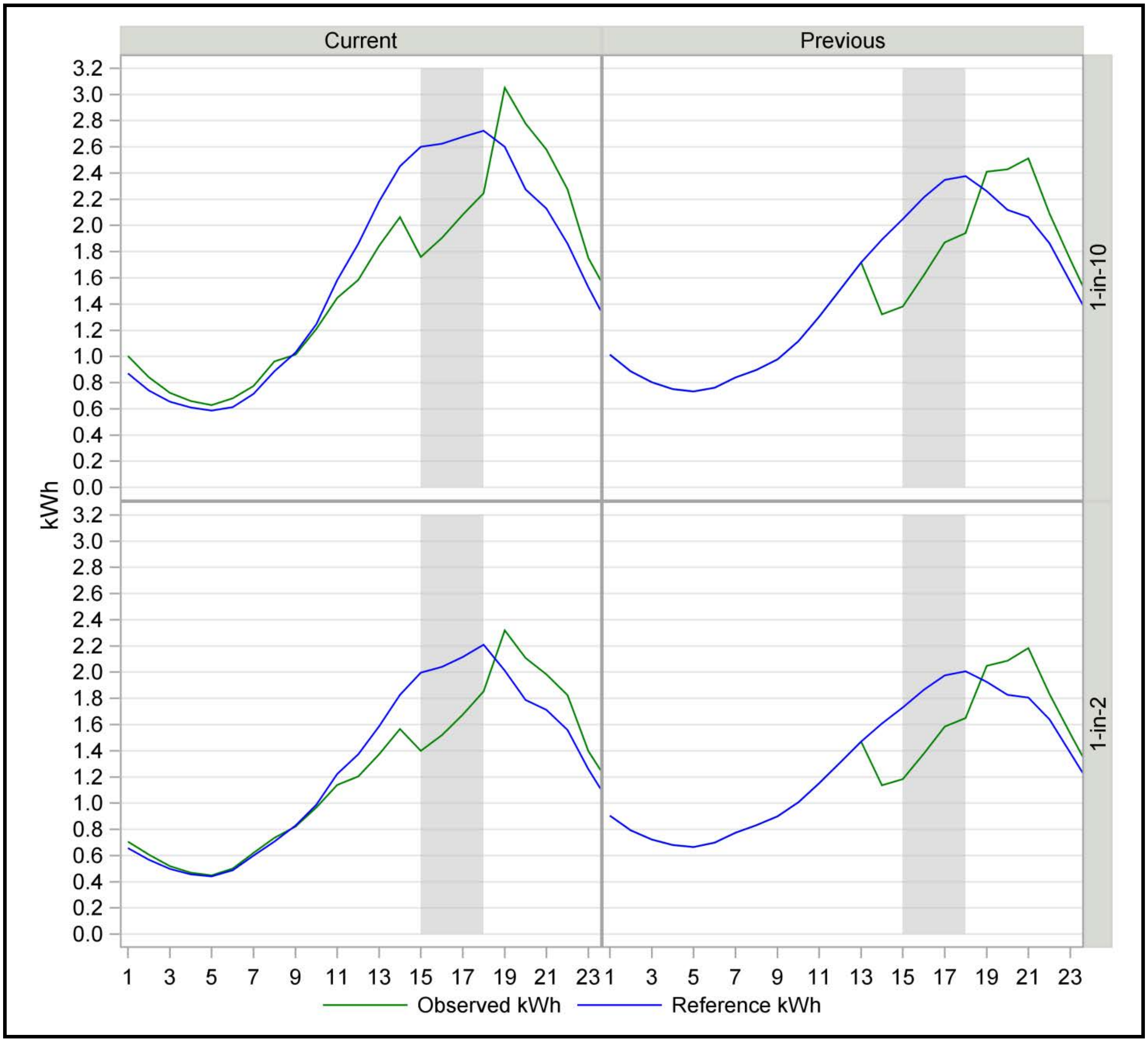


Figure 4-7: Comparison of 2013 and 2014 Ex Ante Hourly Load Profiles – PTR Dually Enrolled in SCTD – Typical Event Day



4.2.6 Relationship between Ex Post and Ex Ante Estimates

Table 4-7 shows comparisons between the *ex ante* and *ex post* estimates from this evaluation. For all of the groups, it seems that the weather in 2014 was particularly hot, and thus the results are more aligned with 1-in-10 weather conditions.

For the overall PTR-only group, both the *ex post* and 1-in-10 *ex ante* show average event hour load reductions of 0.09 kW, 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 (0.64 kW, or 28%) are slightly higher than the *ex post* impacts (0.60 kW, or 27%). The same relationship exists for the 50% and 100% cycling sub-groups. For the dually enrolled PTR-SCTD group, the *ex post* and 1-in-10 *ex ante* estimates are essentially identical, at 0.6 kW, approximately 23% of the reference load. The estimates for the load control sub-groups are also similar. The 4 degree setback group's 1-in-10 *ex ante* estimate 0.03 kW higher than the *ex post* estimate, while the 50% cycling group's is 0.02 kW lower. As with the other groups, the SCTD-only *ex post* estimates are very similar to the 1-in-10 *ex ante* estimates. The overall event hour load reduction estimate is 0.46 kW in both cases, representing about 17% of the reference load. The 50% cycling sub-group also has the same estimates, with averages of 0.45 kW, approximately 16% of the reference load. The 4 degree setback has ex post estimate of 0.47 kW, compared to the ex ante average of 0.49 for the 1-in-10 typical event day.

Table 4-7: Comparison of Ex Ante and Ex Post Estimates

Participant Segment	Control Strategy	Weather Year	Day / Type	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction	Average °F
PTR Only	**_NA_**	**1-In-10**	**Monthly System Peak Day**	1.59	1.50	0.09	5.8%	86.91
			Typical Event Day	1.57	1.48	0.09	5.8%	86.52
		1-In-2	**Monthly System Peak Day**	1.39	1.32	0.07	5.0%	81.34
			Typical Event Day	1.37	1.30	0.07	4.8%	80.55
		Ex Post	**Ex Post**	1.56	1.47	0.09	6.0%	87.08
PTR/SS	**100**	**1-In-10**	**Monthly System Peak Day**	2.21	1.40	0.81	36.7%	87.64
			Typical Event Day	2.19	1.40	0.79	36.2%	87.45
		1-In-2	**Monthly System Peak Day**	1.86	1.27	0.59	31.9%	81.73
			Typical Event Day	1.82	1.25	0.58	31.7%	81.07
		Ex Post	**Ex Post**	2.14	1.39	0.75	35.0%	86.08
	50	**1-In-10**	**Monthly System Peak Day**	2.53	2.25	0.28	11.1%	88.12
			Typical Event Day	2.53	2.25	0.27	10.8%	88.05
		1-In-2	**Monthly System Peak Day**	2.14	1.94	0.20	9.4%	81.98
			Typical Event Day	2.11	1.91	0.20	9.5%	81.41
		Ex Post	**Ex Post**	2.43	2.18	0.25	10.4%	86.31
	ALL	**1-In-10**	**Monthly System Peak Day**	2.31	1.66	0.66	28.4%	87.79
			Typical Event Day	2.30	1.65	0.64	28.0%	87.63
		1-In-2	**Monthly System Peak Day**	1.94	1.47	0.48	24.5%	81.80
			Typical Event Day	1.91	1.44	0.47	24.4%	81.17
		Ex Post	**Ex Post**	2.23	1.63	0.60	27.0%	86.15
PTR/SCTD	**4 Degree Setback**	**1-In-10**	**Monthly System Peak Day**	2.63	1.94	0.69	26.2%	87.64
			Typical Event Day	2.60	1.92	0.68	26.2%	87.44
		1-In-2	**Monthly System Peak Day**	2.08	1.58	0.51	24.4%	81.72
			Typical Event Day	2.03	1.54	0.49	24.2%	81.07
		Ex Post	**Ex Post**	2.50	1.85	0.65	26.0%	86.33
	50% Cycle	**1-In-10**	**Monthly System Peak Day**	2.65	2.10	0.56	21.0%	87.50

Table 4-7 Cont'd): Comparison of Ex Ante and Ex Post Estimates

Participant Segment	Control Strategy	Weather Year	Day / Type	Average Hourly Reference Load	Average Hourly Observed Load	Average Hourly Impact	Percent Load Reduction	Average °F
PTR/SCTD			Typical Event Day	2.63	2.07	0.55	21.0%	87.26
		1-In-2	Monthly System Peak Day	2.11	1.69	0.41	19.6%	81.65
			Typical Event Day	2.05	1.65	0.40	19.4%	80.97
		Ex Post	Ex Post	2.70	2.13	0.57	21.1%	87.97
	ALL	1-In-10	Monthly System Peak Day	2.64	2.03	0.61	23.1%	87.57
			Typical Event Day	2.62	2.01	0.60	23.1%	87.35
		1-In-2	Monthly System Peak Day	2.09	1.64	0.45	21.5%	81.69
			Typical Event Day	2.04	1.60	0.43	21.3%	81.02
		Ex Post	Ex Post	2.61	2.01	0.60	23.1%	87.25
SCTD Only	4 Degree Setback	1-In-10	Monthly System Peak Day	2.67	2.17	0.50	18.8%	87.67
			Typical Event Day	2.64	2.15	0.49	18.7%	87.48
		1-In-2	Monthly System Peak Day	2.12	1.76	0.37	17.3%	81.74
			Typical Event Day	2.07	1.72	0.36	17.2%	81.09
		Ex Post	Ex Post	2.58	2.11	0.47	18.3%	86.53
	50% Cycle	1-In-10	Monthly System Peak Day	2.82	2.37	0.45	16.0%	87.68
			Typical Event Day	2.79	2.35	0.45	15.9%	87.50
		1-In-2	Monthly System Peak Day	2.24	1.91	0.33	14.8%	81.75
			Typical Event Day	2.18	1.86	0.32	14.7%	81.10
		Ex Post	Ex Post	2.81	2.36	0.45	16.0%	87.63
	ALL	1-In-10	Monthly System Peak Day	2.74	2.27	0.47	17.2%	87.68
			Typical Event Day	2.72	2.25	0.46	17.1%	87.49
		1-In-2	Monthly System Peak Day	2.19	1.84	0.35	15.8%	81.74
			Typical Event Day	2.13	1.79	0.34	15.8%	81.09
		Ex Post	Ex Post	2.70	2.25	0.46	17.0%	87.12

5

SCTD Supplementary Analyses

5.1 Energy Savings Analysis

5.1.1 Methodology

The energy conservation effects of the smart thermostats installed through the SCTD Program were estimated using a panel time-series regression analysis. The analysis uses both a participant sample and a matched control group and includes both pre and post periods (May through October of 2013 and 2014 respectively) so as to estimate the net program impact on participants' energy usage behaviors. Propensity score matching was used to identify the control group. The matching was performed for all SCTD participants as part of the PTR analysis[1] and these matches were maintained for the energy savings analysis. As treatment customers had a smart thermostat installed, they were moved from inactive participants to active participants. Only participants who had a smart thermostat installed by August where included in the analysis. The active participant counts by month are shown in Table 5-1.

