FINAL

2003 SMART THERMOSTAT PROGRAM IMPACT EVALUATION

Prepared for

San Diego Gas and Electric Company
San Diego, California

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X

EXECUTIVE SUMMARY

X.1 INTRODUCTION

X.1.1 Background

On March 27, 2001, the California Public Utility Commission (CPUC) issued Decision 01-03-073 (D.01-03-073) mandating San Diego Gas and Electric (SDG&E) to implement a pilot program designed to test the viability of a new approach to residential load control and demand responsiveness through the use of Internet technology and thermostats to affect residential air conditioning use. To meet this mandate, SDG&E implemented the Smart Thermostat Program beginning in the spring of 2002.

In the summer of 2002, the program was invoked once. Previous reports provided a process and impact evaluations of the 2002 program. The impact evaluation provided both estimates of impacts on the single 2002 re-set day and projections of savings under alternate conditions.

The present report provides the findings from an impact evaluation of the second summer of the program in 2003. While the program itself was not operated in 2003, customers in the metering sample were re-set on the critical peak days of the Statewide Pricing Pilot (SPP). This report estimates impacts per unit for those days as well as projected savings under alternate conditions.

X.1.2 Program Description

General Structure

The Smart Thermostat Program is designed to include approximately 5,000 residential customers representing an estimated 4 MW in peak demand reduction before 2002 year-end. Through the program, customers are provided the necessary technology installation and a small incentive for program participation. The equipment deployed allows SDG&E to remotely raise the cooling setpoints on participating customers' thermostats. Participating customers may over-ride the re-set, but forfeit a portion of their incentive each time they do so.

Conditions for Calling a Re-set Event

The program plan calls for the deployment of the Smart Thermostat system when the California Independent System Operator (ISO) calls for a Stage 2 Emergency Notice (Stage 2 Alert). This alert is based on statewide conditions, and may occur at times when the weather in San Diego is mild.

As noted, there were no program events during the summer of 2003. However, customers in the metering sample for this evaluation were re-set during each of the SPP events. There were 12 such events, ranging from 1.75 to 5 hours in length, with re-set amounts varying from 3 to 5 degrees.

The impact results presented here are based on these re-set events. The projected savings under alternate conditions are based on the same load data models used to estimate the impacts of the particular events.

X.2 FINDINGS

X.2.1 Estimated Impacts for the Observed Re-set Events

Savings per unit enrolled in the program averaged over the re-set period ranged from a low of 0.05 kW to a high of 0.72 kW across the 12 events. The event average was statistically significantly different from zero (at 90 percent confidence) for 7 of the 12 events. However, the estimated savings in individual intervals were positive for all but 8 of the 187 15-minute intervals included in the 12 events.

Averaged across all 12 re-set periods, the program impact was 0.33 kW. The 90 percent confidence interval, reflecting variation across days as well as units, is from –0.12 to +0.79 kW. Considering only this confidence interval, which includes zero, it would seem questionable if savings occur at all. However, given that positive savings are estimated for almost every re-set interval, it is clear that savings are positive from the program. At the same time, for any particular event, the magnitude can be small.

If 5,000 units had received the re-set signal, the estimated savings on the best day would have been 3.6 MW, with a 90 percent confidence interval of 1.4 to 5.9 MW. This estimate compares favorably with the *ex ante* estimate of 4 MW for 5,000 units. However, this is for the best, not average, day. Across all 12 re-set periods, the savings from 5,000 units would have averaged an estimated 1.7 MW, with a 90 percent confidence interval from –0.6 to +3.9 MW. These estimates are summarized in Table X-1.

Table X-1
Estimated Impacts

	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
Average of All Events				
per unit	0.33	0.28	-0.12	0.79
5000 units	1,653	1,384	-623	3,929
Best Event				
per unit	0.73	0.27	0.28	1.18
5000 units	3,662	1,369	1,410	5,914

X.2.2 What Fraction of Units Contribute to Savings

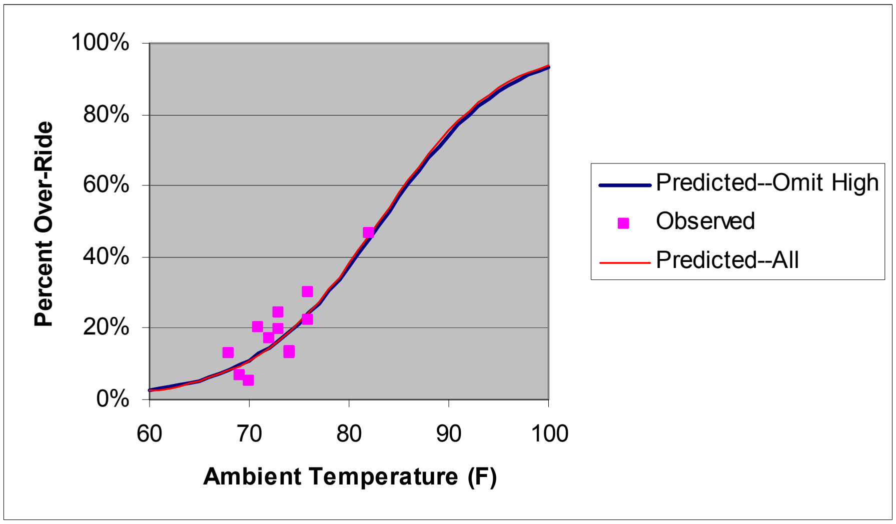
The fraction of participating units contributing to savings was found to be low in this analysis.

1. On the positive side, about 96 percent of the thermostats in the program appeared to operate correctly during each re-set event. The non-response rate ranged from 3 percent to 6 percent across the 12 events.
2. The over-ride rate varied substantially across the re-set events, from a low of 5 percent to a high of 47 percent. The highest over-ride rate occurred on the day with the highest ambient temperature. Between 75°F and 85°F, each 1°F increase in temperature is estimated to increase the over-ride rate by 3.6 percentage points. While this relationship is not surprising, the magnitude of the over-ride rates observed and projected at higher temperatures raises concerns about the effectiveness of the program when it is likely to be most needed. Averaged across all events and re-set units, the over-ride rate was 19 percent.
3. Over-ride rates increase with the duration of the re-set event, as would be expected. On each of the re-set days, the percent of units over-ridden increased throughout the re-set period.
4. Eighteen percent of participating AC units were not used at all during the summer of this study. While some of these units might be used during severe hot weather, they contribute no savings in the milder weather. This is a slightly lower percentage than was found in 2002, during an unusually cool summer.

The combined effect of non-response, over-ride, and non-use was that only about 60 percent of the participating units are "potential contributors" to impacts. Across the different re-set days, that fraction ranged from 32 percent to 74 percent. The variation is mainly attributable to the varying over-ride levels.

The relationship between outdoor temperature and over-ride rate is shown in Figure X-1.

Figure X-1
Predicted and Observed Over-ride Rates vs. Outdoor Temperature



X.2.3 Projected Impacts for Future Events

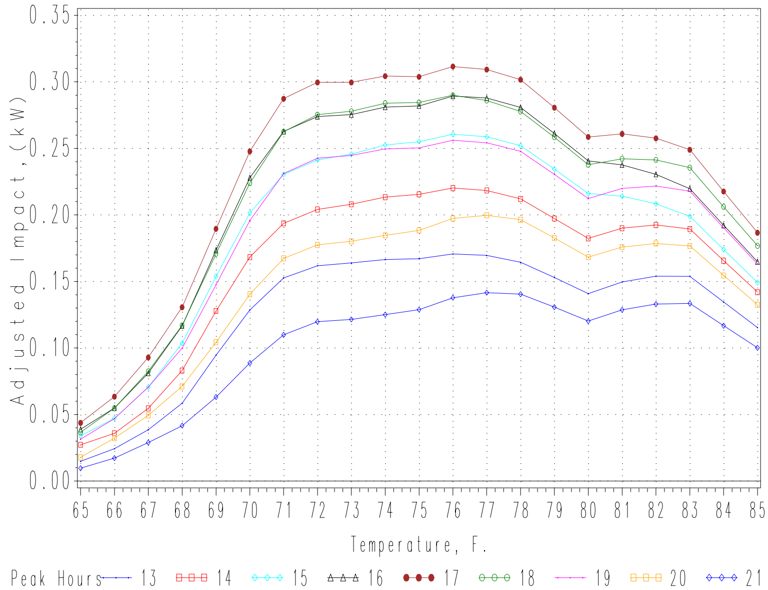
Impacts projected for a future re-set of 3°F are indicated in Table X-2 for the hour ending 5 PM. This is the hour with the highest peak impacts for all ambient temperatures. Maximum savings occur at 76 and 77°F. A 3°F re-set is estimated to yield 0.31 kW savings per thermostat at this temperature. The savings at noon is only 0.11 kW.

Table X-2
Projected Impacts per Participating AC Unit by Outside Temperature
3°F Re-set, Hour Ending 5 PM

Average Daily Temperature	Impact per Thermostat (kW)
65	0.04
66	0.06
67	0.09
68	0.13
69	0.19
70	0.25
71	0.29
72	0.30
73	0.30
74	0.30
75	0.30
76	0.31
77	0.31
78	0.30
79	0.28
80	0.26
81	0.26
82	0.26
83	0.25
84	0.22
85	0.19
86	0.16
87	0.13
88	0.10
89	0.07
90	0.05
91	0.03
92	0.01
93	0.00

Figure X-2 shows the projected savings per participating unit as a function of daily average temperature for hours ending 1 PM to 9 PM. For the hours between noon and 7 PM, projected savings are fairly flat across temperatures between 71°F and 78°F, and drop off at higher and lower temperatures. This pattern reflects the balancing effects of increasing savings per re-set unit and increasing rates of over-riding the re-set as the outside temperature increases.

Figure X-2
Projected Impacts per Participating AC Unit by Outside Temperature
3°F Re-set, Hour Ending 1 PM through 9 PM



X.3 IMPLICATIONS OF THE FINDINGS

The findings from this study confirm the finding from the previous study that future performance of the program as a mechanism to respond to statewide emergencies is not reliable. One factor is the limited used of air conditioning in the territory, with one-fifth of participating units never used over the summer. Another factor is that statewide emergency conditions do not necessarily coincide with hot weather in the San Diego area. This was the case for several of the 2003 re-set events. As long as the emergency condition that triggers a re-set event is not tied to hot weather in San Diego, a high number of non-users is likely to be found during future re-sets.

On the other hand, when the weather is hot, high rates of over-ride are projected to occur. On the hottest of the 2003 re-set days, the observed over-ride rate was 47 percent. Our modeled over-ride rate was close to this level, and fairly robust. Further investigation of the relationship between over-ride rates on the one hand and event characteristics—amount, duration, and ambient temperature—on the other could provide further guidance on the best program designs to provide effective participation.

1 INTRODUCTION

1.1 BACKGROUND

On March 27, 2001, the California Public Utility Commission (CPUC) issued Decision 01-03-073 (D.01-03-073) mandating San Diego Gas and Electric (SDG&E) to implement a pilot program designed to test the viability of a new approach to residential load control and demand responsiveness through the use of Internet technology and thermostats to affect residential air conditioning use. The Energy Division recommended a budget of $3.9 million per program year. To meet this mandate, SDG&E implemented the Smart Thermostat Program beginning in the spring of 2002. This report provides the findings from an impact evaluation of the second summer of this program, the summer of 2003.

1.2 PROGRAM DESCRIPTION

1.2.1 General Structure

The Smart Thermostat Program was designed to include approximately 5,000 residential customers representing an estimated 4 MW in peak demand reduction before 2002 year-end. In fact, the program enrollment reached 5000 devices in November 2003. Through the program, customers are provided the necessary technology installation and a small incentive for program participation. The equipment deployed allows SDG&E control of the thermostat for emergency demand reduction, yet allows the customer the ability to over-ride the company signal remotely or directly at the thermostat.

The program's paging technology allows SDG&E to remotely raise the cooling setpoints on participating customers' thermostats. We refer to this action by SDG&E as a "re-set event." The effect of the higher setpoint is a reduction in the average demand of the air conditioners. This reduction is the desired demand impact.

1.2.2 Conditions for Calling a Re-set Event

The program plan calls for the deployment of the Smart Thermostat system when the California Independent System Operator (ISO) calls for a Stage 2 Emergency Notice (Stage 2 Alert). A Stage 2 Alert is issued when an Operating Reserve of less than 5 percent exists or is forecast to occur within the next two hours for the state. A Smart Thermostat Program re-set event is triggered by a Stage 2 Alert. This alert is based on statewide conditions, and may occur at times when the weather in San Diego is mild.

When a Smart Thermostat re-set event is initiated, SDG&E will increase the setting of the thermostat in participants' homes for a period of four hours. The re-set may be extended or terminated as necessary. The maximum length of the re-set is six hours per day. SDG&E has set a maximum of 20 re-sets per calendar year.

1.2.3 Incentives

The customer receives a state-of-the-art digital thermostat installed at no cost to the participant. In addition, the participant will receive up to $100 per year in incentives for the years 2002 through 2004. As noted, the participant may over-ride the increased setpoint of the re-set. However, each time the customer over-rides the re-set, the incentive will be reduced by $2. The incentive, less any reduction due to over-ride, will be paid each year.

1.2.4 Targeting

The targeting strategy for the program was prescribed by the CPUC in D.01-03-073, the decision mandating the program. The decision directed SDG&E to target the following three customer groups:

1. Residential customer whose average monthly electricity consumption is greater than average for their customer class, with the exact specified consumption level to be determined by SDG&E.
2. Residential customers residing in geographical areas in SDG&E's service territory known to have high electricity consumption due to climate.
3. Residential customers residing in known limited-to-moderate-income areas.

Medical baseline customers are not permitted to participate due to the potential air conditioner needs of these customers.

SDG&E met criteria 1 and 2 by selecting customers from California Energy Commission (CEC) Climate Zone 10 who had average monthly summer consumption of 700 kWh or greater. Data from MIRACLE XIII, SDG&E's residential appliance saturation survey, were used to estimate the average consumption for those residing in SDG&E's Transitional Climate Zone with central air conditioning. The average monthly summer kWh consumption for SDG&E's Transitional Climate Zone residents with central air conditioners is 700 kWh. The Transitional Climate Zone was used as a proxy for CEC Climate Zone 10, since the MIRACLE survey data were collected for the SDG&E climate zones (Maritime, Coastal, and Transitional zones). Initially, residents in CEC Climate Zone 10 with average monthly summer consumption of 700 kWh or greater were selected. In an effort to increase participation, an additional mailing was conducted during October 2002 with a follow-up mailing to take place approximately one month later. Targeted customers for this mailing included those in CEC Climate Zone 10 with average monthly summer consumption of at least 600 kWh.

Criteria 3 was met by selecting customers under SDG&E's low-income rate class, the DR-LI rate, in CEC Climate Zone 10, whose average monthly summer consumption was 700 kWh or greater.

1.3 Impact Evaluation

SDG&E was required to evaluate this program effort, including both a process evaluation and a load impact evaluation component. The process evaluation was completed for program year 2002. The primary objectives of the process evaluation were to assess how efficiently and effectively SDG&E runs the program and to make suggestions for improvements. As part of that evaluation effort, survey data were collected from a sample of participants. These survey results shed some light on impact findings. An impact evaluation for the single re-set event in 2002 was also complete.

The load impact evaluation presented in this report provides estimates of the aggregate demand reduction and energy savings from summer 2003 re-sets. There were no Stage 2 Alerts called in the summer of 2003 and, thus, no re-set events for the Smart Thermostat Program as a whole. However, because of the need to evaluate the impact potential of the Smart Thermostat Program, part of the metering sample was, in fact, re-set 12 times during the summer of 2003. These re-set events coincided with implementation of the Statewide Pricing Pilot (SPP). SPP is a different demand response program available statewide, for which all Smart Thermostat participants are eligible. From the perspective of the impact evaluation the re-set events were identical for the sample participants. These events ranged from 1.75 to 5 hours in duration. The re-set amount varied from 3 to 5 degrees. Starting times ranges from 2 PM to 4 PM

Estimates are provided also for projected savings in future events as a function of the degrees increase in thermostat setpoints and the ambient temperature for the day.

1.4 Organization of the Report

Section 2 describes the impact analysis methods, including the data sources and the analytic approach. The findings from the analysis are presented in Section 3. Conclusions are summarized in Section 4. Plots of observed and estimated loads and impacts for each re-set day are given in Appendix A for the air conditioner load data analysis, and in Appendix B for the whole-house load data analysis. Tables of projected savings by temperature, time of day, and re-set amount are given in Appendices C and D.

2 METHODS

This section describes the various data used in the impact analysis as well as the methods by which demand impacts were estimated. Section 2.1 discusses the data and how it was collected. Section 2.2 discusses the analytical approach to processing the data and estimating the demand impacts.

2.1 DATA SOURCES

There were three types of data collected for this study:

1. Interval metering data,
2. Weather data, and
3. Re-set operations data.

The data most necessary and difficult to collect were the interval metered energy consumption data from a sample of Smart Thermostat Program participants. A great effort was managed by SDG&E to gather that data. As a result of the 2002 evaluation, some limited data quality issues were identified. These issues were addressed at that time with future analysis in mind.

For the 2003 analysis, SDG&E provided weather data from 10 local weather stations. This is a substantial improvement over the single weather station used for the 2002 analysis as modeling the dependency of air conditioning energy consumption on ambient temperature is a central part of the method employed in this impact analysis.

Silicon Energy, the implementation contractor responsible for the web-based control system, collected data on Smart Thermostat Program participants and on thermostat performance during re-set events. Those data were available directly from the Silicon Energy EEM Suite website.

2.1.1 Metered Data

Energy Consumption Data

Two streams of energy consumption data were collected at each study participant's premise:

1. whole-premise, and
2. air conditioning (AC).

These streams were monitored on separate meters installed by SDG&E. Both meters recorded energy consumption accumulated over 15-minute intervals. All observations were recorded at quarter-hour intervals. SDG&E provided the energy consumption data sets at the end of the metering period. In addition to these data, SDG&E provided a meter installation survey data set. The survey data included information on nominal cooling capacity, estimated age of AC condenser, and AC type. The survey data also contained information necessary to collate the energy consumption data with the re-set event data, discussed below.

As the name suggests, whole-premise data included all loads at the premise including the AC condenser. Whole-premise data are valuable to the impact assessment of an AC demand reduction program because other loads may be affected by changes in the AC load. For example, greater use of ceiling, floor, or desk fans may accompany decreased cooling by the AC. Refrigerators will run more as less cooling allows the interior temperature to climb, and water heaters may run less. There may be an increased tendency among occupants to lessen internal heat gains, such as cooking, clothes drying, and lighting. These uncertain variables can have marked effects on the impact of an AC demand reduction program. Theoretically, the total impact at a premise is best viewed from the perspective of whole-house consumption.

Unfortunately, the variation of non-AC electrical loads at a premise can make it difficult to discern the impacts of AC demand reduction from whole-premise data alone. The fundamental dependency of AC use on ambient temperature may become more difficult to capture. For this reason, AC data itself were also collected.

The AC energy consumption data collected were taken from the circuit of the AC condenser, that part of the AC system located outdoors that dumps heat from the premise to the ambient environment. The condenser's load includes those of the refrigerant compressor motor, the cooling fan motor, condenser controls, and case or emollient heaters if present. The heaters are found generally in older condensers and serve to vaporize any liquid refrigerant that might enter the compressor. It seems that many run near continuously, perhaps even throughout the heating season.

The condenser is the largest but not the only load in an AC system. The system typically includes the same interior air distribution fan used by a forced-air furnace. The fan demand is approximately 150 Watts per nominal ton of AC capacity, or on the order of an additional 10 percent of condenser demand. Common air conditioner load control programs of the past involve controlling only the condensers with exterior control switches. This type of "cycling" control does not turn off the interior air distribution fan. By contrast, during re-set the Smart Thermostat is understood to turn off the interior air distribution fan just as it would under ordinary AC operation when the cooling setpoint is raised.

The interior air distribution fan is not on the same circuit as the condenser. In fact, it may be on a circuit with other, non-AC loads. To collect data from both the condenser and the interior distribution fan alone thus may become a time-consuming task of wiring sensors. For that reason, energy consumption data are collected from the condenser circuit alone and does not capture the impact of turning the interior fan off when the cooling setpoint is raised. This, then, is another reason to consider whole-premise data in a demand impact analysis.

Sample Design

The energy consumption data were collected from the same random sample of 100 premises of program participants that were selected early in the first year of the program. At that time, premises were limited to those with no more than two thermostats. The sample was divided randomly into two groups of approximately equal numbers of premises. The grouping was intended to allow one-half of the sample to serve as a comparison group for the other, for each re-set event. Thus, for each re-set, one group would be re-set while the other group continued to operate their AC as usual. With multiple re-set events, this would permit each group to be re-set in about half the events, and to act as the comparison group for the other group in the other half of the event.

Table 2-1 describes the original sample in terms of numbers of premises, thermostats, and AC metered for each group. The table divides premises into categories by count of thermostats on the premise and numbers of AC metered. Each group had a two-thermostat premise where only one AC was metered. Otherwise, all AC were metered at all premises.

Table 2-1
Original 2002 Distribution of Premises, Thermostats, and Metered AC by Group in Sample

Premise Category	Sample Group A			Sample Group B		
	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
One AC, one metered	45	45	45	42	42	42
Two AC, one metered	1	2	1	1	2	1
Two AC, both metered	5	10	10	6	12	12
Total	51	57	56	49	56	55

The re-set and comparison groups differed by no greater than a count of one between premise, thermostat, and metered AC categories. The two groups likewise were very similar in terms of nominal cooling capacity. Sample group A had a combined capacity of 214.5 tons, while sample group B had a combined capacity of 202.5 tons. Average sizes were 3.8 and 3.7 tons per unit, respectively.

Between the first and second years of the Smart Thermostat Program, the sample lost eight participants. Two participants moved and their metering equipment was removed. Six other participants opted out of the re-set program. Their meters were maintained and these data are still a potential resource for the analysis. Table 2-2 describes the changes in the distribution of premises, thermostats, and metered AC.

Table 2-2
2003 Distribution of Premises, Thermostats, and Metered AC by Group in Sample

Premise Category	Sample Group A			Sample Group B		
	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
One AC, one metered	40	40	40	39	39	39
Two AC, one metered	1	2	1	1	2	1
Two AC, both metered	5	10	10	6	12	12
Total	46	52	51	46	53	52

The two sample groups are still almost identical in terms of counts of premises, thermostats, and metered AC. The two groups remained very similar in terms of nominal cooling capacity. Sample group A had a combined capacity of 178.5 tons, while sample group B had a combined capacity of 169.5 tons. Averages sizes were 3.9 and 3.7 tons per unit, respectively.

2.1.2 Weather Data

SDG&E provided observations of hour-ending average drybulb temperature and relative humidity for the period from January through October 2003 from 10 weather stations in the SDG&E service territory. SDG&E provided a list of program premises indicating the most appropriate weather station for this analysis. Seven of the 10 weather stations are used to describe the weather conditions for the 2003 sample of 92 premises. Table 2-3 shows the distribution of premises across the seven weather stations as well as the monthly mean temperature.

Table 2-3
Sample Group Distribution Across Weather Stations
with Summer Monthly Mean Temperature

Weather Station ID	Sample Group		Monthly Mean Temperature				
	A	B	June	July	August	September	October
S01	1	0	64	70	72	70	67
S02	19	22	64	72	75	71	68
S04	1	0	64	70	70	68	66
S05	13	15	66	74	76	73	71
S06	0	1	63	70	72	69	68
S08	9	6	64	74	75	71	68
S09	3	2	63	69	71	68	66

Multiple weather stations are a substantial improvement over the single weather station used for the 2002 impact analysis. The combination of the ocean and mountainous terrain has the potential to cause highly variable weather conditions across the SDG&E service territory. These weather data should better represent the varied ambient conditions faced by the sample of program participants. Figures 2-1 through 2-4 show the average day temperature for the seven weather stations represented in the sample for the four months with re-set events. The variability across weather stations is clearly evident in these plots. Vertical lines indicate the days on which thermostats were re-set. It should be noted that re-set events do not necessarily coincide with peak temperatures. This is a visual reminder that San Diego area temperatures are not driving the Statewide Pricing Pilot curtailment events.

Figure 2-1

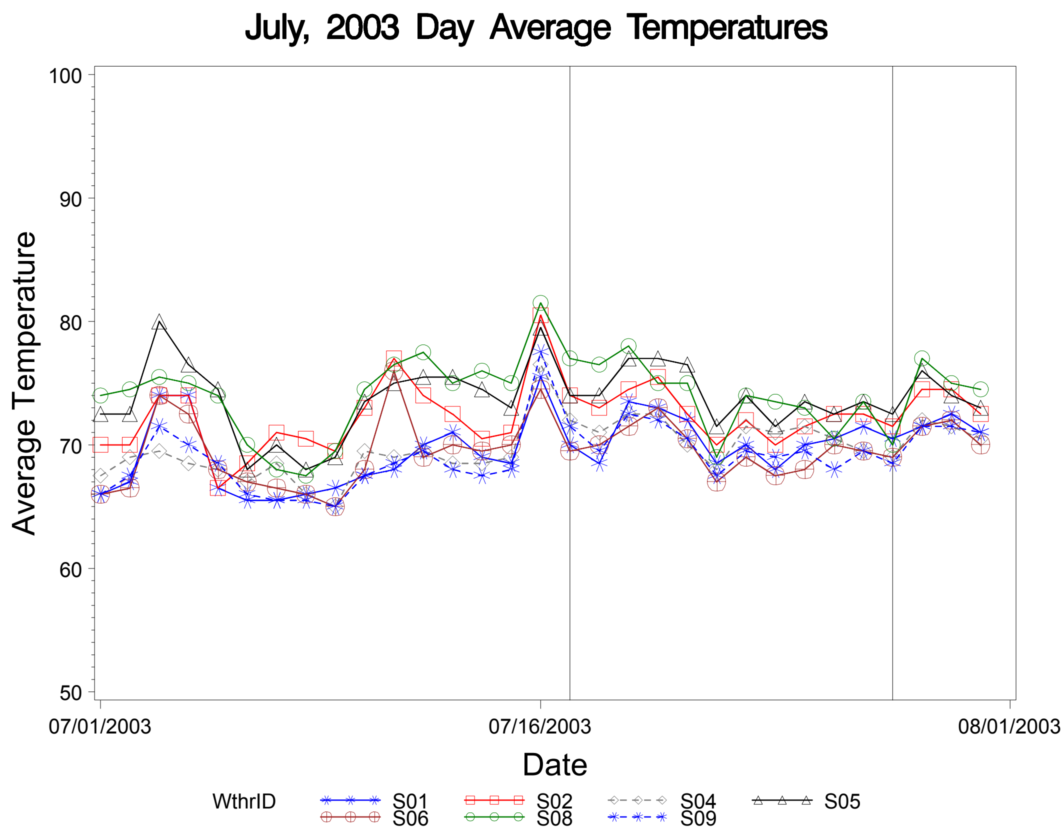
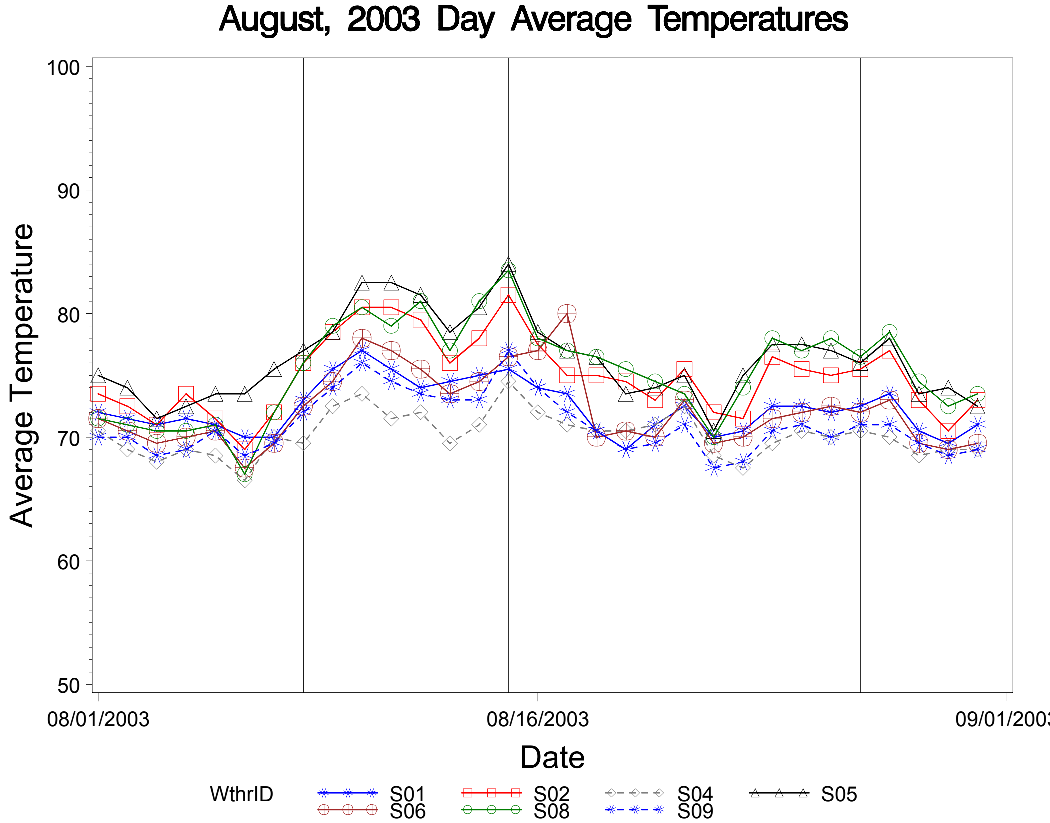


Figure 2-2



August, 2003 Day Average Temperatures
Average Temperature
100
90
80
70
60
50
08/01/2003
08/16/2003
09/01/2003
Date
WthrID
S01
S02
S04
S05
S06
S08
S09

Figure 2-3

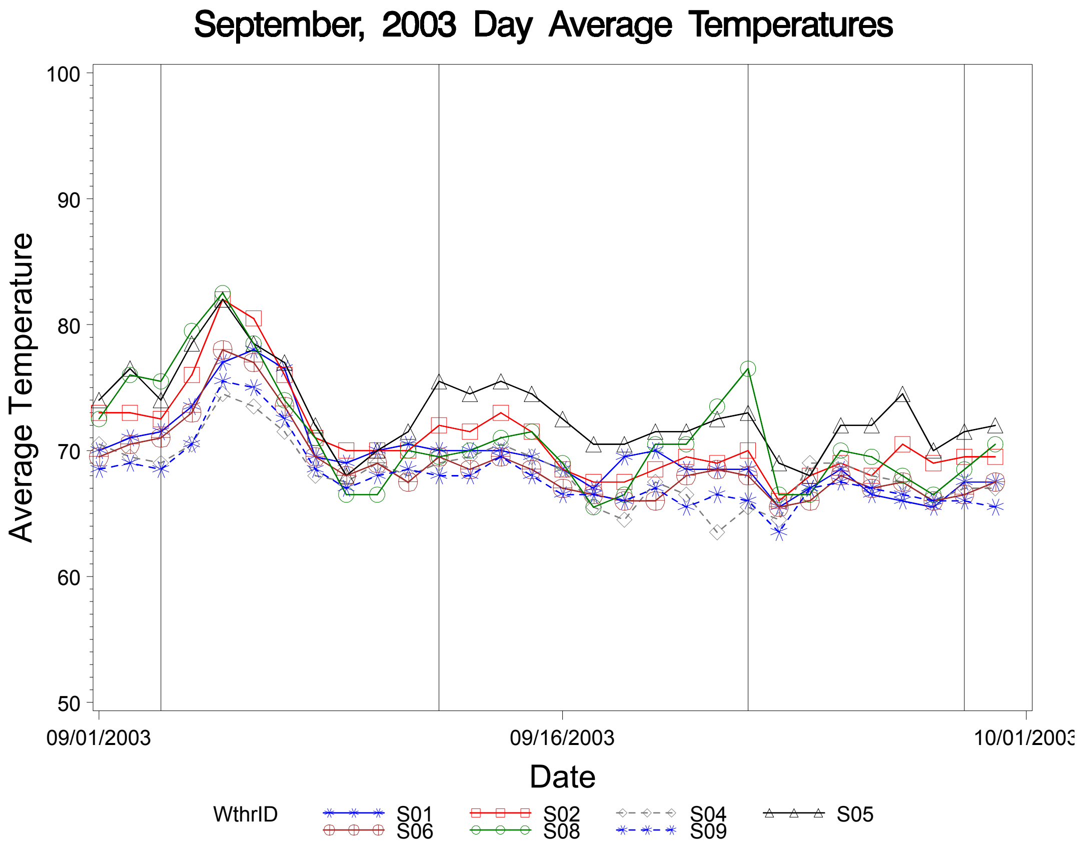
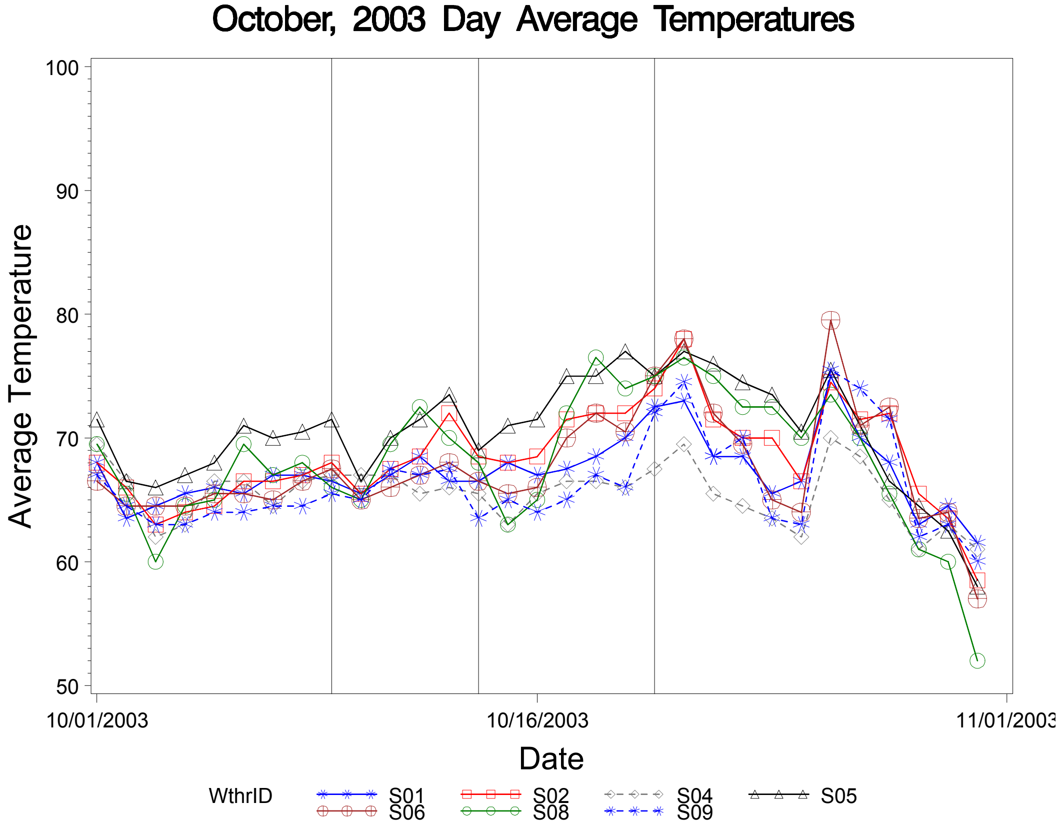

September, 2003 Day Average Temperatures
100
90
80
70
60
50
Average Temperature
09/01/2003
09/16/2003
10/01/2003
Date
WthrID
S01
S02
S04
S05
S06
S08
S09

Figure 2-4



2.1.3 *Event and Customer History Reports from Silicon Energy*

The Silicon Energy EEM Suite website (rem.siliconenergy.com/siliconenergy/rem/asp/ event_summary_setup.asp) allowed ready access to, and downloading of, data on customer participation in the summer's re-set events. These data included an observation for each thermostat that had been included in each re-set. Each observation identified the sample group to which the thermostat belonged, as well as customer name and account number information. Additional fields described the start time and planned duration of the re-set event, the amount in degrees Fahrenheit of the thermostatic cooling setback, and time stamps of thermostat acknowledgement of re-set and of over-ride as appropriate. It was these last two time stamps that identified "non-responder" thermostats that did not appear to receive the re-set signal, and over-ride thermostats where the thermostat was manually lowered after being raised by the re-set signal.

For the 2003 program, the customer participation data described above included the device ID or PIN associated with the re-set thermostat. This was a change from the 2002 program year when this variable had to be merged from a separate customer history dataset. The PIN provides a direct link between event participation data and survey data collected at the outset that characterizes each premise.

2.2 Methods

This section describes the methods by which the collected data were examined to estimate demand impacts. The same methods were employed as for the 2002 impact analysis. The 12 re-set events provided more data to analyze. However, the fact that only a subset of Smart Thermostat customers participated necessitated a change from elements of the 2002 analysis that utilized operations data from the full program population.

The analysis, as in 2002, has three main parts.

1. The fraction of units potentially contributing to savings for each event is determined.
2. The impacts for each re-set period are calculated from analysis of the load data for potential contributors, then adjusted for the fraction not contributing.
3. The impacts for a range of conditions are projected based on the same load models used for the analysis of the actual re-set days, and adjusted for the same fraction of non-contributors.

These steps are described below.

2.3 Potential Contributors

Not all AC units in the program provide savings during a re-set event. This analysis determines the average savings per unit in two parts. First, the average savings per unit is determined for the subset of units classified as "potential contributors" to savings. Savings for the remaining units are zero. The overall average savings across all units is then calculated by multiplying the average savings for potential contributors by the fraction of units in this category. Thus, for example, if only one-quarter of the units in the program are determined to be potential contributors to savings, the unit savings estimated for the potential contributors is multiplied by one-quarter to get the savings per unit across all units in the program.

An alternative approach to accounting for units that do not contribute to savings would be simply to calculate savings directly over all units, both contributors and non-contributors, in the metered samples. With this more direct approach, however, the fraction of zero contributors in each metered group is random. This random variation in the proportion of zero contributors in each group adds to the variance of the estimated savings.

The two-part approach used for the 2002 evaluation provided a way to take advantage of available population data to calculate a more accurate estimate of the overall program savings. The accuracy was higher because we did not have to estimate the percentages of some kinds of non-contributors. We knew the actual percentage from the full population of participants in the event participation data. There is no estimation involved, thus no variance. Using this technique, the impact estimate for the whole group, including zero contributors, can be estimated with the variance of only a subset of participants.

Because the re-set events that occurred during the summer of 2003 were SPP events rather than Smart Thermostat event, the whole population of the Smart Thermostat Program was not paged. This lack of population data requires adjustments to the approach proposed last year. Clearly we cannot take advantage of zero-variance percentages, but the analysis follows a similar approach and takes advantage of the previous method where possible.

There are three reasons a unit might not provide demand savings during a re-set period.

1. The unit fails to receive the re-set signal.
2. The unit receives the re-set signal, but the customer over-rides the re-set.
3. The unit is not in use at the time the re-set signal was sent, therefore has no reduction to provide.

If the full Smart Thermostat Program had been called, data on the fraction of units that did not receive signals and the fraction that over-rode would be available from the Silicon Energy website for the full participant population, for each re-set event. As it is, we do have this data for all Smart Thermostat participants who joined the SPP program as well as our sample groups. We leverage this additional data to lower the variance of the estimate of the percentage of non-responders. The fraction of participants that over-ride is estimated using only the re-set sample group. As in 2002, whether or not an AC unit was in use on a particular day is determined only from the metering data.

2.3.1 Signal Failure Fraction

Signal receipt itself is not directly observed. What is known for all participating units is whether they returned a signal to the system head end, acknowledging receipt of the re-set signal. We use the percent of units that do not send an acknowledgement as an upper bound on the percent that did not receive a signal. If the signal transmission in each direction is such that virtually any unit that successfully received a re-set signal would successfully return an acknowledgement, this percent of non-responders is very close to the percent that didn’t receive a signal, and is not an overstatement.

On the other hand, if signal failure randomly affects a fraction of units essentially symmetrically and independently in each direction, the fraction non-responding overstates the fraction not receiving a signal. In this case, we can assume that half the non-responders did not receive a signal, and half received a signal but the response signal failed. Thus, we would treat one-half the observed fraction of non-responders as a lower bound on the percent not receiving the re-set signal.

For the 2002 analysis, the percent of non-responders was known, with zero variance, from the participation data. In the summer of 2003, only the designated Smart Thermostat sample group and the SPP participants got the re-set signal. Unlike 2002, we must estimate the percent of non-responders. We could use the sample group alone to estimate this percent. However, the full set of participants, including the SPP participants, provide more data for the estimation, lowering the variance of the estimate. The fundamental question is whether there are systematic differences between the curtailed sample group and the SPP participants with respect to re-set signal non-response. As SPP participants were originally Smart Thermostat Program participants there would appear to be no difference from a hardware perspective. As the two groups were re-set as part of the same event by Silicon Energies, there appear to be no differences with respect to the source of the re-set signal. We therefore assume that the full set of participants are representative of the larger Smart Thermostat Program population and can be used to estimate the non-responder percentage.

2.3.2 Over-ride Fraction

The number of switches over-ridden is recorded directly in the event participation data. However, only those switches that received a signal can over-ride. Thus, we consider the over-ride fraction as a fraction of those that received the signal. Once again, for the 2002 analysis, this percentage was known directly from the full program population data.

For the 2003 program we have only the sample group and SPP participant data with which to determine the over-ride percent. As with the non-responder percent, we must estimate the over-ride percent, since we do not know it outright. Unlike the non-responder situation, it may not be reasonable to use the additional SPP data to improve the estimate. Unlike the non-response percent, which is a function of an automated communications process, the over-ride percent is a function of, among other things, the incentive structure of the program. The Smart Thermostat Program and SPP have different incentive structures. Thus, SPP over-ride data cannot be considered representative of the Smart Thermostat Program.

There are three remaining options for accounting for premises that over-ride the re-set.

1. **Separate over-ride percent adjustment.** Use the load data analysis to calculate average savings per unit for non-over-riders (potential contributors) only. Calculate the percent of over-riders from the sample for each re-set event. Adjust the non-over-rider savings per unit by the fraction of non-over-riders, to provide the savings per unit across all potential contributors. This method is the same as the 2002 method, except that the percent of over-riders is calculated from the sample rather than from the full population.
2. **Over-riders included in the load data analysis.** Use the load data analysis to calculate average savings per unit across all responding users, regardless of whether they over-ride or not. No separate adjustment is needed for over-riders.
3. **Over-riders directly included in average savings per unit, but with savings set to zero.** Use the load data analysis to calculate the savings for each non-over-rider unit. Set over-rider unit savings to zero. Calculate the average savings per unit across the whole pool of responding users, non-over-riders and over-riders combined. This method is similar to Method 1. It would give the same result as Method 1 if only re-set participants were included in the analysis, without the "difference of differences" calculation. This method also provides a basis for calculating the standard error of the savings per potential contributor.