The regression equation used controls for the variation in consumption due to weather and other behavioral differences. It also allows the effect of the program to vary as other conditions change. The model was as follows:

$$
\begin{aligned}
kWh_{i,t} = \alpha_i + \sum\nolimits_m \gamma_m \times Month_m + \sum\nolimits_d \gamma_d \times DOW_d + \sum\nolimits_m \sum\nolimits_d \gamma_{m,d} \times Month_m \times DOW_d \\
+ \beta_1 \times CDD_{i,t} + \beta_2 \times Post_{i,t} + \beta_3 \times Post_t \times CDD_{i,t} \\
+ \beta_4 \times ActiveParticipant_{i,t} \times Post_t \\
+ \beta_5 \times InactiveParticipant_{i,t} \times Post_t \\
+ \beta_6 \times ActiveParticipant_{i,t} \times Post_t \times CDD_{i,t} \\
+ \beta_7 \times InactiveParticipant_{i,t} \times Post_t \times CDD_{i,t} + \epsilon_{i,t}
\end{aligned}
$$

Where:

- kWh_t represents the usage for a customer *i* on day *t*,

[1] See Section 2.1 of this report for a description of the propensity score matching methodology.

- α_i is the "customer-specific" intercept (or fixed effect) for customer *i*, accounting for unobserved heterogeneity among customers such as the number of occupants, appliance holdings, lifestyle and etc.,
- $CDD_{i,t}$ is a cooling degree day variable for customer *i* on day *t*,
- $Post_t$ is a dummy variable indicating that the year is 2014,
- $ActiveParticipant_{i,t}$ is a dummy variable indicating that customer *i* is in the treatment group by day *t*,
- $InactiveParticipant_{i,t}$ is a dummy variable indicating that participant *i* had not been in the treatment group by day *t*,
- β_1 through β_7 is a matrix of coefficients to be estimated that quantify the impacts associated with the various interactions between variables, and
- $\epsilon_{i,t}$ is the error term.

The energy savings of the program are estimated by using both a dummy variable (ActiveParticipant=1 * Post = 1) and this same dummy variable interacted with CDD to allow for linear changes in energy savings as temperatures vary. A negative and significant β_7 would indicate higher energy savings when the temperature rises.

Custom behavior with respect to energy can change over time. As time goes from May to August and from August to October, customers may develop different comfort tolerances for hot weather, vacation plans will vary, and children's school and activity schedules will vary. As a result, these changing behaviors affect their energy consumption. Similarly, people's behaviors differ across the twenty four hours of the day. To allow for these differences, monthly dummy variables have been added into the model and interacted with all program[2] and none-program[3] impact variables. This is similar to running one regression model for each month except that the site specific effects, α_i, are restricted to be constant for each site across all months. Similarly, the hourly dummy variables were added into the hourly model, interacting with all variables except the site specific effects, too.

5.1.2 Daily Model Regression Results

The daily model was estimated separately for weekdays and weekends. The holidays were included in the weekend model. Since each effect has six parameters, one for each month, the estimates are not reported here to save space. The estimated program impacts for weekdays are reported in Table 5-1, by month.

[2] Including 1) the $ActiveParticipant_{i,t}$ and its interaction with dummy variable $Post_t$, and with weather variable $CDD_{i,t}$; and 2) the $InactiveParticipant_{i,t}$ and its interaction with dummy variable $Post_t$, and with weather variable $CDD_{i,t}$.

[3] Including weather variable $CDD_{i,t}$ and dummy variable $Post_t$.

Table 5-1: Daily Energy Savings Estimation by Month – Weekday Model

Month	# Active Participants	kWh Observed	kWh Impact	kWh Reference	% Impact	Temp. (F)	t Value	p Value
May	45	21.29	-3.25	24.54	-13.26%	67.55	-6.22	<.0001
June	441	19.17	-0.30	19.47	-1.54%	67.43	-2.00	0.0451
July	997	25.12	-0.47	25.59	-1.85%	72.39	-5.03	<.0001
Aug.	1,097	26.02	-0.88	26.90	-3.28%	72.85	-9.68	<.0001
Sept.	1,097	26.22	-0.98	27.20	-3.59%	73.76	-10.01	<.0001
Oct.	1,097	19.16	-0.64	19.80	-3.24%	70.49	-7.21	<.0001

Table 5-1 above shows the estimated kWh savings by month during weekdays. The kWh Observed is the average realized kWh consumed by the participants; the kWh Impact is the average program impacts estimated by the model; the kWh Reference is the average energy consumption predicted by the model, were there not be the program; and the % Impact is calculated by kWh Impact divided by the kWh Reference.

The t-Value and the Pr>|t| are the statistics that tell how spread out the estimated impacts are, and the p values show that they are all statistically significant at 1% significance level, except for June, which is statistically significant at 5% significance level.

The participants' energy saving actions appear to have grown gradually over time. This energy saving analysis includes only those who participated before August 1st. Comparing the savings among months, the savings in May is the highest both in absolute value and percentage wise. However, this result should be interpreted with care because there are only 45 active participants in the model for May comparing to 1,097 active participants in the models for August through October. As the number of participants in this program grew, the savings appears to become more stable on average; more than 3% compared to the reference kWh. Overall, the average saving across all months is 0.73 kWh per day, accounting for 3.01% of the reference kWh usage.

Table 5-2 lists the daily energy savings by month estimated for weekends and holidays. The results are not as stable as in the weekday model, probably because of the relatively small sample size. Also, the savings on weekends appears lower than on weekdays. An explanation might be that it is relatively easy to reset their thermostats to save more energy when they are not at home during weekdays. Still, there is 0.39 kWh saving per day, which is about 1.49% of the reference usage.

Table 5-2: Daily Energy Savings Estimation by Month – Weekend Model

Month	# Active Participants	kWh Observed	kWh Impact	kWh Reference	% Impact	Temp. (F)	t Value	p Value
May	45	23.26	-2.54	25.80	-9.84%	66.74	-1.12	0.2646
June	441	20.83	0.16	20.67	0.78%	67.43	2.33	0.0196
July	997	25.79	-0.44	26.23	-1.69%	72.3	-1.43	0.1541
Aug.	1,097	27.42	-0.45	27.87	-1.62%	72.55	-2.21	0.0269
Sept.	1,097	30.31	-0.08	30.39	-0.26%	73.56	-0.11	0.9118
Oct.	1,097	21.04	-0.72	21.76	-3.30%	70.26	-3.71	0.0002

5.1.3 Hourly Model Regression Results

Figure 5-1 and Figure 5-2 below show the hourly impact on the average weekday and weekend respectively. As expected, the hourly impact on weekdays show savings during the day when people likely have their thermostats set higher while they are at work. Later in the evening, at about 6 pm, their consumption crosses the reference line[4] indicating higher consumption likely due to a snapback effect. The weekend hourly impact is not as substantial.

[4] Reference line is often referred to as the baseline. In this analysis, this is the household load profile in the absence of the treatment effect; i.e. no smart thermostat programming and load control.

Figure 5-1: Average Hourly Energy Savings on Weekdays

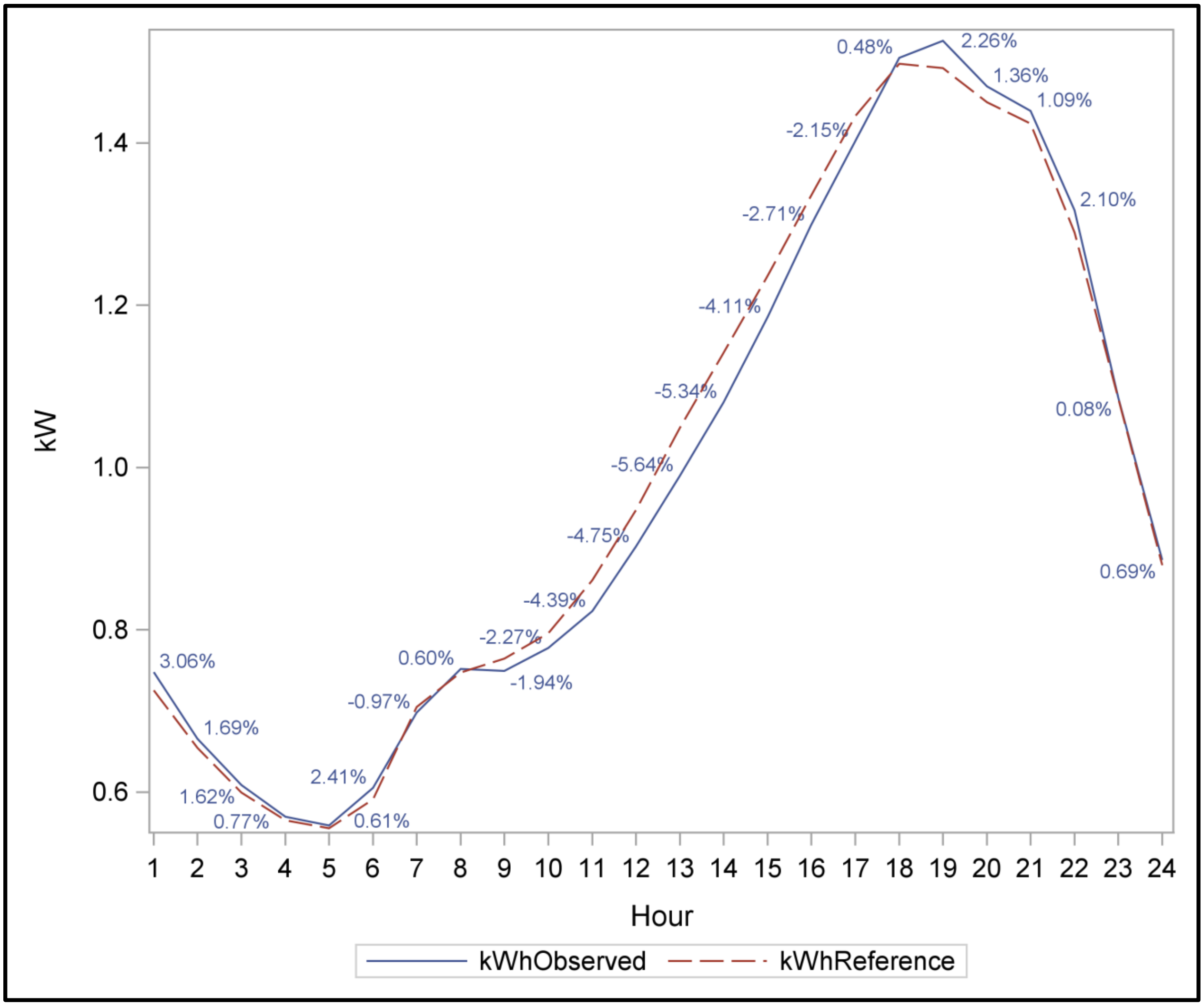
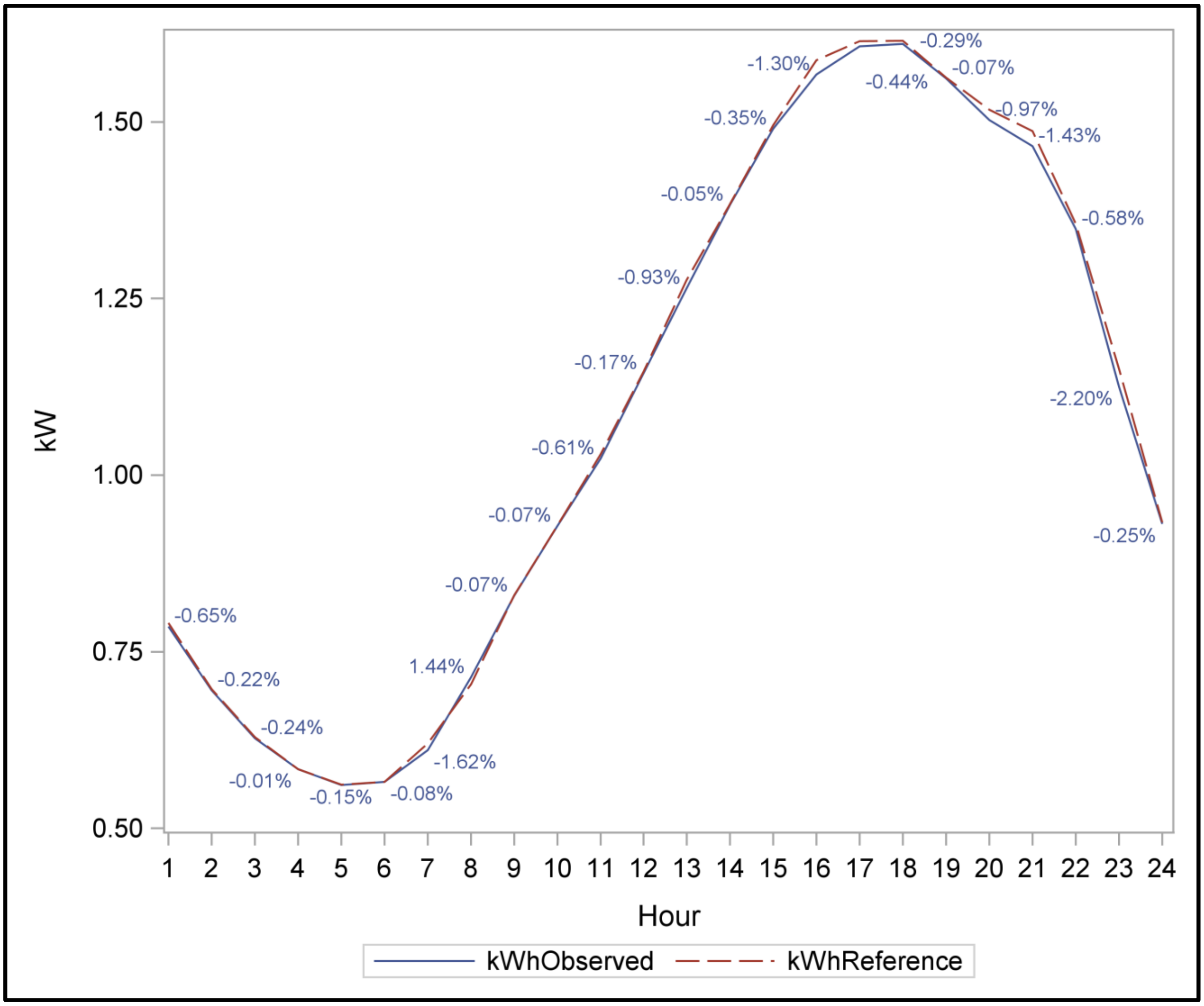


Figure 5-2: Hourly Energy Savings on Weekends

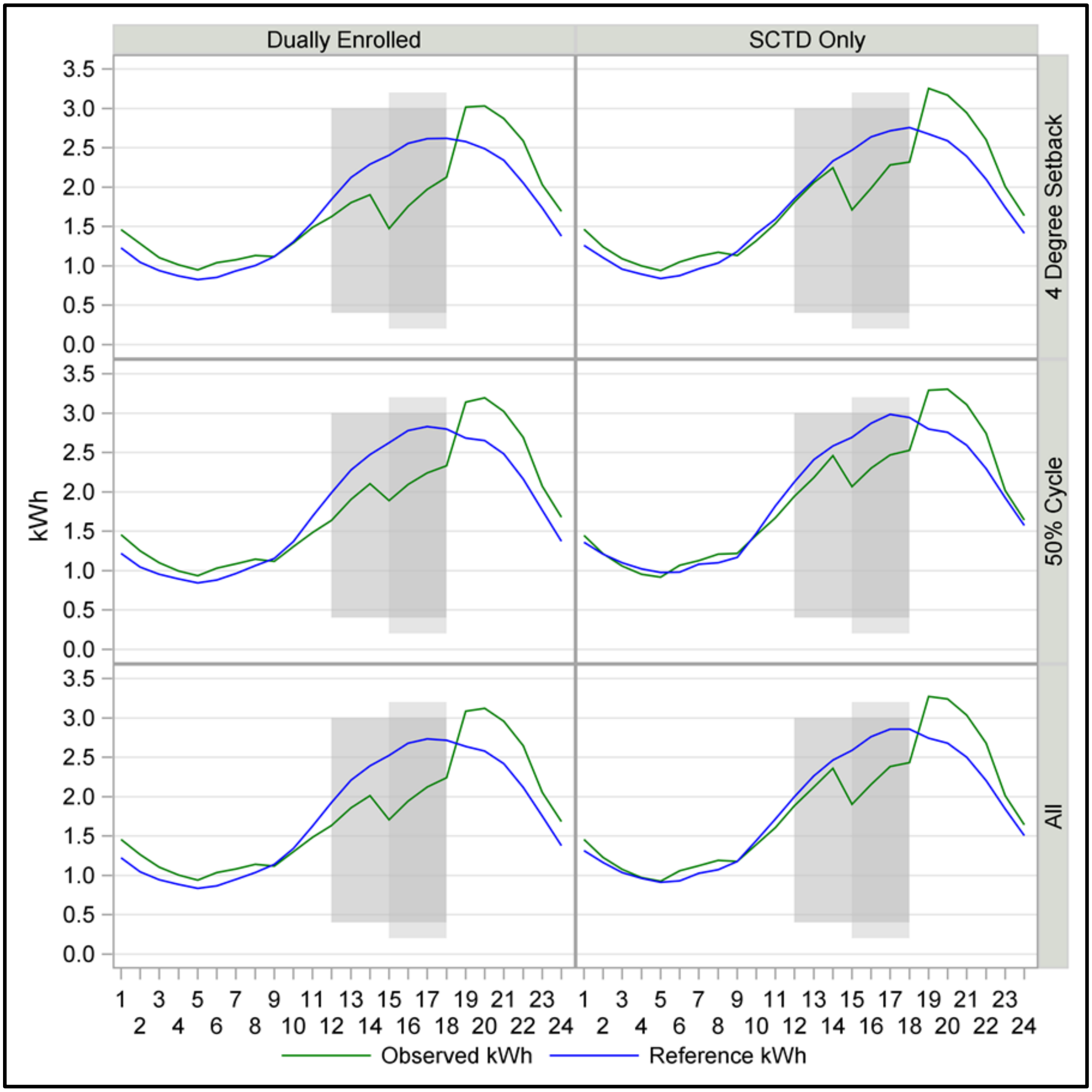


5.2 Comparison of Dually Enrolled SCTD/PTR and SCTD Only Participants

One of the secondary research topics for this study was the question of how the impacts for the PTR participant dually enrolled in SCTD compared to those enrolled in SCTD only. The two questions associated with this topic are: 1) whether there are impacts in the two PTR event hours before the SCTD load control begins, and 2) whether there are any marginal additional impact associated with the dually enrolled PTR participants. Underlying both these questions is the issue of whether PTR participants also enrolled in SCTD take any actions beyond allowing the cycling of their AC units.

The first means of addressing this topic is based on a graphical comparison of the estimated reference and observed loads on an average event day for the two groups, which is shown below in Figure 5-3. In this figure, the event hours PTR and SCTD are shown in overlapping shaded areas, and for the hours before the SCTD event begins there is a clear difference between the dually enrolled and SCTD only participants that suggests there is load reduction during that period. In the overlapping hours, the difference in load reduction is not as clear, but there is still evidence that the dually enrolled participants have higher impacts.

Figure 5-3: Average Event Comparison for Dually Enrolled and SCTD-Only Participants by Control Strategy



As a means of quantifying the differences observed in Figure 5-3, Table 5-3 presents a summary of the average hourly impacts observed during the PTR only hours, the overlapping hours, and over the entire day. Because some of the differences observed in reference and observed loads is due to noise, the impacts are also summarized based on whether the regression parameter coefficient was statistically significant. The summary provides strong evidence that the dually enrolled participants are taking actions in the PTR only hours. For example, for both control strategies combined, the dually enrolled participants show a load reduction of 15.7% compared to 5.4% for the SCTD only group. Furthermore, not of the impacts for the SCTD only group were statistically significant. Additionally, the numbers also suggest these impacts continue into the overlapping event hours, with the dually enrolled participants showing a load reduction of 24.7% compared to 19.8% for the SCTD only group.

Table 5-3: Average Hourly Impacts for Dually Enrolled and SCTD – Only Participants by Control Strategy and Time Period

		Dually Enrolled				SCTD Only			
Control Strategy	**Time Period**	**Average Hourly Impact**	**Average Percent Load Reduction**	**Average Significant Hourly Impact**	**Average Significant Percent Load Reduction**	**Average Hourly Impact**	**Average Percent Load Reduction**	**Average Significant Hourly Impact**	**Average Significant Percent Load Reduction**
4 Degree Setback	Entire Day	-0.006	-0.4%	0.018	1.1%	-0.051	-2.9%	-0.009	-0.5%
	PTR Only Hours	0.311	14.9%	0.237	11.4%	0.055	2.6%	0.000	0.0%
	PTR and SCTD Hours	0.715	28.1%	0.715	28.1%	0.569	21.5%	0.569	21.5%
50% Cycle	Entire Day	0.003	0.2%	0.027	1.5%	0.019	1.0%	0.005	0.3%
	PTR Only Hours	0.366	16.3%	0.366	16.3%	0.177	7.5%	0.000	0.0%
	PTR and SCTD Hours	0.619	22.5%	0.619	22.5%	0.532	18.5%	0.532	18.5%
All	Entire Day	-0.002	-0.1%	0.022	1.3%	-0.013	-0.7%	0.004	0.2%
	PTR Only Hours	0.341	15.7%	0.341	15.7%	0.120	5.4%	0.000	0.0%
	PTR and SCTD Hours	0.659	24.7%	0.659	24.7%	0.547	19.8%	0.547	19.8%

It is important to stress that these differences are based on comparisons of the *ex post* results. Given the relatively small number of participants in these two groups, there could very well be unexplained variables that account for some of the differences seen here. Nevertheless, these comparisons do provide compelling evidence that the dually enrolled participants are not relying on only the SCTD load control for their participation.

5.3 SCTD Override Analysis

SCTD participants have the ability to override their thermostats' demand response signals during events. Using the thermostat run-time data reports, a subset of participants was analyzed separately to determine the effects, if any, of overrides during events[5]. Table 5-4 shows the summary of SCTD participants that overrode the event signals during the three September events, when the program was in full swing and generally free of signaling errors (the September 15th event did have a signaling error for the 4 degree setback group). About 15-20% of participants overrode the event signal for any amount of time during the three events, with the total minutes overridden averaging about 55-65% of the event duration. About 10-15% of the SCTD participants overrode the event signal for the majority of the event minutes. These participants overrode an average of about 80-85% of the event duration. The 50% cycling participants overrode the event signal for a slightly larger portion of the event window, but the differences between the 4 degree setback group are not substantial.