As noted, Method 1 is most similar to the 2002 analysis. However, the reason for separating the over-ride percent from the average savings for non-over-riders in the prior analysis was that the over-rider percent could be determined without error. Using this information rather than relying on the sample percent over-ride reduced the variance of the overall savings estimate. Since this reduction is not possible for 2003, the separation offers no advantage in terms of variance reduction. However, isolation of the fraction of over-riders is useful in terms of understanding the program response, as well as providing direct comparability to the 2002 results. Moreover, for the calculation of projected savings under general conditions, it is necessary to calculate the fraction of potential contributors, accounting explicitly for the over-ride rate.

On the other hand, the variance calculation described below for the event-specific analysis requires that the over-riders and non-over-riders be combined. Method 3 provides nearly the same estimate as Method 1, but allows direct calculation of the standard error of the resulting estimate. For the event-specific analysis, therefore, we use Method 3.

Method 2 could be viewed as providing the most complete estimate, since it recognizes that over-rides do not take place instantly, but affect the savings differently over the duration of the re-set period. However, including the load data from over-riders in the analysis serves to increase the variance of the estimate. In addition, this approach is inconsistent with that used for the 2002 program and expected to be used for the 2004 program. In the interests of consistency and variance reduction, we use Methods 1 and 3 for the primary analysis and presentation. We focus on Method 1, which corresponds to the 2002 approach. However, we express the nearly equivalent results via Method 3 for the variance calculations and certain explanations.

If we used Method 2, including estimated over-ride impacts from the load data analysis, rather than Method 3, setting over-ride impacts to zero, we would likely get somewhat higher impacts in the early intervals of the re-set period, and lower impacts in later intervals. In the early intervals, units that will over-ride but have not yet done so contribute positive savings, rather than zero as in Method 3. In later intervals, the over-riders are likely to have some “pay-back” for the foregone cooling in the earlier intervals, resulting in increased usage or negative savings, rather than zero as in Method 3. However, as noted, the trade-off for this finer-grained look at the effect of over-rides would be increased overall variance.

2.3.3 Fraction Zero Use

Units that are never used during weekdays over the entire summer do not contribute to savings from this program at any time. We determine the fraction of zero users based on analysis of the metered air conditioning data. This fraction is determined from the full usable metering sample, not just those in the re-set group on the particular day a re-set occurred. The full sample is the largest group for which we can estimate this population characteristic.

The “summer non-zero users” are those units that were used on a weekday at some time over the summer. Included in this group may be some units that had zero use on a particular re-set day. We do not attempt to estimate a zero use fraction separately by re-set event. The effects of zero use by a subset of those who are at least sometimes non-zero users are included in the average impacts estimated for the non-zero use group.

2.3.4 Potential Contributors and Non-contributors

Estimating Percent of Non-contributors

For the 2002 analysis we estimated the fraction of units that were complete non-contributors to savings as:

$$p_{NC} = p_F + (1\text{-}p_F)(p_{OR} + p_z),$$

where

p_{NC} = fraction of units that are non-contributors,

p_F = fraction of units that had signal failure,

p_{OR} = fraction of units that over-rode, out of those that did not have signal failure, and

p_z = fraction of units with zero weekday AC usage all summer.

That is, all units with signal failure (p_F) are non-contributors. Of the remaining units (1-p_F), those that cannot contribute to savings are those that over-ride (p_{OR}) and those that were never used (p_z). These proportions are additive because they are essentially mutually exclusive. Whether a unit has zero use is assumed to be independent of whether or not the signal was received.

For the 2003 analysis, this calculation of the fraction of non-contributors is used in the calculation of projected savings. However, the over-ride and non-responding fractions are taken from the samples, as described above, rather than being provided for the entire population from the operating system.

For the 2003 event-specific analysis, we still consider non-responders (F), zero summer users (z) and over-riders (OR) all to be non-contributors to savings. Those who have nonzero summer use and respond to the signal we call ***responding users.*** Responding users can either be potential contributors or over-riders. While the 2002 over-ride rate was determined from the Silicon Energy population data, the 2003 over-ride rate p_{OR} is determined from the same pool of responding users as provide the savings per unit via the load data analysis. For this reason, we break up the non-contributor fraction somewhat differently.

First, we calculate the proportion of responding users as those who do not have a signal failure and do not have zero summer usage. These are assumed to be independent, so that the combined probability is multiplicative:

$$p_{RU} = (1- p_F)(1-p_z).$$

We then determine the over-riders as a fraction of the responding users. The non-over-riders are the potential contributors. Thus,

$$p_C = (1-p_F)(1-p_z)(1-p_{OR}).$$

The non-contributors are everyone else. That is

$$\begin{aligned} p_{NC} &= 1- p_C \\ &= 1- [(1-p_F)(1-p_z)(1-p_{OR})] \\ &= 1- (1-p_F)(1-p_z-p_{OR} + p_z p_{OR}) \\ &= 1- [(1-p_F) -(1-p_F)(p_z+p_{OR} + (1-p_F)p_z p_{OR}] \\ &= p_F + (1-p_F)(p_z+p_{OR}) + (1-p_F)p_z p_{OR} . \end{aligned}$$

This expression differs from that given above by the last term,

$$(1-p_F)p_z p_{OR} .$$

Strictly speaking, this term should be removed. It would be appropriate if zero summer use and over-ride were independent, whereas in fact they are mutually exclusive. However, the product is small, and the use of the expression for the proportion of contributors p_C simplifies the analysis.

Standard Error Calculation

In the 2002 analysis, only p_z entered the percent non-contributor equation as an estimated percent with an associated variance. The standard error was calculated as

$$\mathrm{SE}(p_{NC})= (1-p_F)\mathrm{SE}(p_z) = (1-p_F) (p_z*(1- p_z)/n_z)^{.5} ,$$

where n_z is the number of premises in the combined samples or, alternatively, the denominator of the fraction that provides the percentage of non-users, p_z.

For the 2003 event-specific analysis, we develop an estimate of the standard error of the savings per unit across all responding users, and adjust this estimate by the proportion of responding users. Thus, we need an estimate of the standard error of this proportion.

This standard error is calculated as

$$\begin{aligned} \mathrm{SE}(p_{RU}) &= \mathrm{SE}[(1- p_F)(1-p_z)] \\ &\simeq [(1- p_F)^2\mathrm{SE}^2(p_z) + (1- p_z)^2\, \mathrm{SE}^2(p_F)]^{1/2}. \end{aligned}$$

The standard errors of the proportions are calculated using standard formulas for proportions from a simple random sample.

Similarly, the standard error of the contributor fraction is calculated as

$$\begin{aligned} SE(p_{NC}) &= SE(p_C) \\ &= [(1-p_F)^2(1-p_z)^2 SE^2(p_{OR}) + (1-p_z)^2(1-p_{OR})^2 SE^2(p_F) \\ &\quad + (1-p_F)^2(1-p_{OR})^2 SE^2(p_z)]^{1/2}. \end{aligned}$$

2.4 Impact Estimates on Re-set Day

2.4.1 Overview

To estimate the demand impact of a re-set event, it is necessary to have an estimate of the demand that would have been present without the re-set event. If the two groups into which our sample was divided were completely identical then we could simply use the comparison group as our estimate of what the load would have been. Taking the difference of the two groups' mean load would provide a good estimate of demand impact. Of course, in reality it is impossible to select two identical sample groups. Alternating curtailments between the sample groups ought to control for some of the differences but that in turn implies conditions are the same across curtail days and we know this was not the case.

Another approach to estimating the demand impact involves using a regression-based estimate of the load on the re-set days. This approach provides an alternative estimate of impacts but this approach assumes that re-set day consumption can be fully explained by the model.

For the 2002 analysis we used a method that combines these two approaches to estimating demand impact. By combining the two approaches, we can overcome the weaknesses of each approach when used alone. The regression-based model controls for differences across the two sample groups and across re-set days. At the same time, the use of a comparison group controls for re-set day conditions not addressed by the regression-based estimates.

2.4.2 Load Model

The weather normalization model estimates load as a function of drybulb temperature, specifically, average daily heating or cooling degree days. Using hour-specific dummy variables, the intercept and both degree day measures enter into the model on an hour-specific basis. This means that each of the 24 hourly load measures for each day are regressed against an hour-specific intercept term and degree day term. The resulting parameter estimates, though based on only a single daily temperature measure, provide an hourly estimate of load as a function of weather.

Degree days are calculated as the degrees above or below a base temperature. The ideal cooling base temperature is the minimum ambient temperature at which AC use begins, and below which there tends to be no AC load. The heating base temperature is the maximum ambient temperature above which there tends to be no heating-related load. Base temperatures vary across premises because the inhabitants have different inside temperature preferences and houses are varied in their physical properties that relate to inside temperature. Our model estimates the same model across a wide range of cooling and heating degree day bases and chooses the combination with the greatest explanatory power

Eqn. 2-1 shows the model in equation form. It was fit separately for each premise to the AC or whole house consumption data. Hourly AC and whole house loads are calculated by summing the 15-minute interval data to the hour. The optimal combination of cooling and heating base temperatures was then chosen on the basis of the maximum R-square statistic.

$$L_{jdh} = \alpha_{jh} + \beta_{Hjh} H_d\left(\tau_{Hj}\right) + \beta_{Cjh} C_d\left(\tau_{Cj}\right) + \varepsilon_{jdh} \qquad \textbf{Eqn. 2-1}$$

where

L_{jdh}	=	sum of 15-minute interval AC consumption at hour *h* of day *d* for premise *j*;
$H_d(\tau_{Hj})$	=	heating degree-days at the heating base temperature τ_{Hj} for premise *j*, on day *d*, based on daily average temperature;
$C_d(\tau_{Cj})$	=	cooling degree-days at the cooling base temperature τ_{Cj} for premise *j*, on day *d*, based on daily average temperature;
ε_{jdh}	=	regression residual;
α_{jh}, β_{Hjh}, β_{Cjh}	=	coefficients determined by the regression; and
τ_{Hj} τ_{cj}	=	base temperatures determined by choice of the optimal regression.

The degree-day variables are calculated as

$$C_d(\tau_{Cj}) = \max((\mathrm{T_d} - \tau_{Cj}),0)$$

$$H_d(\tau_{Hj}) = \max((\tau_{Hj} - T_d),0),$$

where T_d is the "daily average temperature," calculated as the mean of the daily minimum and maximum for day *d*. Because of thermal lags in the house, this form of daily average tends to be a better predictor of heating and cooling loads than the current hourly temperature, or an average for particular hours of the day.

An alternative approach considered was to use lagged temperature variables in the cooling model. This approach can be effective. However, lag effects get confounded with time-of-day effects so that it may be difficult to obtain meaningful hourly coefficients if lag terms are also included. Using coefficients that do not vary by hour doesn't allow behavioral effects to be captured. The hourly coefficients β_{jh} account both for different behavior by time of day and also for the effects of thermal lags.

Using regression coefficients from this fitted equation, as indicated in Eqn. 2-2 by the overscript '^', and cooling and heating degree-days $H_d(\tau_{Hj})$ and $C_d(\tau_{Cj})$ for day d of the re-set event, the estimated load (without re-set) L_{jdh} , was calculated for each premise, day, and hour using Eqn. 2-2.

$$\hat{L}_{jdh} = \hat{\alpha}_{jh} + \hat{\beta}_{Hjh} H_d\left(\hat{\tau}_{Hj}\right) + \hat{\beta}_{Cjh} C_d\left(\hat{\tau}_{Cj}\right) \qquad \textbf{Eqn. 2-2}$$

2.4.3 Load Model Error Correction

Any load model will have some estimation error. The particular model used in this analysis is relatively simple, using just the time of day and the daily average temperature. Effects of humidity, sunshine, wind, and lagged temperature are not explicitly modeled.

Because of some of these physical factors, a portion of the modeling error for a given day and hour will be similar across AC units. The model may simply not have the data to estimate usage on the hottest days. Alternatively, if the day is the third day of a heat wave, all homes might have higher usage than the load model would indicate based on that day's temperature alone. Likewise, if the day is very breezy, usage might tend to be lower than the temperature model would indicate. Further, even with a more sophisticated physical model there may be behavioral changes related to events in the news or holiday schedules that would be similar across homes.

The use of the comparison group provides a basis for correcting these systematic modeling errors. We take the average modeling error for the comparison group as an estimate of the likely average modeling error for the re-set group.

First we have to calculate the unadjusted impact estimate for the re-set group

$$S_{Rh} = \frac{1}{n_R} \sum_{j \in R} \left(\hat{L}_{jh} - L_{jh} \right),$$

where

$\hat{L}_{jh}$ is the weather normalized estimate of hourly load,

L_{jh} is actual hourly load,

S_{Rh} is the unadjusted load impact estimate of the re-set group, and

n_R is the number of units in the re-set group.

The model estimates for each premise tell us what would have happened without the re-set. The differences from the observed load for each premise are the estimated savings. The premise-level impacts are averaged over the group to get the mean unadjusted load impact estimate per unit. This estimate is still "unadjusted" because the quality of the weather-normalized estimate is unknown.

The model estimate does not need to be perfect, only consistent across the two sample groups. With this assumption, the average modeling error, or what we are considering the error adjustment, is, in fact, the same calculation for the comparison group.

$$S_{Ch} = \frac{1}{n_C} \sum_{j \in C} \left(\hat{L}_{jh} - L_{jh} \right),$$

where

S_{Ch} is the unadjusted load impact estimate of the comparison group, and
n_C is the number of units in the comparison group.

If the weather normalization model were perfect, the model estimate for each comparison premise would be identical to the observed load. The mean "impact" across the comparison group, $\hat{L}_{ch}$ would equal zero and there would be no adjustment necessary. However, we do not expect the model to be perfect. We use the comparison group average error to estimate the average error for the re-set group. Thus, the comparison group average modeling error indicates if the model tends to be high or low, and by how much. The adjustment is made by taking the difference of these two differences:

$$S_h = S_{Rh} - S_{Ch}.$$

If the model, on average, over-estimates the comparison group's actual load for a particular interval, then it will also give too much impact credit to the re-set group. In this case, the error adjustment will be positive and will be subtracted from inflated re-set group estimate. If the model is low, a negative error adjustment is removed (a double negative) so the original re-set impact estimate is increased.

This "difference of differences" approach combines the model estimation and comparison group approaches to determining "what would have been." The above explanation implies the model estimate is the primary step, with the comparison group serving to adjust the model-based result. The method can just as easily be explained the other way around and this may be more intuitive for some. With this approach, the difference between the observed loads of the comparison and re-set groups is the primary impact estimate. The weather normalized load estimates are only compared with each other to determine if any systematic influences are affecting the two groups differently. These two approaches are mathematically identical.

2.4.4 Savings Estimates by Time Interval

The load model is estimated on an hourly basis, and the savings equations above indicate estimates for each hour. However, the load data were available on a quarter-hour basis. Kilowatt-hour savings for each quarter-hour interval were calculated analogously to the hourly equations indicated above. For the quarter-hourly estimates, the load in each time increment was estimated using the load model coefficients for the hour that included that increment.

Savings were also calculated for the average of the entire re-set period. The re-set periods are all listed as starting and ending on the hour except for the July 17 event that was terminated early. Apparently, though, the actual start and end times are slightly offset so as not to have too extreme a system affect when the group is returned to full cooling. For this reason the impact is estimated for both the first and last intervals of the re-set period.

For the overall re-set period savings, each AC unit's average observed load during the re-set period was calculated across all increments in the period. Each unit's estimated load was similarly averaged across all re-set period time increments. The difference of difference calculation was then applied to these re-set period averages to obtain the re-set period average kW savings.

2.4.5 Final Impact Estimate

The difference of difference method gives the savings per unit among potential contributors. When we include over-riders (with impacts set to zero) in the re-set group average, the resulting difference of differences gives the savings per unit across all responding users, for each time interval in the re-set period. Multiplying by the fraction of participants that are responding users gives the savings per unit across all participants.

Thus, the final impact S_{Th} for each interval h is given by

$$S_{Th} = p_{RU}\, S_h \,,$$

where S_h is the average impact per responding user, as defined above.

2.4.6 Standard Error of the Impacts

The standard error of the impact estimate is calculated from the separate standard errors of the proportion of responding users p_{RU} and the savings per unit S_h for this group. This responding user unit savings is calculated by the difference of differences method.

The corresponding standard error is calculated for each interval by first calculating the standard error of each group's difference between observed and modeled load. This standard error is simply the standard deviation of individual units' modeling errors, divided by the square root of the number in the group. The standard error of the difference of difference impact estimate SE(S_h) is the square root of the sum of squared standard errors for the re-set and comparison groups.

The standard error of the final estimate S_{Th} is then

$$SE(S_{Th}) = [p_{RU}{}^2 SE^2(S_h) + S_h{}^2 SE^2(p_{RU})]^{1/2},$$

where the calculation of the standard error of the proportion was given above.

2.4.7 Assessing Comparability of the Comparison Group

The savings estimation approach assumes that the modeling error for the comparison group is a good indicator of the likely modeling error for the re-set group if no re-set had occurred. Thus, an important step prior to applying this method was to assess whether the two groups were in fact similar.

Premises were selected at random for the metering sample, and were randomly assigned to group A or B. Thus, there was no *a priori* reason the groups should have been different. However, random effects could result in observable differences at the outset that would suggest a need for some kind of adjustment.

A particular concern was that the sizes of the air conditioning units in the two samples might be different. In this case, the comparison group error might be a good indicator of the re-set group error, but a scaling factor might need to be applied to the comparison group error to adjust for the size difference. Our original plan was to calculate savings after normalizing the two groups' observed and estimated loads by dividing by their respective average air conditioner capacity, in tons.

The 2002 analysis decided the two groups had practically the same distribution of AC unit size, and this normalization was not necessary. That analysis compared the two groups in terms of the mean, median, minimum, maximum, and standard deviation of tons, both for the full sample and for the smaller sample used in different stages of the analysis. In terms of these distribution statistics, the two groups were very similar to one another, and were similar also across the different subsets used in the analysis. This comparison is repeated for the groups used in the 2003 analysis.

An additional check is also repeated. It plots the average re-set group model error against the average comparison-group model error, for warm weekday afternoons excluding the re-set day. This plot is presented in Section 3.

This comparison showed a strong relationship between the two groups' errors. The comparison also showed a similar standard deviation of error between the two groups, indicating no scale difference. A regression of re-set average error on comparison group average error had an intercept very close to zero, indicating no systematic shift between the two. These comparisons support the use of the comparison group without scale adjustment.

Even with very comparable groups, normalization by capacity could be considered as a variance reduction technique. Ratio estimation, such as calculating savings per ton rather than mean savings per unit, can often be effective in reducing the variance of impact estimates. However, for this method to be effective in variance reduction, it is necessary to have the normalization variable known for the entire population. In this study, capacity data were collected for the metering sample to allow for scaling between the re-set and comparison groups if necessary, but were not available for the general population of participating AC units. Thus, once it was determined that scale adjustment was not required between the two groups, no normalization by capacity was used in calculating the savings estimate.

2.4.8 Whole-premise Analysis

For the re-set event, the same analysis method was applied to the whole-premise data as the AC data. The same units identified as potential contributors by the end-use analysis were included in the whole-premise analysis.

The results presented in Section 3 show that, as in 2002, the whole premise analysis was less reliable, in terms of the standard errors of the resulting estimates, than was the AC analysis. We therefore continue to rely on the AC results for the impacts.

2.5 Projected Impact Estimates for General Conditions

This section describes the methods by which demand impacts were estimated under general conditions. A general condition is defined simply by a daily average temperature and an hour of the day. The methods for general conditions used the same load models as described above, but essentially applied a theoretical model of equivalent temperature differences to describe the effect of re-set.

2.5.1 Model AC Loads at Different Temperatures

The load models described above to estimate load *without* re-set were used here in that same way. The average daily temperature and hour of day were the independent variables determining the load at a premise. The same models then were used to describe the load *with* re-set. The modeling difference was simply the daily average temperature used.

Loads *with* re-set were estimated using the daily average temperature less the thermostat setback. This in effect lowers the average daily temperature and thereby decreases the cooling load. That is, the effect of setting the thermostat forward by δ degrees is essentially the same as the effect of dropping the ambient temperature by δ degrees. The magnitude of the thermostat setback, in degrees Fahrenheit, thus was a critical determinant of the load with re-set. The basis for the demand impact estimate for a premise was simply the load without re-set less the load with re-set.

2.5.2 Accounting for Non-contributors and Non-responders

As for the impact on the actual re-set day, this method is applied to the set of AC units with "effective impacts"; that is, to those that had non-zero usage and were not non-responders or over-rides. The effects of zero usage and non-response were estimated by applying the average adjustment for these effects over the 12 re-set days.

2.5.3 Calibration Against a Single Re-set Event

The impact estimates developed for the individual re-set events were compared to estimates using this more general approach, with the corresponding average temperatures and re-set amounts. The comparison showed wide variations between the event-specific estimates and the general projections on days when the event-specific estimates had relatively large standard errors. The correspondence was better on the days with better-determined estimates. Because of the range of variation, there was not a strong basis for developing an adjustment to the projected savings from the event-specific estimates.

3 FINDINGS

This section describes the findings of the analysis of the metered consumption data and the re-set event data for Summer 2003. We first describe the data screening used to determine which meters had usable data for the analysis. We then present the results of the analysis steps described in Section 2:

- Estimation of the Fraction Noncontributing
- Impacts for the Re-set Event
- Projected Impacts for General Conditions.

3.1 UNITS USED IN THE ANALYSIS

3.1.1 Identifying Participants Still in Program

One hundred premises were originally chosen for the Smart Thermostat Program sample. Of this number, only 92 are still active. Two participants moved from their residences and as a result metering equipment was removed. Six other original participants opted out of the re-set program before the first re-set event of 2003. Load data are still being collected for these six sites but their thermostats are never re-set. Table 3-1 describes the premises removed from the sample as well as the distribution of the premises remaining in the program.

Table 3-1
Premises Included in the 2003 Impact Report, Distribution of Premises, Thermostats and Metered AC by Curtail Group

		Sample Group A			Sample Group B			Total		
Participant Status	Premise Category	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
Left Program before July 7th, 2003	One AC, One metered	5	5	5	3	3	3	8	8	8
Participated in at least on 2003 re-set event	One AC, One metered	40	40	40	39	39	39	79	79	79
	Two Ac, one metered	1	2	1	1	2	1	2	4	2
	Two Ac, both metered	5	10	10	6	12	12	11	22	22
	Total	51	57	56	49	56	55	100	113	111

3.1.2 Identifying Meters with Good Data

Most of the remaining 92 premises from which 15-minute interval energy consumption data were collected had acceptable whole-premise and AC observations. There were nine exceptions. These were premises with missing or suspicious AC data. Furthermore, there were five more participants that left the program during the summer of 2003. Their metering data are perfectly good but they no longer participate in the re-set events

Almost all of the 92 premises whose consumption data were initially considered for use in the analysis had 10 full months of energy consumption data from January through October. Only 10 premises had less than ten months and many of these were only missing a month of data early in the year before the air conditioning season.

Two premises were removed because they had insufficient data to estimate the necessary weather normalization model. One premise had only a single month of data. The other premise had more than seven months of data but was missing 72 days starting in June and going through the beginning of September.

Of the remaining 90 premises, there were seven premises with observations having AC energy consumption greater than whole-premise consumption. This should never be possible. Five of these premises had the same problem in the 2002 impact evaluation. At that time, the problem was identified as a meter configuration issue. The problem was addressed and SDG&E reported the meters fixed or adjusted, as necessary. Based on our current analysis, the problems appear not to have been resolved for all the meters that were problematic in 2002. In addition, there are two premises that were included in the 2002 analysis that were problematic in 2003. SDG&E metering staff are aware of the current problems and are working to resolve them. Based on the questionable data, all seven premises were excluded from the analysis.

After excluding the nine premises with incomplete or questionable data, there were 83 premises remaining with usable consumption data. The consumption data collection failure rate was 10 percent, the same as in the program's first year. This is somewhat high but not entirely unexpected in AC metering studies of this duration.

Table 3-2 lists the counts of premises by an initial data classification of their consumption data and by group.

Table 3-2
Premise, Thermostat, and Metered AC for Removed Premises

	Sample Group A			Sample Group B			Total		
Premise Category	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
All 2003 Participants	46	52	51	46	53	52	92	105	103
Insufficient Data	2	3	3	0	0	0	2	3	3
Bad Data	6	6	6	1	1	1	7	7	7
Participants in analysis	38	43	42	45	52	51	83	95	93

3.1.3 Units Included in Each Analysis Component

As described in Section 2, the AC units were classified as either "non-contributors" or "potential contributors" for each re-set day. Premises that had zero usage on all summer weekdays were non-contributors for the whole scope of the analysis. Premises that did not receive the re-set signal for a particular event, or who over-rode the re-set signal once it was received, were considered non-contributors for that event. Thus, for any particular re-set event potential contributors were those with successful signal receipt, no over-ride, and non-zero usage during summer weekdays. Load data analysis was used to determine the savings per unit for potential contributors. This unit savings was then adjusted by the estimated population percent of potential contributors to obtain the average savings over all units, including the non-contributors.

Identifying AC Non-users

AC non-users were identified by the absence of AC data indicating more than minimal AC use during weekday afternoons. AC use was defined as a quarter-hourly consumption observation greater than 0.025 kWh to allow for the possibility of continuously running case or emollient heaters in the condenser. Minimal AC use then was defined as having less than one percent of quarter-hourly observations between 10 AM and 10 PM on weekdays between May 1 and October 1 showing AC use.

Since only one AC energy consumption meter was used at any one premise, two-thermostat premises considered non-users necessarily showed no AC use from either thermostat. If they showed AC use, it could not be discerned whether one thermostat might have been a non-user. It is also recognized that metering errors could result in the appearance of no AC use at any hour.

Table 3-3 lists the counts of premises Thermostats and Metered AC for AC Non-users in the remaining sample members.

Table 3-3
Premise, Thermostat and AC Meter Count of AC Non-users

	Sample Group A			Sample Group B			Total		
Premise Category	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
Participants in analysis	38	43	42	45	52	51	83	95	93
AC Non-Users	9	9	9	8	8	8	17	17	17
Potential Impact Contributors	29	34	33	37	44	43	66	78	76

Non-responding Thermostats

Non-responding thermostats are identified as non-responders on the Silicon Energy EEM Suite website. The non-responders were identified by event reports available from that website (sdgerem.siliconenergy.com/siliconenergy/rem/asp/event_summary_setup.asp). Non-responder thermostats had neither an acknowledgement time stamp nor an over-ride time stamp in the event report.

As discussed in Section 2, for some non-responders the unit may in fact have raised the cooling setpoint successfully but failed to send an acknowledgement reply to the system head end. Thus, the percentage of thermostats reported as non-responders could be viewed as an upper bound on the signal failure rate. On the other hand, there could also be cases where the signal was received but the re-set did not occur. Recognizing these potential sources of over- and under-statement, we treat the percent not responding to the re-set signal as the percent that were not re-set.

Over-riding Thermostats

Over-ride thermostats also were identified by event reports available from the Silicon Energy EEM Suite website. Over-ride time stamps were available in those reports. They were believed to indicate the time of receipt of the over-ride acknowledgement message. Thus, there could be some delay between the time the occupant changed the setpoint and the reported over-ride time. The possible range of delay times is believed to exceed 15 minutes.

3.2 Fractions Potentially Contributing and Not Contributing to Savings

The method employed in the 2002 analysis utilized population data where possible to provide more accurate estimates of per unit load impact. Because of the effective changes in program delivery, data reflecting the whole population are not available for the 2003 analysis. Thus, while we still follow the same basic method as the 2002 analysis, some changes are necessary. Whereas for the 2002 analysis only the non-zero AC use portion of the non-participant fraction had to be estimated, for the 2003 analysis, all three parts (non-response, over-ride, and non-zero AC use) will have to be estimated.

3.2.1 AC Non-users

For the 2003 analysis, the percentage of AC non-users must be estimated from the final set of premises with good data. Table 3-3 above indicates that 17 units were categorized as non-users out of the total of 93 units still in the analysis. For every re-set day, then, the fraction of AC non-users is 17/93.

3.2.2 Non-responding Thermostats

The non-response fraction must be calculated differently for the summer of 2003. On the single re-set day in the summer of 2002, SDG&E sent a re-set signal to all the Smart Thermostat Program participants. Those that did not respond were considered unable to contribute to savings. This fraction of participants, 232/2,259, was known with certainty. It entered into the impact estimate with zero variance.

The 2003 program activities did not include the full Smart Thermostat population, only the sample groups and other Smart Thermostat participants who had opted to participate in the SPP. As a result, the fraction of the full population that did not respond cannot be known with certainty. To determine an impact estimate that reflects the whole Smart Thermostat Program population, we must instead estimate the fraction of non-responders. Estimating this fraction will add variance to the ultimate impact estimates.

One option for reducing the variance is to include the SPP population in the estimate. The increased number of units (between 114 and 134 depending on the date), in addition to the individual Smart Thermostat sample groups (at 42 and 51 units) will decrease the variance of this estimate by a factor of roughly $\sqrt{3}$. If the two populations are not believed to have systematic differences, then use of the large group is clearly preferable. As re-set confirmation is a purely mechanical issue, there is little reason to suspect systematic differences on thermostat response. Table 3-4 compares the re-set percentages for the groups.

Table 3-4
Comparison of Re-set Rates Between the Smart Thermostat Sample Groups and the SPP Program Participants

Re-set Date	Sample Group	Smart Thermostat Sample AC			SPP AC Counts		
		Confirmed	No Response	No Response Percent	Confirmed	No Response	No Response Percent
7/17/2003	A	31	2	6%	117	6	5%
7/28/2003	B	41	2	5%	105	9	8%
8/8/2003	B	40	2	5%	104	10	9%
8/15/2003	A	30	1	3%	121	13	10%
8/27/2003	A	30	1	3%	128	5	4%
9/3/2003	A	29	2	6%	116	17	13%
9/12/2003	B	41	1	2%	114	10	8%
9/22/2003	A	30	1	3%	116	5	4%
9/29/2003	B	39	2	5%	120	4	3%
10/9/2003	A	30	1	3%	117	14	11%
10/14/2003	B	38	2	5%	111	12	10%
10/20/2003	A	30	1	3%	118	2	2%

3.2.3 Over-ride Thermostats

The over-ride stamp always indicates that the setpoint has been reduced from the re-set signal level. A thermostat that was set to a higher setpoint than that set by the re-set signal, or an AC unit that was turned off, would not be registered as over-riding. Thus, over-riding thermostats always reduce the total savings.

As with the non-response percentage discussed above, because the full Smart Thermostat population did not participate in re-set events, over-ride percents must be estimated. Once again, taking advantage of the combined SPP/Smart Thermostat group numbers could lower the variance on this estimate. Unfortunately, the choice to over-ride is much more complex than the mechanical possibility of non-response. In addition, the Smart Thermostat Program sample and the SPP participants are responding to different programs. Table 3-5 compares the over-ride rates for the two groups. This comparison appears to show quite different rates of over-ride.

Table 3-5
Comparison of Over-ride Rates Between the Smart Thermostat Sample Groups and the SPP Program Participants

Re-set Date	Sample Group	Smart Thermostat Sample AC			SPP AC Counts		
		Confirmed	Over-ride	Over-ride Percent	Confirmed	Over-ride	Over-ride Percent
7/17/2003	A	31	4	13%	117	13	10%
7/28/2003	B	41	7	17%	105	10	9%
8/8/2003	B	40	9	23%	104	16	13%
8/15/2003	A	30	14	47%	121	35	22%
8/27/2003	A	30	9	30%	128	20	14%
9/3/2003	A	29	7	24%	116	25	18%
9/12/2003	B	41	8	20%	114	20	15%
9/22/2003	A	30	6	20%	116	22	16%
9/29/2003	B	39	2	5%	120	13	10%
10/9/2003	A	30	2	7%	117	3	3%
10/14/2003	B	38	5	13%	111	9	8%
10/20/2003	A	30	4	13%	118	13	10%

For determining an over-ride fraction we will not make use of the additional participants in the SPP. The fraction will be estimated from the Smart Thermostat sample alone.

For purposes of this analysis, we use the percent that over-rode at any point during each event. Since over-rides increase as the re-set event continues, this over-ride percent is the maximum that occurred over the event—that is, the percent that had over-ridden as of the end of the event. Figure 3-1 shows the percent overriding as a function of time since the start of each re-set event.

Figure 3-1
Over-ride Percent as Function of Time During Event

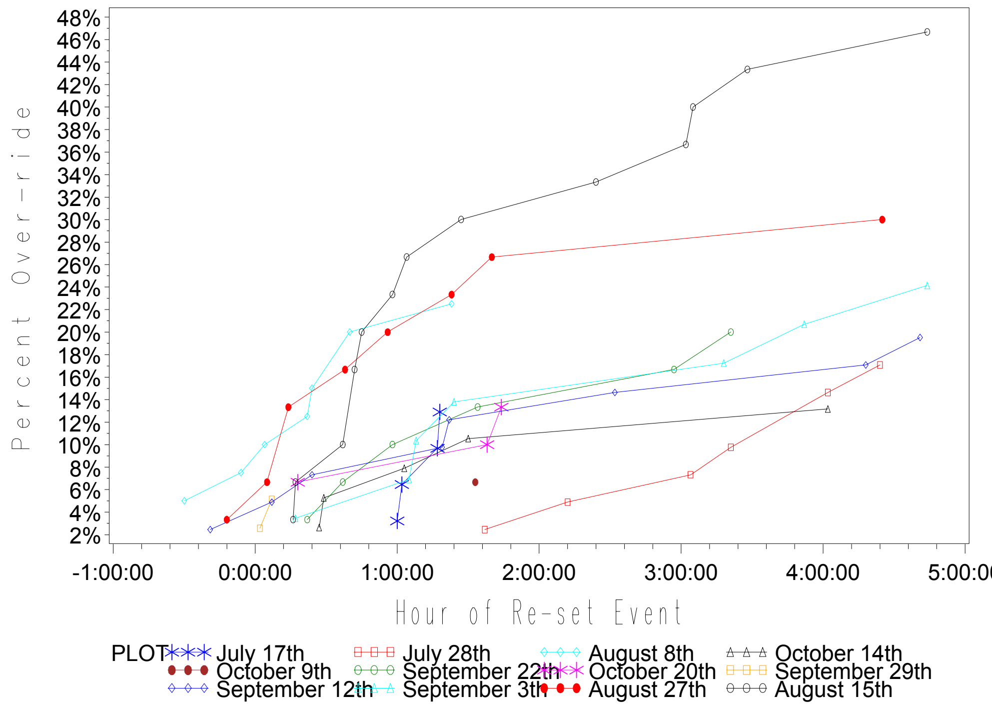


Table 3-6 shows the percent of over-riders with the factors most likely to be correlated with over-riding. The strongest correlation is with average temperature. The two highest over-ride percents correspond to the two hottest days. Those days were also 3-degree setbacks indicating setback is not a driving factor. Time and duration are variable across the range of over-ride percents.

Table 3-6
Percent Over-ride Compared to Average Temperature, Re-set Amount Event Duration and Time

Date	Sample Group	Start time	End time	Hours Duration	Degrees setback	Average Temperature	Percent Over-ride
July 17, 2003	A	2:00 PM	3:45 PM	1:45	5	74	13%
July 28, 2003	B	2:00 PM	7:00 PM	5:00	5	72	17%
August 8, 2003	B	3:00 PM	5:00 PM	2:00	3	76	23%
August 15, 2003	A	2:00 PM	7:00 PM	5:00	3	82	47%
August 27, 2003	A	4:00 PM	6:00 PM	2:00	3	76	30%
September 3, 2003	A	2:00 PM	7:00 PM	5:00	4	73	24%
September 12, 2003	B	2:00 PM	7:00 PM	5:00	4	73	20%
September 22, 2003	A	2:00 PM	6:00 PM	4:00	4	71	20%
September 29, 2003	B	2:00 PM	7:00 PM	5:00	4	70	5%
October 9, 2003	A	3:00 PM	5:00 PM	2:00	4	69	7%
October 14, 2003	B	2:00 PM	7:00 PM	5:00	4	68	13%
October 20, 2003	A	3:00 PM	5:00 PM	2:00	4	74	13%

Modeling the Over-ride Rate

To account for the varying over-ride rates with re-set event conditions, we modeled the over-ride rate using a logistic regression. The over-ride rate p_{OR} is transformed to the log odds ratio

$$f(p_{OR}) = \ln(p_{OR}/(1-p_{OR})).$$

The log odds ratio is then modeled as a linear function of temperature, duration, and re-set amount. The predicted log odds is then transformed back to the predicted over-ride proportion as

$$p_{OR} = e^{f} /(1+ e^{f}).$$

The transformation ensures that the predicted over-ride rates from the fitted model all fall in the range from 0 to 100 percent.

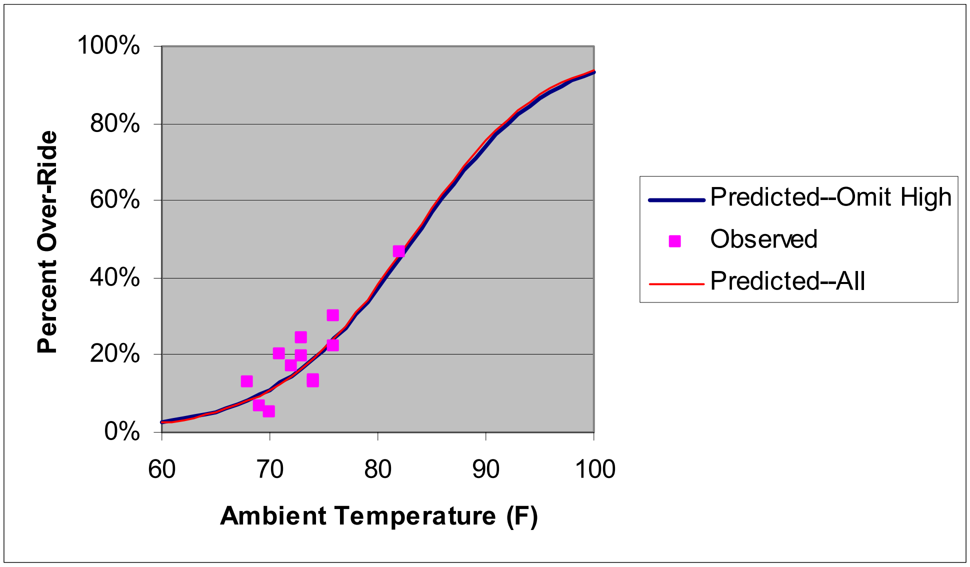
In this analysis, temperature was found to be the dominant driver of the over-ride rate, statistically significant at the 99 percent confidence level. With the other terms accounted for, degrees setback was not at all statistically significant (t-statistic = –0.6) and the estimate was negative. All re-set events had between 3 and 5°F re-set; within this range, there may be little difference in over-ride behavior. The re-set amount was therefore left out of the regression, though it may be important if data are available on a broader range of conditions.

Duration had a positive effect, but was not statistically significant at the 90 percent confidence level (t-statistic of 1.3). In addition, inclusion of duration resulted in some residuals that indicated potential large influence of one or two points. To avoid potentially spurious effects from trying to estimate multiple coefficients from limited data with wide variation, duration was also left out of the model. Thus, the final model had temperature only.

Figure 3-2 shows the fitted regression line and the observed data. Two lines are actually shown in the figure. One is for a regression using data from all 12 days. The second excludes the day with the highest temperature and over-ride rate.

The two curves are nearly indistinguishable. Moreover, both are very close to the observed value of 47 percent on this most extreme day. Thus, while the over-ride rate of 47 percent may seem anomalous, it is nearly exactly what the model would predict based on the other days. This finding gives some confidence that the model is giving reasonable results for temperatures through the low 80s, despite the fact that we have only one observation above 76°F. At higher temperatures, where no observations have been made, the estimates are less certain. Between 75°F and 85°F, each 1°F increase in temperature is associated with an increase of 3.6 percentage points in the over-ride rate.

Figure 3-2
Predicted and Observed Over-ride Rates vs. Outdoor Temperature



3.2.4 Percent Not Contributing

Table 3-7 summarizes the fraction not contributing to impacts for the 12 re-set events in the summer of 2003. As discussed the non-responder percentages reflect the percent non-response of the combined Smart Thermostat/SPP group for each date. The AC non-use percentage is constant across the whole summer and reflects the percent of units still remaining in the analysis with zero AC usage. The over-ride fraction is calculated from the re-set sample group alone. The combined percent not contributing ranged from 26 to 68 percent across the 12 re-set days. This can be compared to 40 percent not contributing due to non-use or non-response for the single 2002 re-set event. The 2002 re-set event had a higher fraction of zero AC use but the over-ride fraction was lower than all but two of the 2003 re-set days.

Table 3-7
Percent Not Contributing During 2003 Re-set Events

Re-set Date	Non-Response Fraction			AC Non-use Fraction (P_z)	Over-ride Fraction			Fraction Not Contributing
	No Response	ST/SPP participants	Fraction (P_F)		Over-riders	ST Sample Participants	Fraction (P_{or})	$P_F + (1-P_F)(P_z+P_{or})$
07/17/03	8	156	5%	18%	4	31	13%	35%
07/28/03	11	157	7%	18%	7	41	17%	40%
08/08/03	12	156	8%	18%	9	40	23%	45%
08/15/03	14	165	8%	18%	14	30	47%	68%
08/27/03	6	164	4%	18%	9	30	30%	50%
09/03/03	19	164	12%	18%	7	29	24%	49%
09/12/03	11	166	7%	18%	8	41	20%	42%
09/22/03	6	152	4%	18%	6	30	20%	41%
09/29/03	6	165	4%	18%	2	39	5%	26%
10/09/03	15	162	9%	18%	2	30	7%	32%
10/14/03	14	163	9%	18%	5	38	13%	37%
10/20/03	3	151	2%	18%	4	30	13%	33%

3.3 VALIDATION OF LOAD MODELS AND COMPARISON GROUP

3.3.1 Re-set and Comparison Group Characteristics

As described in Section 2, the size distribution of the comparison group was compared with that for the re-set group. The primary reason was to determine if there was a need to scale the savings by capacity and the appropriate magnitude of the scaling. The review also would reveal anomalous units. The 2002 analysis concluded there was no need for scaling with the original sample groups. The comparison is repeated for 2003 to make sure the removed premises have not changed the character of the groups.

Table 3-8 shows the distribution of AC unit capacity for each analysis group. The table shows that the re-set and comparison groups do change slightly as they are reduced to the analysis premises and further to the non-zero use analysis premises. Overall, though, the two groups used in the analysis remain quite similar to one another in terms of size distribution. The analysis is therefore done, as in 2002, without a scale adjustment for size.