Table 5-4: Summary of SCTD Participants Opting Out by Event Date

Event Date	Control Strategy	Total Participants	Participants Overriding (> 0%)	% Event Minutes Overridden	Participants Overriding (> 50%)	% Event Minutes Overridden
September 15, 2014	4 Degree Setback[6]	1,187	n/a	n/a	n/a	n/a
	50% Cycling	1,268	201	59%	115	82%
September 16, 2014	4 Degree Setback	1,203	296	63%	176	85%
	50% Cycling	1,292	316	65%	193	88%
September 17, 2014	4 Degree Setback	1,226	207	53%	95	78%
	50% Cycling	1,328	203	59%	115	82%

Figure 5-4 and Table 5-5 show comparisons of hourly load profiles for SCTD-only participants that did not override the event signal and those that did. It is clear from the graphs that the participants that did override experienced lower average load reductions during the event hours. During SCTD event hours, these participants had an average event hour load reduction of 0.35 kW, which is approximately half of the average for those who did not override (0.67 kW). Also, those who did override showed slightly larger snapback effects in the hours after an event, with an

5 Thermostat run time data were not available for all of the participants analyzed for the overall impacts.

6 The 4 degree setback participants did not receive an event signal on September 15th, 2014.

average load increase of 22.1%, compared to those who did not, with an average increase of 19.0%. The 50% cycling group who did override showed very small load reductions during SCTD event hours of 0.14 kW, or 4.6% of the reference load. In contrast, the 50% cycling group had the highest load reduction when there was no override during event hours, at 0.71 kW, or 25.1% of the reference load. The snapback effect in the hours after an event was also higher for the 50% group that overrode the signal. The 4 degree setback group showed smaller differences in load reduction and snapback effect between override and no override.

Figure 5-4: Average Event Comparison for SCTD-Only Participants, by Override Status and Control Strategy

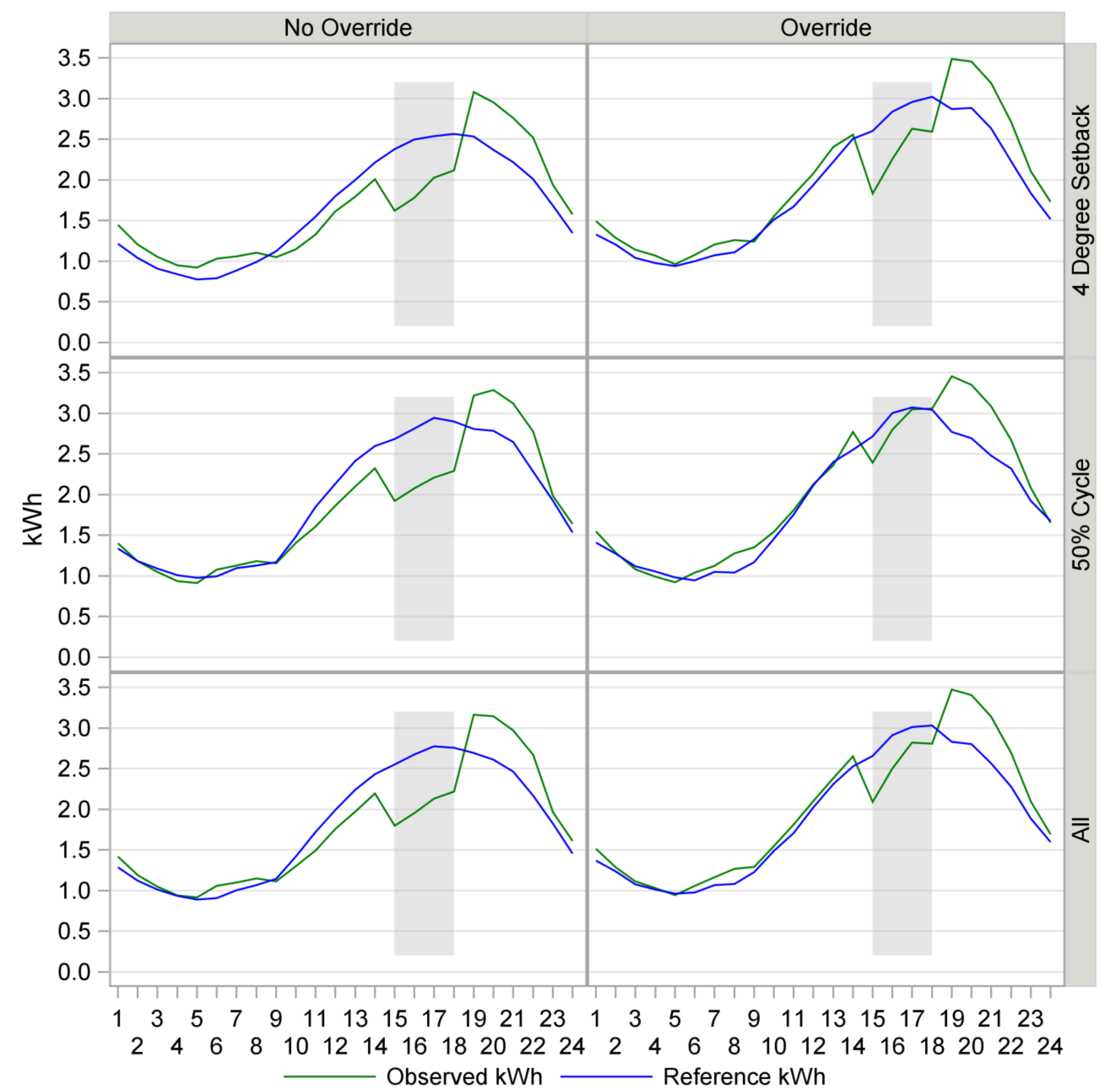


Table 5-5: Average Hourly Impacts for SCTD Only Participants by Override Status and Control Strategy

Control Strategy	Time Period	SCTD Only			
		No Override		Override	
		Average Hourly Impact	Average Percent Load Reduction	Average Hourly Impact	Average Percent Load Reduction
4 Degree Setback	Entire Day	-0.02	-1.2%	-0.08	-4.3%
	SCTD Only Hours	0.61	24.4%	0.53	18.5%
	Two Hours Post Event	-0.56	-23.0%	-0.59	-20.6%
50% Cycle	Entire Day	0.08	4.2%	-0.12	-6.1%
	SCTD Only Hours	0.71	25.1%	0.14	4.6%
	Two Hours Post Event	-0.46	-16.3%	-0.67	-24.5%
All	Entire Day	0.04	2.0%	-0.09	-4.9%
	SCTD Only Hours	0.67	24.7%	0.35	12.0%
	Two Hours Post Event	-0.50	-19.0%	-0.62	-22.1%

Appendix A

Propensity Score Matching Results

A.1 Stage One PSM Results

A.1.1 PTR Participants

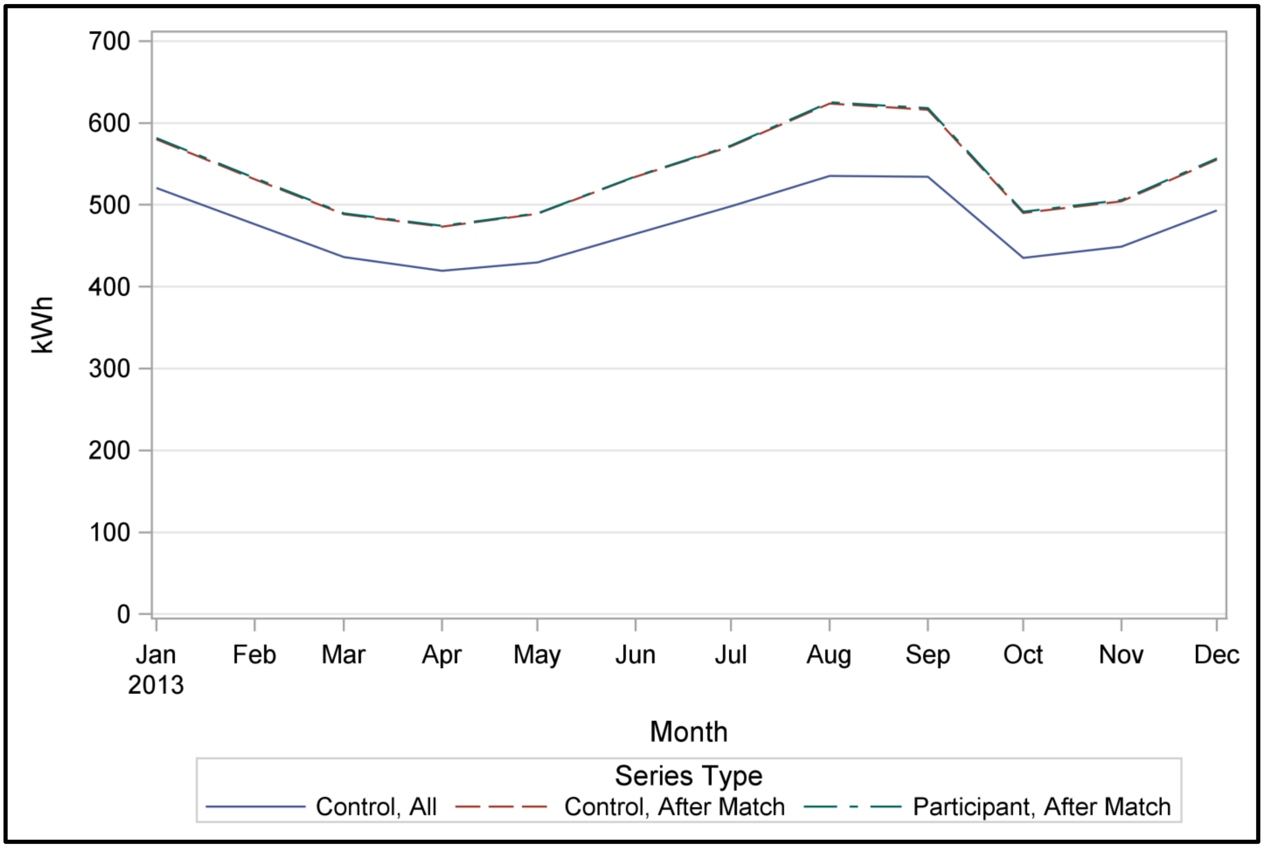
Table A-1: Summary of Premise Counts and Mean Annual kWh for Participant and Control Group Before and After Stage One Matching – PTR

Strata	Before Matching				After Matching			
	Control		Participant		Control		Participant	
	Premises	Mean Annual kWh	Premises	Mean Annual kWh	Premises	Mean Annual kWh	Premises	Mean Annual kWh
Coastal, Small	221,267	2,384	7,694	2,543	38,470	2,547	7,694	2,543
Coastal, Medium	206,775	4,718	12,379	4,723	61,895	4,725	12,379	4,723
Coastal, Large	190,668	10,005	14,378	9,699	71,890	9,665	14,378	9,699
Inland, Small	135,675	2,449	5,079	2,618	25,395	2,636	5,079	2,618
Inland, Medium	159,720	4,744	9,932	4,750	49,660	4,754	9,932	4,750
Inland, Large	170,498	9,865	13,461	9,609	67,305	9,555	13,461	9,609
NEM Customers	33,823	7,298	4,286	7,319	21,430	7,235	4,286	7,319
All	**1,118,426**	**5,749**	**67,209**	**6,527**	**336,045**	**6,506**	**67,209**	**6,527**

Table A-2: Summary of T-Test Results for Propensity Score Variables Before and After Stage One Matching - PTR

	Before Match				After Match			
Variable	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.010	-53.15	<.0001	-2.1%	-0.000	-0.42	0.6709	-0.0%
Corr. CDD-Usage	-0.023	-10.58	<.0001	-5.9%	-0.001	-0.64	0.5202	-0.4%
Corr. HDD-Usage	0.014	4.43	<.0001	143.0%	-0.001	-0.31	0.7572	20.3%
COV Monthly Usage	0.729	9.91	<.0001	3.0%	0.012	0.15	0.8803	0.0%
Ratio Hot to Cold Months	-0.037	-2.50	0.0125	-3.3%	-0.017	-1.18	0.2375	-1.5%
Ratio Usage to CDD	-0.557	-48.33	<.0001	-15.4%	-0.010	-0.80	0.4215	-0.2%
Jan kWh	-64.069	-40.64	<.0001	-12.1%	-1.663	-0.99	0.3227	-0.3%
Feb kWh	-57.654	-40.02	<.0001	-12.0%	-1.916	-1.25	0.2122	-0.4%
Mar kWh	-53.926	-40.59	<.0001	-12.3%	-1.657	-1.17	0.2419	-0.3%
Apr kWh	-54.390	-42.01	<.0001	-12.9%	-1.463	-1.06	0.2897	-0.3%
May kWh	-59.203	-43.66	<.0001	-13.7%	-1.370	-0.95	0.3444	-0.3%
Jun kWh	-69.715	-46.09	<.0001	-14.9%	-1.161	-0.72	0.4730	-0.2%
Jul kWh	-74.166	-45.70	<.0001	-14.8%	-1.791	-1.03	0.3020	-0.3%
Aug kWh	-89.983	-50.32	<.0001	-16.6%	-1.748	-0.91	0.3620	-0.3%
Sep kWh	-83.523	-49.51	<.0001	-15.5%	-2.027	-1.12	0.2613	-0.3%
Oct kWh	-54.349	-41.45	<.0001	-12.4%	-1.865	-1.33	0.1822	-0.4%
Nov kWh	-56.329	-42.22	<.0001	-12.4%	-1.953	-1.37	0.1696	-0.4%
Mean kWh	-65.037	-47.10	<.0001	-13.6%	-1.702	-1.15	0.2485	-0.3%
Dummy - Low Income	-0.003	-1.40	0.1617	-0.8%	-0.002	-0.90	0.3697	-0.6%
Dummy - Small usage	0.121	74.58	<.0001	36.8%	0.000	0.25	0.8013	0.2%
Dummy - Medium Usage	-0.015	-7.99	<.0001	-4.5%	-0.000	-0.10	0.9201	-0.1%
Dummy - Coastal	0.024	12.07	<.0001	4.2%	-0.000	-0.02	0.9842	-0.0%

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



A.2 Stage Two PSM Results

A.2.1 PTR Participants

Table A-3: Summary of Premise Counts for Participant and Control Group Before and After Stage Two Matching

Strata	Before Matching		After Matching	
	Control Premises	Participant Premises	Control Premises	Participant Premises
Coastal, Small	38,971	7,687	7,675	7,675
Coastal, Medium	62,702	12,379	12,372	12,372
Coastal, Large	71,961	14,368	14,363	14,363
Inland, Small	25,626	5,074	5,065	5,065
Inland, Medium	49,791	9,929	9,920	9,920
Inland, Large	66,416	13,449	13,444	13,444
All	**315,467**	**62,886**	**62,839**	**62,839**

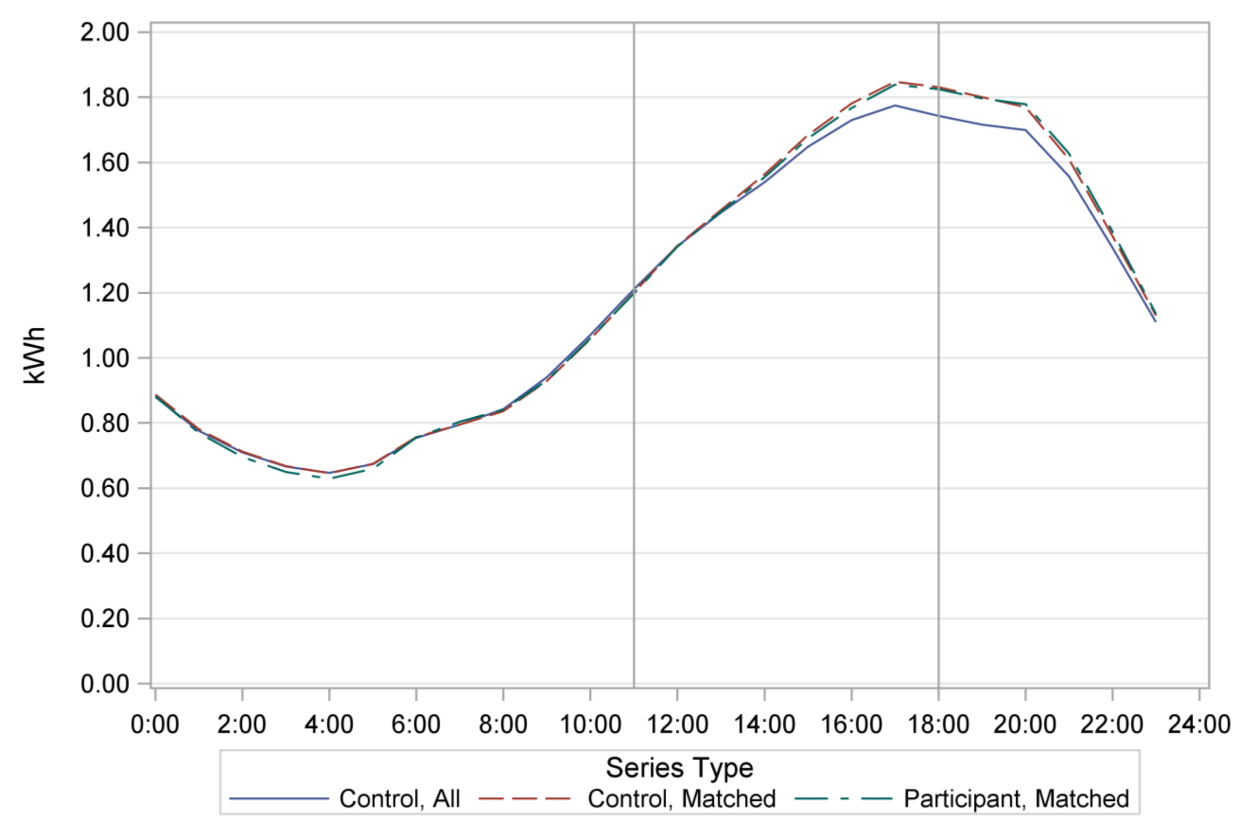
Table A-4: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching - PTR

	Before Match				After Match			
Variable	**Mean Control - Participant**	**t Value**	**Pr > |t|**	**% Difference**	**Mean Control - Participant**	**t Value**	**Pr > |t|**	**% Difference**
Propensity Score	-0.008	-40.00	<.0001	-1.8%	-0.000	-0.00	0.9999	-0.0%
Corr. - Hot Day CDH	0.005	2.35	0.0188	16.9%	-0.002	-0.86	0.3884	-11.5%
Corr. - Winter HDH	0.000	0.52	0.6016	0.3%	-0.000	-0.53	0.5985	-0.5%
Coeff. Of Var - Event Window kWh	-0.014	-0.18	0.8533	-0.0%	0.159	1.46	0.1444	0.5%
Coeff. Of Var - Weekday kWh	0.079	1.21	0.2265	0.3%	0.059	0.64	0.5195	0.2%
Ratio Hot to Cold Months	-0.004	-0.91	0.3635	-0.3%	0.002	0.55	0.5793	0.2%
Ratio Usage to CDD	-0.015	-1.22	0.2238	-0.4%	-0.002	-0.13	0.8976	-0.1%
Summer kWh - Hour 12	0.012	4.04	0.0011	1.6%	-0.003	-0.78	0.4426	-0.4%
Summer kWh - Hour 13	0.012	4.10	0.0008	1.6%	-0.003	-0.73	0.4746	-0.4%
Summer kWh - Hour 14	0.014	4.47	<.0001	1.8%	-0.002	-0.60	0.5681	-0.3%
Summer kWh - Hour 15	0.016	5.34	<.0001	2.1%	-0.001	-0.40	0.6974	-0.2%
Summer kWh - Hour 16	0.017	5.92	<.0001	2.2%	0.000	-0.01	0.7324	0.0%
Summer kWh - Hour 17	0.015	4.99	<.0001	1.8%	0.001	0.27	0.7740	0.1%
Summer kWh - Hour 18	0.001	0.06	0.0936	0.1%	0.001	0.11	0.5598	0.1%
Summer kWh - Hour 19	-0.014	-3.94	0.0095	-1.2%	-0.001	-0.11	0.6721	-0.0%
Summer kWh - Hour 20	-0.017	-4.95	<.0001	-1.5%	-0.001	-0.15	0.7830	-0.1%
Hot Day kWh - Hour 12	0.008	1.53	0.1264	0.7%	0.000	0.02	0.9815	0.0%
Hot Day kWh - Hour 13	-0.002	-0.30	0.7618	-0.1%	0.004	0.44	0.6580	0.3%
Hot Day kWh - Hour 14	-0.014	-2.24	0.0248	-1.1%	0.007	0.81	0.4187	0.5%
Hot Day kWh - Hour 15	-0.029	-4.23	<.0001	-2.0%	0.007	0.77	0.4387	0.5%
Hot Day kWh - Hour 16	-0.040	-5.61	<.0001	-2.7%	0.004	0.41	0.6822	0.3%

Table A-4 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching - PTR

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Hot Day kWh - Hour 17	-0.050	-6.98	<.0001	-3.2%	0.008	0.76	0.4476	0.5%
Hot Day kWh - Hour 18	-0.066	-9.27	<.0001	-4.1%	0.009	0.93	0.3541	0.6%
Hot Day kWh - Hour 19	-0.079	-11.52	<.0001	-4.9%	0.006	0.64	0.5225	0.4%
Hot Day kWh - Hour 20	-0.077	-12.12	<.0001	-4.9%	0.003	0.37	0.7093	0.2%
Jan Event Window kWh	-1.347	-1.11	0.2671	-0.3%	-0.569	-0.34	0.7339	-0.1%
Feb Event Window kWh	-1.973	-1.73	0.0828	-0.5%	-0.516	-0.33	0.7424	-0.1%
Mar Event Window kWh	-1.272	-1.26	0.2095	-0.4%	-0.526	-0.38	0.7046	-0.2%
Apr Event Window kWh	-1.100	-1.12	0.2648	-0.3%	-0.668	-0.50	0.6200	-0.2%
May Event Window kWh	-1.184	-1.12	0.2620	-0.3%	-0.835	-0.58	0.5630	-0.2%
Jun Event Window kWh	-0.839	-0.74	0.4600	-0.2%	-0.993	-0.64	0.5244	-0.3%
Jul Event Window kWh	-2.289	-1.74	0.0815	-0.6%	-0.323	-0.18	0.8598	-0.1%
Aug Event Window kWh	-1.836	-1.38	0.1667	-0.4%	0.210	0.11	0.9098	0.0%
Sep Event Window kWh	-2.412	-1.82	0.0682	-0.6%	0.326	0.18	0.8606	0.1%
Oct Event Window kWh	-1.811	-1.84	0.0662	-0.5%	-0.947	-0.69	0.4891	-0.3%
Nov Event Window kWh	-2.069	-2.04	0.0410	-0.6%	-0.876	-0.62	0.5328	-0.3%
Dec Event Window kWh	-2.312	-1.95	0.0516	-0.6%	-0.395	-0.24	0.8115	-0.1%
Dummy - Low Income	0.000	0.08	0.9341	0.1%	-0.000	-0.15	0.8803	-0.1%