Table 3-8
Distribution of AC Unit Capacity (tons) by Data Scope

Data Scope	Group	Premises	AC Units	Mean	Median	Min	Max	Standard Deviation
Original Sample	A	49	55	3.7	3.5	2.0	6.0	1.1
	B	51	56	3.9	4.0	2.0	6.0	0.8
	Total	100	111	3.8	4.0	2.0	6.0	0.9
All Units With Good Data for the 2003 Analysis	A	38	42	3.9	4.0	2.5	6.0	0.8
	B	45	51	3.7	3.5	2.0	6.0	1.0
	Total	83	93	3.8	4.0	2.0	6.0	0.9
All Units with Good Data and Non-Zero Usage	A	29	33	4.0	4.0	2.5	6.0	0.9
	B	37	43	3.7	3.5	2.0	6.0	1.1
	Total	66	76	3.8	4.0	2.0	6.0	1.0

3.3.2 Observed and Modeled Loads

Another type of method validation was examination of the quality of the load model fits for both the re-set and comparison groups. We considered both the AC end-use data and the whole-house data.

Table 3-9 summarizes key regression diagnostics for the end-use and whole-house model fits. The table indicates that the whole-house fits were generally better than the AC fits. The R^2 statistics were generally higher, and the t-statistics for the cooling slopes were also higher.

Table 3-9
Regression Diagnostics for End-use and Whole-house Load Model Fits

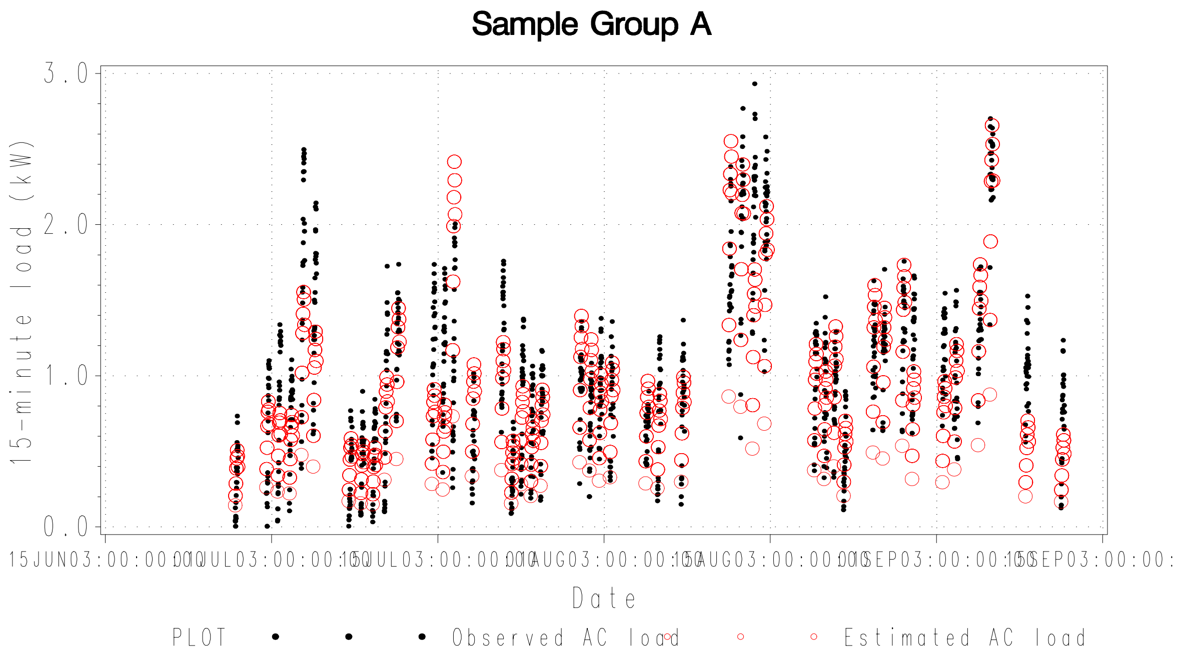
Regression Statistic		AC Data	Whole-Premise Data
Median R-Squared		0.50	0.80
Median Cooling Slope t-statistic	Hour		
	12	0.63	11.03
	13	0.61	11.01
	14	0.84	12.42
	15	1.33	13.72
	16	2.44	14.85
	17	2.83	15.23
	18	2.11	16.65

These comparisons are somewhat deceiving, because the data in the two models are different. Thus, despite the higher R^2 for the whole-house data, the end-use data generally exhibited smaller absolute modeling error. This smaller absolute error was reflected in a smaller overall standard error of the final estimate when the AC data were used. For this reason, we focus on the AC model results.

For the AC model, Table 3-9 shows that the slope coefficients were reasonably well estimated for the afternoon hours relevant to this analysis. Estimates for earlier hours are not as good, largely because air conditioning usage was generally low and more intermittent.

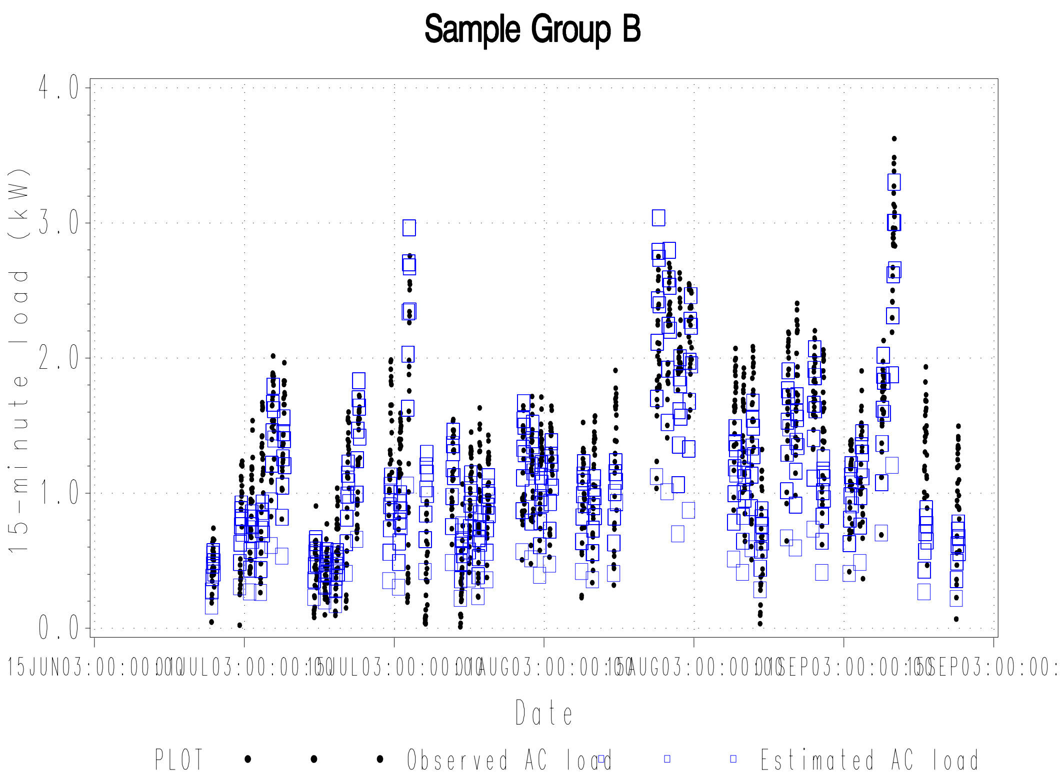
Figures 3-3 and 3-4 show observed and modeled AC loads for the re-set and comparison groups, respectively. The plotted data are limited to that from weekdays with an average temperature of 68°F or higher in summer 2002, time between the hours from 12 PM to 6 PM inclusive. The data shown are for the 33 re-set group and 43 comparison group units classed as "potential contributors." Each plot shows the estimated load tracking the actual load fairly well across the summer, for warm weekday afternoons. Comparison between the two plots also shows that the observed loads between the two groups also were similar, although there were some days with substantially different AC use.

Figure 3-3
Group A Warm Weekday 15-minute Mean Observed (•) and Mean Estimated (◦) Loads vs. Time



Points plotted are average values over 33 “potentially contributing” AC units in group A.

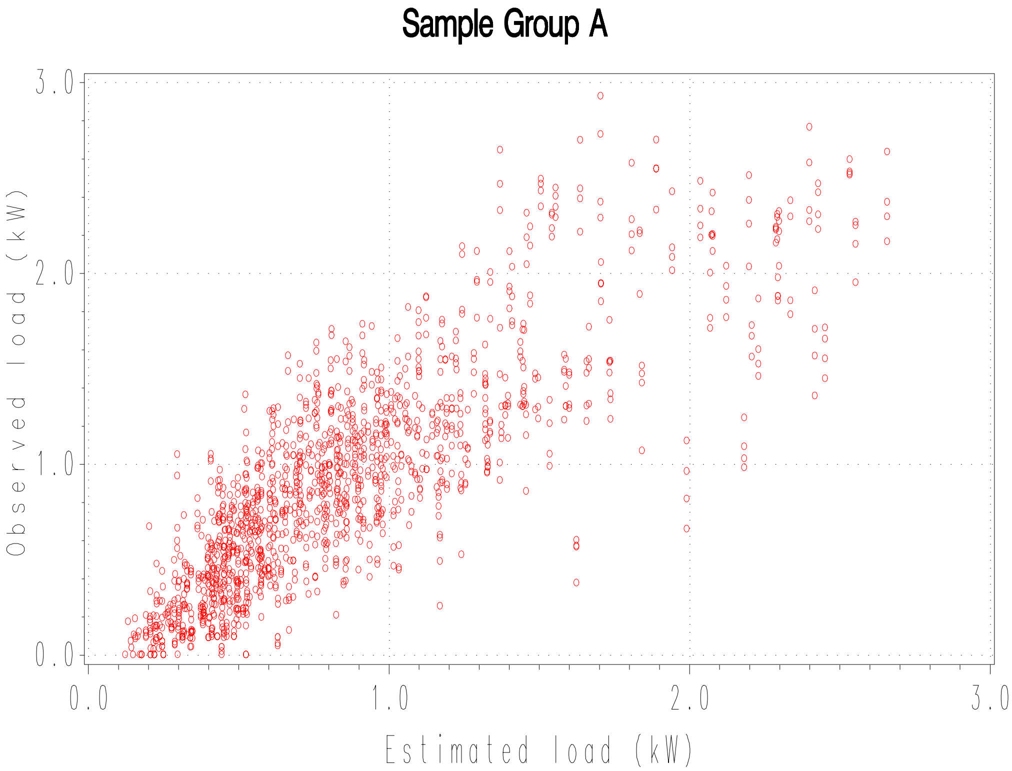
Figure 3-4
Group B Warm Weekday 15-minute Mean Observed (•) and Mean Estimated (◦) Loads vs. Time



Points plotted are average values over 43 “potentially contributing” AC units in group B.

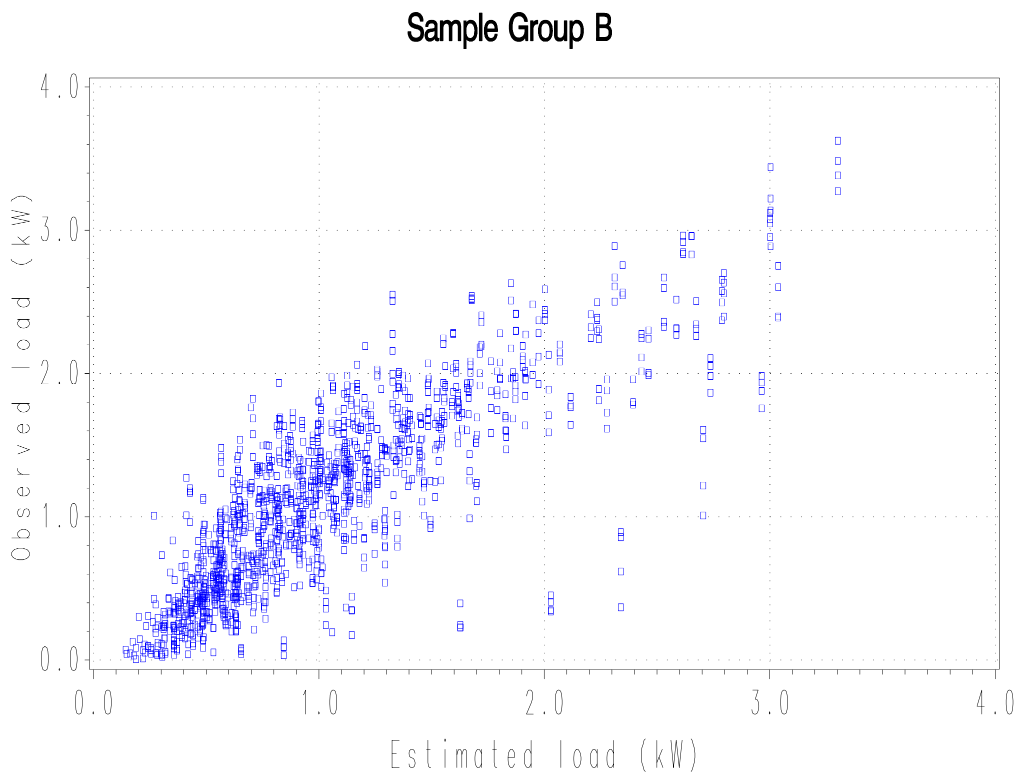
The same data shown in Figures 3-3 and 3-4 are plotted in Figures 3-5 and 3-6. These charts show observed versus modeled hourly mean loads. Both charts show a fairly uniform linear relationship along a 1:1 ratio of observed to estimated load. This is a good indicator of model fit. Still there is a fair amount of estimation error given that each point is an average error over 33 and 43 AC units.

Figure 3-5
Group A Warm Weekday Observed vs. Modeled 15-minute Mean Loads



Points plotted are average values over 33 “potentially contributing” AC units in group A.

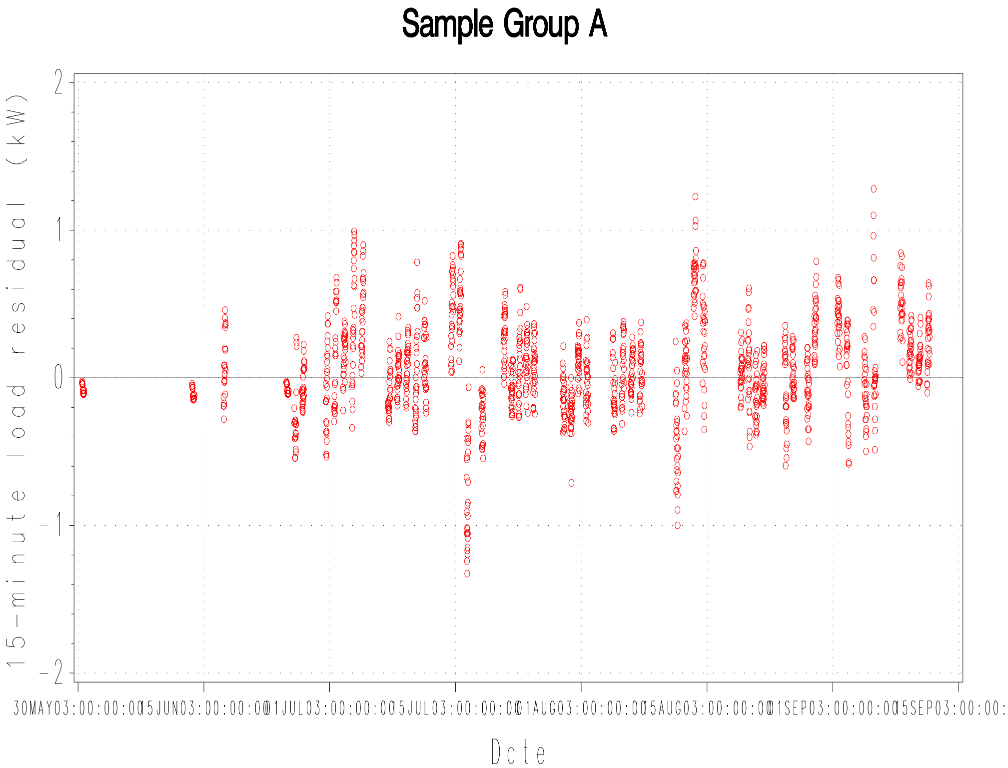
Figure 3-6
Group B Warm Weekday Observed vs. Modeled 15-minute Mean Loads



Points plotted are average values over 43 “potentially contributing” AC units in group B.

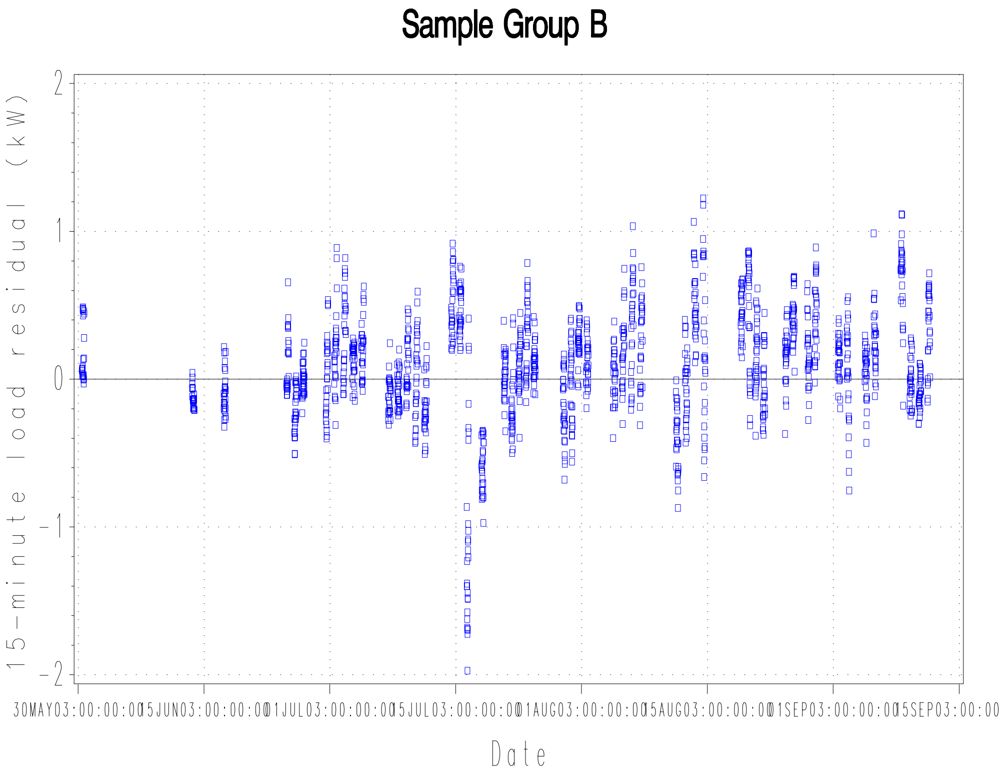
Figures 3-7 and 3-8 show the residuals, or errors, of the model estimates of hourly mean load from June 15 to September 15 for the re-set and comparison groups, respectively. The larger magnitude errors are concentrated among a few hours and not scattered across all hours. The patterns of errors over time are very similar between the re-set and comparison groups. This relationship is consistent with the conjecture that particular weather conditions for those days with larger errors create systematic modeling errors across premises. The similarity of the error pattern also shows that errors of the comparison group can be a good indicator of the error of the re-set group error for a given day and hour.

Figure 3-7
Group A Warm Weekday 15-minute Mean Load Residual vs. Time



Points plotted are average values over 33 “potentially contributing” AC units in group A.

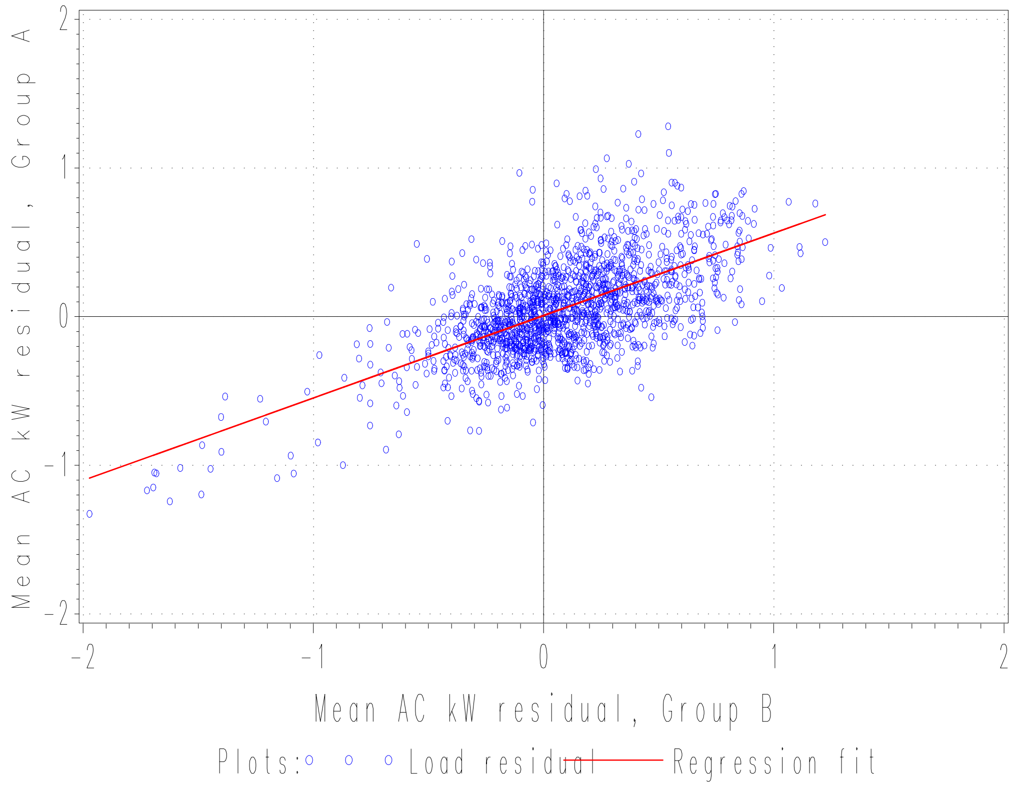
Figure 3-8
Group B Warm Weekday 15-minute Mean Load Residual vs. Time



Points plotted are average values over 43 “potentially contributing” AC units in group B.

The difference of difference method requires not just that the two groups be similar in actual load, but also that the modeling error for the comparison group be a good indicator of the modeling error for the other. Figure 3-9 shows a plot of the comparison group’s hourly mean residuals against the re-set group’s. Also shown is the regression line, which gave an R^2 of 0.41.

Figure 3-9
Comparison Group vs. Re-set Group 15-minute
AC Mean Load Residuals and Regression

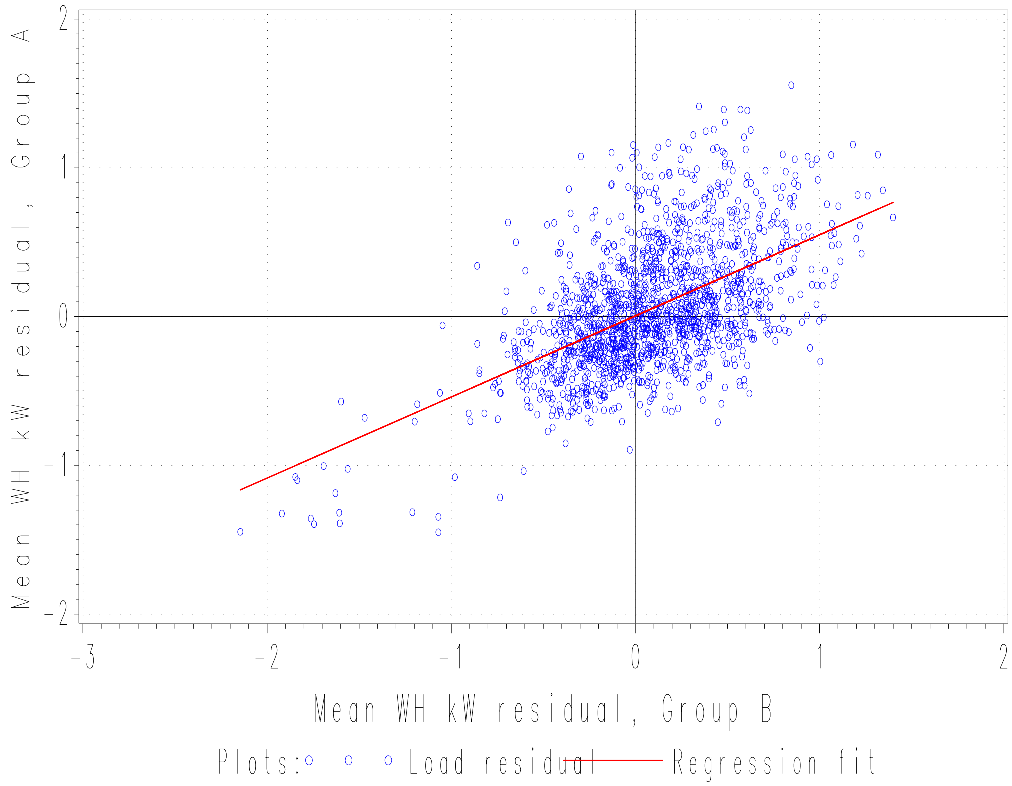


Points plotted are average values over 33 re-set group and 43 comparison group “potentially contributing” AC units.

The figure shows a strong relationship between comparison group and re-set group modeling error, with the regression line passing very close to the center point (0,0). The plot also indicates that the scale of the errors is similar, so that no scaling adjustment is required when using the comparison group to estimate the re-set group error. Thus, the difference of difference method appears to be well founded for the end-use AC data.

Figure 3-10 shows a similar plot for the whole-house data. In the 2002 analysis, the whole-house data not only showed greater modeling variability than the AC data, but also showed less systematic correspondence between the two groups’ modeling errors. For the current analysis, the general pattern of correspondence between the two groups in the whole-house analysis is similar to that for the AC analysis. However, the range of variation is seen to be greater, as indicated before. Thus, the difference of differences method is appropriate using the whole-house data, but the accuracy of the estimates will be worse than with the AC data.

Figure 3-10
Comparison Group vs. Re-set Group Modeling Error
Whole-House Data



Points plotted are average values over 28 re-set group and 40 comparison group "potentially contributing" AC units.

3.4 Estimated Impacts of the Re-set Event

There were 12 re-set events during the summer of 2003. Table 3-10 gives an overview of the times, degrees re-set, and sample group for each re-set day.

Table 3-10
Re-set Event Times, Degrees Re-set, and Sample Group

Date of Re-set	Sample Group	Start time	End time	Average Temperature	Degrees setback
July 17, 2003	A	2:00 PM	3:45 PM	74	5
July 28, 2003	B	2:00 PM	7:00 PM	72	5
August 8, 2003	B	3:00 PM	5:00 PM	76	3
August 15, 2003	A	2:00 PM	7:00 PM	82	3
August 27, 2003	A	4:00 PM	6:00 PM	76	3
September 3, 2003	A	2:00 PM	7:00 PM	73	4
September 12, 2003	B	2:00 PM	7:00 PM	73	4
September 22, 2003	A	2:00 PM	6:00 PM	71	4
September 29, 2003	B	2:00 PM	7:00 PM	70	4
October 9, 2003	A	3:00 PM	5:00 PM	69	4
October 14, 2003	B	2:00 PM	7:00 PM	68	4
October 20, 2003	A	3:00 PM	5:00 PM	74	4

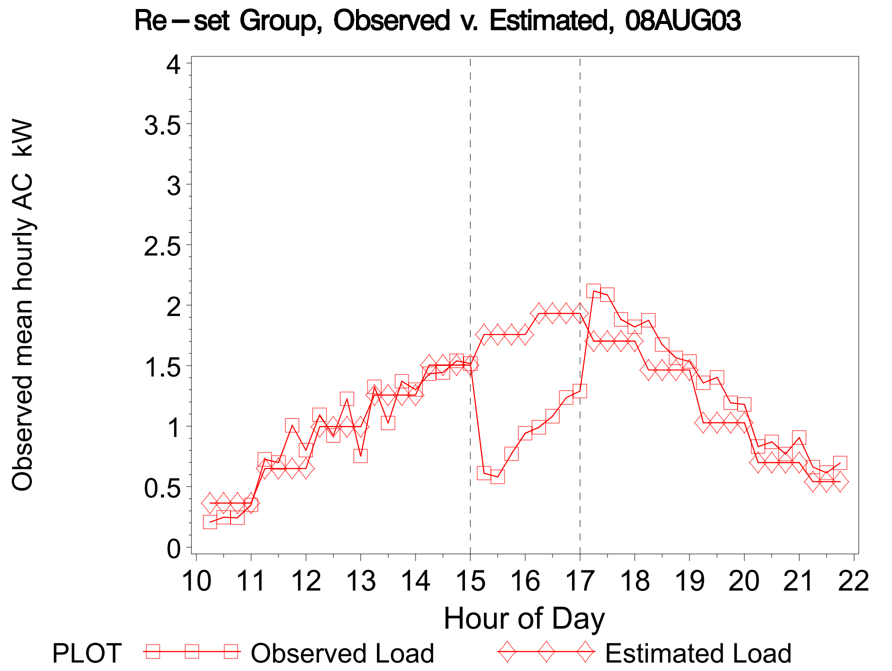
Clearly, the sample groups were not re-set on a strictly alternating basis. As a result, sample group A was re-set seven times while sample group B was only re-set five times.

The following section displays the methodology used in this analysis in visual plots. The re-set event that occurred on August 8 is used as an example. Similar plots for all remaining re-set events can be found in Appendix A. Corresponding plots for the whole-house analysis are in Appendix B.

3.4.1 Modeled and Observed Load on a Re-set Day for Potential Contributors

Group B was re-set on August 8 between 3 PM to 5 PM or hours 15 to 17. Figure 3-11 shows the re-set group's observed load compared to the estimated load. These data reflect only the "potential contributor" premises. These were weekday AC users that responded to the re-set and did not over-ride.

Figure 3-11
Observed (—) and Estimated (--) AC Loads on Re-set Day vs. Time

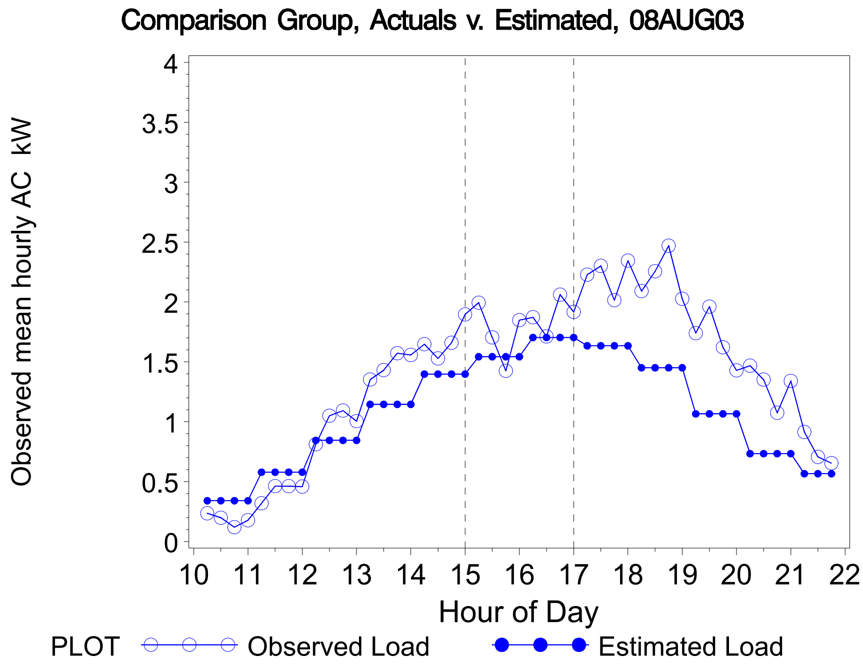


Points plotted are average values over re-set group comparison group "potentially contributing" AC units.

This plot has all the characteristics one would expect to see in plot of this kind of demand response program. The plot of the re-set group's observed load diverges dramatically from the estimated load at the hour 15 start time. As the re-set period progresses, the difference between the observed and estimated load decreases as units come on to maintain even the higher re-set temperature. After hour 17, the re-set group's load jumps above the expected load as those AC units come on full time to compensate for lost cooling. The period after hour 17 when observed is higher than expected is the "payback" period discussed earlier. The difference between observed and estimated load for the re-set group is the unadjusted estimate of the impact for this re-set period.

Figure 3-12 shows the comparison group observed load compared to the estimated load. The difference between observed and estimated load for the comparison group provides the adjustment for the impact estimate shown in Figure 3-11.

Figure 3-12
Observed (—) and Estimated (--) AC Loads on Re-set Day vs. Time

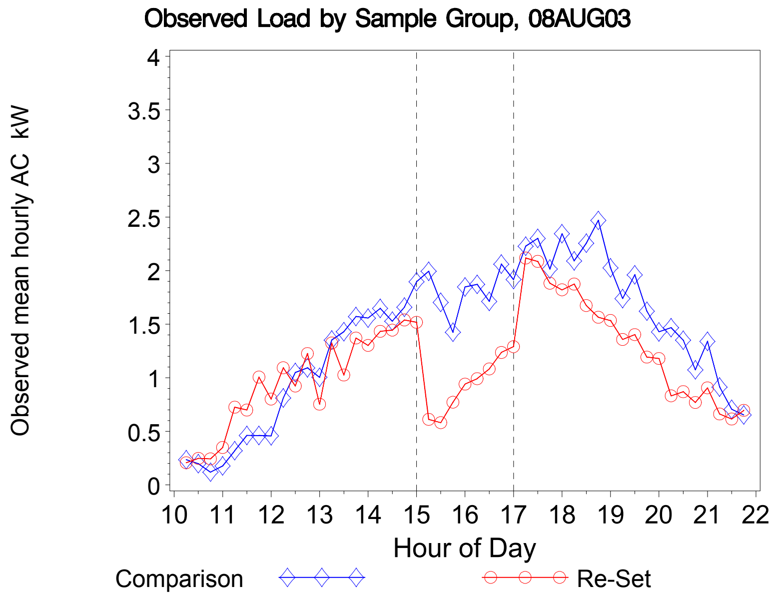


Points plotted are average values over comparison group “potentially contributing” AC units.

Figure 3-12 indicates that the estimated load was generally below the observed load for the comparison group. Subtracting observed from estimated load results in a negative error adjustment. When this is subtracted from the unadjusted impact estimate in Figure 3-11 to get the difference in differences result, the double negative makes for a net increase to the impact estimate. Alternatively, imagine increasing the re-set group model estimated load from Figure 3-11 by the amount the comparison model estimate is too low above in Figure 3-12. If that line were added to Figure 3-11, it would be the adjusted estimate of the re-set group’s uncurtailed load.

As indicated above we can conceive of the “difference of differences” method starting with either difference. Above we started with an unadjusted impact estimate for the re-set group derived from the estimated load and then adjusted it with the error from the comparison group. Alternatively, we can start with the difference between the two sample groups and adjust that impact estimate with the difference in the model-estimated loads. Figure 3-13 shows the re-set and comparison group loads on the re-set day.

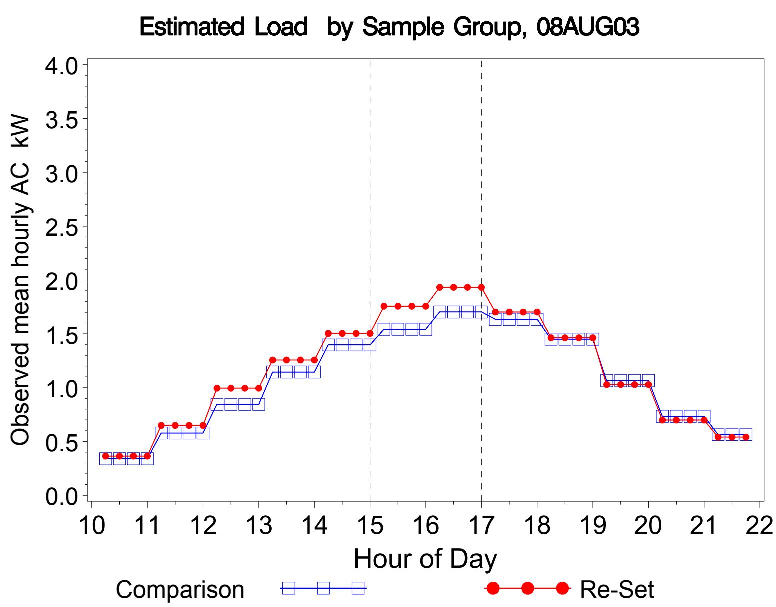
Figure 3-13
Observed 15-min Average AC Loads on Re-set Day vs. Time



Points plotted are average values over re-set and comparison group "potentially contributing" AC units.

This plot needs to be adjusted by the difference of the estimated loads for the two sample groups. Figure 3-14 compares the two load estimates.

Figure 3-14
Estimated 15-min Average AC Loads on Re-set Day vs. Time



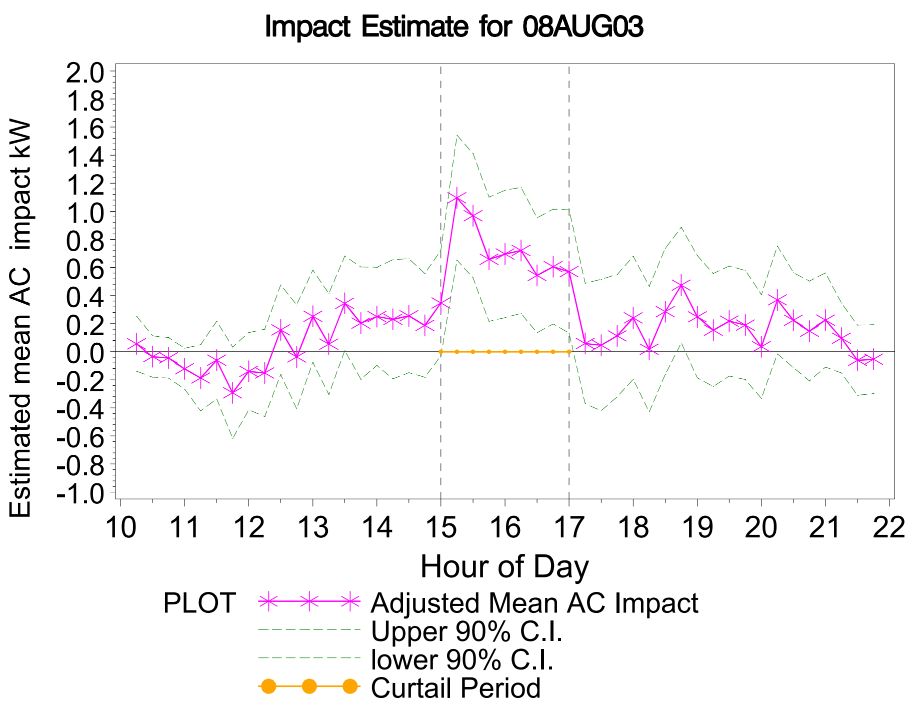
The re-set group estimated load is higher than the comparison group through the re-set period. This indicates that, all weather related effects being equal, the re-set group should have been that much higher than the comparison group. Thus, once again, the original impact estimate is increased by the error adjustment.

3.4.2 Savings Estimates

Air Conditioning Unit Impacts

The adjusted impact estimates, derived through the difference in differences approach, reflect the per-unit impact of all potentially contributing units. These are units that have non-zero consumption for at least some part of the summer, received a re-set signal and did not over-ride. It is still necessary to adjust this result so that it reflects a per-unit impact for all units in the program. This adjustment is to multiply the savings per potential contributor by the fraction these potential contributors represent of the whole. The percent of non-contributors for each day was given in Table 3-7 above. The remainder is the percent potential contributors. The final adjusted impact estimates for the August 8 re-set event are displayed in Figure 3-15.

Figure 3-15
Estimated Impacts on Re-set Day vs. Time



The 90 percent confidence interval lines indicate the level of statistical confidence in the estimate. If the confidence interval includes zero, then the estimate cannot be considered statistically different from zero at a 90 percent confidence level. Every 15-minute interval in the re-set period for August 8 is statistically significant.

These 15-minute interval results can be presented in aggregate form for the whole re-event. That is, the average kW savings across all intervals in the re-set period is determined. Table 3-11 presents the results for all 12 re-set events.

Table 3-11
AC Impacts and Standard Errors for 12 Re-set Days

Re-set Event Date	Start time	End time	Sample Group Re-set	Average Temperature	Degrees Setback	Group A AC Count	Group B AC Count	Mean Impact for Responding AC Users	Percent Responding AC Users	Mean Impact per AC Unit	Standard Error
7/17/2003	2:00 PM	3:45 PM	A	74	5	27	38	0.29	78%	0.22	0.22
7/28/2003	2:00 PM	7:00 PM	B	72	5	31	39	0.23	76%	0.17	0.14
8/8/2003	3:00 PM	5:00 PM	B	76	3	28	36	0.97	75%	0.73	0.27
8/15/2003	2:00 PM	7:00 PM	A	82	3	29	40	0.40	75%	0.30	0.27
8/27/2003	4:00 PM	6:00 PM	A	76	3	27	37	0.87	79%	0.68	0.21
9/3/2003	2:00 PM	7:00 PM	A	73	4	28	40	0.36	72%	0.26	0.14
9/12/2003	2:00 PM	7:00 PM	B	73	4	30	39	0.41	76%	0.32	0.16
9/22/2003	2:00 PM	6:00 PM	A	71	4	28	39	0.38	78%	0.30	0.16
9/29/2003	2:00 PM	7:00 PM	B	70	4	30	37	0.38	79%	0.30	0.12
10/9/2003	3:00 PM	5:00 PM	A	69	4	27	36	0.08	74%	0.06	0.11
10/14/2003	2:00 PM	7:00 PM	B	68	4	30	36	0.13	75%	0.10	0.09
10/20/2003	3:00 PM	5:00 PM	A	74	4	27	36	0.66	80%	0.53	0.25

As indicated by the confidence intervals in Figure 3-15, the average kW impact for the August 8 re-set event is, in fact, statistically significant at the 90 percent level. This day also had statistically significant impacts during each 15-minute interval of the re-set period. Half of the re-set days, however, do not have average impacts that are statistically different from zero. Impacts for these days are highlighted. Average impacts estimated for all of the days are positive, but the accuracy is low for several of the days. In fact, all but five of the 175 intervals are positive. All of the intervals with negative impact are either at the very beginning or end of the re-set period.

Table 3-12 provides the impact results with confidence intervals for both a single unit and for 5,000 units, the target size of the Smart Thermostat Program.

Table 3-12
AC Impacts with Confidence Intervals, Per Unit and for 5000 Units

	Mean kW Per Unit				kW for 5000 Units		
Date	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound	Impact	90% Confidence Lower Bound	90% Confidence Upper Bound
7/17/03	0.22	0.22	-0.14	0.59	1,124	-690	2,939
7/28/03	0.17	0.14	-0.06	0.41	869	-318	2,057
8/8/03	0.73	0.27	0.27	1.19	3,662	1,362	5,962
8/15/03	0.30	0.27	-0.15	0.75	1,482	-761	3,726
8/27/03	0.68	0.21	0.33	1.04	3,414	1,632	5,195
9/3/03	0.26	0.14	0.02	0.50	1,302	109	2,495
9/12/03	0.32	0.16	0.04	0.59	1,577	202	2,951
9/22/03	0.30	0.16	0.03	0.56	1,475	154	2,797
9/29/03	0.30	0.12	0.10	0.50	1,491	497	2,485
10/9/03	0.06	0.11	-0.12	0.24	308	-597	1,213
10/14/03	0.10	0.09	-0.05	0.24	493	-227	1,213
10/20/03	0.53	0.25	0.11	0.94	2,637	563	4,712

Whole-premise Impacts

The energy savings based on the whole-premise metering data are presented in Table 3-13.