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



A.2.2 SCTD Participants

Table A-5: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – SCTD

	Before Match				After Match			
Variable	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.007	-34.20	<.0001	-78.2%	0.000	0.00	0.9975	0.0%
Corr. - Hot Day CDH	-0.030	-3.87	0.0001	-111.1%	0.021	1.87	0.0611	26.8%
Corr. - Winter HDH	-0.005	-2.29	0.0223	-5.3%	-0.003	-1.04	0.2980	-3.5%
Coeff. Of Var - Event Window kWh	-3.656	-12.28	<.0001	-12.3%	-0.124	-0.29	0.7700	-0.4%
Coeff. Of Var - Weekday kWh	0.415	1.92	0.0555	1.8%	-0.236	-0.78	0.4352	-1.0%
Ratio Hot to Cold Months	-0.120	-16.27	<.0001	-10.6%	0.012	1.07	0.2849	0.9%
Ratio Usage to CDD	-0.905	-19.85	<.0001	-22.6%	0.033	0.50	0.6170	0.7%
Summer kWh - Hour 12	-0.108	-9.91	<.0001	-14.7%	0.007	0.45	0.6732	0.8%
Summer kWh - Hour 13	-0.122	-10.57	<.0001	-16.0%	0.011	0.65	0.5272	1.2%
Summer kWh - Hour 14	-0.136	-11.29	<.0001	-17.4%	0.012	0.68	0.5282	1.3%
Summer kWh - Hour 15	-0.148	-11.97	<.0001	-18.4%	0.013	0.70	0.4976	1.3%
Summer kWh - Hour 16	-0.160	-12.34	<.0001	-18.7%	0.012	0.59	0.5931	1.1%
Summer kWh - Hour 17	-0.176	-13.49	<.0001	-19.2%	0.008	0.38	0.7202	0.7%
Summer kWh - Hour 18	-0.217	-16.61	<.0001	-21.5%	0.004	0.15	0.5738	0.3%
Summer kWh - Hour 19	-0.225	-17.44	<.0001	-21.0%	-0.002	-0.14	0.7213	-0.2%
Summer kWh - Hour 20	-0.214	-17.39	<.0001	-19.7%	-0.009	-0.54	0.6067	-0.7%
Hot Day kWh - Hour 12	-0.442	-19.88	<.0001	-41.0%	0.006	0.17	0.8636	0.4%
Hot Day kWh - Hour 13	-0.546	-21.47	<.0001	-45.6%	0.024	0.66	0.5099	1.4%
Hot Day kWh - Hour 14	-0.672	-24.00	<.0001	-51.7%	0.022	0.53	0.5948	1.1%

Table A-5 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – SCTD

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Hot Day kWh - Hour 15	-0.778	-26.56	<.0001	-56.0%	0.022	0.51	0.6092	1.0%
Hot Day kWh - Hour 16	-0.870	-28.61	<.0001	-58.5%	0.015	0.33	0.7388	0.6%
Hot Day kWh - Hour 17	-0.918	-30.17	<.0001	-58.8%	0.008	0.18	0.8560	0.3%
Hot Day kWh - Hour 18	-0.917	-30.86	<.0001	-56.9%	0.019	0.44	0.6603	0.8%
Hot Day kWh - Hour 19	-0.855	-31.15	<.0001	-53.4%	-0.004	-0.09	0.9302	-0.1%
Hot Day kWh - Hour 20	-0.762	-29.73	<.0001	-48.2%	-0.033	-0.84	0.3982	-1.4%
Jan Event Window kWh	-45.271	-10.47	<.0001	-11.2%	-1.552	-0.25	0.8009	-0.3%
Feb Event Window kWh	-47.256	-11.62	<.0001	-12.5%	-2.525	-0.44	0.6614	-0.6%
Mar Event Window kWh	-47.115	-13.20	<.0001	-13.9%	0.929	0.18	0.8561	0.2%
Apr Event Window kWh	-45.570	-13.15	<.0001	-13.9%	1.723	0.34	0.7318	0.5%
May Event Window kWh	-58.895	-15.54	<.0001	-17.1%	2.625	0.48	0.6325	0.6%
Jun Event Window kWh	-69.181	-16.68	<.0001	-19.0%	2.267	0.38	0.7060	0.5%
Jul Event Window kWh	-96.620	-19.03	<.0001	-23.3%	1.237	0.17	0.8658	0.2%
Aug Event Window kWh	-109.339	-21.73	<.0001	-25.7%	4.698	0.64	0.5247	0.9%
Sep Event Window kWh	-118.359	-23.54	<.0001	-27.3%	6.596	0.88	0.3764	1.2%
Oct Event Window kWh	-51.095	-14.34	<.0001	-15.2%	3.741	0.72	0.4707	1.0%
Nov Event Window kWh	-50.451	-14.02	<.0001	-14.6%	2.001	0.38	0.7013	0.5%
Dec Event Window kWh	-54.989	-12.99	<.0001	-13.7%	1.160	0.19	0.8502	0.3%
Dummy - Low Income	0.153	24.00	<.0001	47.5%	-0.013	-1.45	0.1480	-8.2%

A.2.3 Summer Saver Participants

Table A-6: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Summer Saver

	Before Match				After Match			
Variable	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.005	-21.44	<.0001	-60.8%	0.000	0.01	0.9895	0.0%
Corr. - Hot Day CDH	-0.010	-1.20	0.2302	-36.7%	0.009	0.80	0.4251	20.0%
Corr. - Winter HDH	-0.016	-6.91	<.0001	-17.0%	0.003	1.06	0.2878	3.1%
Coeff. Of Var - Event Window kWh	2.566	8.98	<.0001	8.6%	0.273	0.68	0.4953	1.0%
Coeff. Of Var - Weekday kWh	3.283	15.82	<.0001	13.9%	0.082	0.28	0.7796	0.4%
Ratio Hot to Cold Months	-0.003	-0.45	0.6545	-0.3%	0.005	0.46	0.6454	0.4%
Ratio Usage to CDD	-0.427	-8.91	<.0001	-10.6%	0.055	0.78	0.4337	1.2%
Summer kWh - Hour 12	-0.080	-6.68	<.0001	-11.0%	0.001	0.06	0.9540	0.1%
Summer kWh - Hour 13	-0.076	-6.34	<.0001	-10.2%	0.003	0.14	0.8874	0.3%
Summer kWh - Hour 14	-0.074	-6.19	<.0001	-9.8%	0.006	0.34	0.7329	0.7%
Summer kWh - Hour 15	-0.066	-5.65	<.0001	-8.6%	0.008	0.42	0.6776	0.9%
Summer kWh - Hour 16	-0.059	-5.20	<.0001	-7.4%	0.009	0.53	0.5988	1.0%
Summer kWh - Hour 17	-0.068	-5.85	<.0001	-7.8%	0.010	0.55	0.5799	1.0%
Summer kWh - Hour 18	-0.108	-8.40	<.0001	-10.7%	0.015	0.77	0.4392	1.3%
Summer kWh - Hour 19	-0.136	-9.99	<.0001	-12.5%	0.015	0.78	0.4420	1.2%
Summer kWh - Hour 20	-0.130	-9.89	<.0001	-11.8%	0.018	0.93	0.3521	1.4%
Hot Day kWh - Hour 12	-0.232	-10.24	<.0001	-21.5%	-0.011	-0.33	0.7386	-0.8%
Hot Day kWh - Hour 13	-0.283	-11.31	<.0001	-23.6%	0.000	0.00	0.9990	0.0%
Hot Day kWh - Hour 14	-0.316	-11.74	<.0001	-24.2%	0.017	0.44	0.6581	1.1%

Table A-6 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Summer Saver

	Before Match				After Match			
Variable	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Hot Day kWh - Hour 15	-0.368	-12.68	<.0001	-26.4%	0.019	0.45	0.6553	1.1%
Hot Day kWh - Hour 16	-0.394	-12.73	<.0001	-26.4%	0.033	0.75	0.4541	1.7%
Hot Day kWh - Hour 17	-0.418	-13.34	<.0001	-26.7%	0.041	0.90	0.3662	2.0%
Hot Day kWh - Hour 18	-0.455	-14.70	<.0001	-28.1%	0.033	0.75	0.4520	1.6%
Hot Day kWh - Hour 19	-0.480	-16.25	<.0001	-29.9%	0.029	0.66	0.5079	1.4%
Hot Day kWh - Hour 20	-0.424	-15.39	<.0001	-26.8%	0.027	0.67	0.5000	1.3%
Jan Event Window kWh	-37.468	-7.75	<.0001	-9.2%	3.717	0.53	0.5932	0.8%
Feb Event Window kWh	-38.530	-8.59	<.0001	-10.2%	3.577	0.55	0.5792	0.8%
Mar Event Window kWh	-36.834	-9.45	<.0001	-10.9%	4.312	0.76	0.4467	1.1%
Apr Event Window kWh	-36.240	-9.42	<.0001	-11.0%	3.301	0.59	0.5540	0.9%
May Event Window kWh	-37.265	-9.06	<.0001	-10.8%	4.537	0.76	0.4500	1.2%
Jun Event Window kWh	-40.252	-8.95	<.0001	-11.0%	3.845	0.58	0.5597	0.9%
Jul Event Window kWh	-45.845	-8.82	<.0001	-11.0%	4.651	0.61	0.5396	1.0%
Aug Event Window kWh	-53.260	-10.21	<.0001	-12.5%	7.096	0.92	0.3566	1.5%
Sep Event Window kWh	-58.526	-11.51	<.0001	-13.5%	5.645	0.75	0.4531	1.1%
Oct Event Window kWh	-35.975	-9.23	<.0001	-10.7%	5.291	0.93	0.3534	1.4%
Nov Event Window kWh	-40.566	-10.17	<.0001	-11.7%	4.853	0.83	0.4055	1.2%
Dec Event Window kWh	-45.480	-9.81	<.0001	-11.3%	4.299	0.63	0.5294	1.0%
Dummy - Low Income	0.109	14.66	<.0001	34.0%	-0.016	-1.52	0.1292	-8.0%

A.2.4 Low Income Participants

Table A-7: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Low Income

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.007	-46.56	<.0001	-4.1%	-0.000	-0.00	0.9994	-0.0%
Corr. - Hot Day CDH	0.006	2.81	0.0049	20.3%	0.000	0.02	0.9812	0.3%
Corr. - Winter HDH	0.001	1.17	0.2429	0.7%	0.001	0.72	0.4705	0.6%
Coeff. Of Var - Event Window kWh	0.063	0.80	0.4211	0.2%	-0.063	-0.58	0.5613	-0.2%
Coeff. Of Var - Weekday kWh	0.064	0.97	0.3333	0.3%	-0.022	-0.24	0.8101	-0.1%
Ratio Hot to Cold Months	-0.001	-0.17	0.8638	-0.1%	-0.003	-1.01	0.3105	-0.3%
Ratio Usage to CDD	0.013	1.04	0.2982	0.3%	-0.022	-1.30	0.1926	-0.6%
Summer kWh - Hour 12	0.016	5.36	<.0001	2.2%	-0.000	-0.11	0.7491	-0.1%
Summer kWh - Hour 13	0.017	5.46	<.0001	2.2%	-0.002	-0.39	0.7008	-0.2%
Summer kWh - Hour 14	0.018	5.94	<.0001	2.4%	-0.003	-0.68	0.5072	-0.4%
Summer kWh - Hour 15	0.021	6.89	<.0001	2.7%	-0.004	-0.79	0.4797	-0.4%
Summer kWh - Hour 16	0.023	7.51	<.0001	2.8%	-0.004	-0.76	0.5148	-0.4%
Summer kWh - Hour 17	0.021	6.69	<.0001	2.4%	-0.004	-0.80	0.5289	-0.4%
Summer kWh - Hour 18	0.007	1.93	0.4325	0.7%	-0.004	-0.74	0.4832	-0.4%
Summer kWh - Hour 19	-0.007	-2.03	0.4575	-0.6%	-0.003	-0.56	0.4159	-0.3%
Summer kWh - Hour 20	-0.010	-3.02	0.0322	-0.9%	-0.002	-0.50	0.4571	-0.2%
Hot Day kWh - Hour 12	0.020	3.88	0.0001	1.9%	-0.002	-0.24	0.8121	-0.2%
Hot Day kWh - Hour 13	0.013	2.18	0.0294	1.1%	-0.004	-0.50	0.6152	-0.3%
Hot Day kWh - Hour 14	0.004	0.57	0.5711	0.3%	-0.007	-0.78	0.4346	-0.5%

Table A-7 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Low Income

	Before Match				After Match			
Variable	**Mean Control - Participant**	**t Value**	**Pr > |t|**	**% Difference**	**Mean Control - Participant**	**t Value**	**Pr > |t|**	**% Difference**
Hot Day kWh - Hour 15	-0.009	-1.30	0.1931	-0.6%	-0.009	-0.94	0.3473	-0.6%
Hot Day kWh - Hour 16	-0.017	-2.40	0.0166	-1.1%	-0.006	-0.61	0.5432	-0.4%
Hot Day kWh - Hour 17	-0.026	-3.60	0.0003	-1.7%	-0.006	-0.60	0.5465	-0.4%
Hot Day kWh - Hour 18	-0.042	-5.90	<.0001	-2.6%	-0.012	-1.23	0.2189	-0.7%
Hot Day kWh - Hour 19	-0.057	-8.29	<.0001	-3.6%	-0.015	-1.56	0.1183	-0.9%
Hot Day kWh - Hour 20	-0.057	-8.94	<.0001	-3.6%	-0.015	-1.73	0.0829	-1.0%
Jan Event Window kWh	0.310	0.25	0.8000	0.1%	-0.798	-0.47	0.6352	-0.2%
Feb Event Window kWh	-0.329	-0.29	0.7742	-0.1%	-0.164	-0.10	0.9170	-0.0%
Mar Event Window kWh	0.316	0.31	0.7574	0.1%	-0.384	-0.28	0.7829	-0.1%
Apr Event Window kWh	0.421	0.42	0.6725	0.1%	-0.331	-0.24	0.8073	-0.1%
May Event Window kWh	0.601	0.56	0.5721	0.2%	-1.168	-0.81	0.4188	-0.3%
Jun Event Window kWh	1.339	1.17	0.2418	0.4%	-1.929	-1.24	0.2132	-0.5%
Jul Event Window kWh	0.675	0.51	0.6100	0.2%	-2.452	-1.35	0.1757	-0.6%
Aug Event Window kWh	1.508	1.13	0.2590	0.4%	-2.712	-1.48	0.1382	-0.6%
Sep Event Window kWh	1.311	0.99	0.3245	0.3%	-1.734	-0.95	0.3417	-0.4%
Oct Event Window kWh	-0.040	-0.04	0.9678	-0.0%	-0.718	-0.53	0.5979	-0.2%
Nov Event Window kWh	-0.300	-0.29	0.7691	-0.1%	-0.083	-0.06	0.9531	-0.0%
Dec Event Window kWh	-0.347	-0.29	0.7720	-0.1%	0.104	0.06	0.9500	0.0%
Dummy - Low Income	-0.004	-1.77	0.0772	-1.1%	0.000	0.00	1.0000	0.0%

A.2.5 Summer Tier Participants

Table A-8: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Summer Tier

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.008	-48.23	<.0001	-4.6%	-0.000	-0.00	0.9964	-0.0%
Corr. - Hot Day CDH	0.006	3.02	0.0025	21.5%	0.005	1.90	0.0575	19.4%
Corr. - Winter HDH	0.001	1.10	0.2715	0.7%	-0.000	-0.14	0.8912	-0.1%
Coeff. Of Var - Event Window kWh	0.066	0.84	0.3984	0.2%	0.041	0.38	0.7070	0.1%
Coeff. Of Var - Weekday kWh	0.065	0.98	0.3272	0.3%	-0.036	-0.39	0.6958	-0.2%
Ratio Hot to Cold Months	-0.001	-0.20	0.8447	-0.1%	-0.002	-0.56	0.5787	-0.2%
Ratio Usage to CDD	0.012	0.98	0.3284	0.3%	-0.006	-0.37	0.7117	-0.2%
Summer kWh - Hour 12	0.016	5.29	<.0001	2.1%	-0.003	-0.64	0.5243	-0.4%
Summer kWh - Hour 13	0.017	5.45	<.0001	2.2%	-0.001	-0.24	0.8120	-0.1%
Summer kWh - Hour 14	0.018	5.96	<.0001	2.4%	-0.000	-0.05	0.8838	-0.0%
Summer kWh - Hour 15	0.021	6.89	<.0001	2.7%	-0.000	-0.00	0.9617	-0.0%
Summer kWh - Hour 16	0.023	7.48	<.0001	2.8%	0.000	0.05	0.9615	0.0%
Summer kWh - Hour 17	0.021	6.66	<.0001	2.4%	0.000	0.14	0.8158	0.1%
Summer kWh - Hour 18	0.007	1.91	0.4135	0.7%	0.000	0.05	0.6805	0.0%
Summer kWh - Hour 19	-0.007	-2.06	0.4536	-0.6%	-0.000	-0.03	0.6875	-0.0%
Summer kWh - Hour 20	-0.011	-3.08	0.0295	-1.0%	-0.001	-0.26	0.8005	-0.1%
Hot Day kWh - Hour 12	0.020	3.89	<.0001	1.9%	0.001	0.12	0.9073	0.1%
Hot Day kWh - Hour 13	0.013	2.16	0.0310	1.0%	-0.005	-0.59	0.5580	-0.4%
Hot Day kWh - Hour 14	0.004	0.57	0.5661	0.3%	-0.002	-0.28	0.7767	-0.2%

Table A-8 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – Summer Tier

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control - Participant	t Value	Pr > |t|	% Difference
Hot Day kWh - Hour 15	-0.009	-1.31	0.1909	-0.6%	-0.002	-0.23	0.8204	-0.2%
Hot Day kWh - Hour 16	-0.018	-2.48	0.0130	-1.2%	-0.004	-0.40	0.6908	-0.3%
Hot Day kWh - Hour 17	-0.027	-3.69	0.0002	-1.7%	-0.000	-0.03	0.9732	-0.0%
Hot Day kWh - Hour 18	-0.043	-6.02	<.0001	-2.7%	-0.004	-0.39	0.6936	-0.2%
Hot Day kWh - Hour 19	-0.058	-8.36	<.0001	-3.6%	-0.005	-0.52	0.6015	-0.3%
Hot Day kWh - Hour 20	-0.058	-9.00	<.0001	-3.7%	-0.002	-0.22	0.8247	-0.1%
Jan Event Window kWh	0.165	0.13	0.8930	0.0%	-0.461	-0.27	0.7868	-0.1%
Feb Event Window kWh	-0.443	-0.39	0.6994	-0.1%	0.176	0.11	0.9123	0.0%
Mar Event Window kWh	0.208	0.20	0.8391	0.1%	-0.502	-0.36	0.7209	-0.1%
Apr Event Window kWh	0.303	0.30	0.7605	0.1%	-0.722	-0.53	0.5972	-0.2%
May Event Window kWh	0.517	0.49	0.6270	0.1%	-0.725	-0.49	0.6230	-0.2%
Jun Event Window kWh	1.248	1.09	0.2752	0.3%	-0.747	-0.47	0.6379	-0.2%
Jul Event Window kWh	0.621	0.47	0.6388	0.1%	-1.106	-0.60	0.5497	-0.3%
Aug Event Window kWh	1.424	1.07	0.2865	0.3%	-0.686	-0.37	0.7148	-0.2%
Sep Event Window kWh	1.119	0.84	0.4001	0.3%	-0.625	-0.33	0.7383	-0.1%
Oct Event Window kWh	-0.158	-0.16	0.8738	-0.0%	-0.476	-0.34	0.7304	-0.1%
Nov Event Window kWh	-0.440	-0.43	0.6670	-0.1%	-0.088	-0.06	0.9513	-0.0%
Dec Event Window kWh	-0.470	-0.39	0.6950	-0.1%	0.283	0.17	0.8676	0.1%
Dummy - Low Income	-0.004	-1.86	0.0631	-1.2%	-0.003	-0.91	0.3614	-0.8%

A.2.6 Net Energy Metering Participants

Table A-9: Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control -Participant	t Value	Pr > |t|	% Difference
Propensity Score	-0.010	-11.74	<.0001	-2.4%	-0.000	-0.02	0.9812	-0.0%
Corr. - Hot Day CDH - Export	0.003	0.54	0.5871	-28.4%	-0.011	-1.25	0.2125	41.8%
Corr. - Hot Day CDH - Import	-0.002	-0.42	0.6734	-2.8%	0.013	1.70	0.0897	13.6%
Corr. - Winter HDH - Export	-0.006	-2.81	0.0049	-4.1%	-0.001	-0.38	0.7064	-0.7%
Corr. - Winter HDH - Import	0.009	4.17	<.0001	-8.0%	-0.005	-1.52	0.1277	3.7%
Coeff. Of Var - Event Window - Export	-0.599	-1.37	0.1704	-1.2%	1.427	2.32	0.0206	2.7%
Coeff. Of Var - Event Window - Import	0.325	0.62	0.5338	1.0%	0.640	0.90	0.3673	1.9%
Coeff. Of Var - Weekday - Export	0.440	2.20	0.0280	1.8%	0.337	1.20	0.2290	1.4%
Coeff. Of Var - Weekday - Import	0.299	0.55	0.5801	0.9%	0.737	1.00	0.3152	2.2%
Summer kWh - Hour 12 - Export	0.018	1.13	0.2576	2.3%	0.020	0.48	0.6345	2.5%
Summer kWh - Hour 12 - Import	-0.034	-1.64	0.1002	-3.1%	0.037	1.20	0.2308	3.1%
Summer kWh - Hour 13 - Export	0.025	1.53	0.1248	3.0%	0.011	0.35	0.7288	1.4%
Summer kWh - Hour 13 - Import	-0.041	-1.84	0.0652	-3.5%	0.043	1.29	0.1983	3.3%
Summer kWh - Hour 14 - Export	0.024	1.49	0.1366	2.7%	-0.017	-0.78	0.4375	-2.1%
Summer kWh - Hour 14 - Import	-0.051	-2.31	0.0209	-4.3%	0.043	1.30	0.1922	3.4%