Table 3-13
Whole-premise Impacts and Standard Errors for 12 Re-set Days

Re-set Event Date	Start time	End time	Sample Group Re-set	Average Temperature	Degrees Setback	Group A Premise Count	Group B Premise Count	Mean Impact for Responding AC Users	Percent Responding AC Users	Mean Impact per Premise	Standard Error
7/17/2003	2:00 PM	3:45 PM	A	74	5	24	32	0.50	71%	0.36	0.30
7/28/2003	2:00 PM	7:00 PM	B	72	5	28	33	0.41	69%	0.29	0.23
8/8/2003	3:00 PM	5:00 PM	B	76	3	25	30	1.11	69%	0.76	0.35
8/15/2003	2:00 PM	7:00 PM	A	82	3	26	34	0.37	68%	0.25	0.35
8/27/2003	4:00 PM	6:00 PM	A	76	3	24	32	1.30	72%	0.93	0.28
9/3/2003	2:00 PM	7:00 PM	A	73	4	25	34	0.47	66%	0.31	0.23
9/12/2003	2:00 PM	7:00 PM	B	73	4	27	33	0.50	69%	0.35	0.23
9/22/2003	2:00 PM	6:00 PM	A	72	4	25	33	0.54	71%	0.39	0.24
9/29/2003	2:00 PM	7:00 PM	B	70	4	27	31	0.70	72%	0.50	0.19
10/9/2003	3:00 PM	5:00 PM	A	69	4	24	30	0.16	67%	0.10	0.16
10/14/2003	2:00 PM	7:00 PM	B	68	4	27	30	0.20	68%	0.13	0.15
10/20/2003	3:00 PM	5:00 PM	A	74	4	24	30	0.97	73%	0.70	0.34

The whole-premise data give a quite consistent set of energy savings results. In all but one instance, the results are higher than the end-use savings estimates. This could reflect the savings related to the interior air distribution fan that is not included in the air conditioning metering data. In general, though, the increase in whole-premise savings, relative to the air conditioning savings, is greater than the 10 percent of AC load we would expect from this source.

As in the 2002 analysis, the greater variation in the whole-premise data makes the final savings estimates less reliable. Only 4 of the 12 re-set days have impact statistically significant as opposed to the 7 days with the AC data. For this reason, we rely on the AC results as the primary impact estimates.

Table 3-14 provides the whole-premise impact results with confidence intervals for both a single premise and for 5,000 premises.

Table 3-14
Whole-premise Impacts with Confidence Intervals, Per Unit and for 5000 Premises

	Mean kW Per Premise				kW for 5000 Premises		
Date	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound	Impact	90% Confidence Lower Bound	90% Confidence Upper Bound
7/17/03	0.36	0.30	-0.16	0.87	1,784	-777	4,345
7/28/03	0.29	0.23	-0.11	0.68	1,428	-528	3,384
8/8/03	0.76	0.35	0.17	1.36	3,815	851	6,779
8/15/03	0.25	0.35	-0.34	0.84	1,242	-1,718	4,201
8/27/03	0.93	0.28	0.46	1.40	4,650	2,299	7,001
9/3/03	0.31	0.23	-0.08	0.70	1,550	-377	3,477
9/12/03	0.35	0.23	-0.04	0.73	1,725	-205	3,656
9/22/03	0.39	0.24	-0.02	0.80	1,931	-119	3,980
9/29/03	0.50	0.19	0.18	0.83	2,506	880	4,133
10/9/03	0.10	0.16	-0.17	0.38	524	-860	1,908
10/14/03	0.13	0.15	-0.12	0.38	668	-587	1,923
10/20/03	0.70	0.34	0.13	1.28	3,515	647	6,384

3.5 Projected Impacts By Temperature and Re-set Amount

Projected impacts at various outside temperatures and re-set amounts were estimated from the same load models developed in the analysis of the specific re-set event, as described in Section 2. For each unit with good data and non-zero summer use, the unit's load model was used to calculate the load for each hour of the day at a given daily average temperature. The same model was used also to calculate the hourly loads assuming an increase in the thermostat setpoint. This increase is represented in the model as an increase in the unit's cooling reference temperature. The difference in the model's estimate of load with and without the setpoint change is the estimated savings at that outside temperature and re-set amount for each hour.

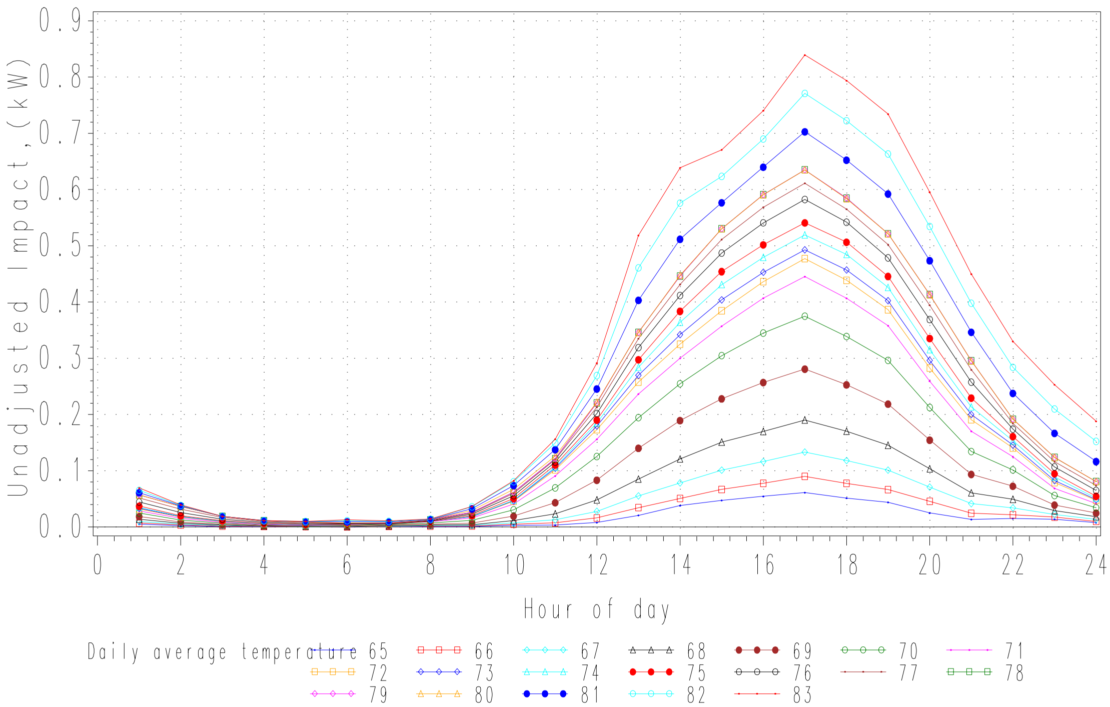
These savings estimates were averaged across all units in the sample for which the model could be estimated. For this projection analysis, the assignment of units to re-set or comparison group was not relevant.

These savings estimates apply to the universe of potential contributors. Multiplying by the estimated proportion of potential contributors gives the projected average savings per unit across all units in the program.

The results are plotted by time of day in Figure 3-16 for a 3°F re-set, and various daily average outside temperatures. These are the impacts per potential contributor, without adjustment for signal failure, over-rides, or zero summer use. That is, Figure 3-16 shows the unadjusted projected impacts. Projected impacts, without adjustment for non-contributors, are tabulated in Appendix C for each combination of re-set amount and average outside temperature.

The figure shows that unadjusted savings are low at low outside temperatures, where air conditioning use is low and higher at higher outside temperatures. Savings are also low in the early morning and overnight. Savings per unit are greater at higher outside temperatures because a larger fraction of AC units are on. At lower temperatures, many of the units have zero estimated load and zero savings.

Figure 3-16
Unadjusted Projected Impacts by Hour, Average per AC Unit
(For 3°F Re-set)



For outside temperatures above 83°F, there is no additional increase in the unadjusted projected savings. This leveling off occurs once the outside temperature exceeds the point where all the units are projected to be based on the individual load model fits. The load models assume a linear relationship between load and outside temperature above each unit's reference temperature. Thus, a 3°F shift in reference temperature has the same affect on load for all outside temperatures above this reference point.

Figures 3-17a and 3-17b show the projected impacts adjusted by an estimate of the potential contributors percentage from the 12 re-set events during the summer of 2003. The first plot shows the adjusted impacts on the same scale as the unadjusted impacts displayed in Figure 3-16. The second plot expands the scale so that the patterns can be seen more easily.

For the adjusted projected impacts shown in Figure 3-17, average signal failure and zero use percentages are applied with an estimated override percent. Override is estimated as a function of temperature as discussed in Section 3.2.3. Projected impacts, adjusted for non-contributors, are tabulated in Appendix D for each combination of re-set amount and average outside temperature.

Figure 3-17a
Adjusted Projected Impacts by Hour, Average per AC Unit
(For 3°F Re-set)

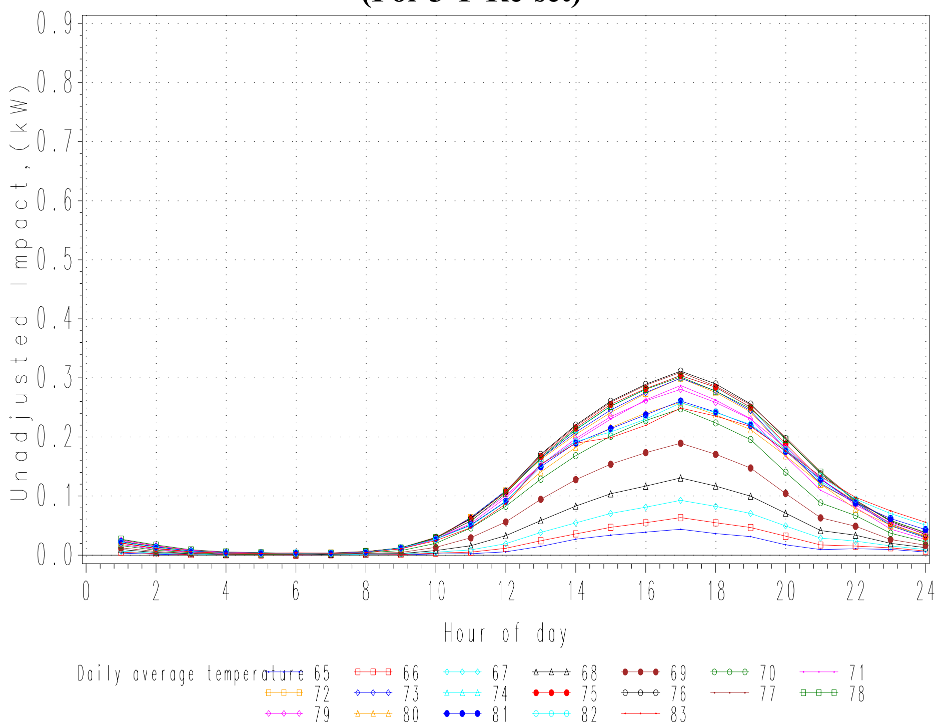
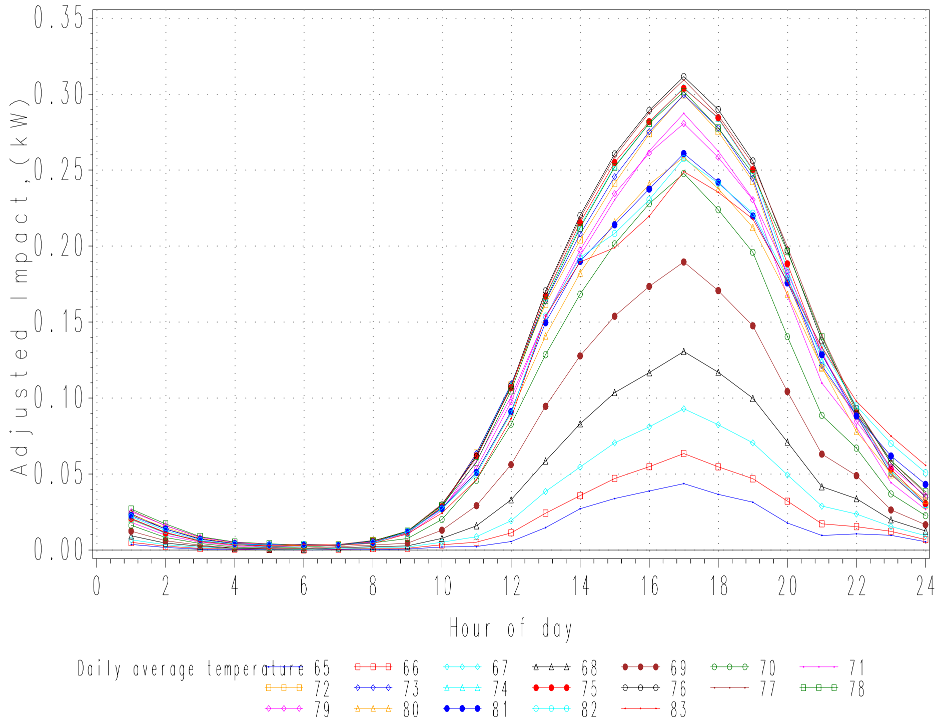


Figure 3-17b
Adjusted Projected Impacts by Hour, Average per AC Unit, Full Scale
(For 3°F Re-set)



In figures 3-17a and 3-17b above the adjusted projected savings show no additional increase above 76°F. Both savings and override rates are functions of temperature. Both increase with increasing temperature, but at different rates. Figures 3-17a and 3-17b indicate that the effect of the increase in override percent is greater above 76°F than the increase in savings.

Figure 3-18, below, illustrates the relationship between savings and temperature for the peak hours. Between around 70 and 77°F, the adjusted impact is fairly flat, indicating that the increasing impact per contributing unit is roughly balanced by the increasing over-ride rate. Impacts drop off above 78°F, particularly for the late afternoon hours.

Figure 3-18
Adjusted Projected Impacts by Temperature, Average per AC Unit
(For 3°F Re-set)

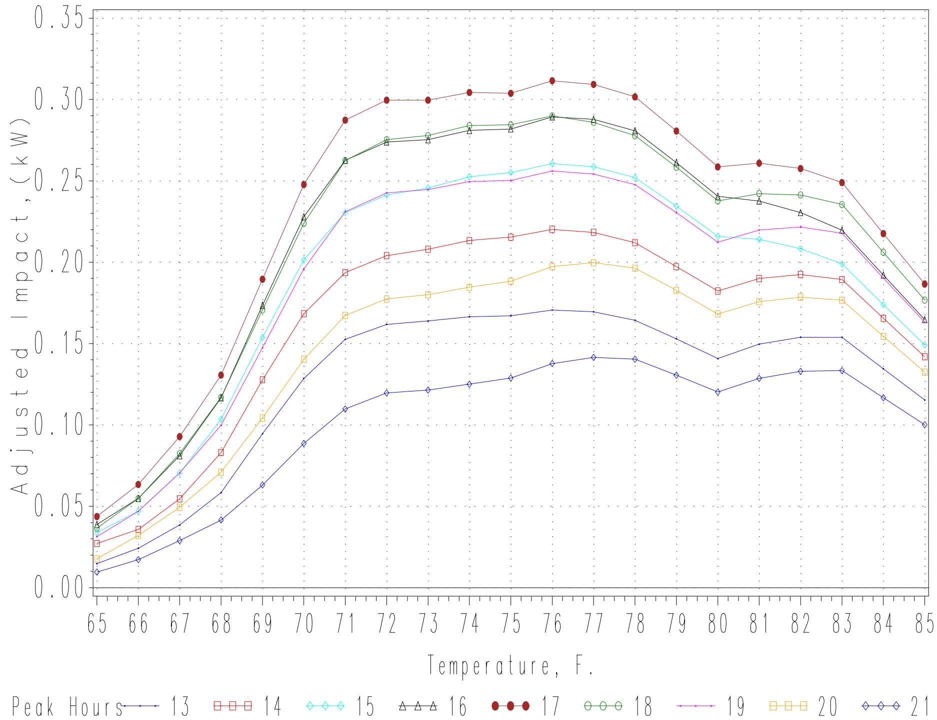


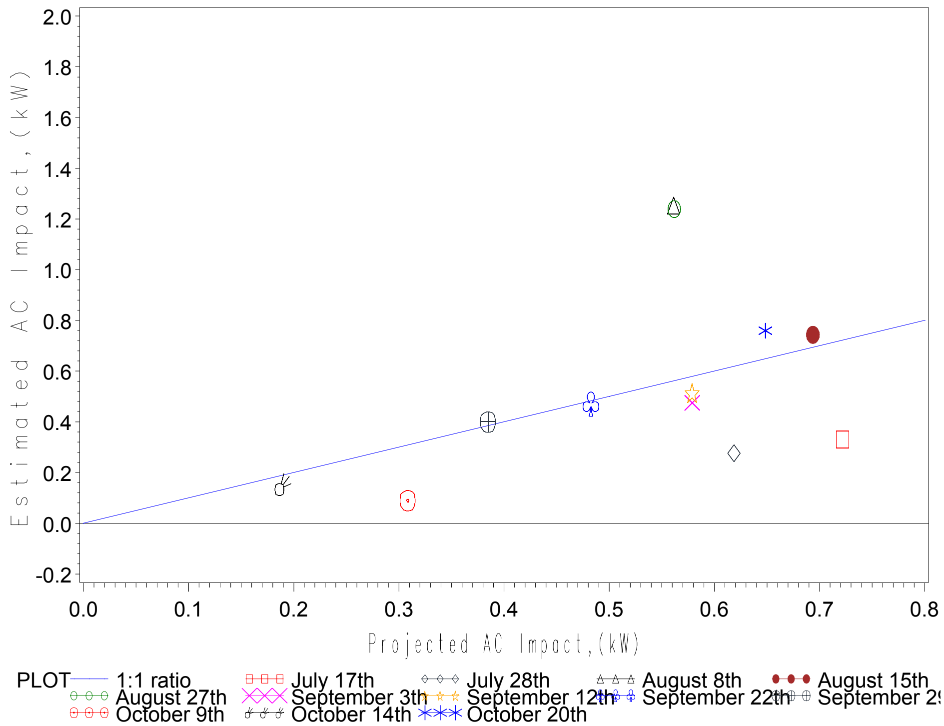
Figure 3-19, below, compares the unadjusted mean AC impact estimated earlier with the differences in differences method with the projected impacts. Projected impacts for each re-set are calculated as for Figure 3-16, but using the actual re-set amount for each event.

In this figure, the over-riding fraction has been backed out of the mean impact per responding user, to provide the mean impact per potential contributor. We focus on this comparison, because it captures all the differences between the general and particular-day estimates. Immediately after an actual re-set event for the regular program, the fractions of over-riders and non-responders would be known directly from the program operation system, so that the same adjustments would be applied for either method. The fraction of non-zero users assumed at this point would also be the same for either.

The diagonal blue line in the figure represents a 1:1 ratio. The plot shows that many of the projected impacts are very close to the actual estimated impacts. There are some outliers in both directions. However, the estimates with relatively low standard errors all cluster around the 1:1 line. The three estimates that are furthest below this line all were not statistically significant at the 90 percent confidence level. The two very high estimates also have relatively high standard errors. For the remaining points, the estimated conforms reasonably well to the projected savings.

One reason for the disparity between the particular-day estimates and the corresponding projections for the general conditions is in how the particular day is mapped to the general condition. The general condition is defined by an ambient temperature and re-set amount. However, the premises in the study are modeled using seven different weather stations. For purposes of this comparison, we used the average temperature across all the nonzero users in the metering sample to define the general condition. Effectively, then, the projection assigns the same temperature to all premises, whereas the particular-day estimates used the local temperature for each. This difference contributes to the variation seen in Figure 3-19.

Figure 3-19
Unadjusted Estimated vs. Projected AC Impact
Average Impact for Each Event



4 CONCLUSIONS

In 2003, the Smart Thermostat Program was not invoked, except on a test basis for the metering sample for this study. Thus, there were no "program impacts" *per se*. Nevertheless, the findings from the 12 re-set days for this sample provide substantial information about the program's likely effectiveness under full-scale operation. This information is an improvement over that available from the 2002 study, which had a single re-set day under cool conditions, and a generally cool summer from which to estimate usage patterns.

Following are some of the key findings from the study.

4.1 WHAT FRACTION CONTRIBUTE TO SAVINGS

1. About 96 percent of the thermostats in the program appeared to operate correctly during each re-set event. The non-response rate ranged from 3 percent to 6 percent across the 12 events.
2. The over-ride rate varied substantially across the re-set events, from a low of 5 percent to a high of 47 percent. The highest over-ride rate occurred on the day with the highest ambient temperature. Between 75°F and 85°F, each 1°F increase in temperature is estimated to increase the over-ride rate by 3.6 percentage points. While this relationship is not surprising, the magnitude of the over-ride rates observed and projected at higher temperatures raises concerns about the effectiveness of the program when it is likely to be most needed. Averaged across all events and re-set units, the over-ride rate was 19 percent.
3. Over-ride rates increase with the duration of the re-set event, as would be expected. On each of the re-set days, the percent of units over-ridden increased throughout the re-set period.
4. Eighteen percent of participating AC units were not used at all during the summer of this study. While some of these units might be used during severe hot weather, they contribute no savings in the milder weather. This is a slightly lower percentage than was found in 2002 during an unusually cool summer.

The combined effect of non-response, over-ride, and non-use was that only about 60 percent of the participating units are "potential contributors" to impacts. Across the different re-set days, that fraction ranged from 32 percent to 74 percent. The variation is mainly attributable to the varying over-ride levels.

4.2 SAVINGS FOR THE RE-SET DAYS

Savings per unit enrolled in the program averaged over the re-set period ranged from a low of 0.05 kW to a high of 0.72 kW across the 12 events. The event average was statistically significantly different from zero (at 90 percent confidence) for 7 of the 12 events. However, the estimated savings in individual intervals were positive for all but 8 of the 187 15-minute intervals included in the 12 events.

Averaged across all 12 re-set periods, the program impact was 0.33 kW. The 90 percent confidence interval, reflecting variation across days as well as units, is from –0.12 to +0.79 kW. Considering only this confidence interval, which includes zero, it would seem questionable if savings occur at all. However, given that positive savings are estimated for almost every re-set interval, it is clear that savings are positive from the program. At the same time, for any particular event, the magnitude can be small.

If 5,000 units had received the re-set signal, the estimated savings on the best day would have been 3.6 MW, with a 90 percent confidence interval of 1.4 to 5.9 MW. This estimate compares favorably with the *ex* ante estimate of 4 MW for 5,000 units. However, this is for the best, not average, day. Across all 12 re-set periods, the savings from 5,000 units would have averaged an estimated 1.7 MW, with a 90 percent confidence interval from –0.6 to +3.9 MW. These estimates are summarized below.

Table 4-1
Estimated Impacts

	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
Average of All Events				
per unit	0.33	0.28	-0.12	0.79
5000 units	1,653	1,384	-623	3,929
Best Event				
per unit	0.73	0.27	0.28	1.18
5000 units	3,662	1,369	1,410	5,914

4.3 PROJECTED SAVINGS FROM FUTURE RE-SET EVENTS

Savings for other re-set conditions were estimated from the load models only, without adjustment for observed re-set or comparison-group loads during re-set. Comparison of the direct estimates per potential contributor for particular days with the corresponding projected impacts for the same temperature and re-set amounts showed a fair amount of variation. However, restricting attention to the events estimated with lower standard errors, the two showed reasonably good agreement.

The projected savings can be used in two ways. One is to provide an estimate of savings for a recently completed re-set event, without requiring collection and analysis of metering data. In this case the over-ride and non-response rates are known. These rates, together with an estimate of the fraction of units with zero summer use, provide an estimate of the fraction of units in the program that were potential contributors in that event. This fraction is then applied to the unadjusted projected savings in Appendix C to produce the impact estimate for the particular event.

The other use is to project savings in advance of a re-set event, either for general planning or to guide a specific operational decision. In this case, the over-ride and non-response rates must also be projected. The projection of the over-ride rate, in particular, adds additional uncertainty to the estimate. The adjusted projected savings shown in Appendix D include the adjustments for noncontributors, based on the projected rates of over-ride, nonresponse, and zero summer usage.

At all ambient temperatures, with and without adjustment for noncontributors, the peak impacts are estimated to occur in the hour ending at 5 PM. With the adjustment for non-contributors, the projected savings are relatively flat over a range of daily average temperatures. Between 71°F and 78°F, the projected savings are around 0.3 kW per unit at that hour. At higher temperatures, projected savings are lower, because the projected over-ride rate increases more than the projected savings per contributing unit. At lower temperatures, savings per potential contributor are low.

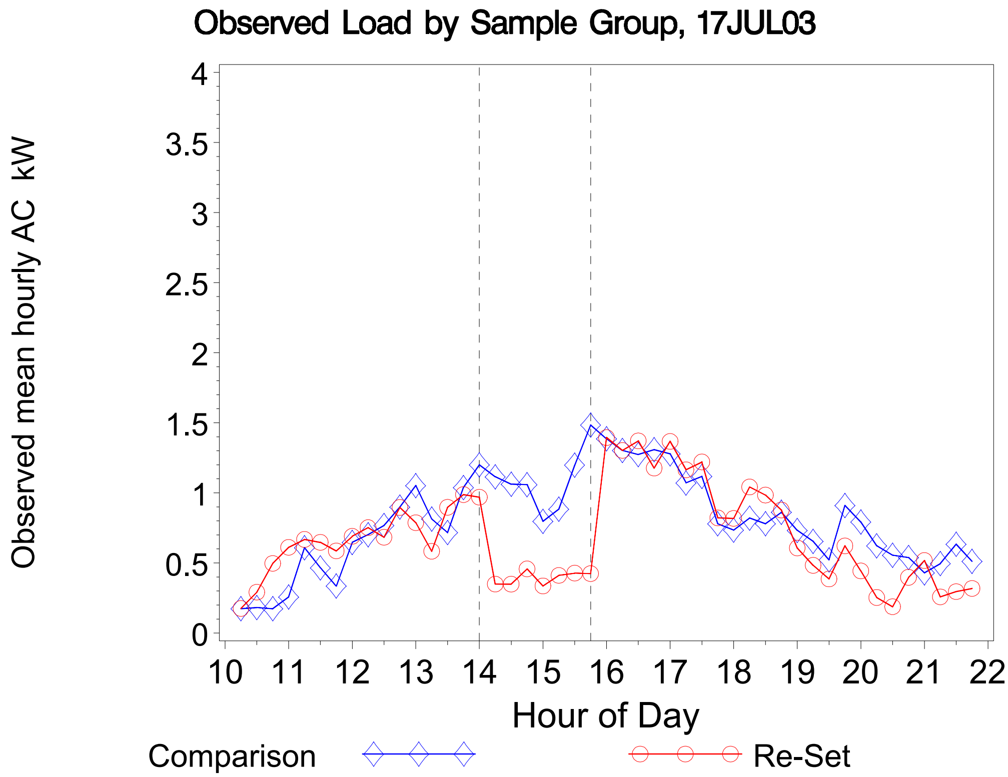
Savings are also lower at other hours. The (adjusted) projected savings at the hour ending 1 PM is 0.17 kW.

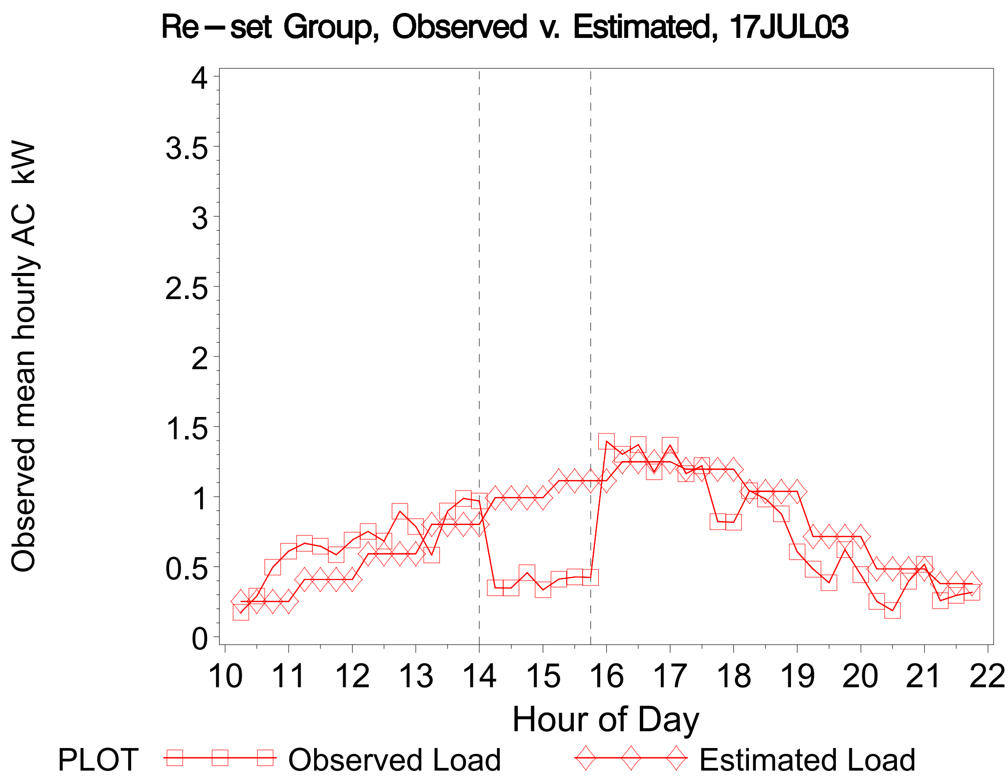
4.4 Future Program Performance

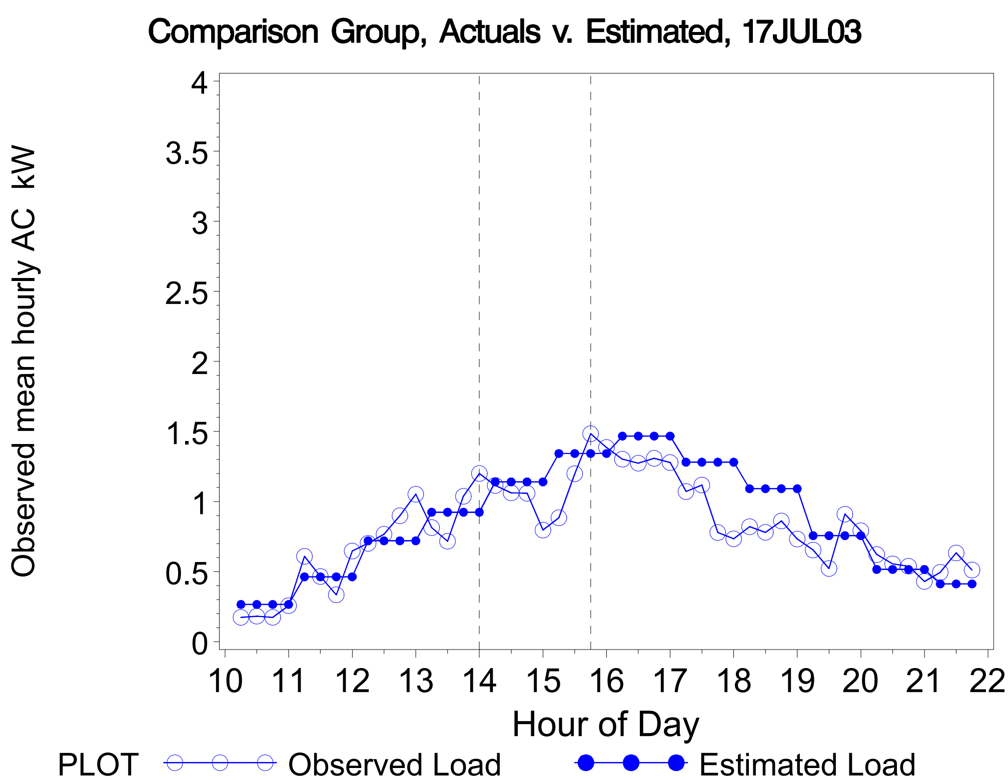
The findings from this study confirm the finding from the previous study that future performance of the program as a mechanism to respond to statewide emergencies is not reliable. One factor is the limited used of air conditioning in the territory, with one-fifth of participating units never used over the summer. Another factor is that statewide emergency conditions do not necessarily coincide with hot weather in the San Diego area. This was the case for several of the 2003 re-set events. As long as the emergency condition that triggers a re-set event is not tied to hot weather in San Diego, a high number of non-users is likely to be found during future re-sets.

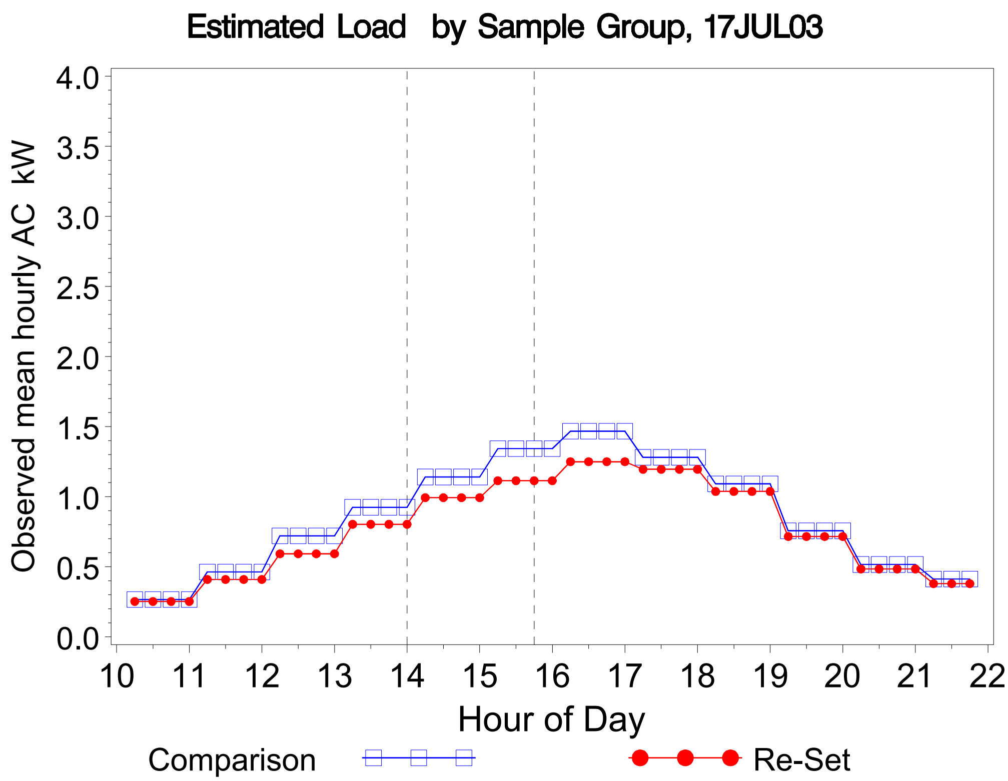
On the other hand, when the weather is hot, high rates of over-ride are projected to occur. On the hottest of the 2003 re-set days, the observed over-ride rate was 47 percent. Our modeled over-ride rate was close to this level, and fairly robust. Further investigation of the relationship between over-ride rates on the one hand and event characteristics—amount, duration, and ambient temperature—on the other could provide further guidance on the best program designs to provide effective participation.

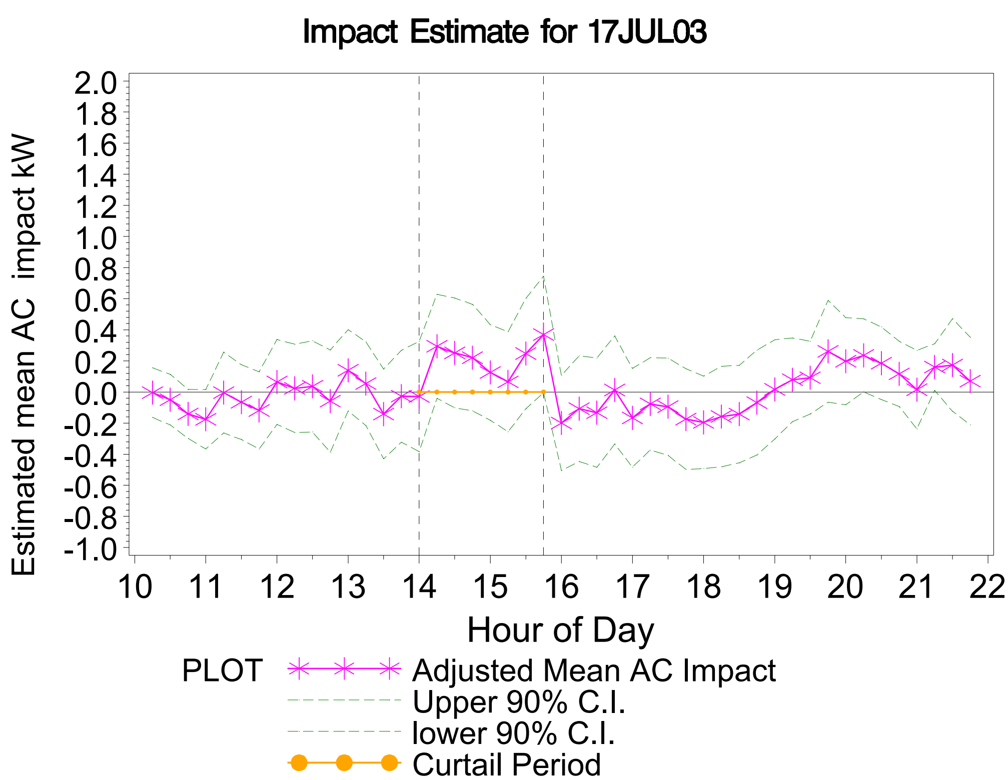
A AIR CONDITIONER IMPACT PLOTS

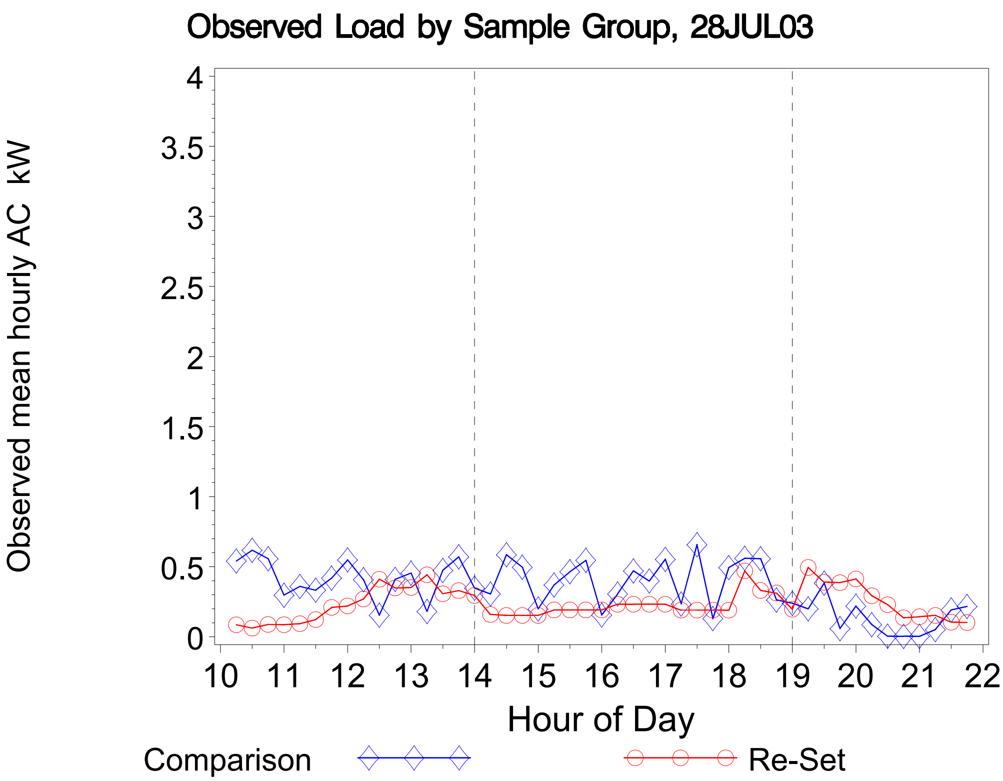


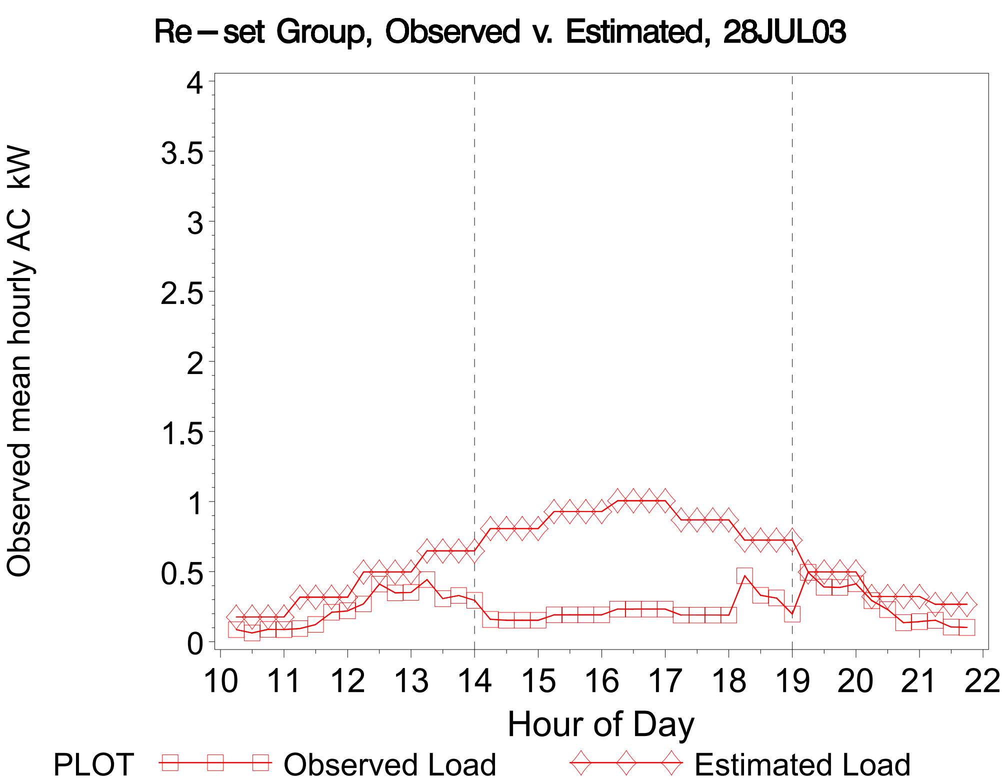

Re – set Group, Observed v. Estimated, 17JUL03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

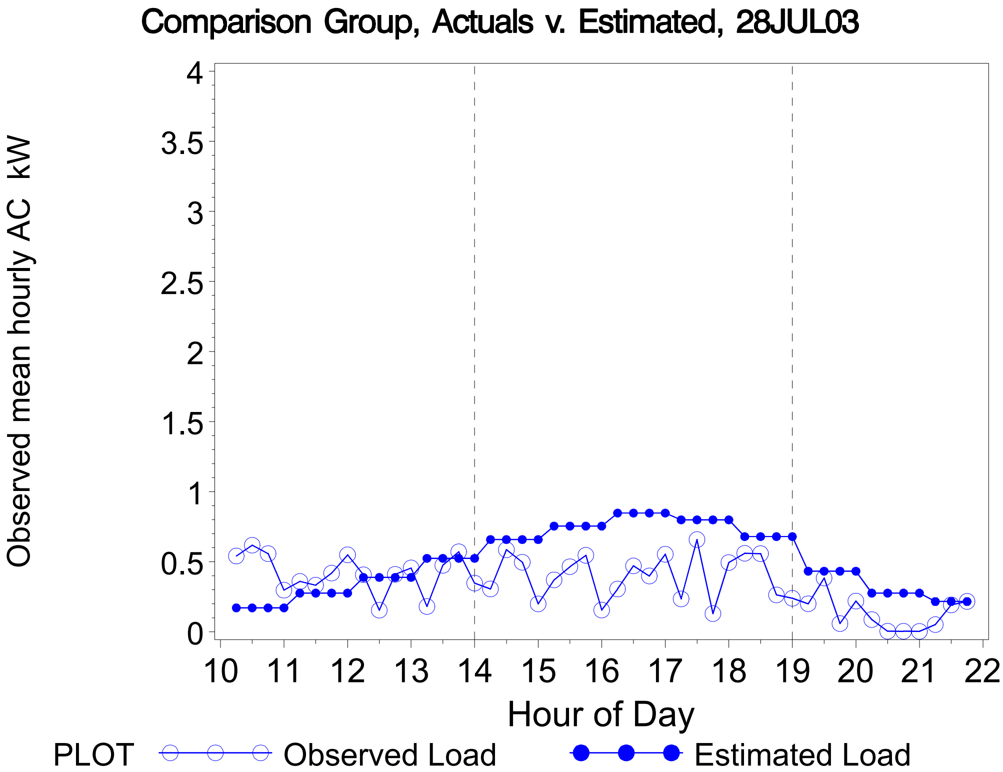

Comparison Group, Actuals v. Estimated, 17JUL03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

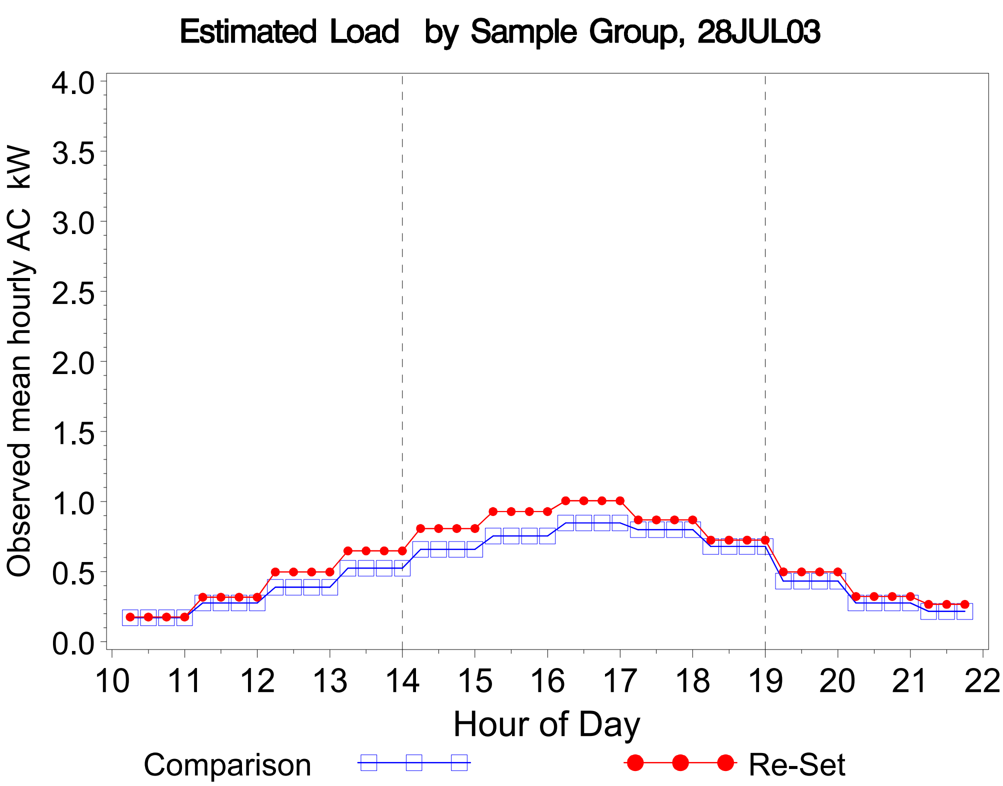

Estimated Load by Sample Group, 17JUL03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

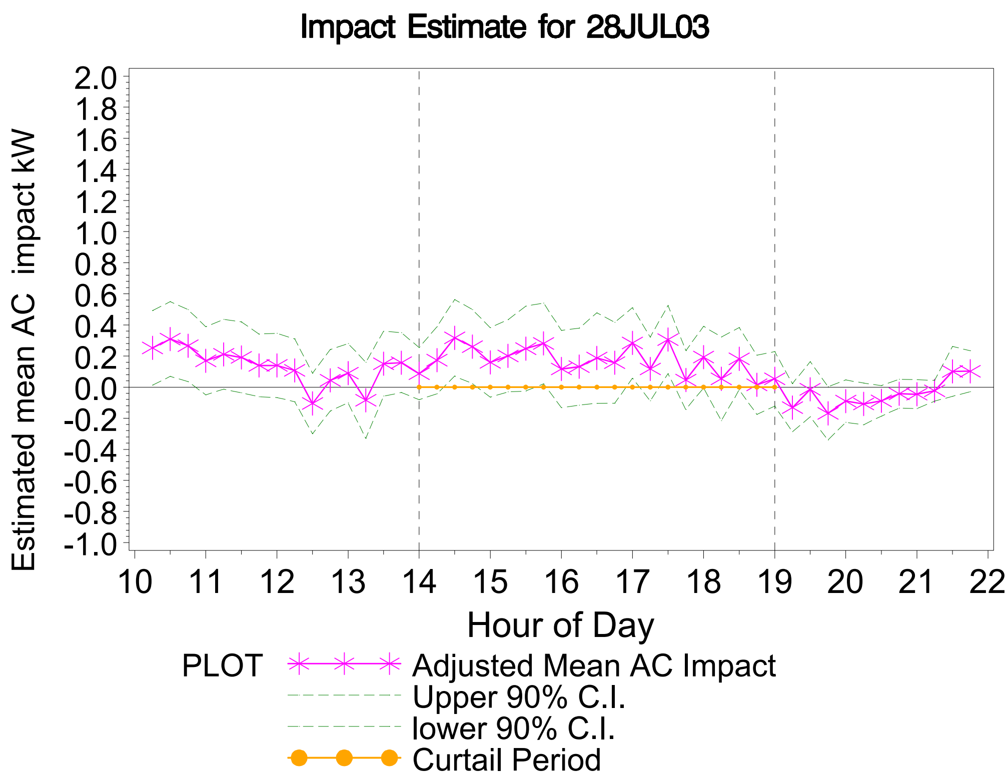

Impact Estimate for 17JUL03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

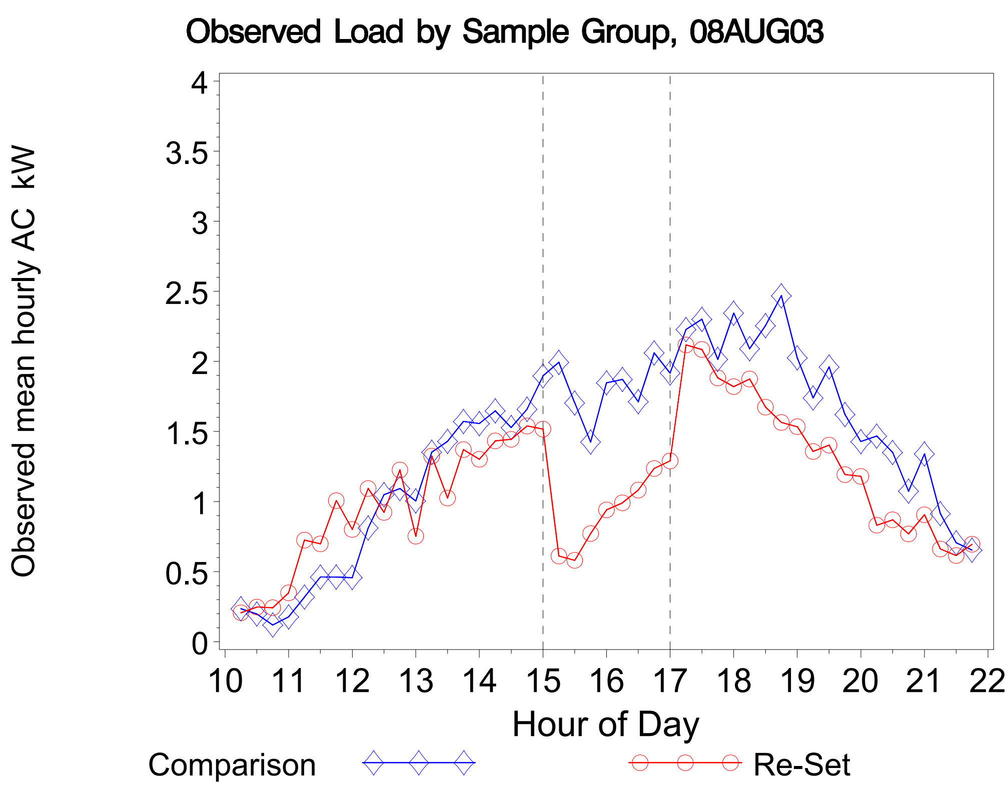

Observed Load by Sample Group, 28JUL03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

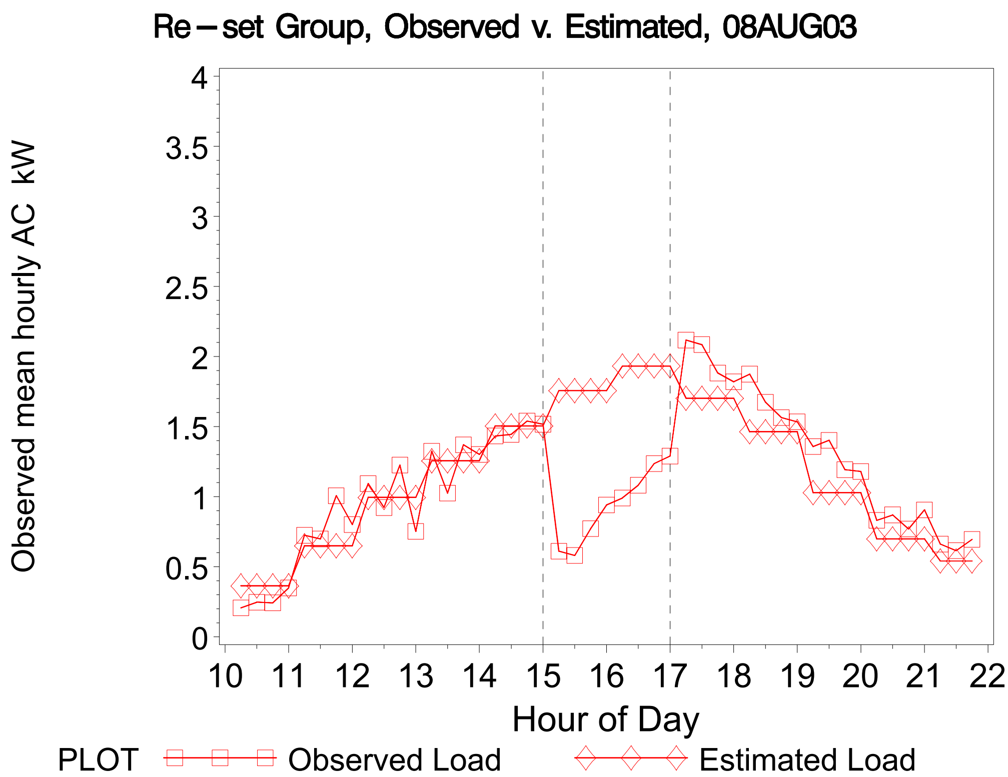

Re–set Group, Observed v. Estimated, 28JUL03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

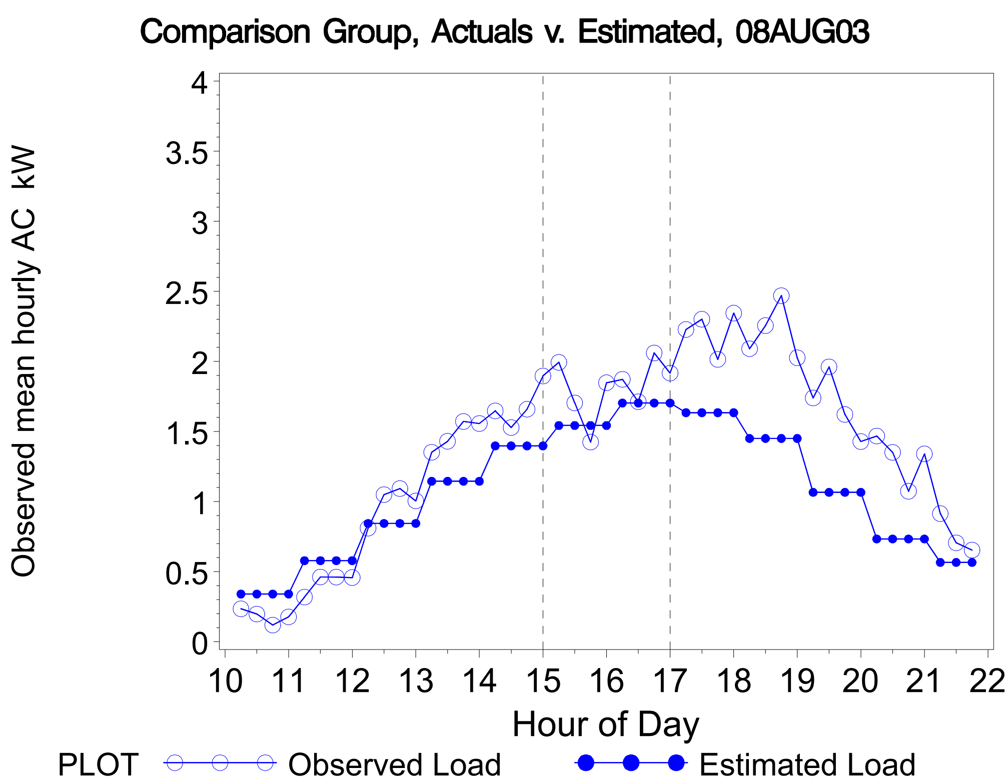

Comparison Group, Actuals v. Estimated, 28JUL03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

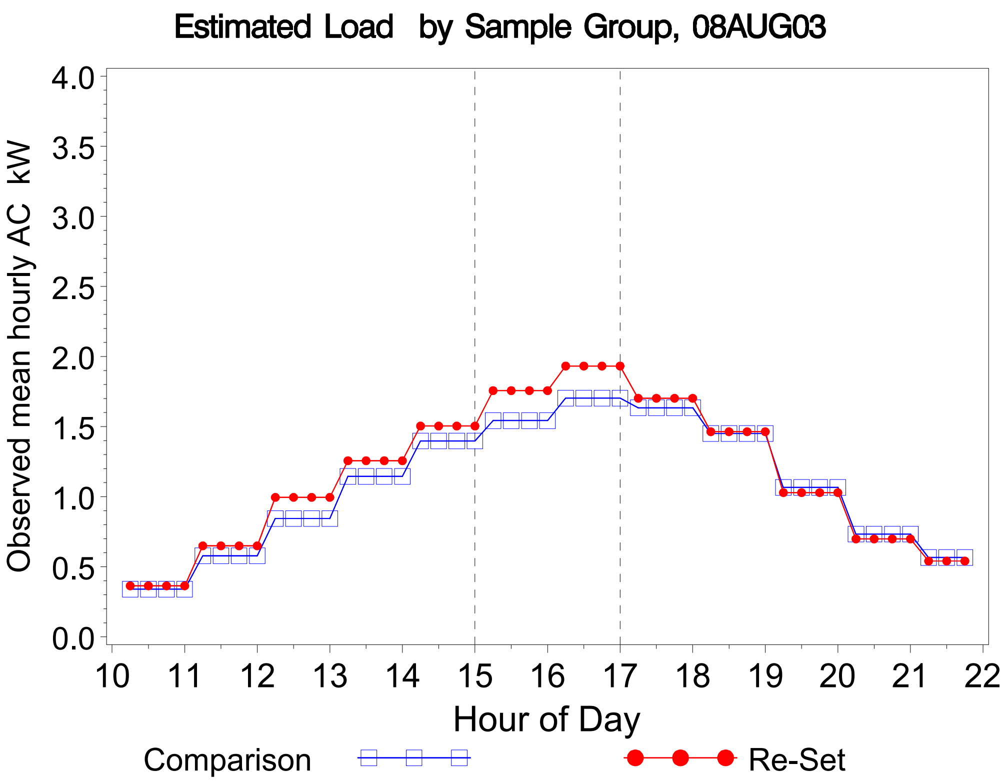

Estimated Load by Sample Group, 28JUL03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

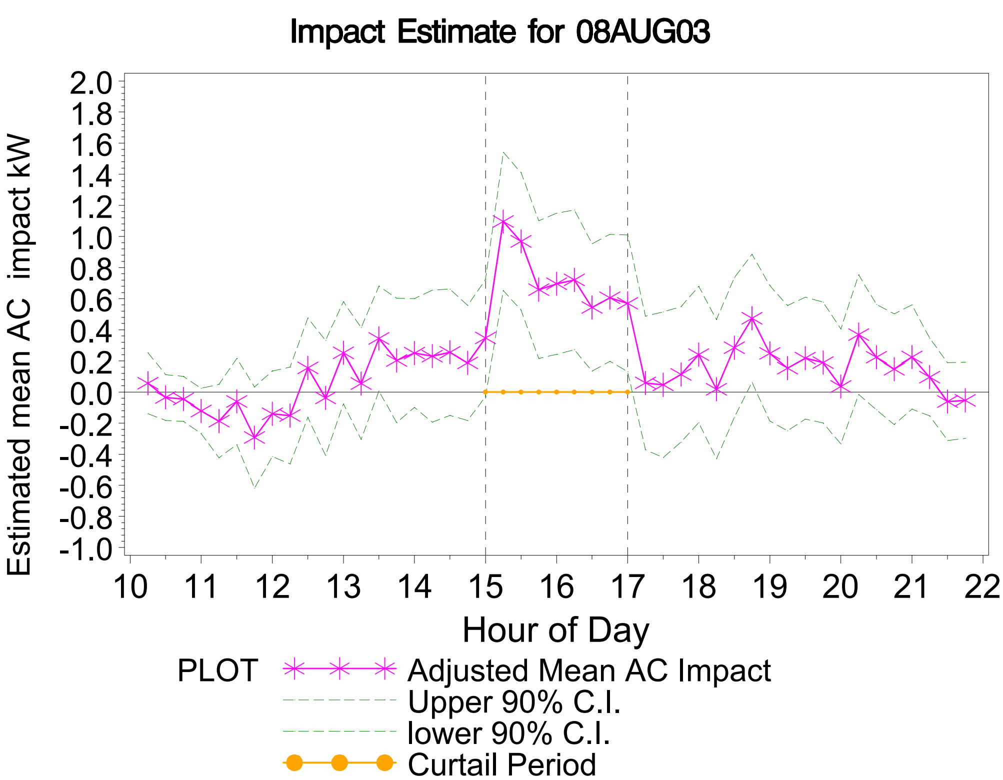

Impact Estimate for 28JUL03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

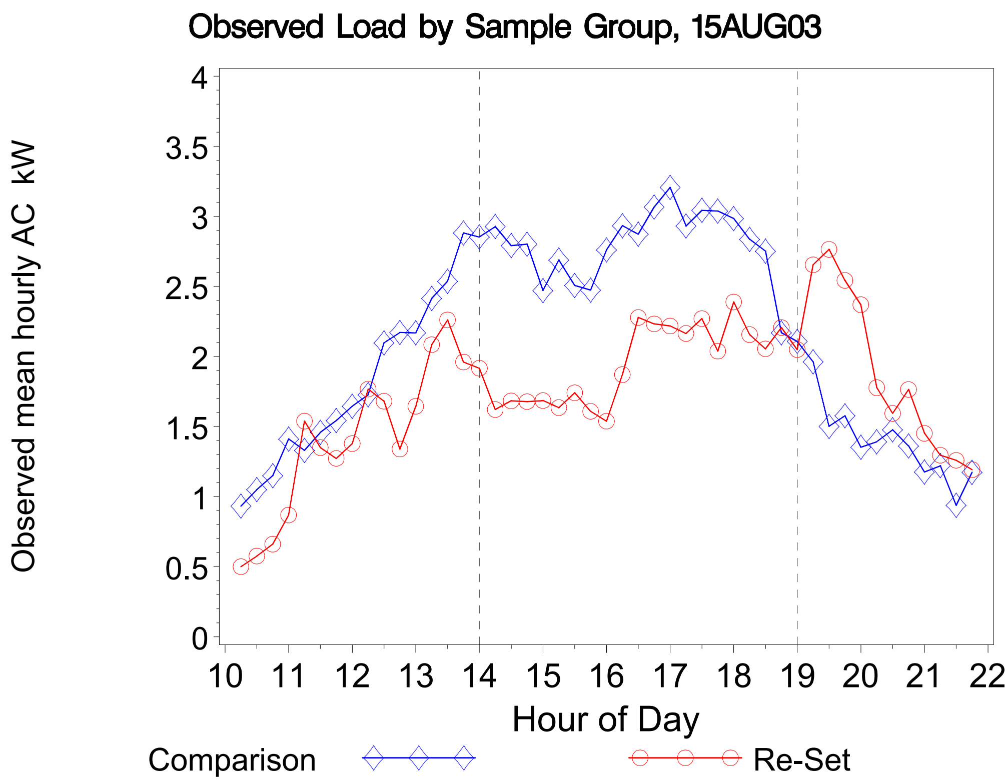

Observed Load by Sample Group, 08AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

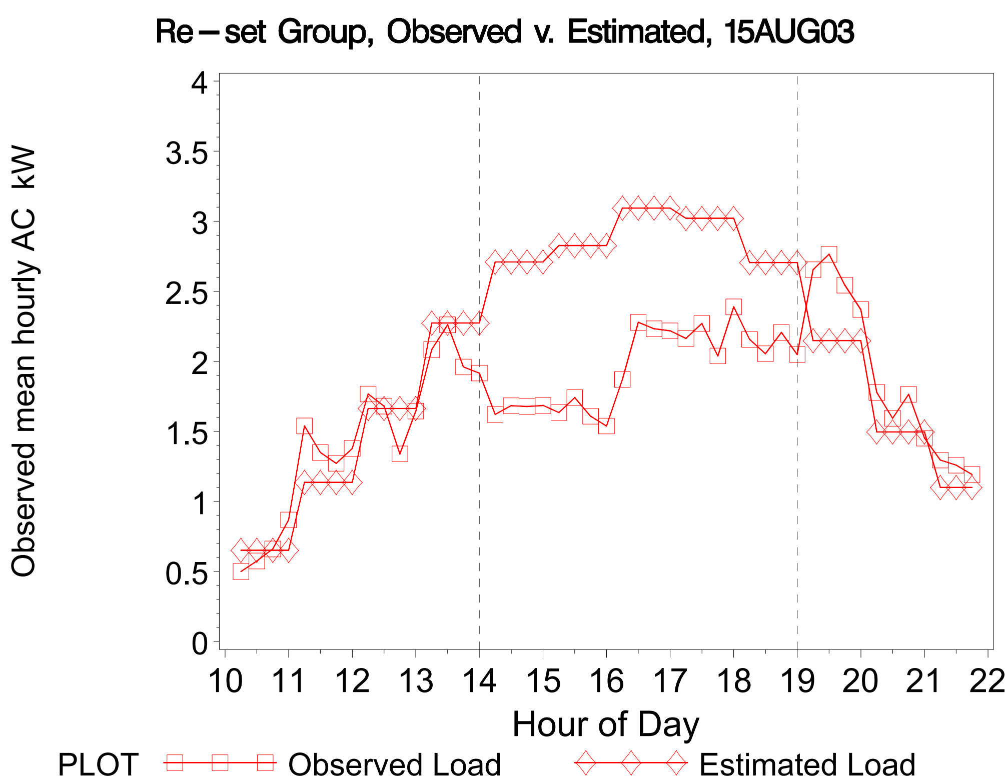

Re-set Group, Observed v. Estimated, 08AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

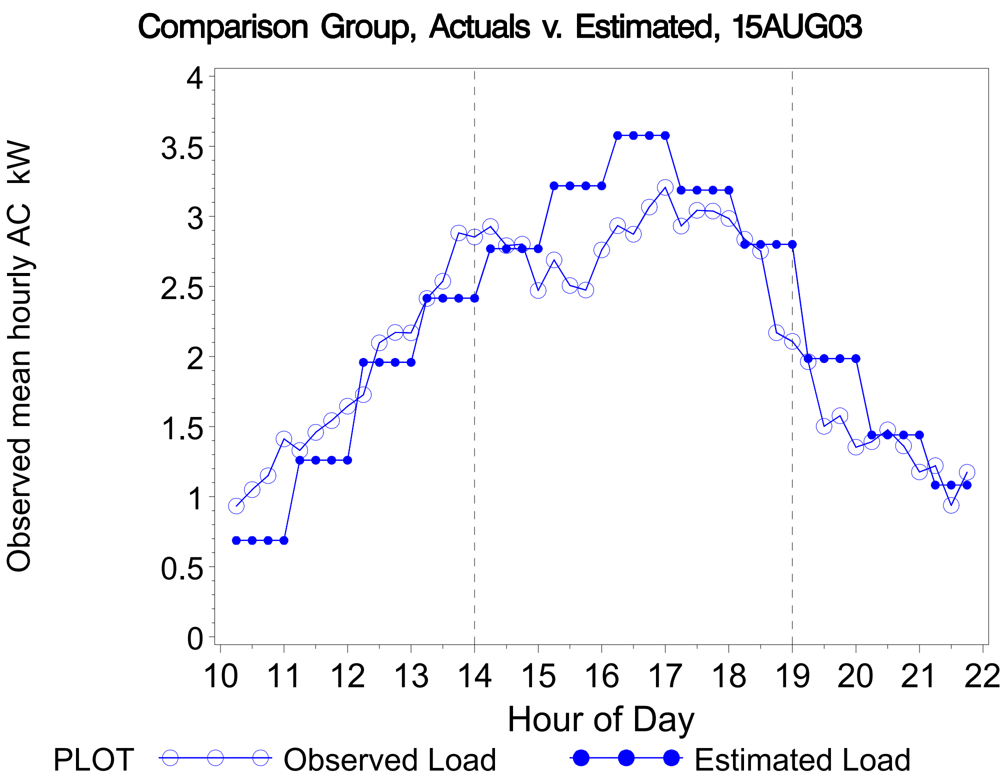

Comparison Group, Actuals v. Estimated, 08AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

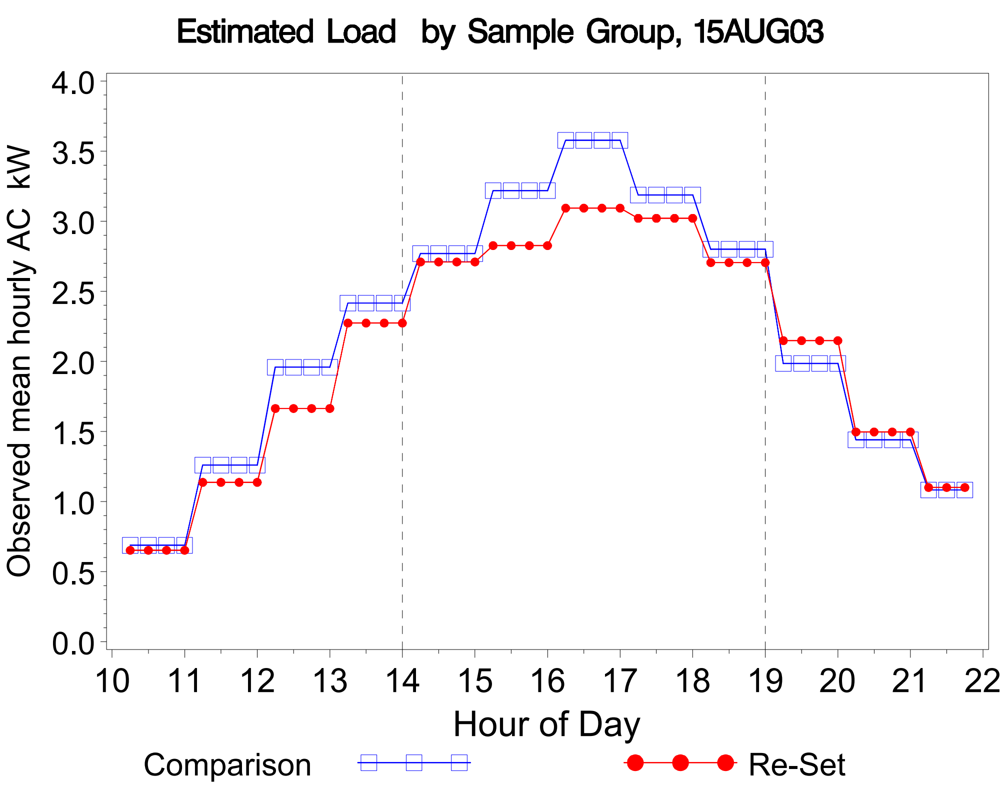

Estimated Load by Sample Group, 08AUG03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

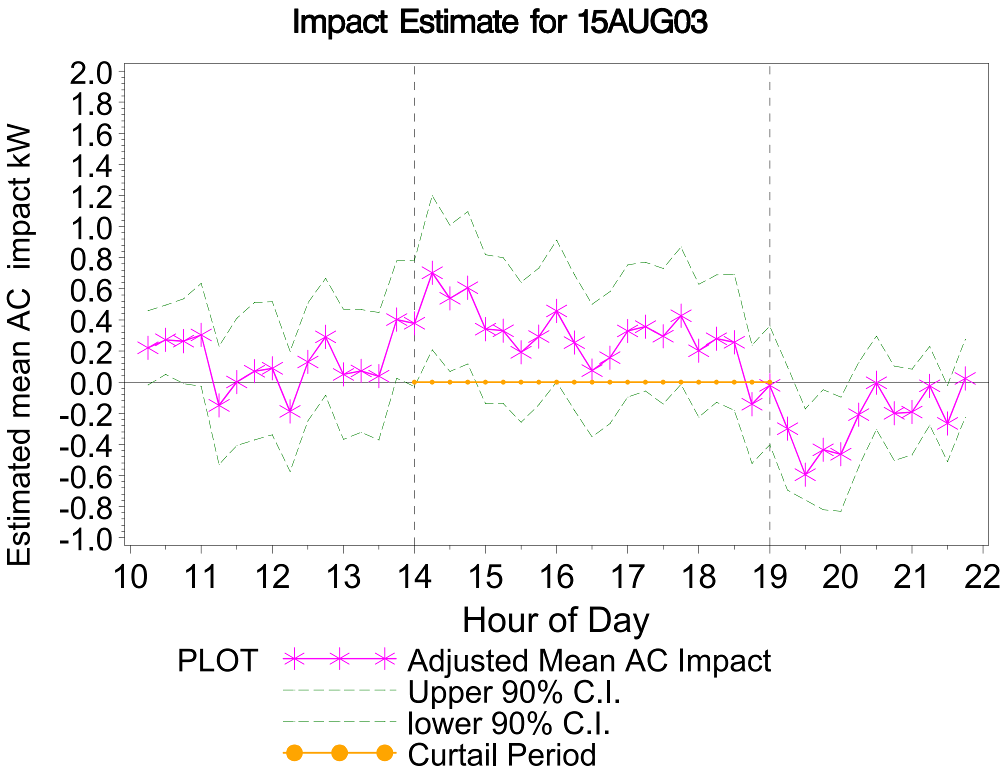

Impact Estimate for 08AUG03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

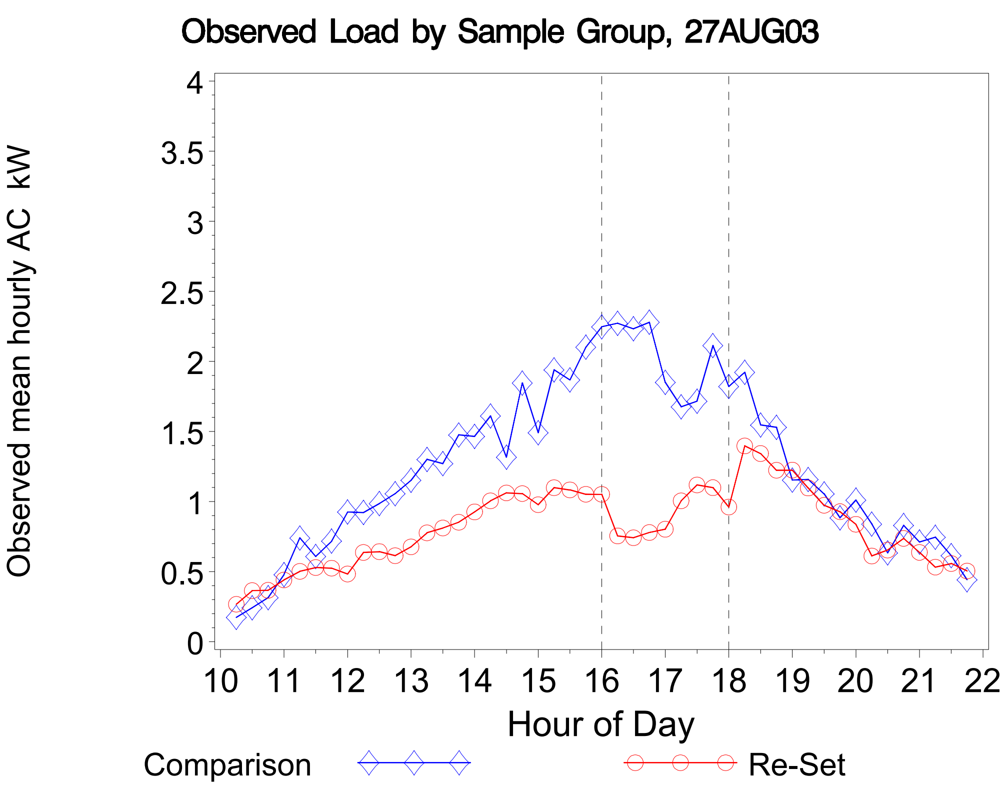

Observed Load by Sample Group, 15AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

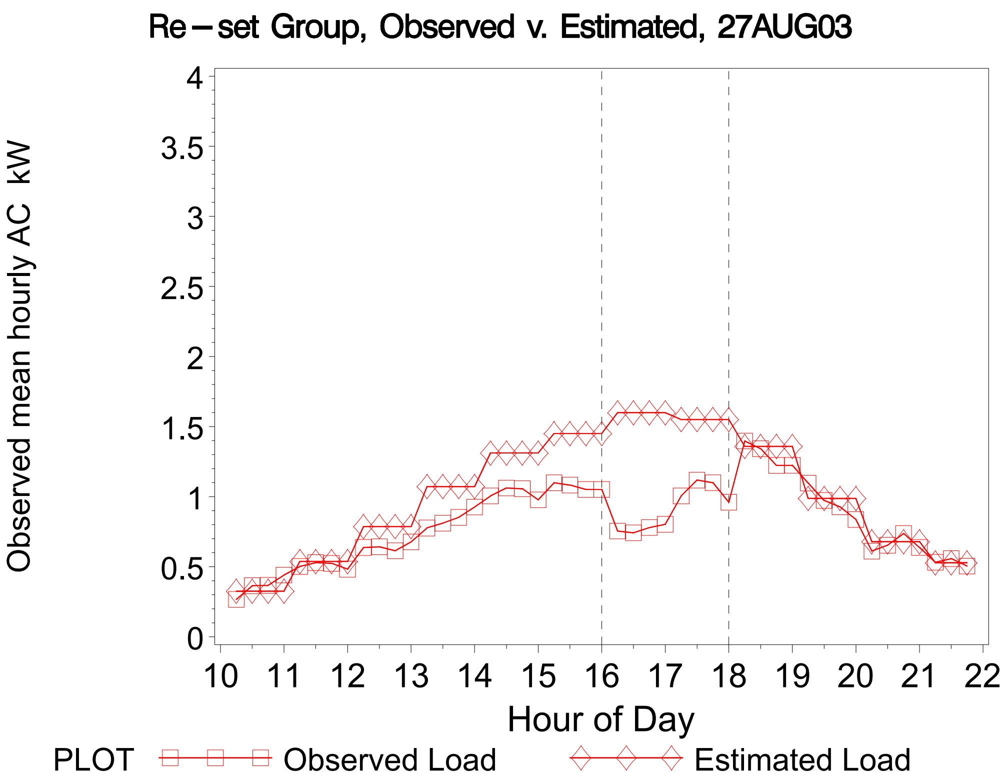

Re–set Group, Observed v. Estimated, 15AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

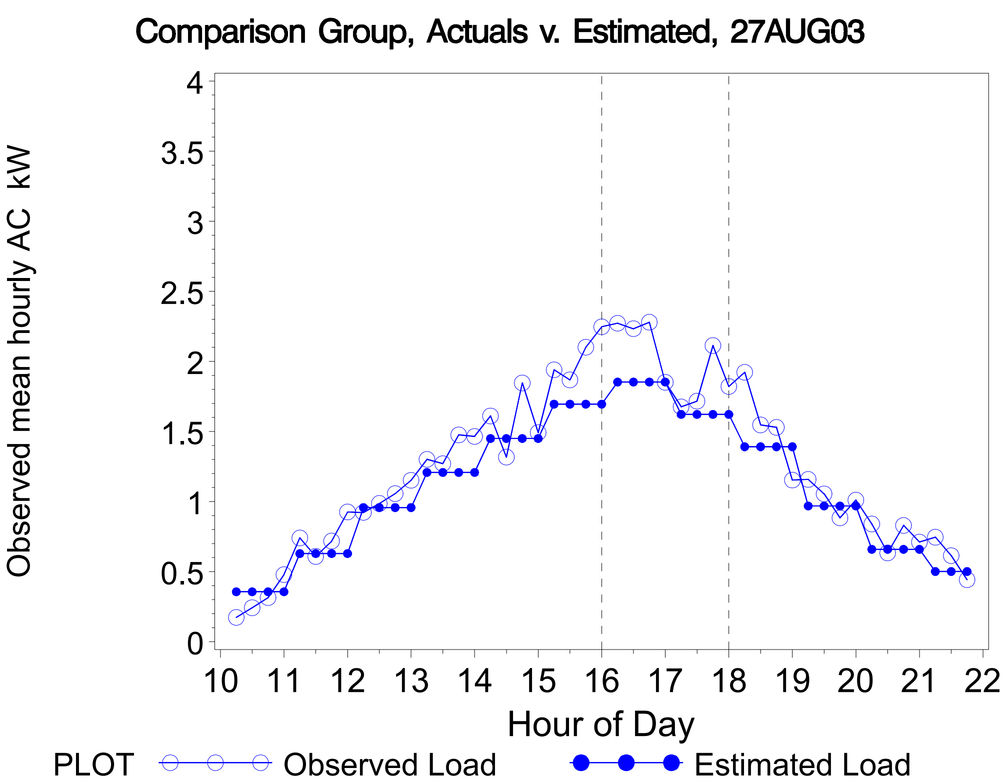

Comparison Group, Actuals v. Estimated, 15AUG03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

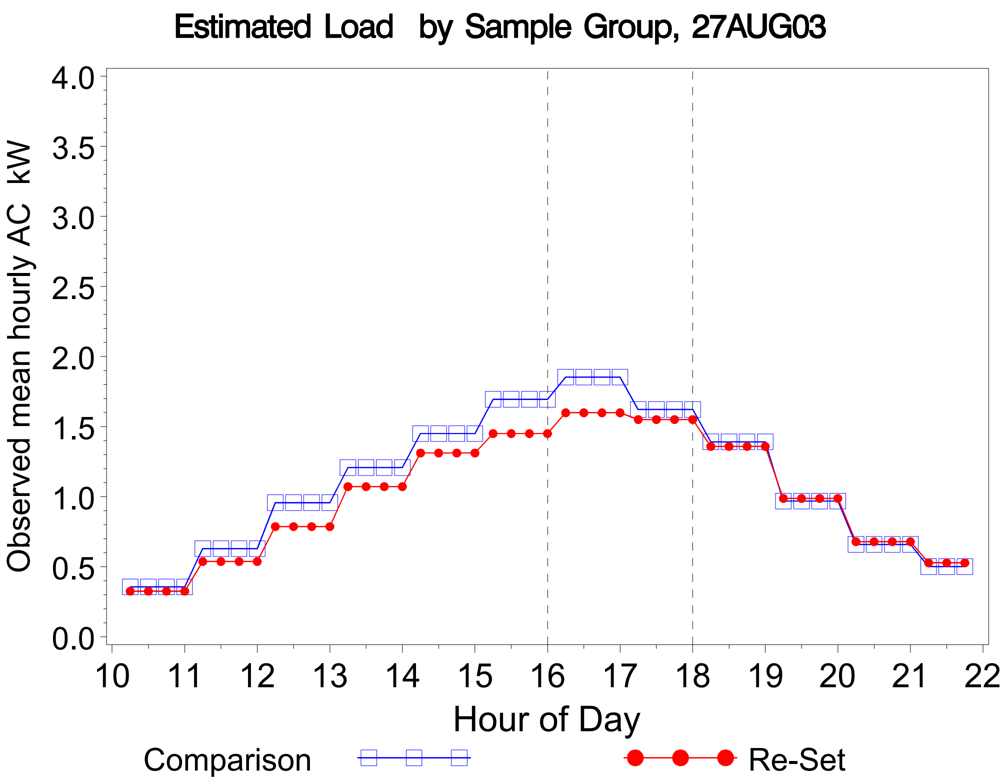

Estimated Load by Sample Group, 15AUG03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison Re-Set