Table A-9 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

	Before Match				After Match			
Variable	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control -Participant	t Value	Pr > |t|	% Difference
Summer kWh - Hour 15 - Export	0.028	1.66	0.0971	3.0%	-0.015	-0.64	0.5221	-1.6%
Summer kWh - Hour 15 - Import	-0.055	-2.65	0.0080	-5.1%	0.039	1.29	0.1964	3.4%
Summer kWh - Hour 16 - Export	0.034	1.97	0.0484	3.4%	0.012	0.42	0.6760	1.2%
Summer kWh - Hour 16 - Import	-0.052	-2.95	0.0032	-5.9%	0.030	1.16	0.2443	3.1%
Summer kWh - Hour 17 - Export	0.030	1.66	0.0967	2.6%	0.011	0.34	0.7306	1.0%
Summer kWh - Hour 17 - Import	-0.040	-2.87	0.0041	-6.6%	0.014	0.70	0.4832	2.1%
Summer kWh - Hour 18 - Export	0.020	1.14	0.2558	1.5%	0.010	0.35	0.7274	0.8%
Summer kWh - Hour 18 - Import	-0.025	-2.21	0.0270	-7.2%	0.000	0.01	0.9924	0.0%
Summer kWh - Hour 19 - Export	0.004	0.22	0.8296	0.2%	0.019	0.63	0.5259	1.2%
Summer kWh - Hour 19 - Import	-0.015	-1.39	0.1655	-7.1%	-0.012	-0.82	0.4125	-5.5%
Summer kWh - Hour 20 - Export	-0.009	-0.53	0.5960	-0.5%	0.023	0.76	0.4492	1.3%
Summer kWh - Hour 20 - Import	-0.015	-1.38	0.1668	-8.0%	-0.014	-0.95	0.3425	-7.4%
Winter kWh - Hour 12 - Export	0.017	1.30	0.1929	2.3%	0.013	0.44	0.6622	1.7%
Winter kWh - Hour 12 - Import	-0.033	-1.75	0.0805	-3.4%	0.054	1.85	0.0643	5.0%
Winter kWh - Hour 13 - Export	0.012	0.89	0.3712	1.6%	0.008	0.30	0.7647	1.2%
Winter kWh - Hour 13 - Import	-0.037	-1.91	0.0562	-3.7%	0.065	2.20	0.0281	5.9%

Table A-9 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

	Before Match				After Match			
Variable	**Mean Control - Participant**	**t Value**	**Pr > |t|**	**% Difference**	**Mean Control -Participant**	**t Value**	**Pr > |t|**	**% Difference**
Winter kWh - Hour 14 - Export	0.013	1.10	0.2716	1.9%	0.007	0.29	0.7722	1.0%
Winter kWh - Hour 14 - Import	-0.032	-1.86	0.0628	-3.7%	0.065	2.48	0.0132	6.8%
Winter kWh - Hour 15 - Export	0.021	1.82	0.0695	2.8%	0.011	0.51	0.6103	1.6%
Winter kWh - Hour 15 - Import	-0.025	-2.02	0.0439	-4.4%	0.046	2.43	0.0153	7.3%
Winter kWh - Hour 16 - Export	0.025	2.35	0.0190	3.0%	0.012	0.65	0.5173	1.5%
Winter kWh - Hour 16 - Import	-0.014	-2.29	0.0221	-6.4%	0.017	1.82	0.0681	6.8%
Winter kWh - Hour 17 - Export	0.013	1.12	0.2633	1.2%	0.016	0.79	0.4283	1.3%
Winter kWh - Hour 17 - Import	-0.001	-1.14	0.2554	-5.4%	0.003	1.51	0.1311	9.2%
Winter kWh - Hour 18 - Export	-0.022	-1.44	0.1498	-1.4%	0.004	0.18	0.8571	0.2%
Winter kWh - Hour 18 - Import	0.000	1.12	0.2645	16.3%	0.000	1.67	0.0946	40.0%
Winter kWh - Hour 19 - Export	-0.035	-2.02	0.0435	-1.9%	0.007	0.26	0.7975	0.4%
Winter kWh - Hour 19 - Import	0.000	1.88	0.0606	83.2%	0.000	1.05	0.2941	86.9%
Winter kWh - Hour 20 - Export	-0.029	-1.69	0.0907	-1.6%	0.010	0.41	0.6809	0.6%
Winter kWh - Hour 20 - Import	0.000	1.68	0.0922	86.1%	0.000	1.04	0.2991	85.6%
Hot Day kWh - Hour 12 - Export	0.022	0.96	0.3381	1.8%	0.018	0.38	0.7066	1.5%
Hot Day kWh - Hour 12 - Import	-0.059	-2.73	0.0064	-5.5%	0.026	0.82	0.4127	2.2%

Table A-9 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control -Participant	t Value	Pr > |t|	% Difference
Hot Day kWh - Hour 13 - Export	0.019	0.75	0.4525	1.4%	-0.002	-0.04	0.9654	-0.1%
Hot Day kWh - Hour 13 - Import	-0.070	-3.01	0.0026	-6.2%	0.030	0.87	0.3825	2.4%
Hot Day kWh - Hour 14 - Export	0.016	0.61	0.5450	1.1%	-0.022	-0.59	0.5560	-1.5%
Hot Day kWh - Hour 14 - Import	-0.079	-3.33	0.0009	-7.2%	0.030	0.86	0.3871	2.5%
Hot Day kWh - Hour 15 - Export	-0.008	-0.26	0.7942	-0.5%	-0.027	-0.66	0.5074	-1.6%
Hot Day kWh - Hour 15 - Import	-0.079	-3.31	0.0009	-7.7%	0.014	0.43	0.6677	1.3%
Hot Day kWh - Hour 16 - Export	-0.019	-0.61	0.5450	-1.0%	-0.001	-0.02	0.9859	-0.0%
Hot Day kWh - Hour 16 - Import	-0.069	-3.10	0.0019	-8.0%	-0.004	-0.13	0.8968	-0.4%
Hot Day kWh - Hour 17 - Export	-0.036	-1.14	0.2560	-1.7%	0.002	0.05	0.9618	0.1%
Hot Day kWh - Hour 17 - Import	-0.068	-3.15	0.0016	-10.1%	-0.018	-0.62	0.5361	-2.6%
Hot Day kWh - Hour 18 - Export	-0.072	-2.22	0.0267	-3.0%	-0.008	-0.18	0.8583	-0.3%
Hot Day kWh - Hour 18 - Import	-0.048	-2.28	0.0224	-9.6%	-0.024	-0.83	0.4038	-4.6%
Hot Day kWh - Hour 19 - Export	-0.089	-2.78	0.0054	-3.4%	0.013	0.28	0.7776	0.5%
Hot Day kWh - Hour 19 - Import	-0.032	-1.61	0.1074	-8.3%	-0.030	-1.08	0.2793	-7.6%
Hot Day kWh - Hour 20 - Export	-0.080	-2.70	0.0069	-3.0%	0.039	0.87	0.3829	1.4%
Hot Day kWh - Hour 20 - Import	-0.030	-1.55	0.1205	-8.3%	-0.031	-1.21	0.2268	-8.8%

Table A-9 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control -Participant	t Value	Pr > |t|	% Difference
Jan Event Window kWh - Export	-1.613	-0.29	0.7686	-0.3%	6.269	0.66	0.5061	1.1%
Jan Event Window kWh - Import	-11.534	-2.13	0.0331	-4.8%	2.548	0.28	0.7768	1.0%
Feb Event Window kWh - Export	-3.771	-0.72	0.4717	-0.7%	5.261	0.56	0.5774	1.0%
Feb Event Window kWh - Import	-10.344	-2.02	0.0438	-4.1%	7.183	0.79	0.4322	2.7%
Mar Event Window kWh - Export	-3.725	-0.79	0.4285	-0.8%	4.892	0.55	0.5812	1.0%
Mar Event Window kWh - Import	-10.069	-2.10	0.0354	-4.0%	10.586	1.18	0.2362	3.9%
Apr Event Window kWh - Export	-2.019	-0.44	0.6593	-0.4%	5.296	0.59	0.5585	1.1%
Apr Event Window kWh - Import	-10.778	-2.26	0.0241	-4.2%	13.507	1.46	0.1440	4.8%
May Event Window kWh - Export	-2.242	-0.45	0.6492	-0.5%	4.822	0.49	0.6249	1.0%
May Event Window kWh - Import	-10.298	-2.05	0.0401	-3.8%	14.050	1.40	0.1615	4.8%
Jun Event Window kWh - Export	-2.620	-0.50	0.6181	-0.5%	4.882	0.45	0.6538	1.0%
Jun Event Window kWh - Import	-10.377	-1.99	0.0465	-3.9%	12.468	1.14	0.2538	4.3%
Jul Event Window kWh - Export	-4.567	-0.75	0.4518	-0.8%	3.055	0.26	0.7970	0.5%
Jul Event Window kWh - Import	-14.428	-2.68	0.0075	-6.1%	6.818	0.61	0.5415	2.7%
Aug Event Window kWh - Export	-5.830	-0.95	0.3405	-1.0%	2.568	0.22	0.8229	0.4%
Aug Event Window kWh - Import	-12.308	-2.49	0.0129	-5.3%	-0.140	-0.02	0.9840	-0.1%

Table A-9 (Cont'd): Summary of T-Test Results for Propensity Score Variables Before and After Stage Two Matching – NEM

Variable	Before Match				After Match			
	Mean Control - Participant	t Value	Pr > |t|	% Difference	Mean Control -Participant	t Value	Pr > |t|	% Difference
Oct Event Window kWh - Export	-5.562	-0.92	0.3564	-0.9%	4.209	0.36	0.7209	0.7%
Oct Event Window kWh - Import	-14.126	-3.04	0.0024	-6.7%	2.798	0.42	0.6718	1.2%
Oct Event Window kWh - Export	-4.516	-1.00	0.3188	-1.0%	3.537	0.38	0.7007	0.7%
Oct Event Window kWh - Import	-9.584	-2.73	0.0064	-5.6%	3.368	0.66	0.5091	1.8%
Nov Event Window kWh - Export	-4.158	-0.92	0.3590	-0.8%	4.404	0.54	0.5864	0.9%
Nov Event Window kWh - Import	-5.648	-2.18	0.0295	-5.0%	3.809	1.02	0.3098	3.1%
Dec Event Window kWh - Export	-8.543	-1.64	0.1020	-1.5%	8.496	0.94	0.3456	1.5%
Dec Event Window kWh - Import	-5.573	-2.62	0.0087	-5.4%	5.002	1.56	0.1186	4.4%
Ratio Hot to Cold Months - Export	0.000	0.02	0.9818	0.0%	-0.006	-0.61	0.5446	-0.6%
Ratio Hot to Cold Months - Import	-0.545	-0.65	0.5161	-39.3%	0.260	0.23	0.8143	11.9%
Ratio Usage to CDD - Export	-0.050	-0.89	0.3719	-0.9%	0.035	0.32	0.7502	0.6%
Ratio Usage to CDD - Import	-0.040	-1.41	0.1598	-3.8%	0.066	1.53	0.1270	5.7%
Low Income	0.003	0.54	0.5867	2.8%	0.004	0.60	0.5458	4.2%