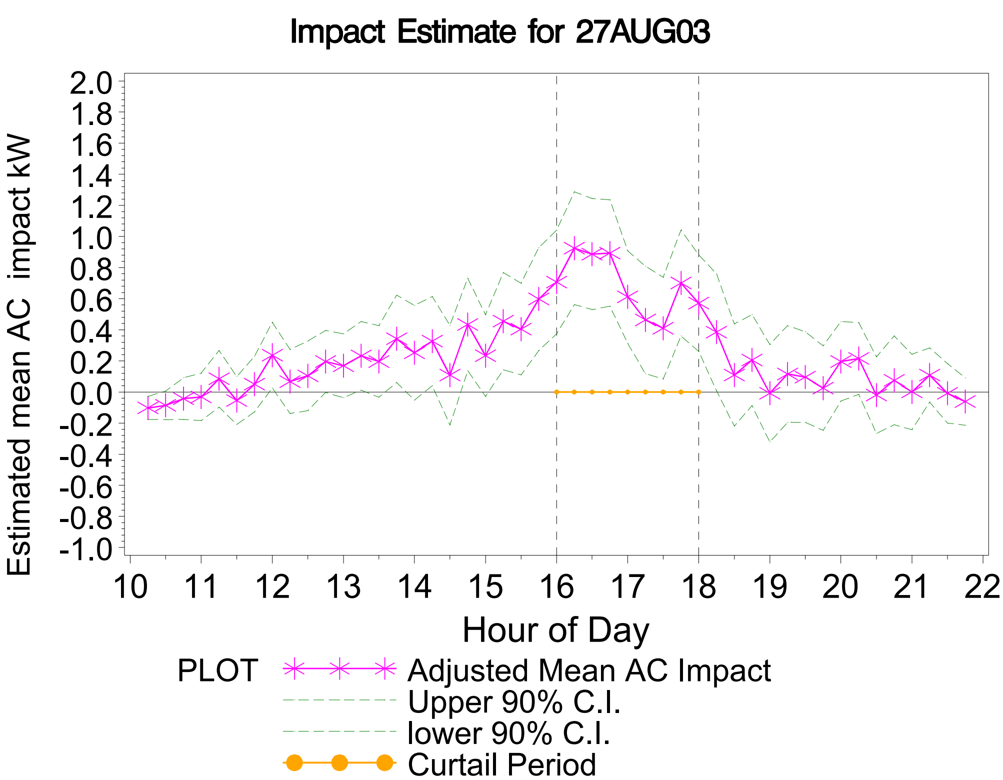

Impact Estimate for 15AUG03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

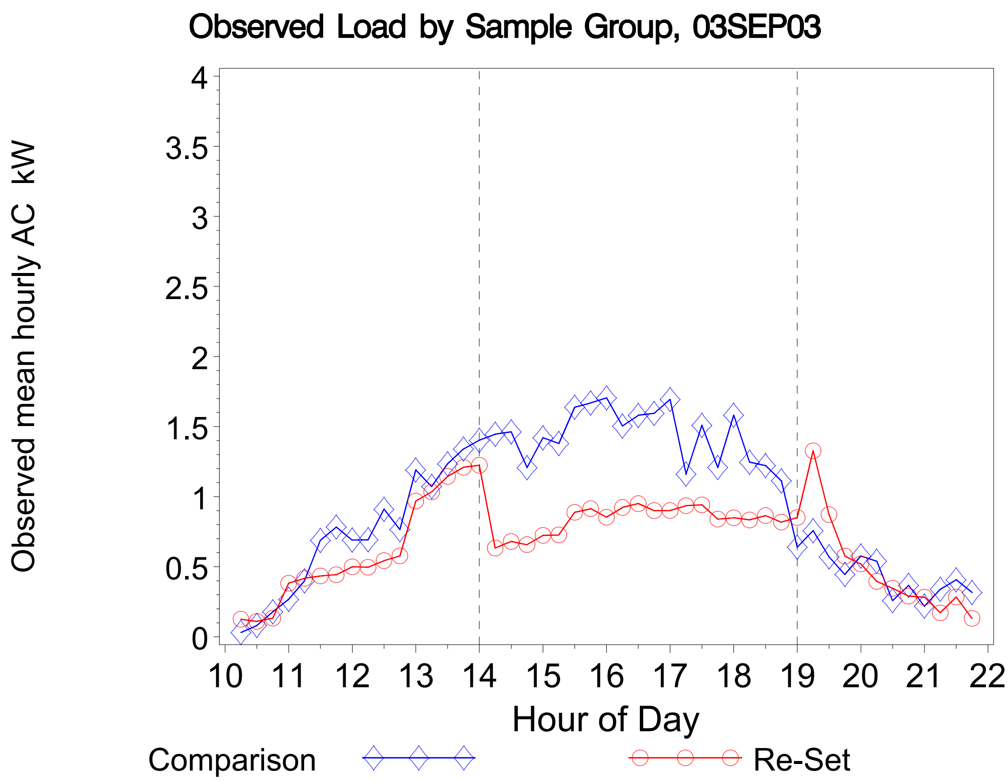

Observed Load by Sample Group, 27AUG03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

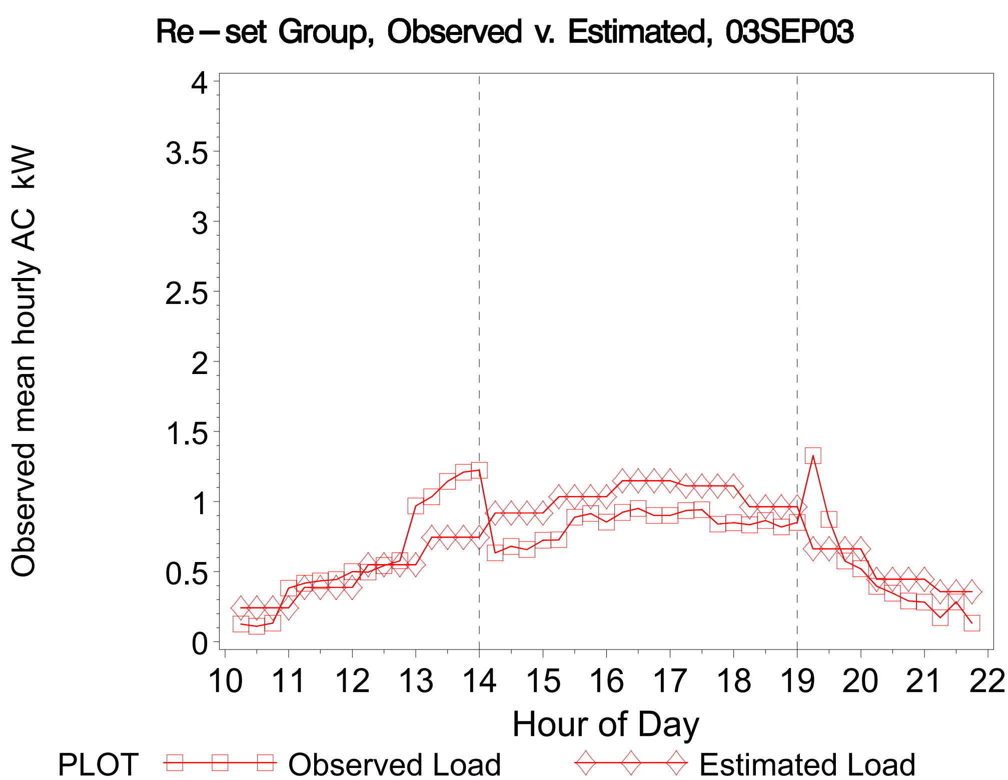

Re – set Group, Observed v. Estimated, 27AUG03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

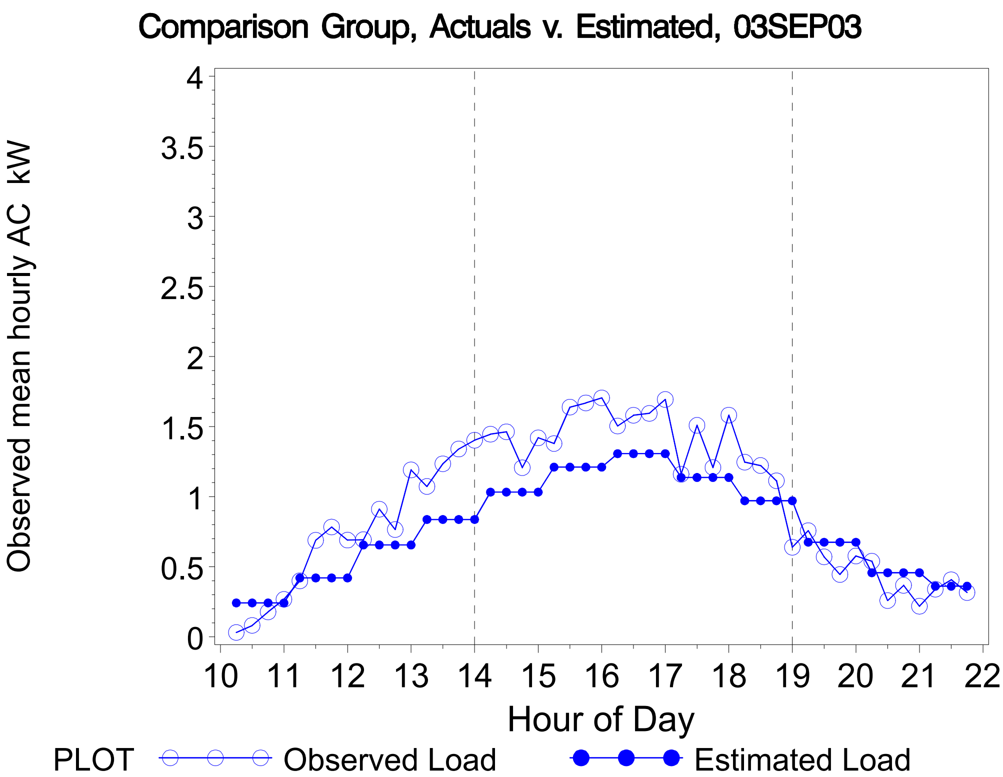

Comparison Group, Actuals v. Estimated, 27AUG03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

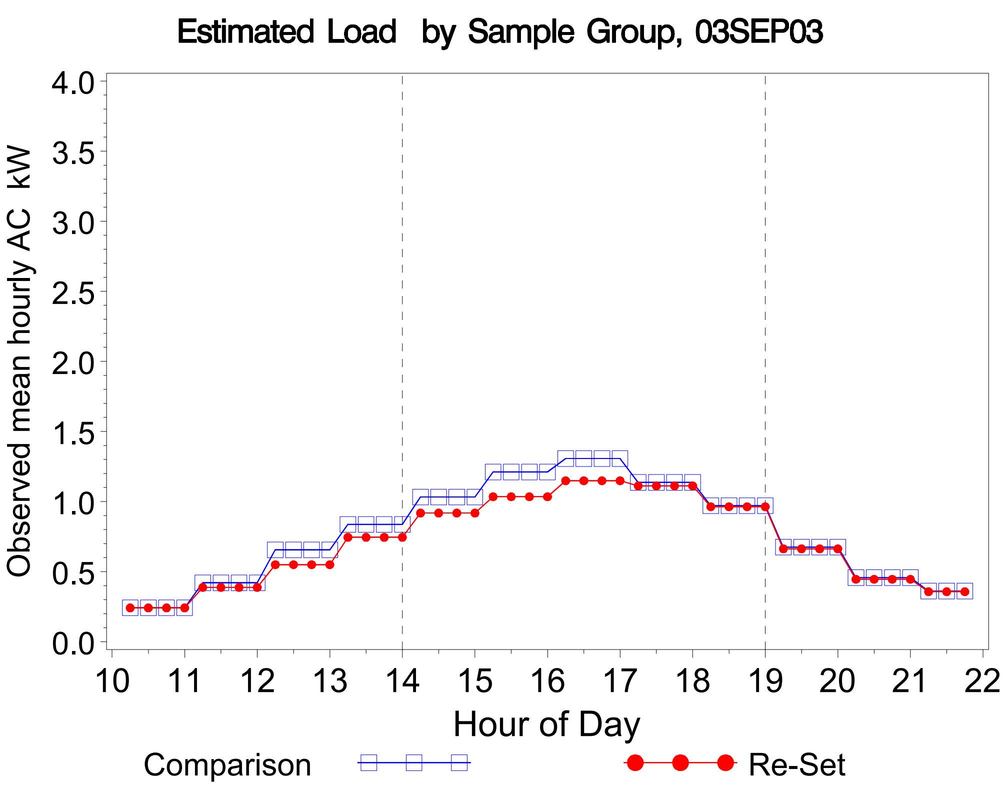

Estimated Load by Sample Group, 27AUG03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

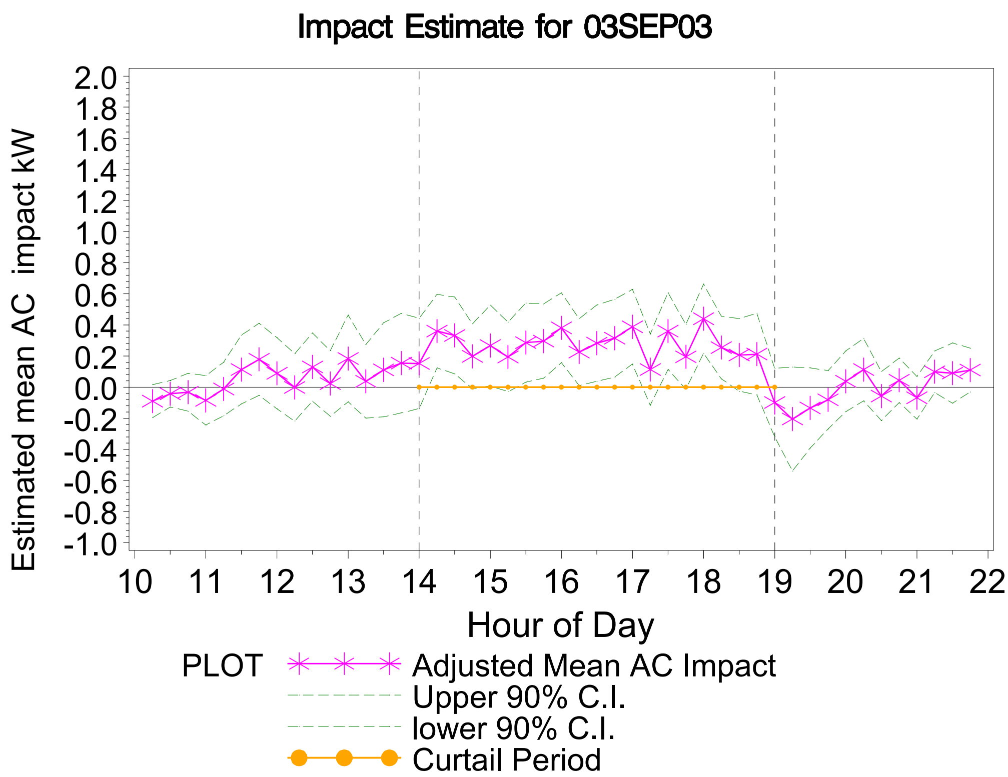

Impact Estimate for 27AUG03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

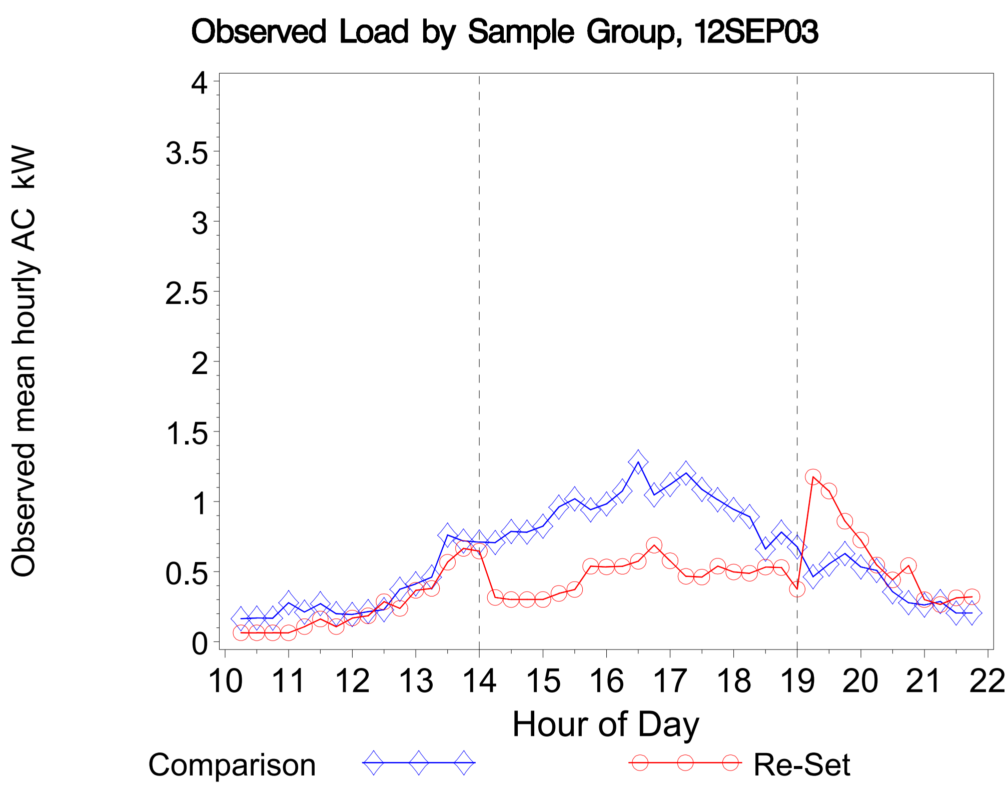

Observed Load by Sample Group, 03SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

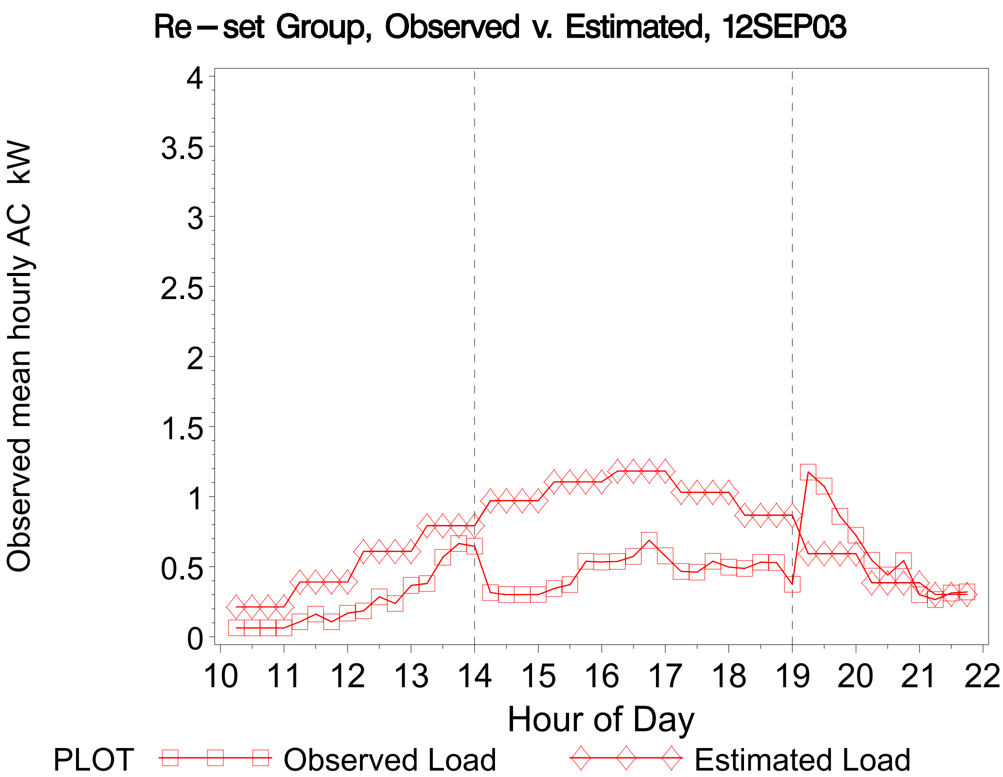

Re–set Group, Observed v. Estimated, 03SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load


Comparison Group, Actuals v. Estimated, 03SEP03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

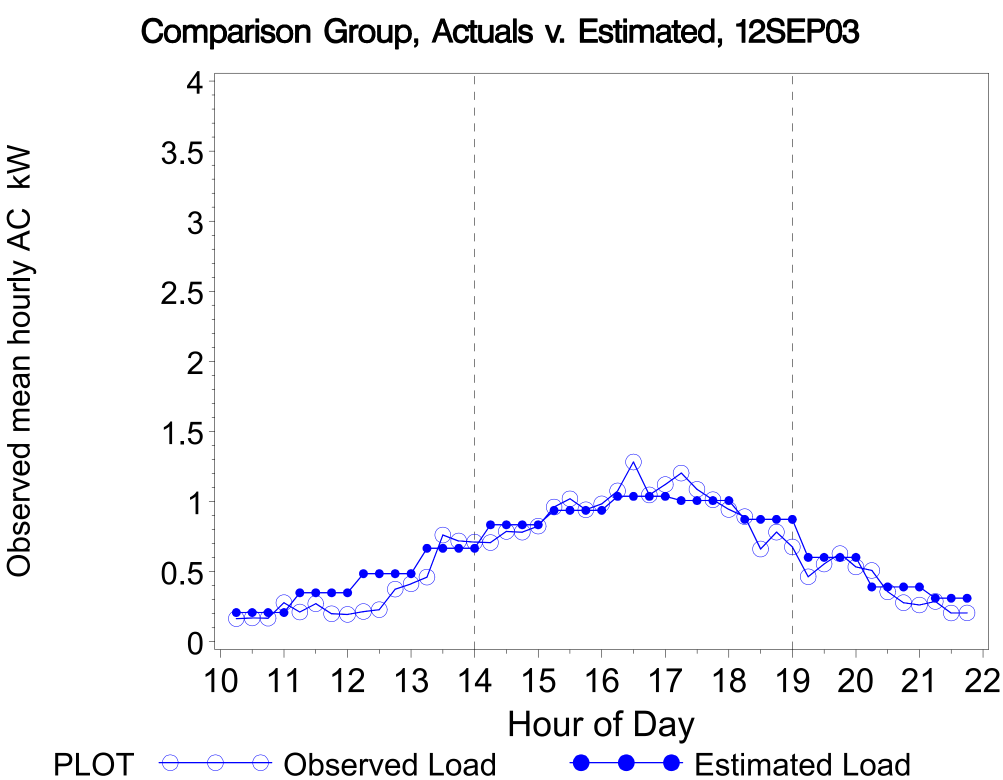

Estimated Load by Sample Group, 03SEP03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set


Impact Estimate for 03SEP03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

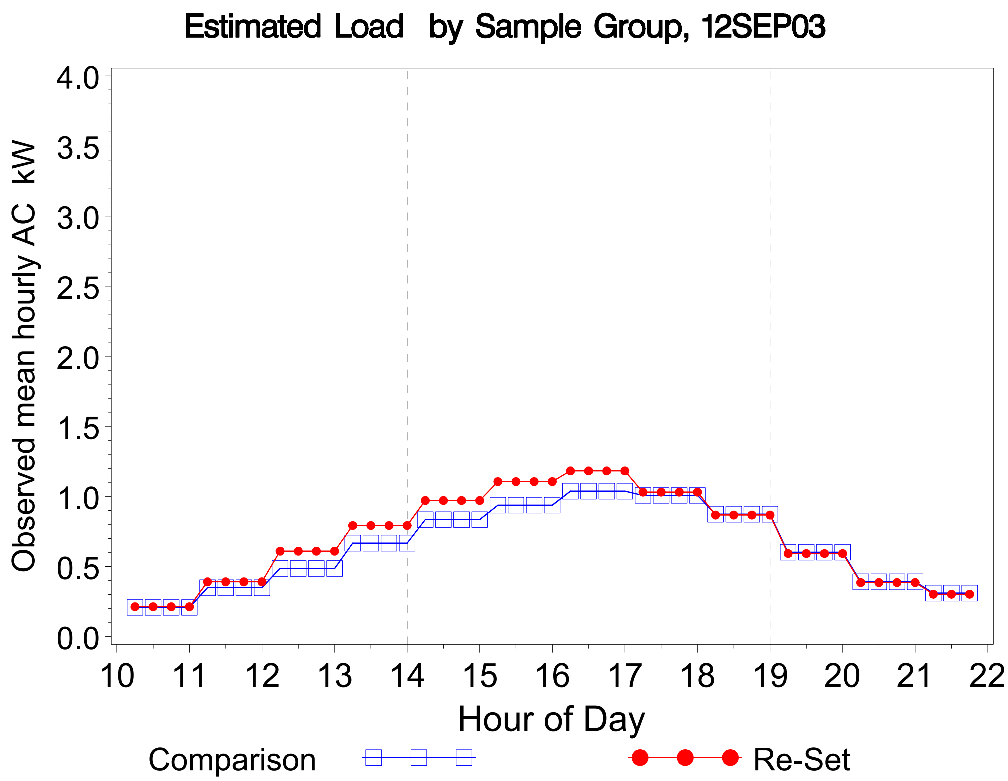

Observed Load by Sample Group, 12SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

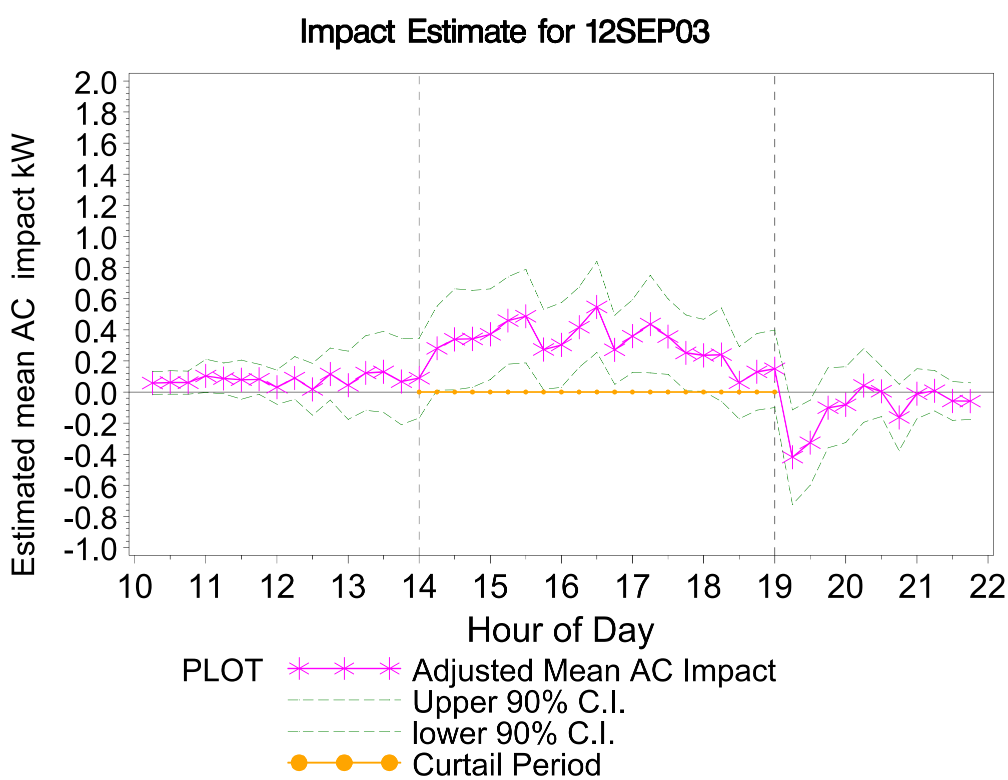


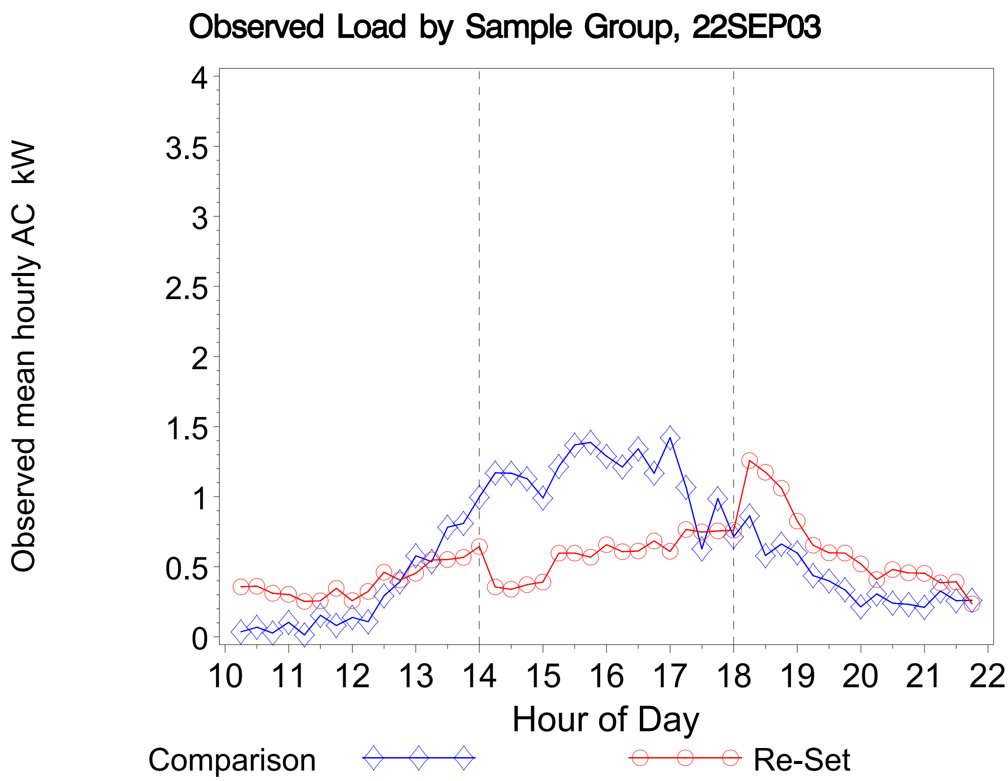
Re – set Group, Observed v. Estimated, 12SEP03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load



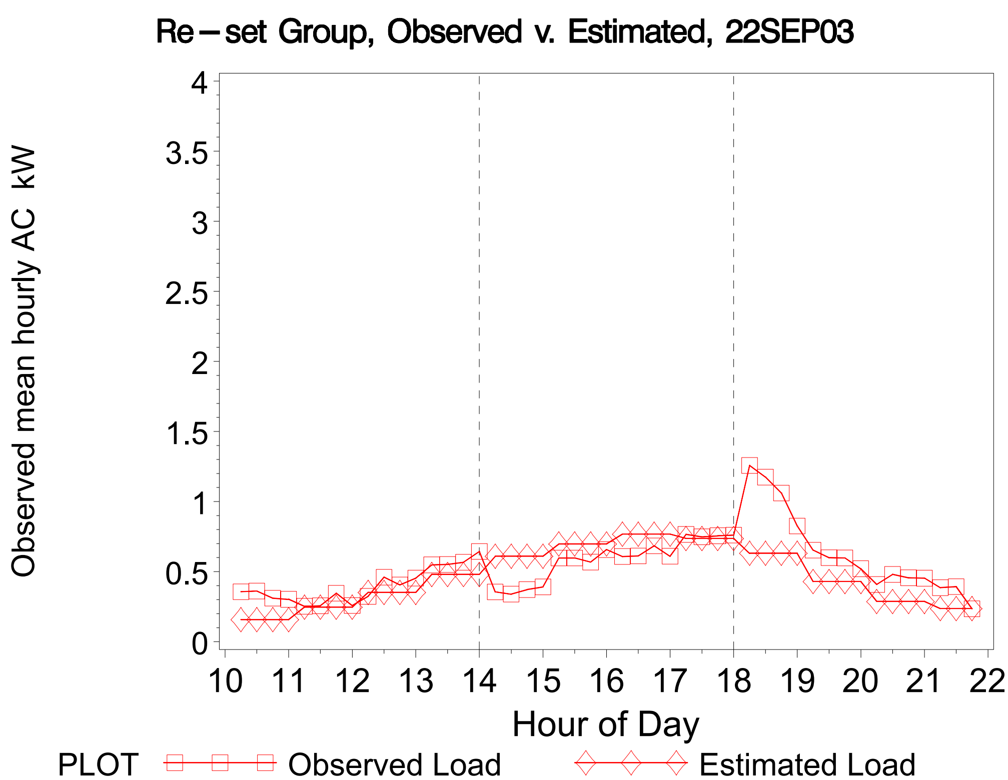
Comparison Group, Actuals v. Estimated, 12SEP03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load


Estimated Load by Sample Group, 12SEP03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

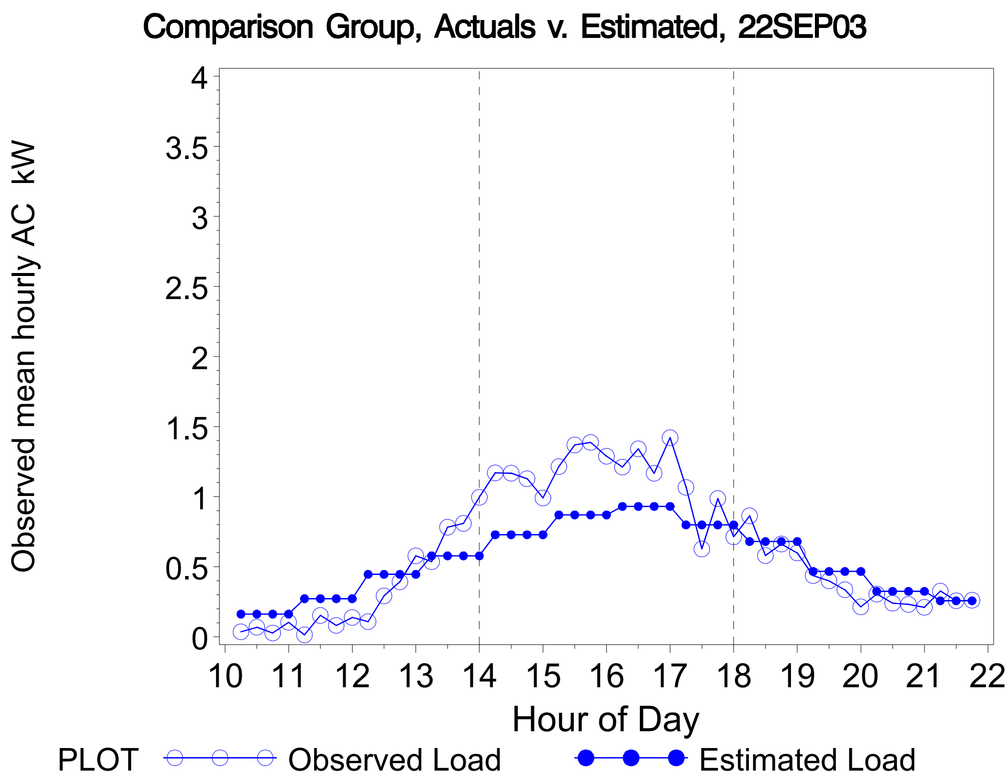

Impact Estimate for 12SEP03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

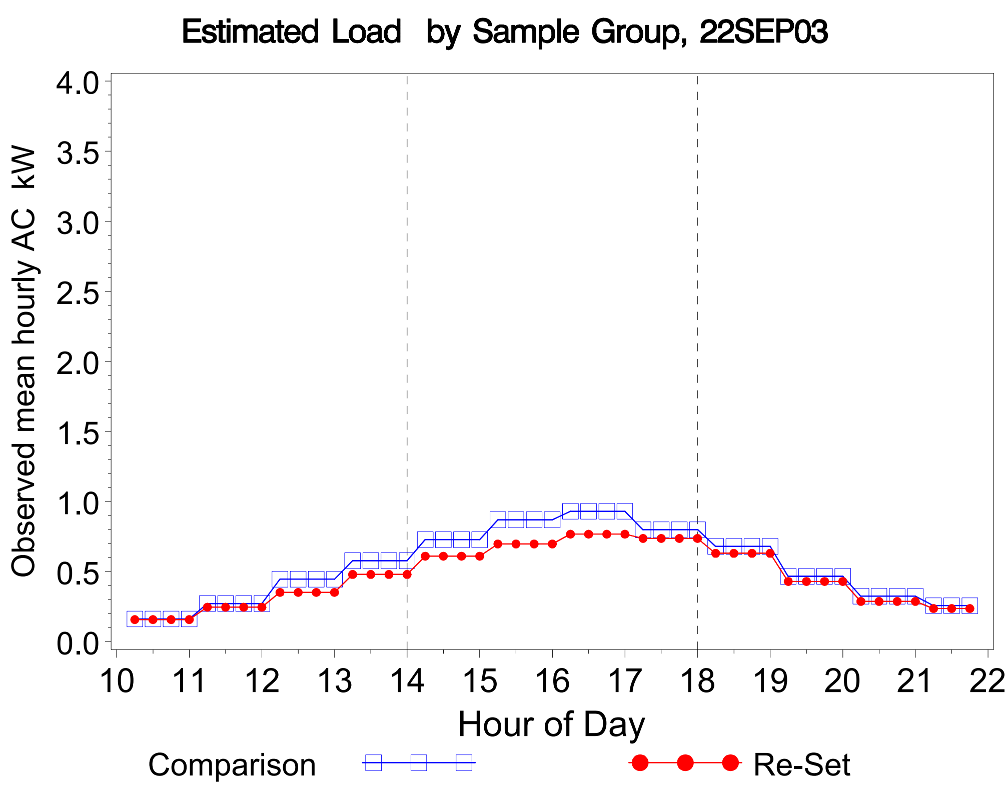


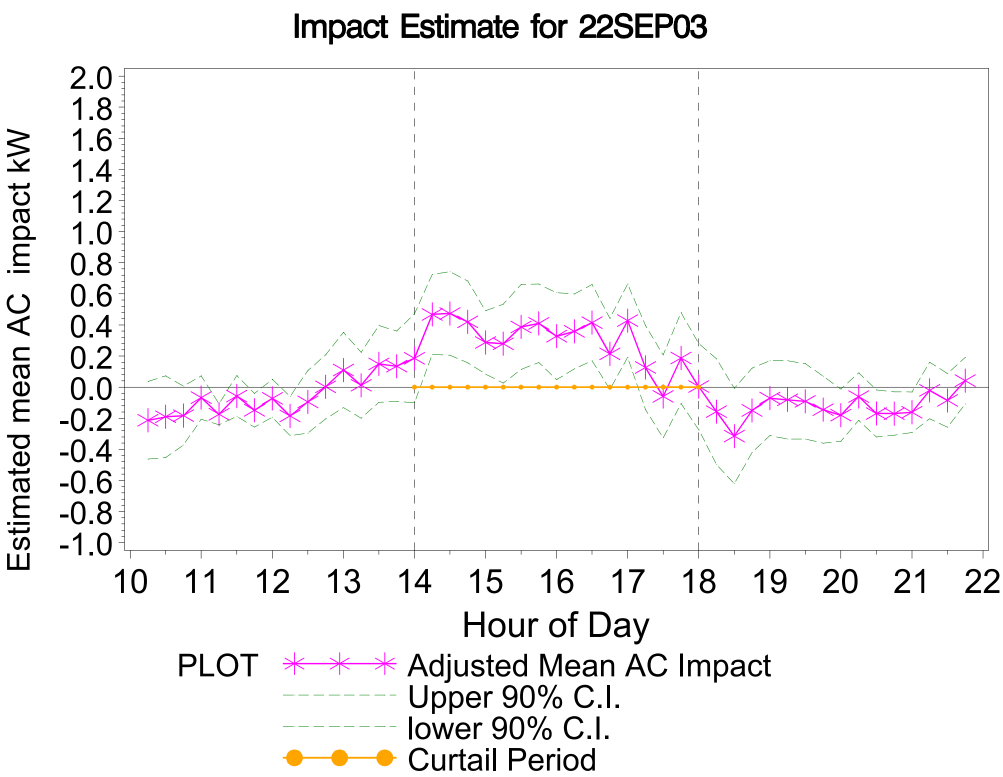
Observed Load by Sample Group, 22SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set



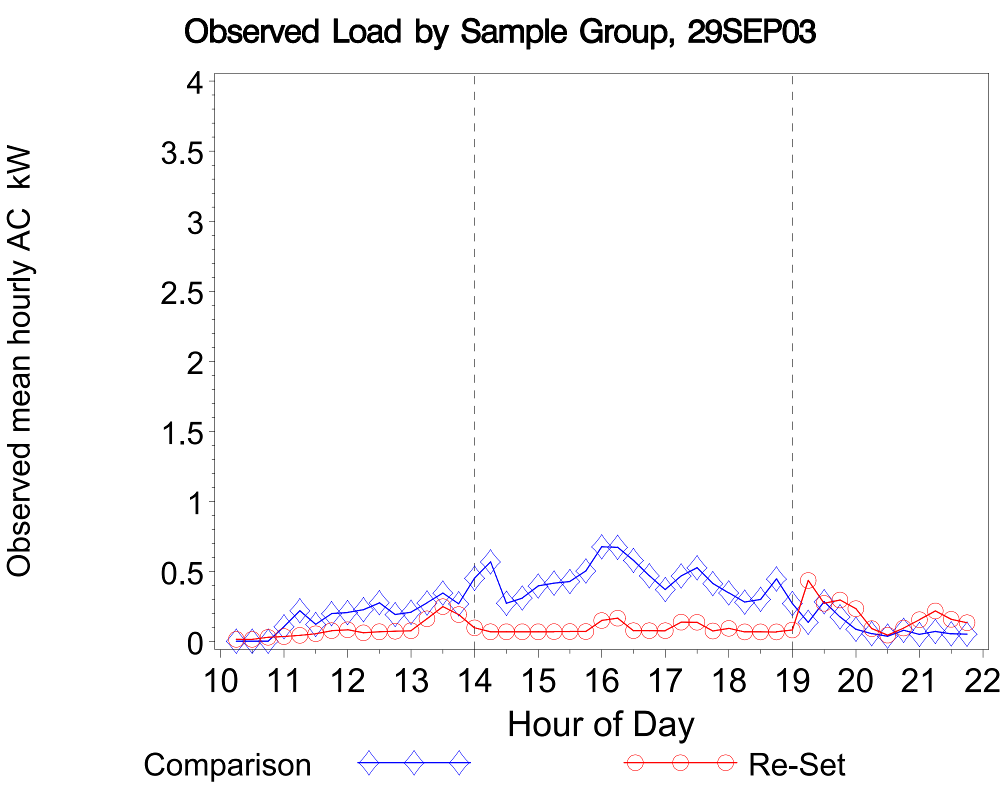
Re−set Group, Observed v. Estimated, 22SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load


Comparison Group, Actuals v. Estimated, 22SEP03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Estimated Load by Sample Group, 22SEP03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison Re-Set

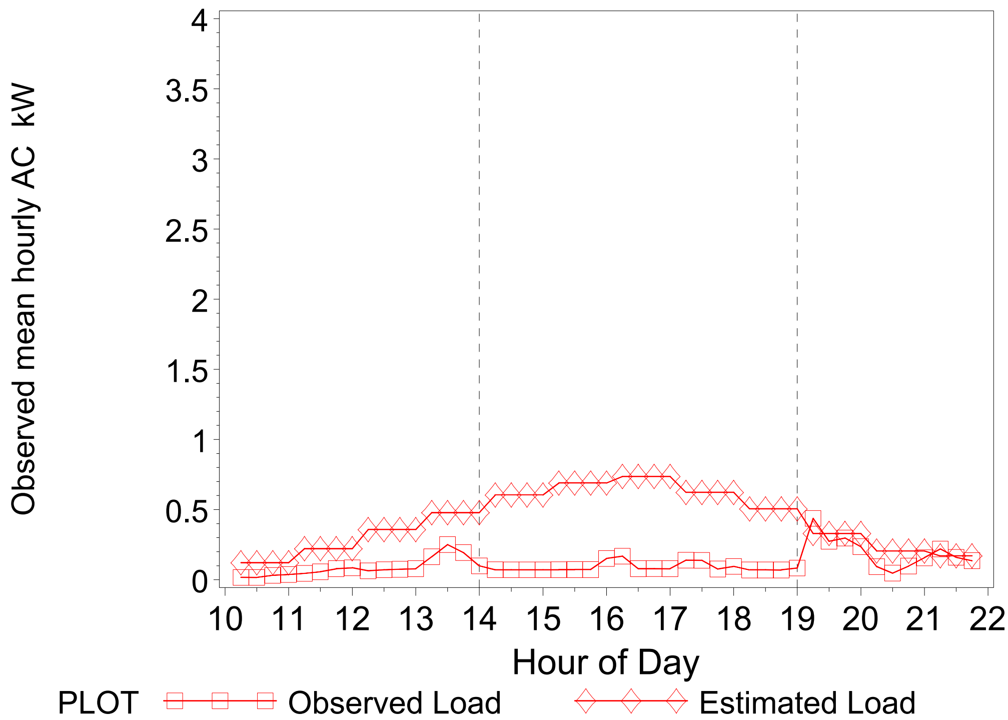


Impact Estimate for 22SEP03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

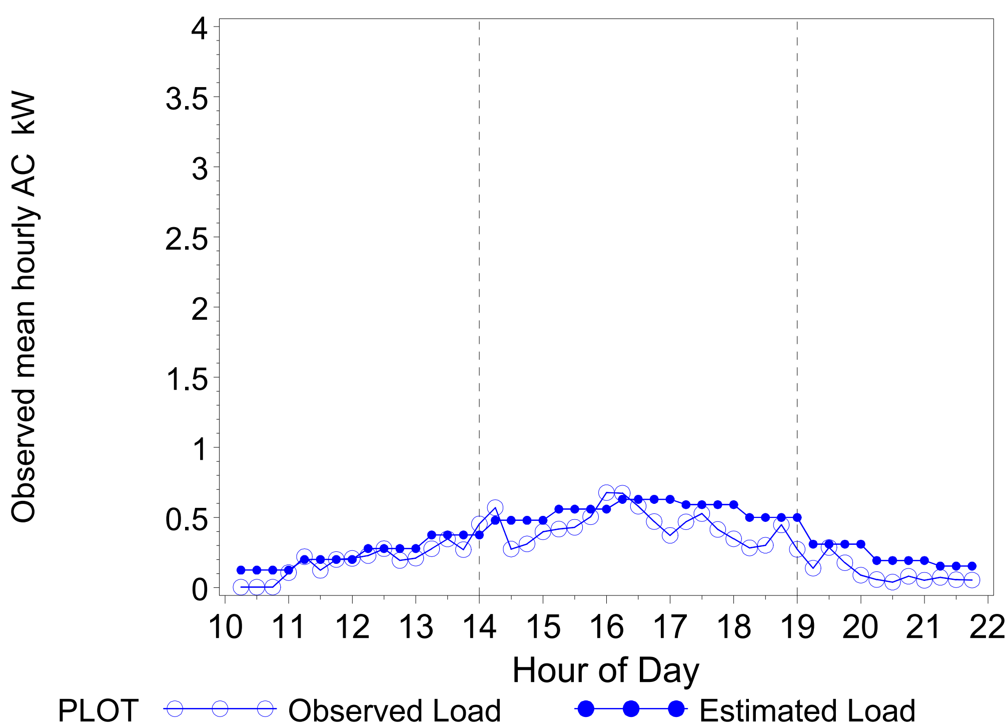


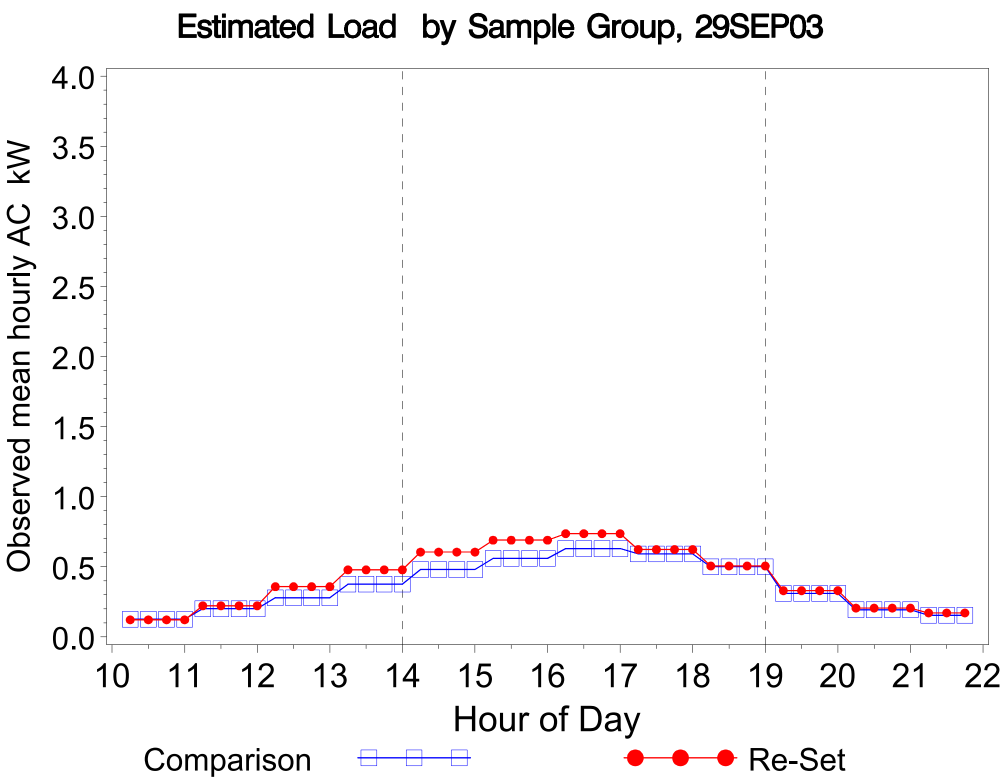
Observed Load by Sample Group, 29SEP03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

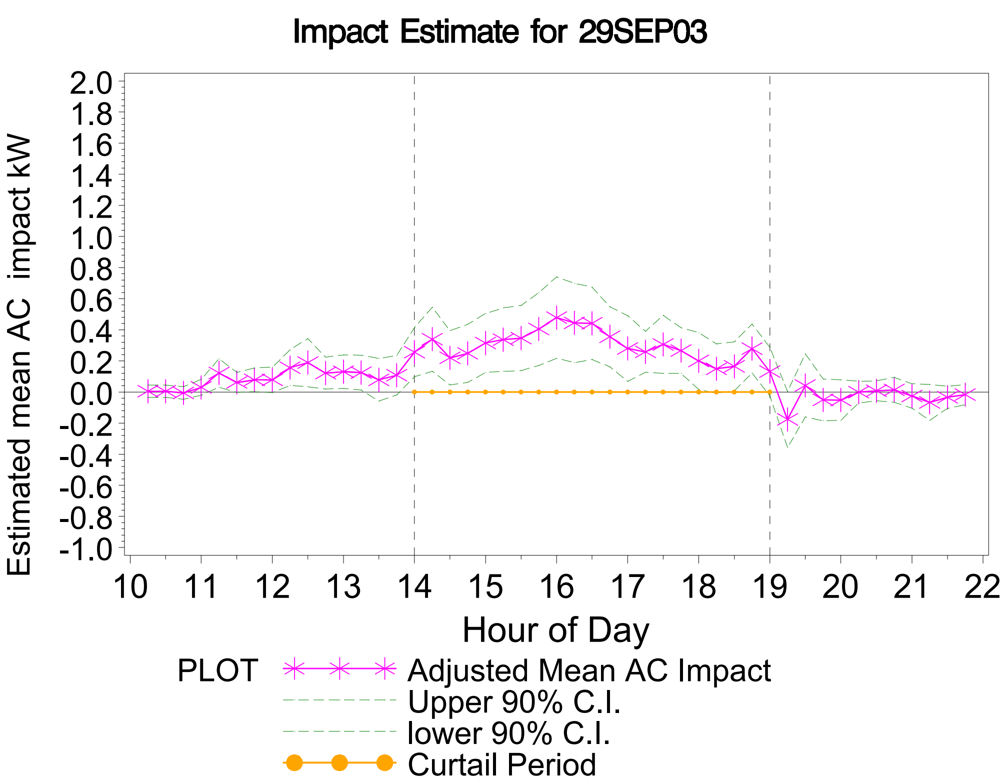
Re–set Group, Observed v. Estimated, 29SEP03

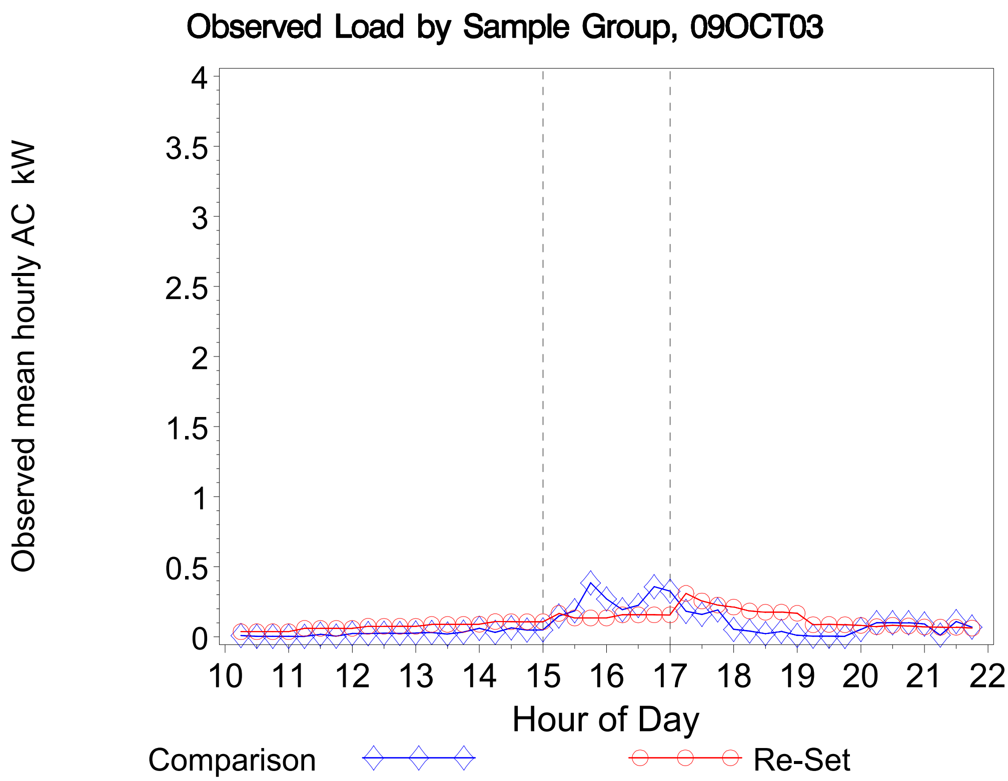


Comparison Group, Actuals v. Estimated, 29SEP03

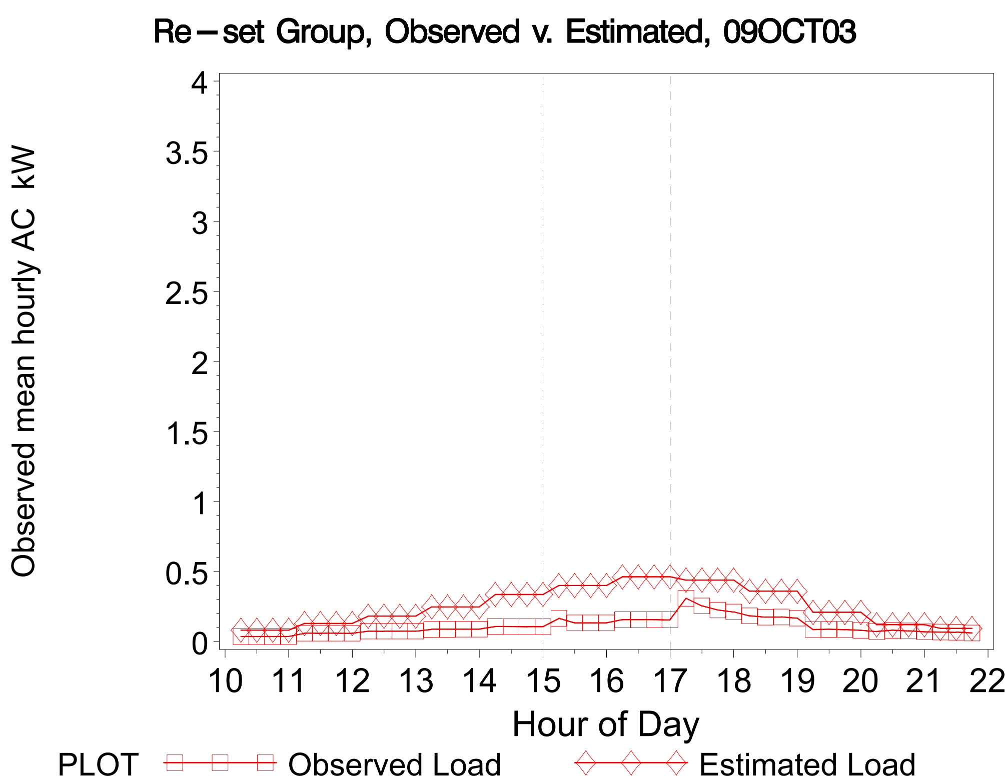



Estimated Load by Sample Group, 29SEP03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

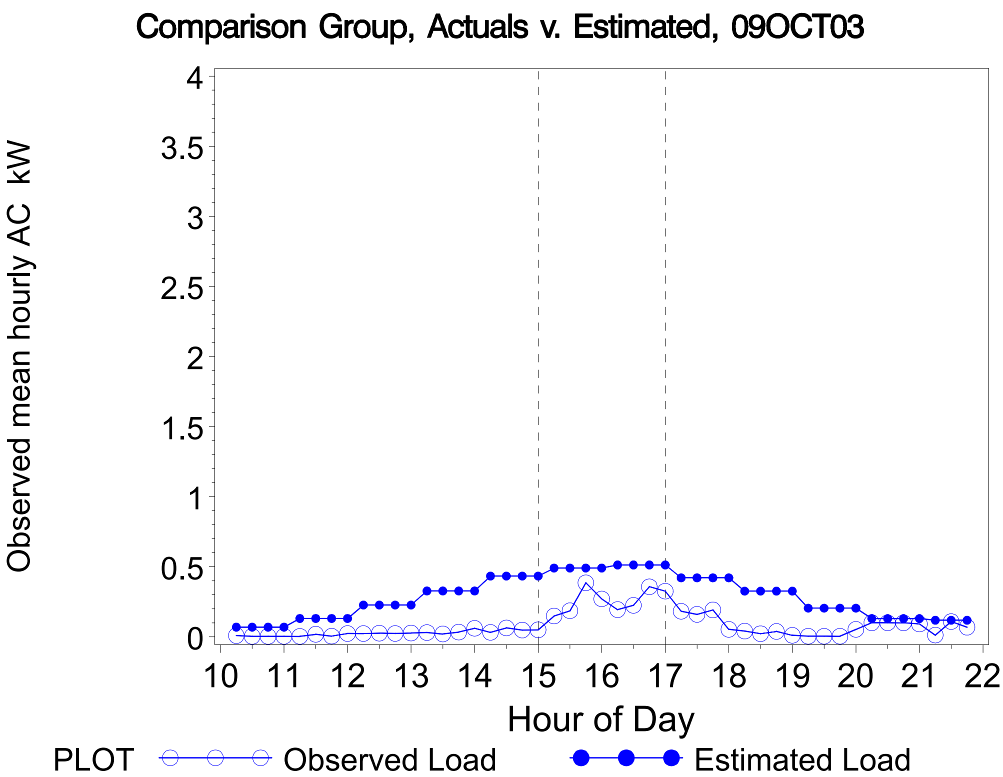

Impact Estimate for 29SEP03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

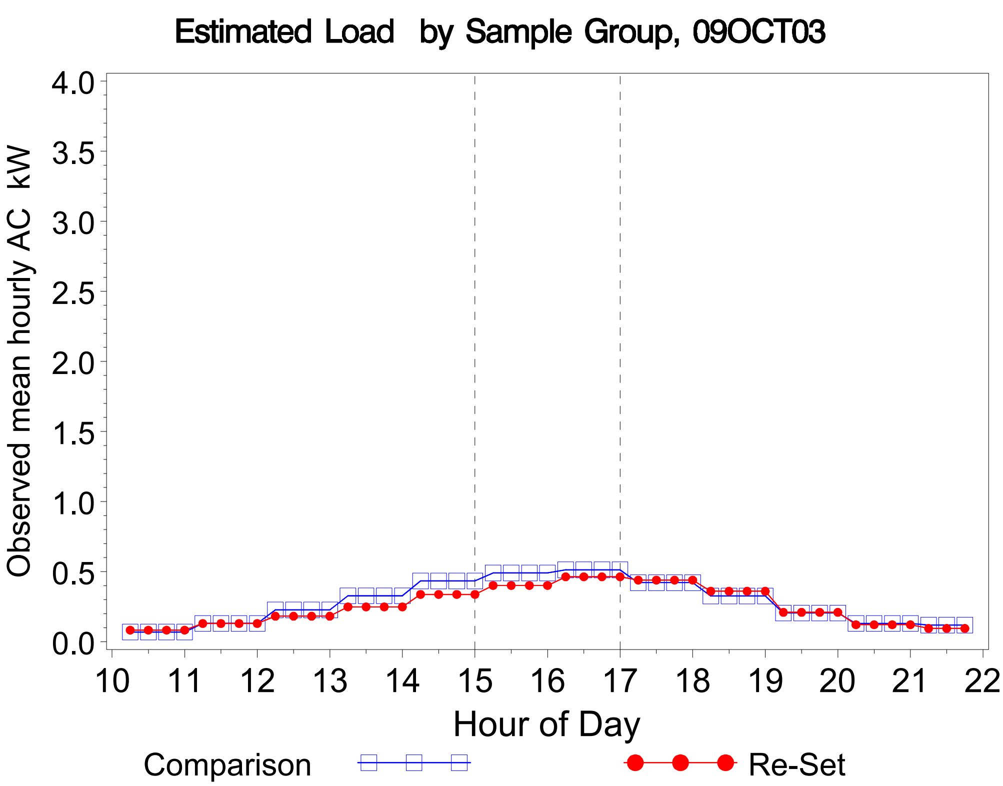


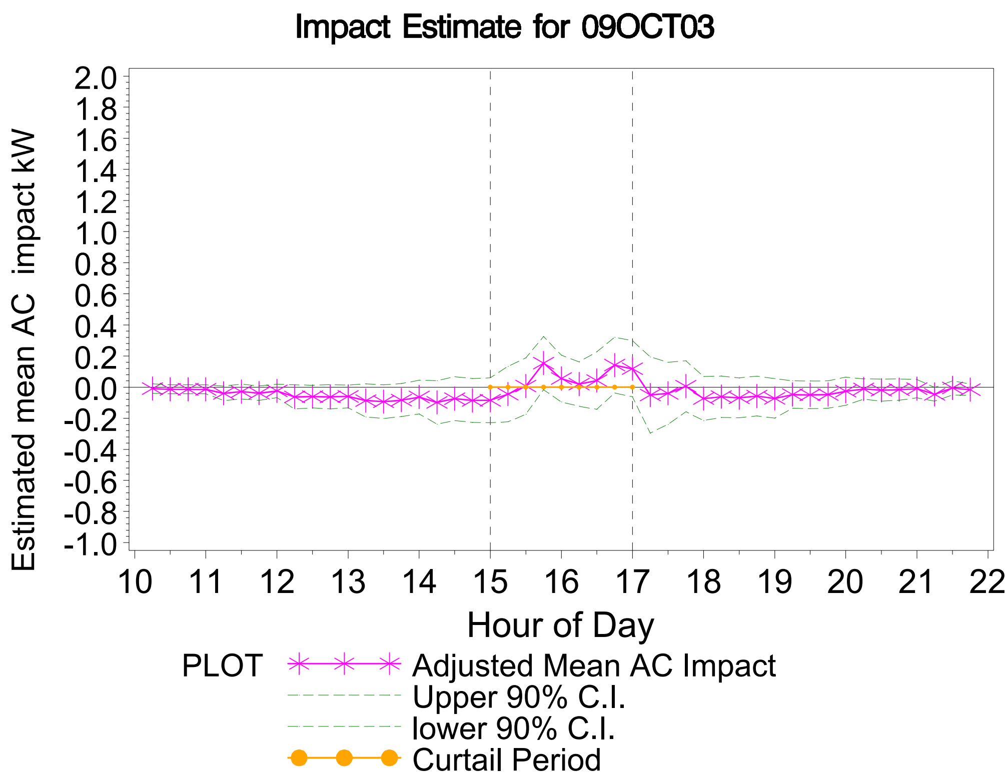
Observed Load by Sample Group, 09OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

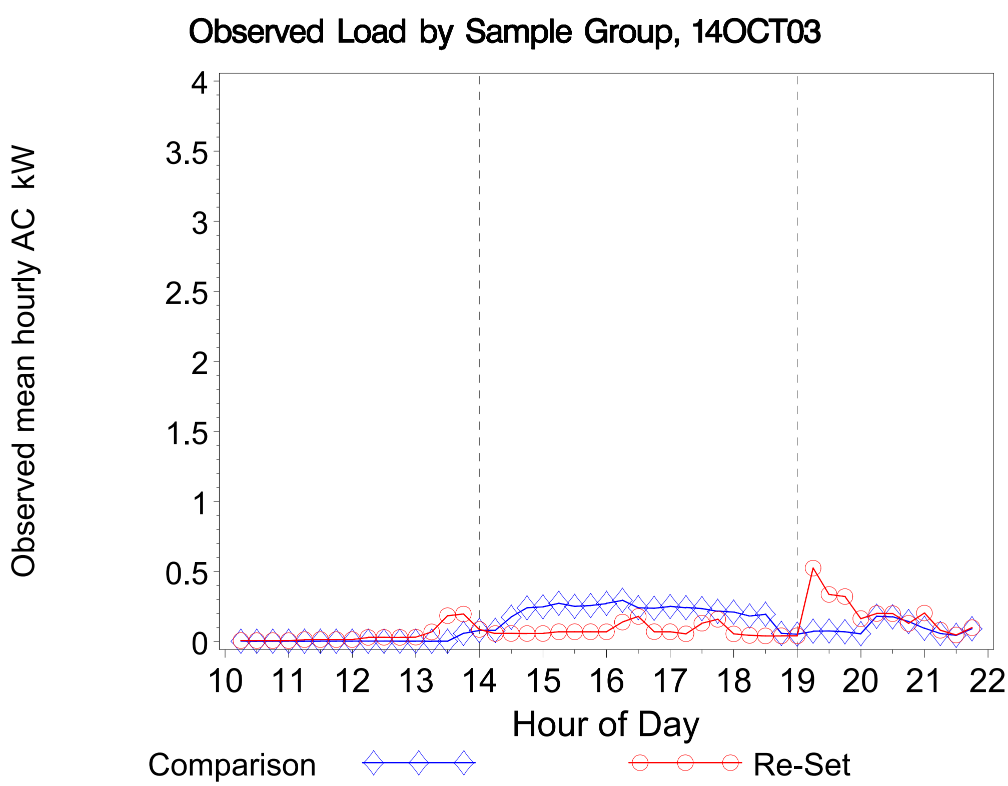


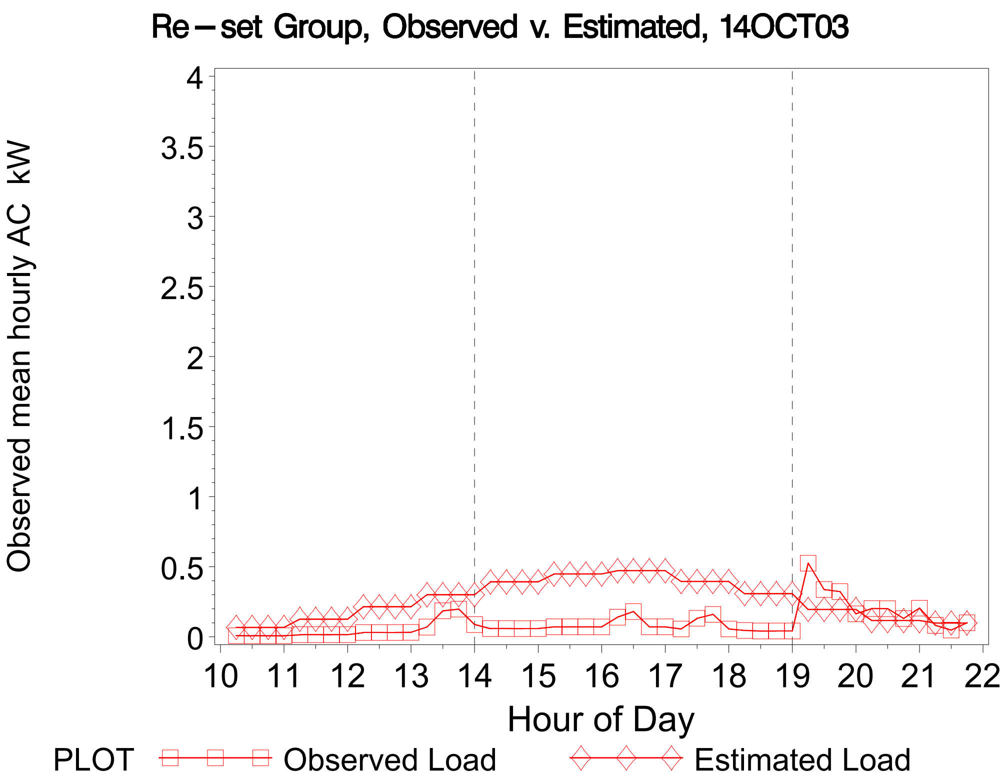
Re-set Group, Observed v. Estimated, 09OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

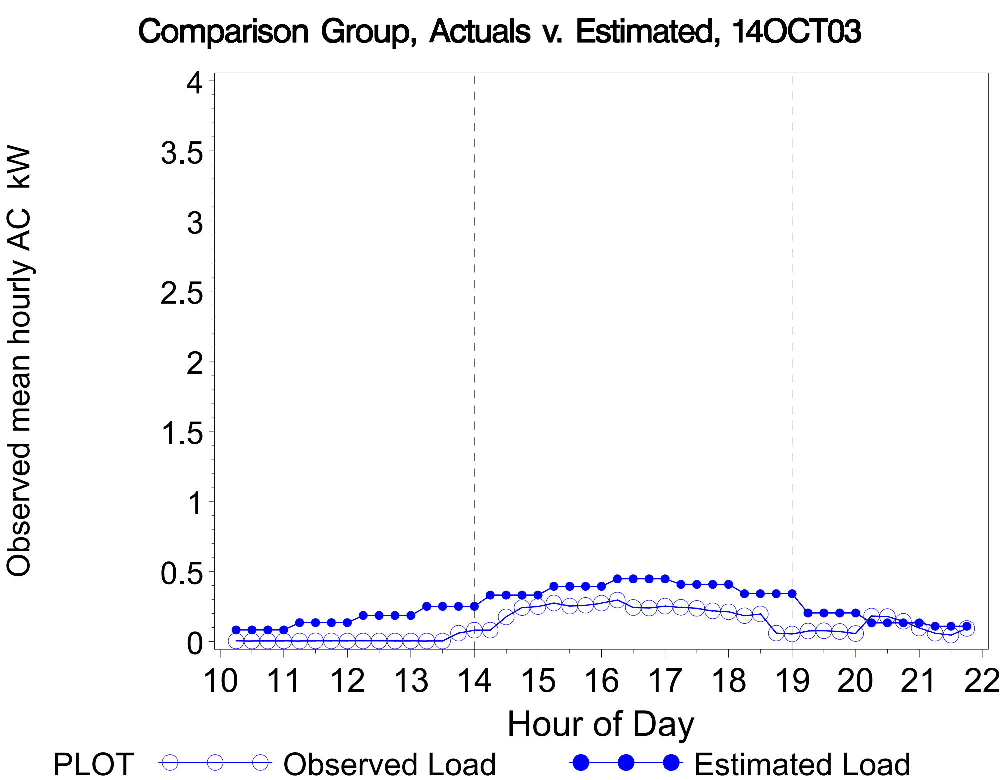

Comparison Group, Actuals v. Estimated, 09OCT03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

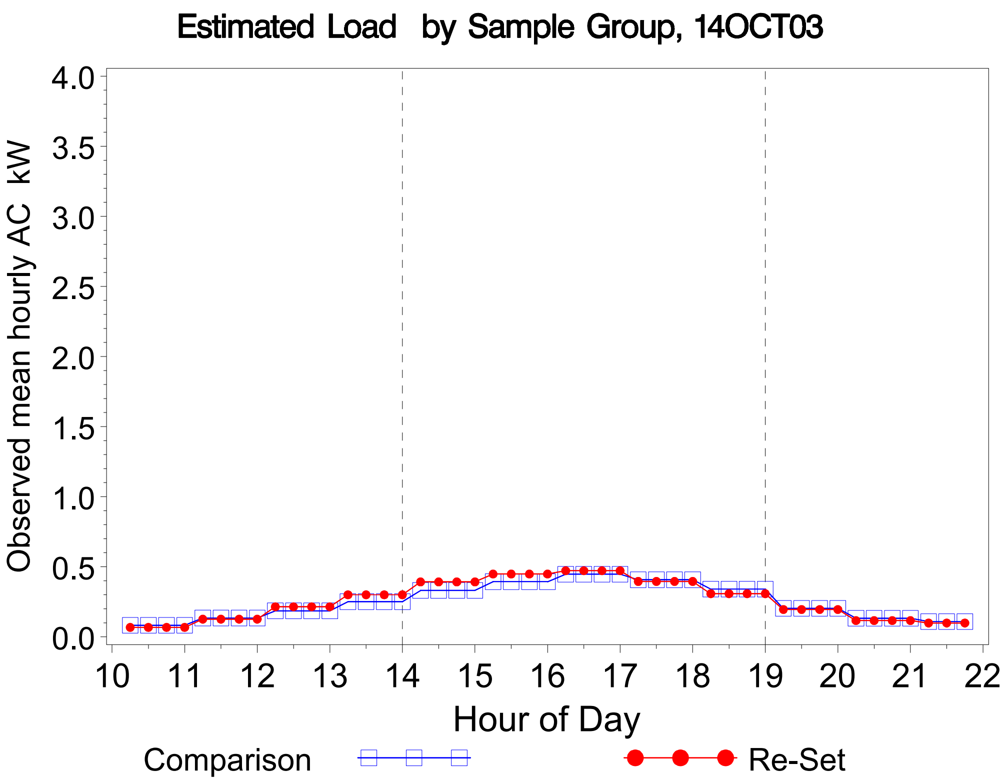

Estimated Load by Sample Group, 09OCT03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

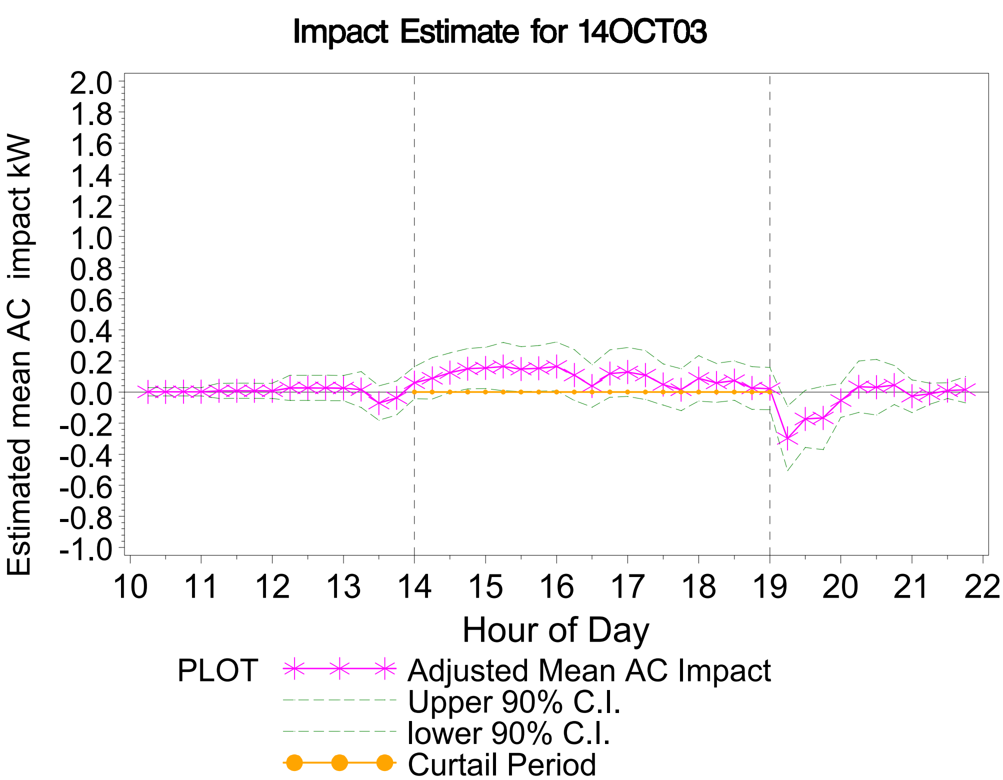

Impact Estimate for 09OCT03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

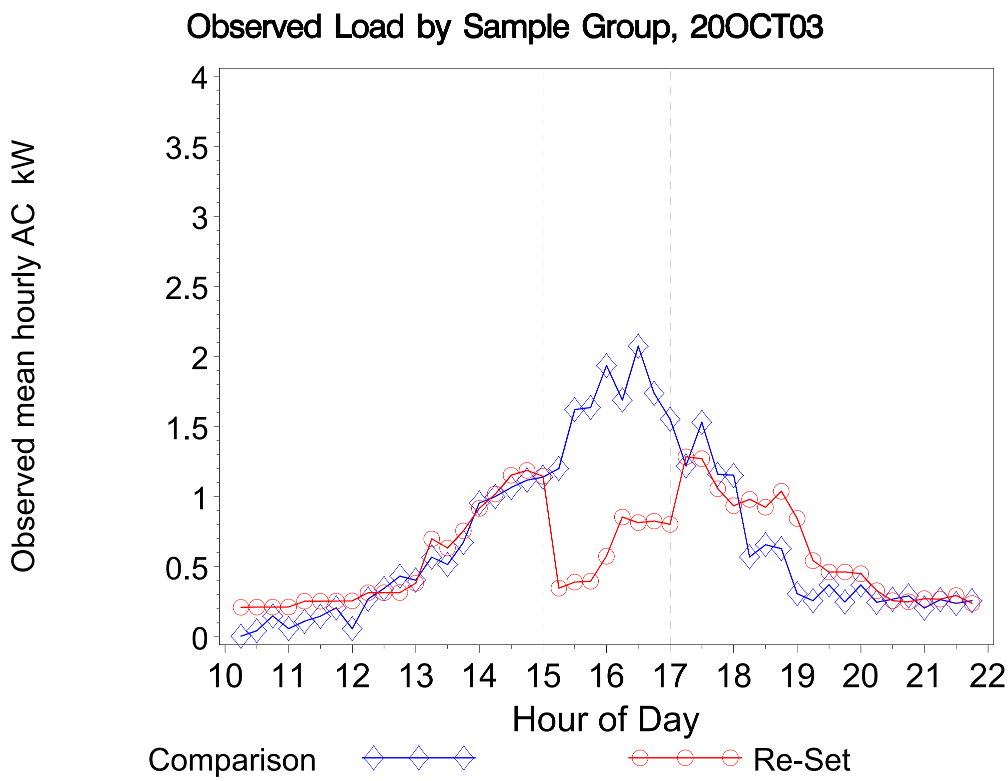

Observed Load by Sample Group, 14OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

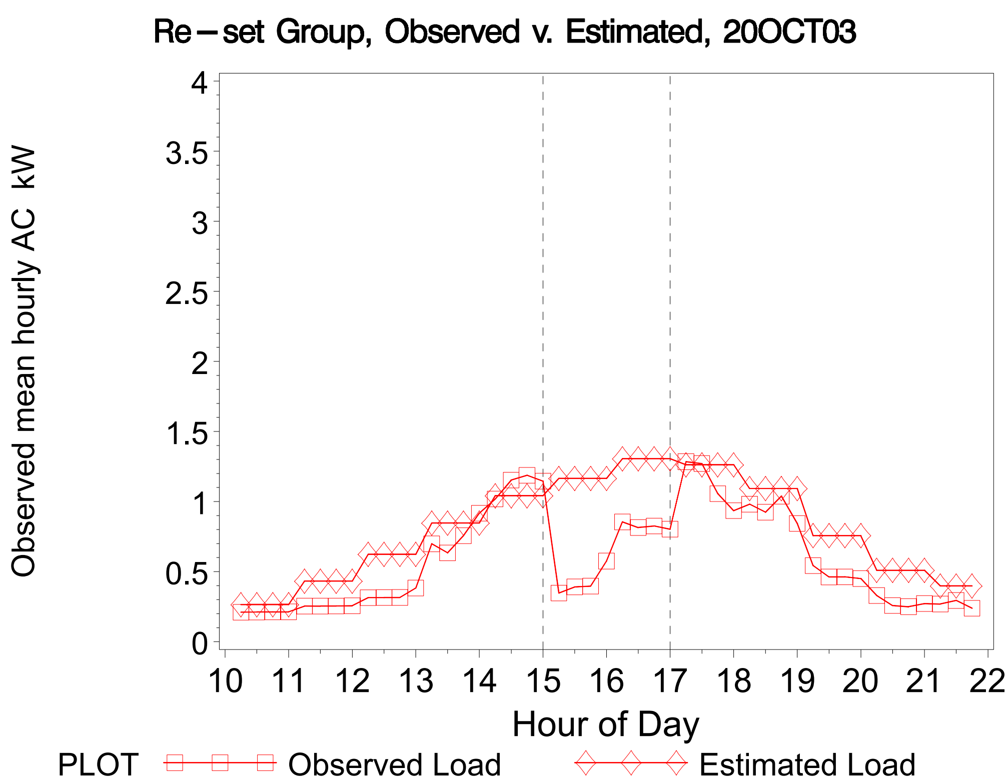

Re – set Group, Observed v. Estimated, 14OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

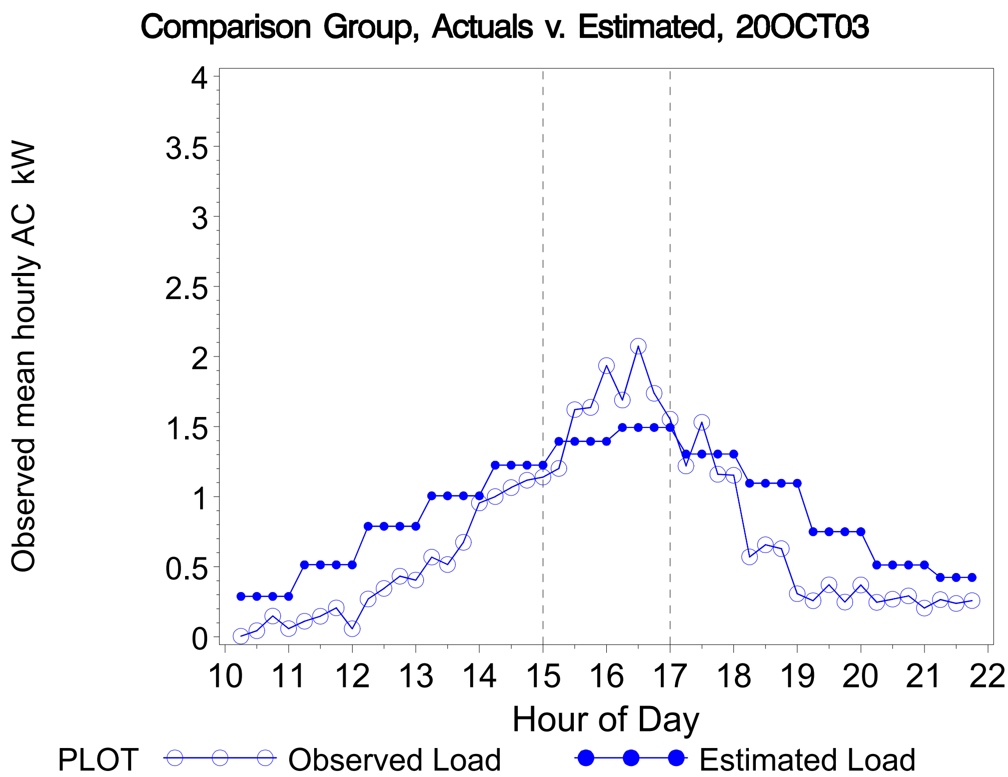

Comparison Group, Actuals v. Estimated, 14OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Estimated Load by Sample Group, 14OCT03
Observed mean hourly AC kW
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

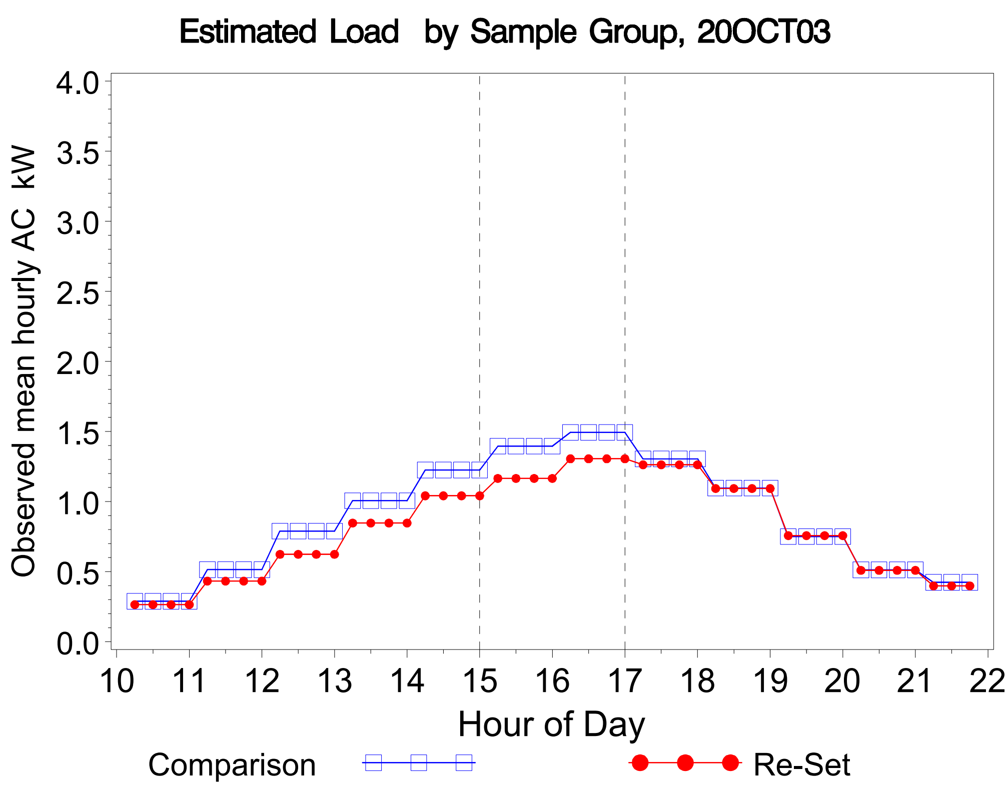

Impact Estimate for 14OCT03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period


Observed Load by Sample Group, 20OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

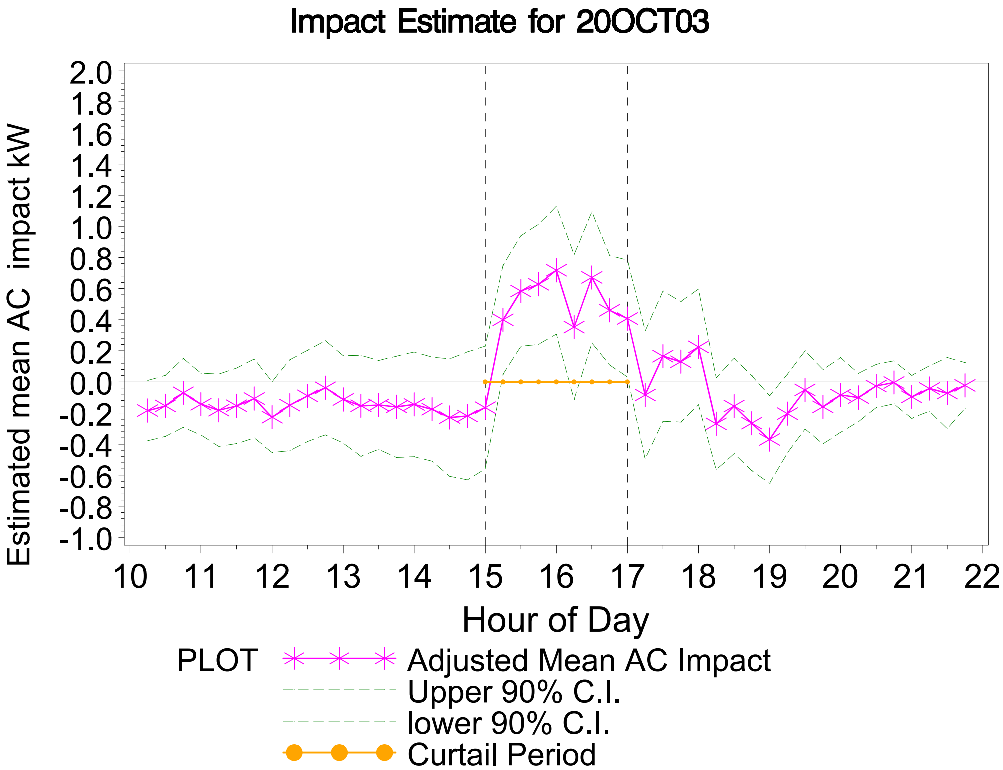

Re–set Group, Observed v. Estimated, 20OCT03
Observed mean hourly AC kW
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load



Comparison Group, Actuals v. Estimated, 20OCT03
Observed mean hourly AC kW
0
0.5
1
1.5
2
2.5
3
3.5
4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load



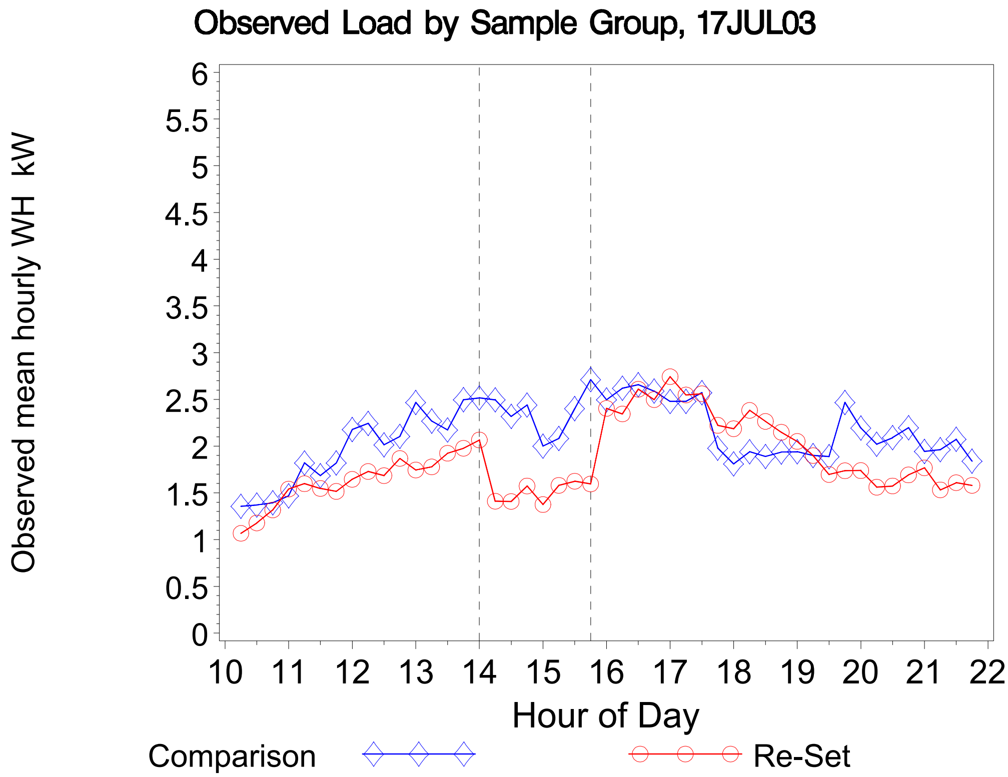
Estimated Load by Sample Group, 20OCT03
Observed mean hourly AC kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

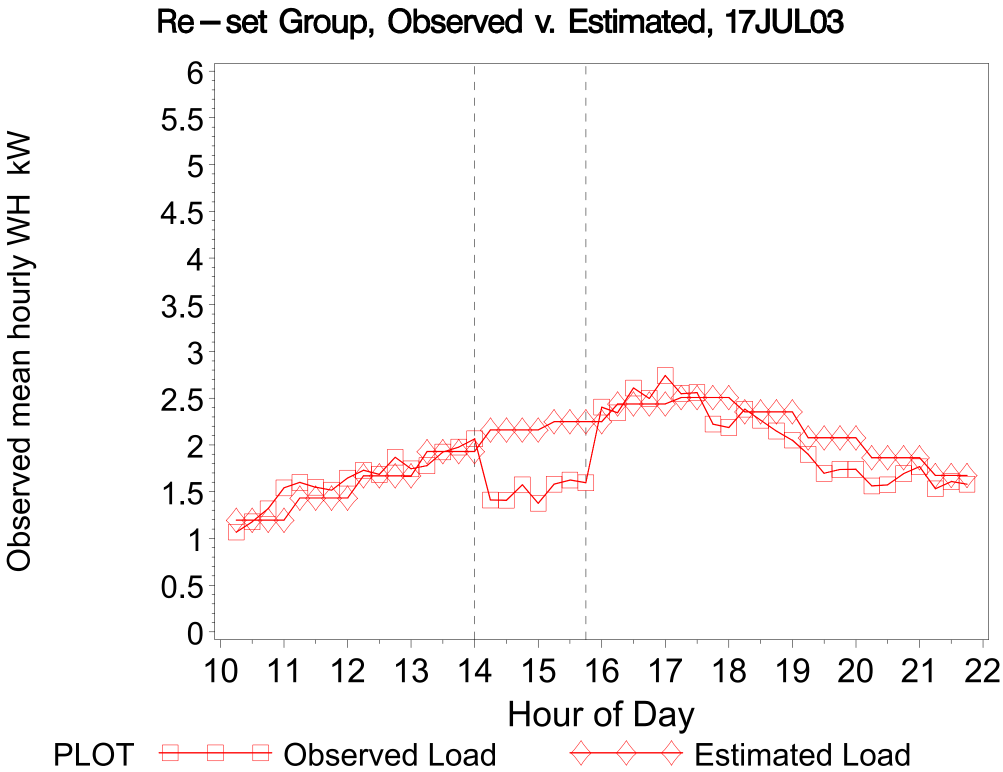


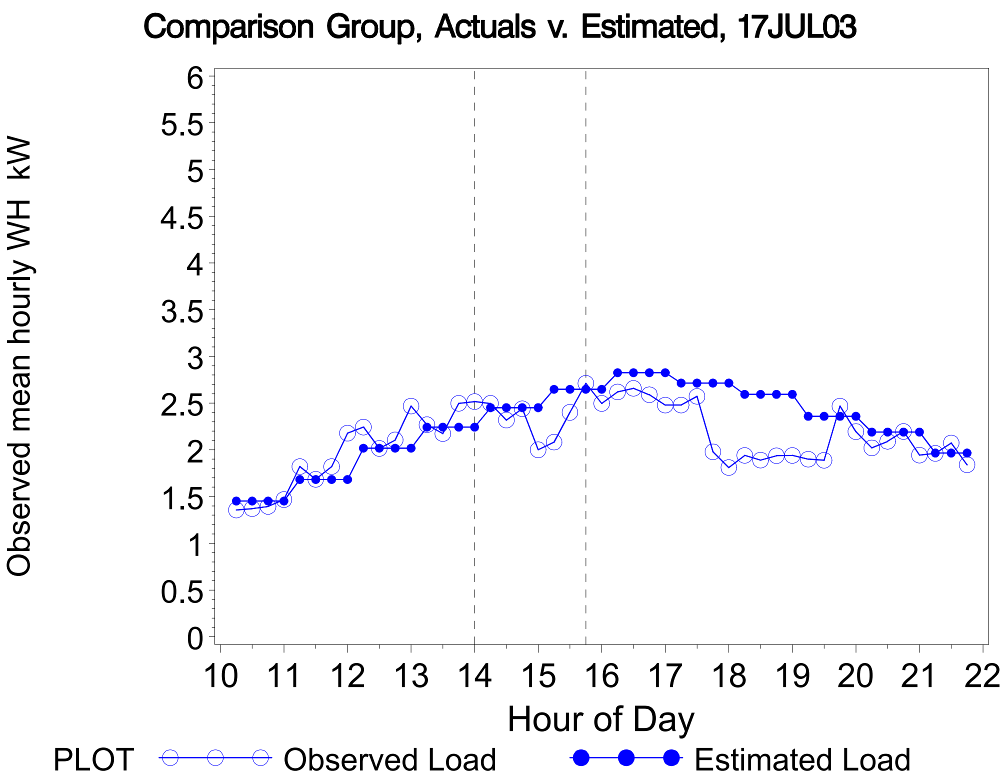
Impact Estimate for 20OCT03
Estimated mean AC impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean AC Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

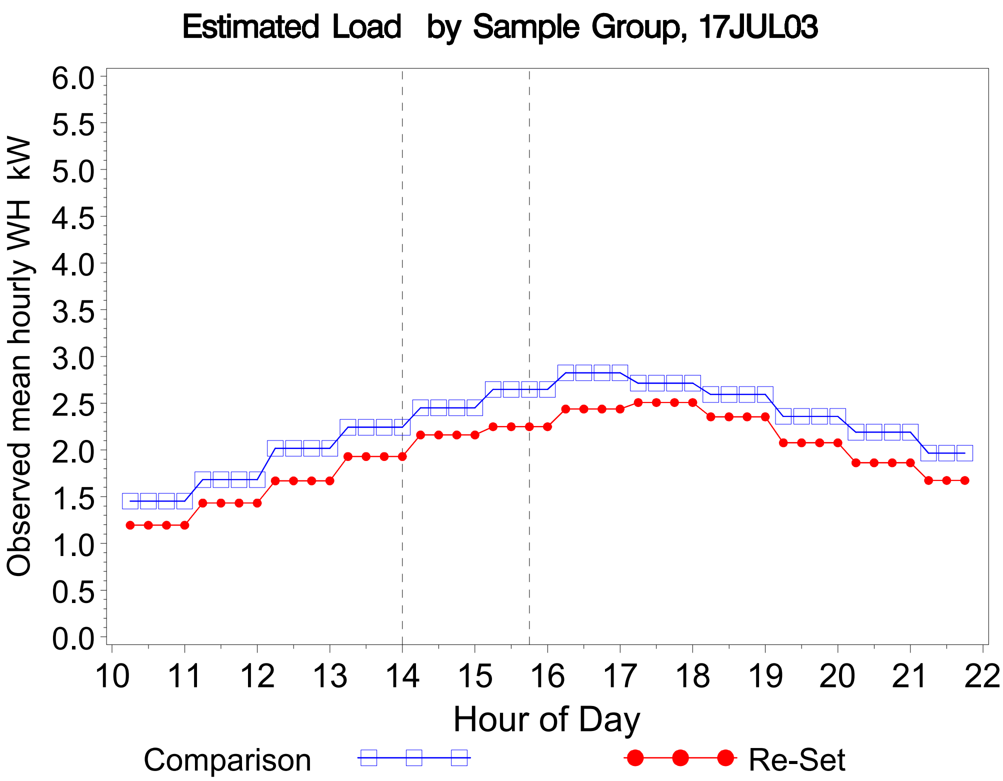
B

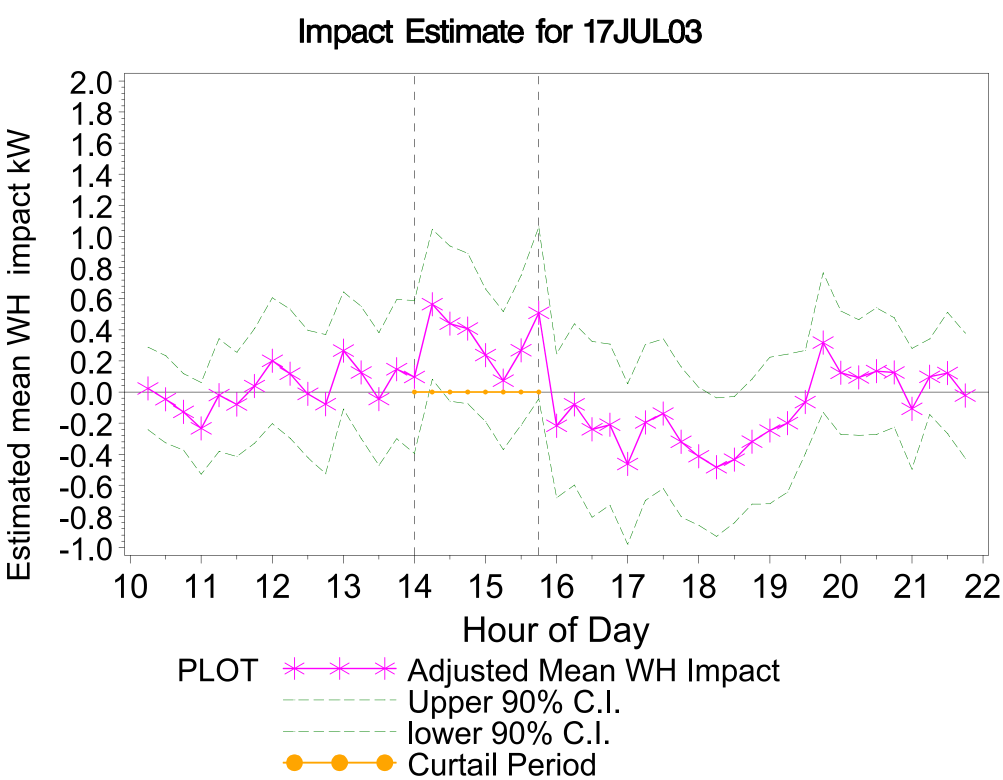
WHOLE HOUSE IMPACT PLOTS

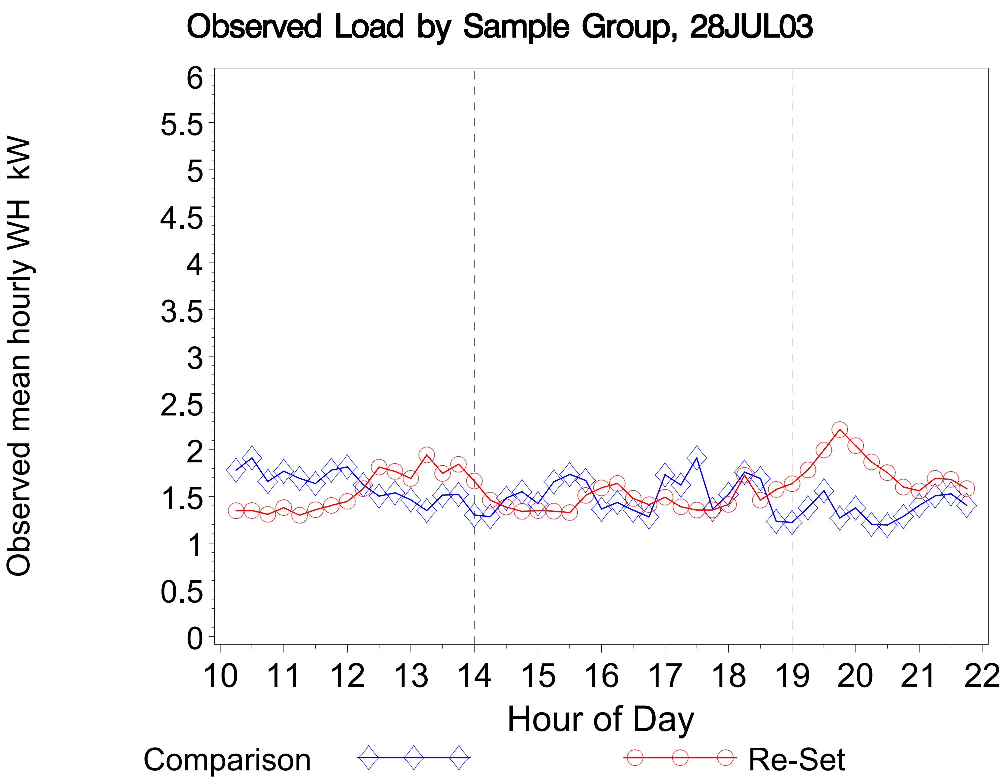


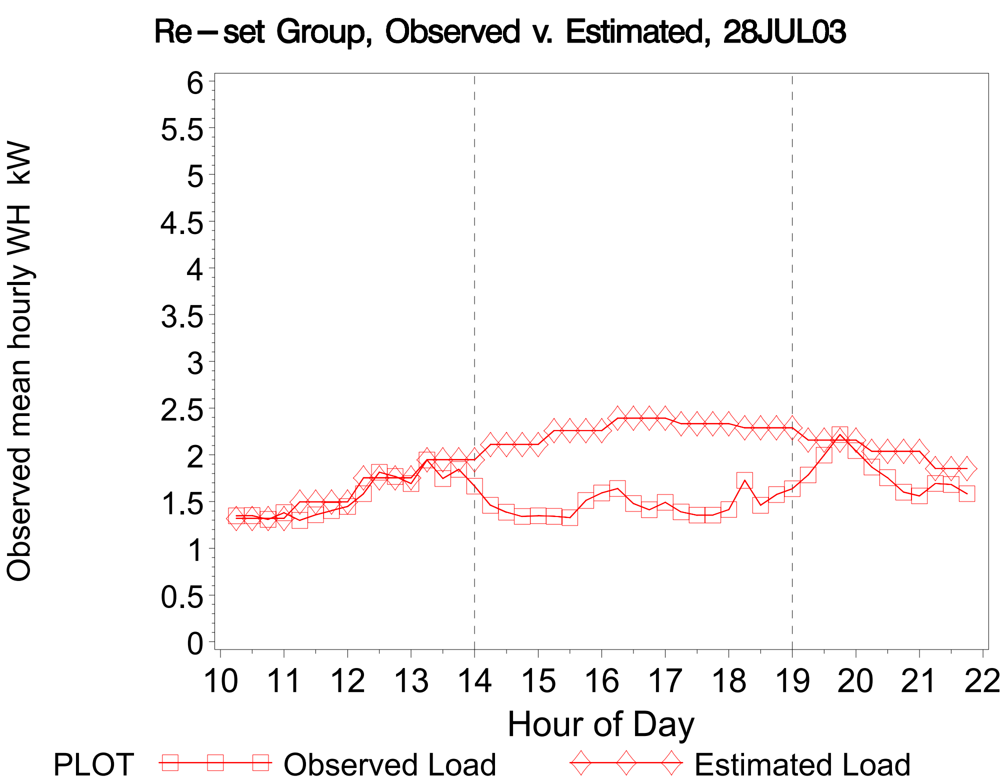

Re–set Group, Observed v. Estimated, 17JUL03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

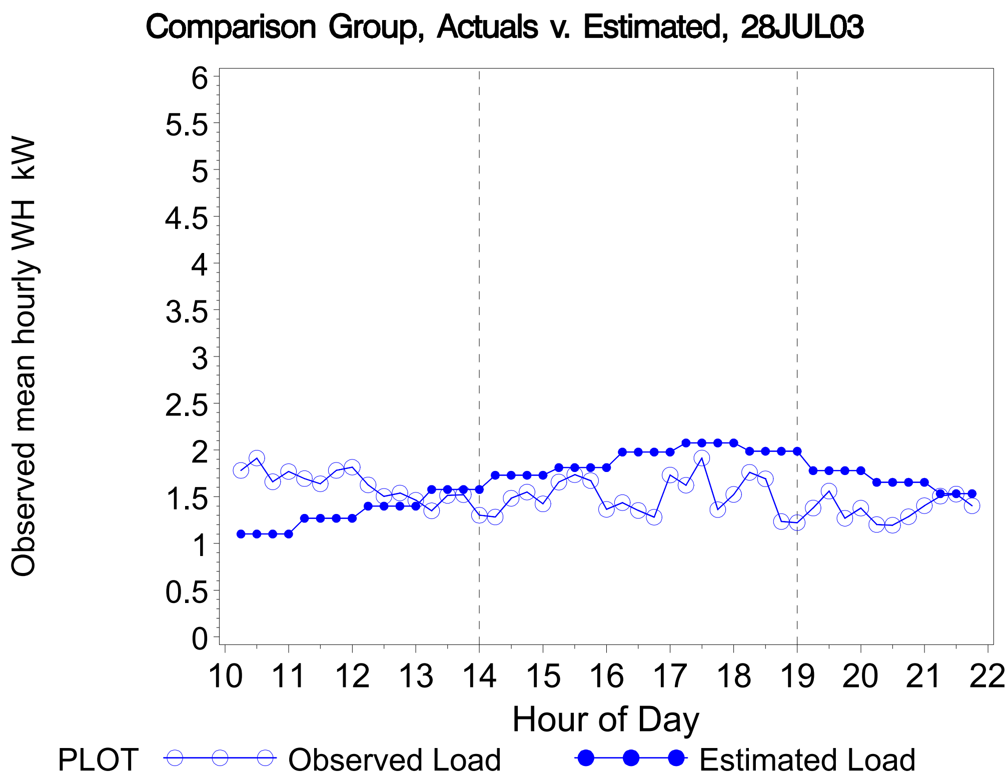

Comparison Group, Actuals v. Estimated, 17JUL03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

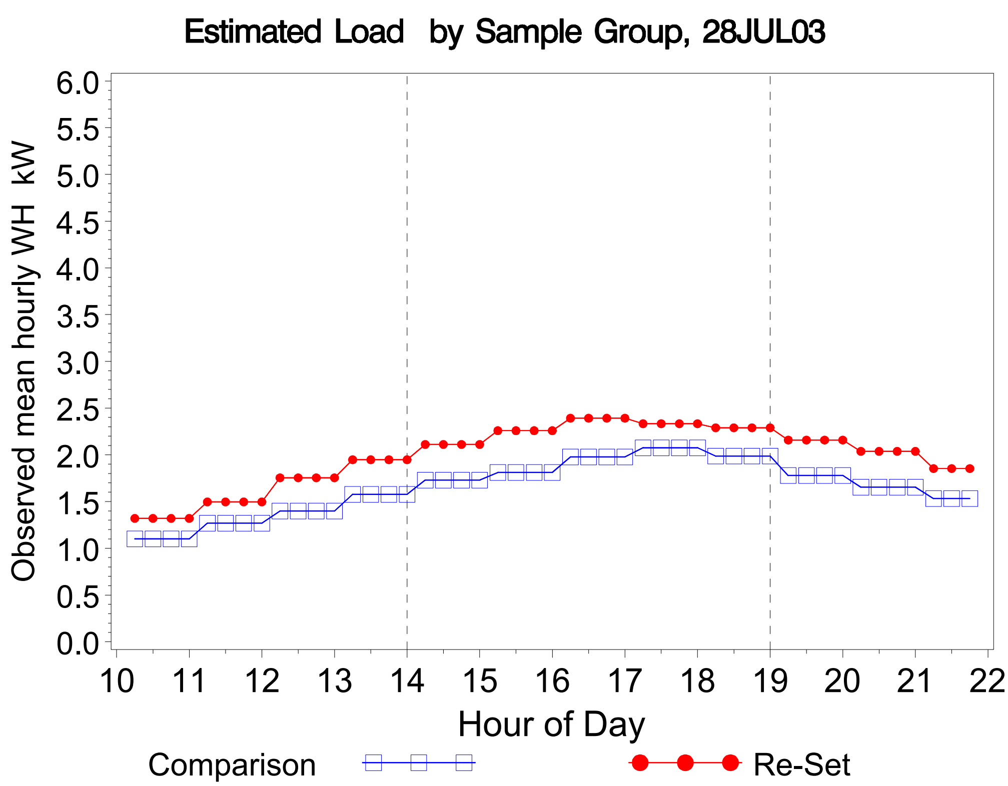

Estimated Load by Sample Group, 17JUL03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

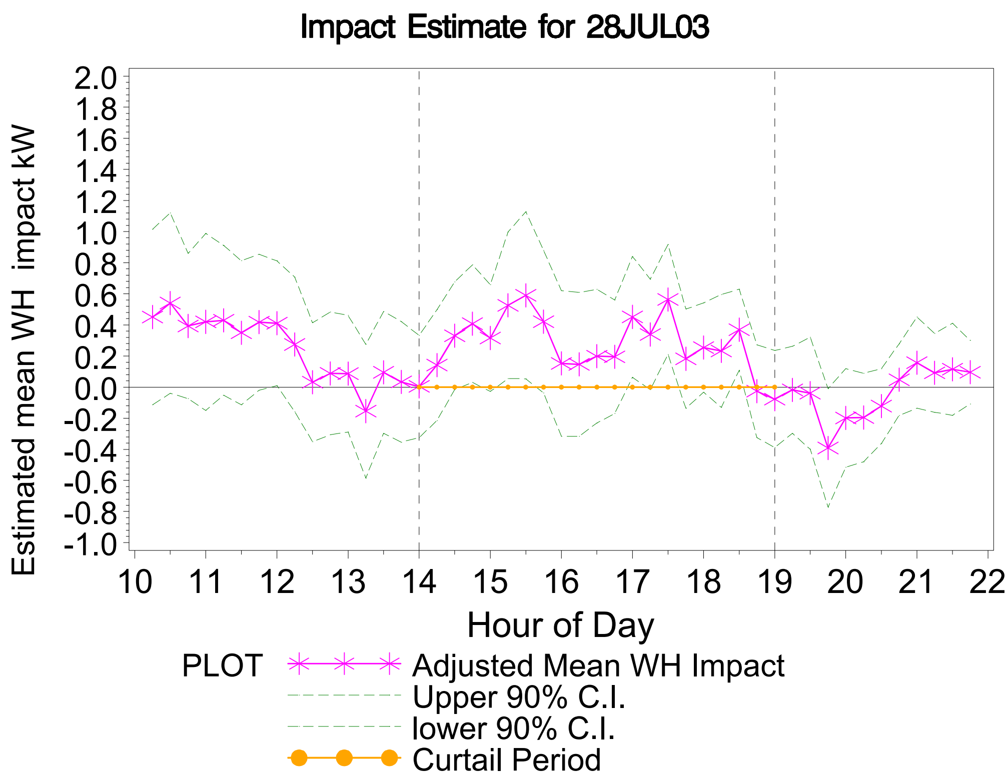

Impact Estimate for 17JUL03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

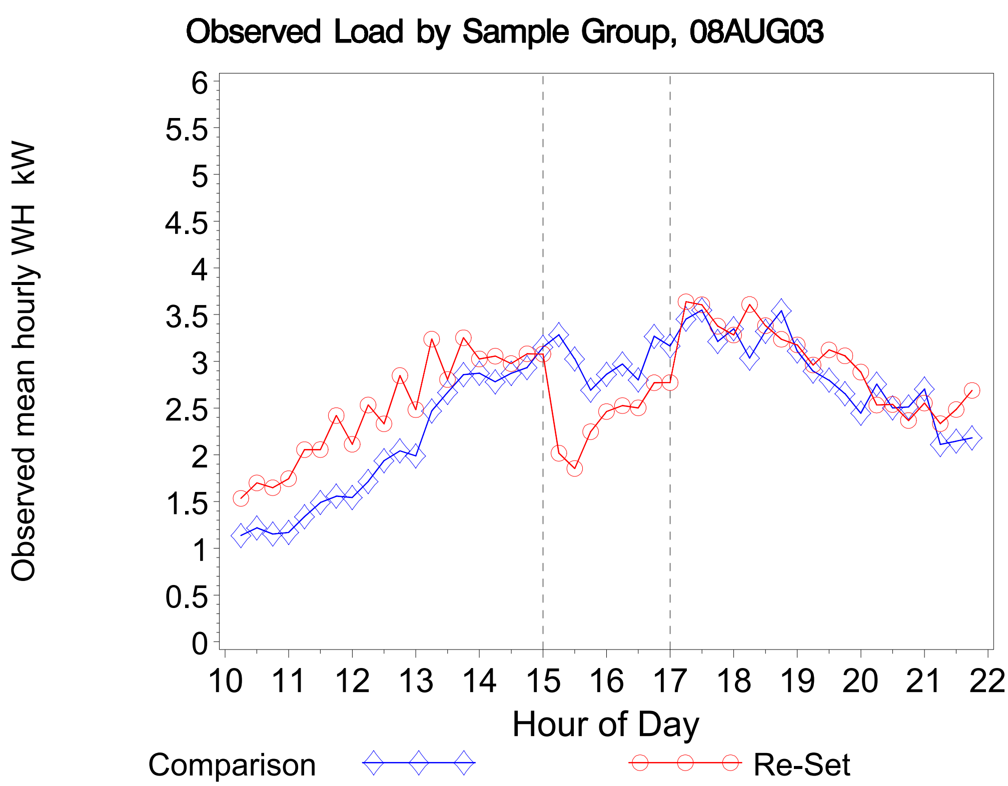

Observed Load by Sample Group, 28JUL03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

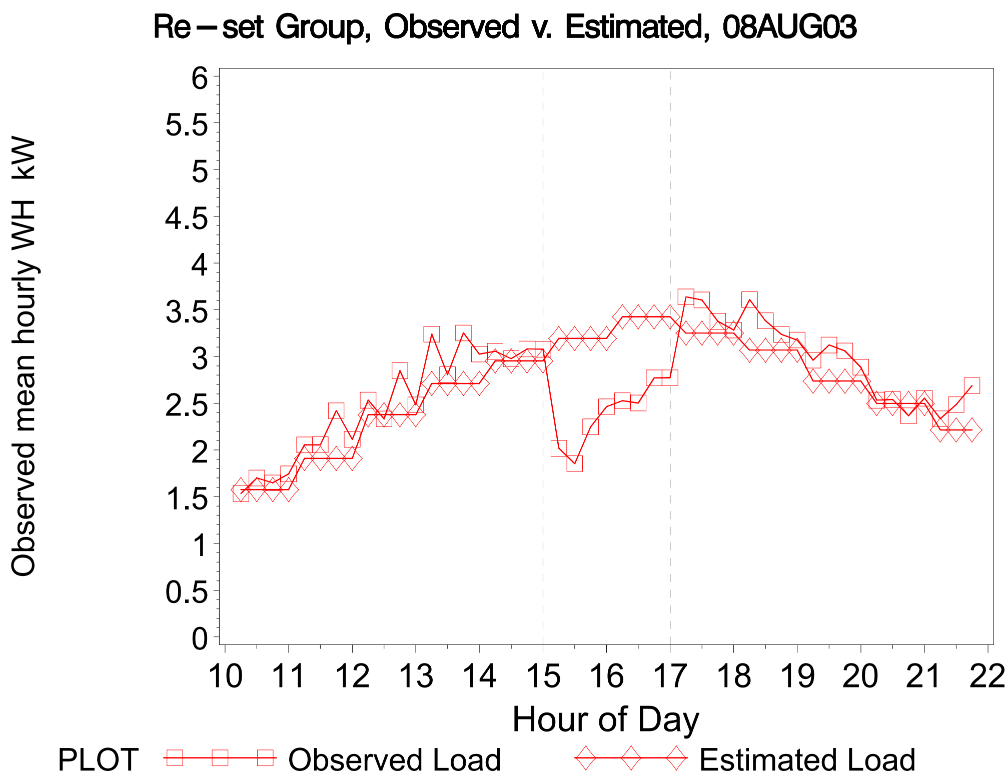

Re-set Group, Observed v. Estimated, 28JUL03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

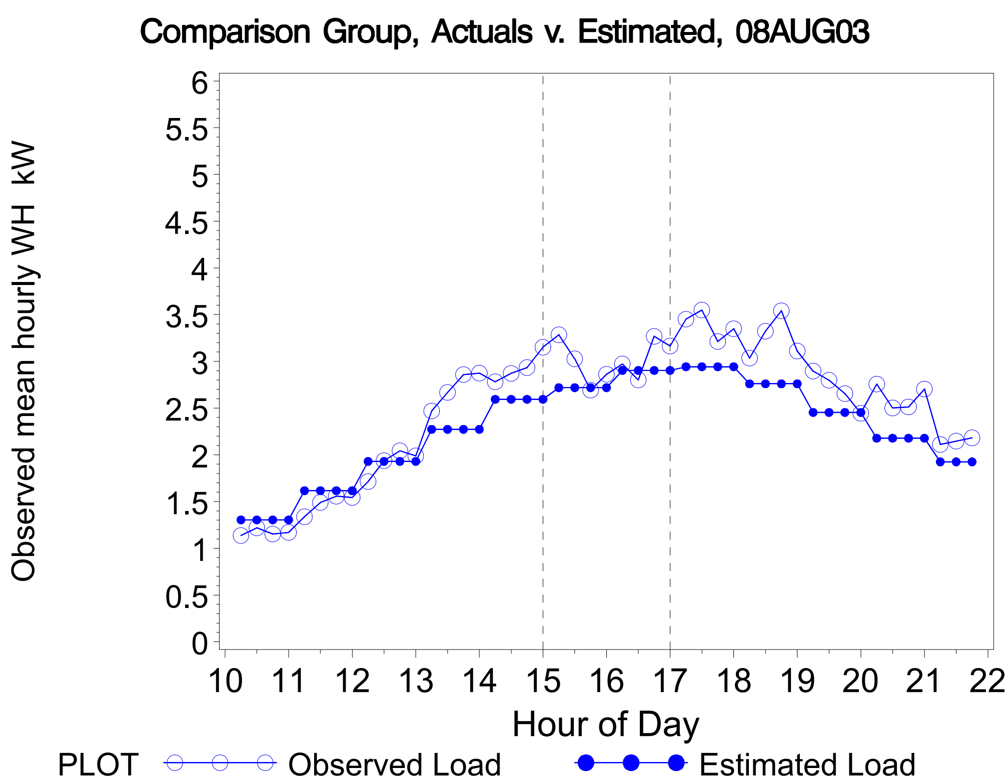

Comparison Group, Actuals v. Estimated, 28JUL03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

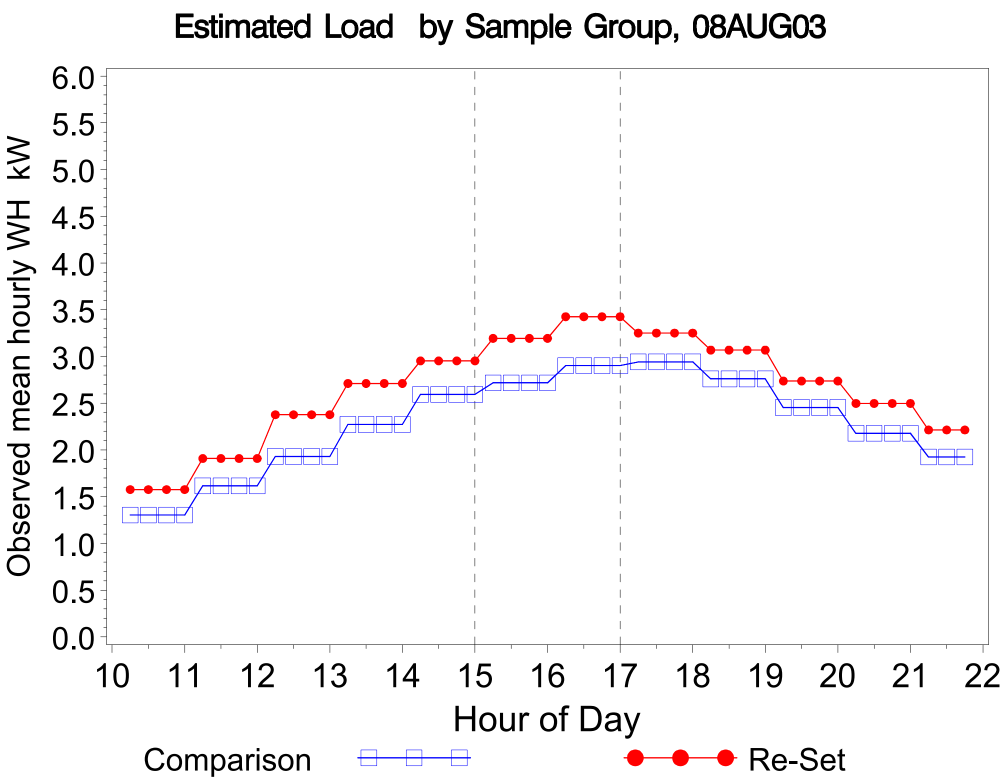

Estimated Load by Sample Group, 28JUL03
Observed mean hourly WH kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

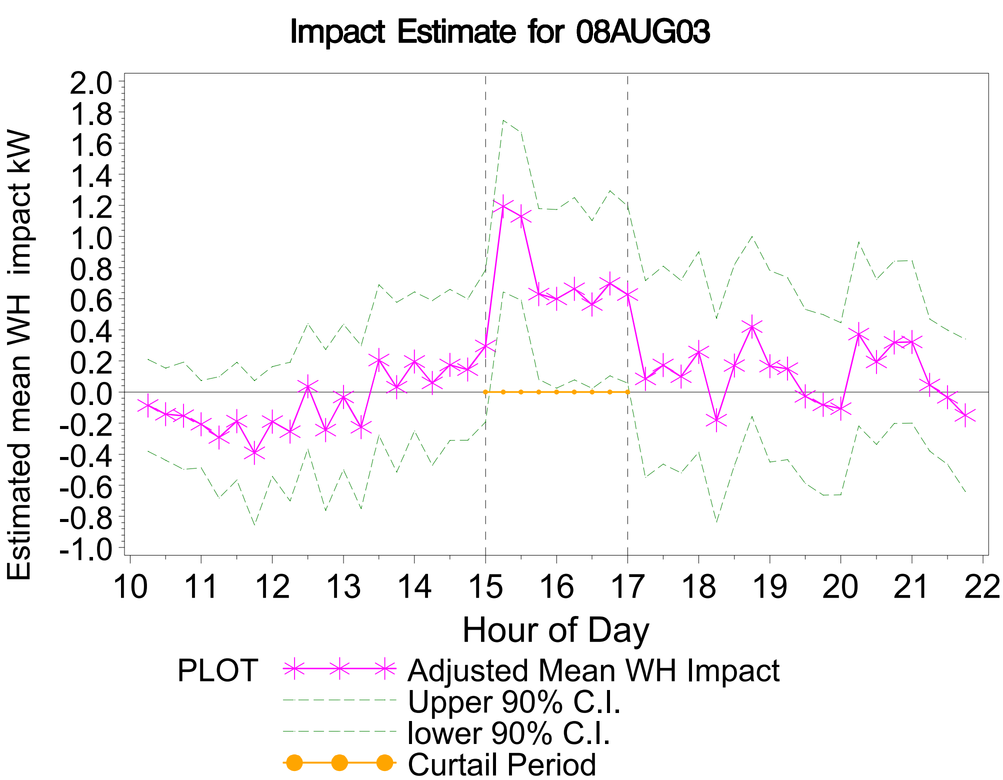

Impact Estimate for 28JUL03
Estimated mean WH impact kW
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

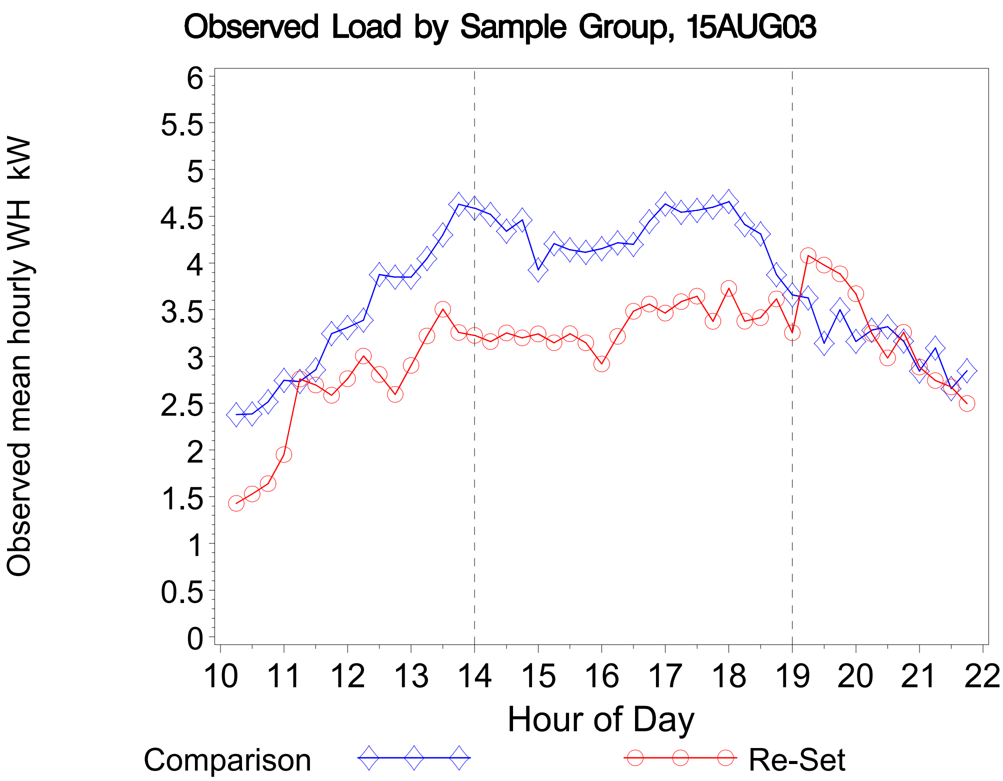

Observed Load by Sample Group, 08AUG03
Observed mean hourly WH kW
Hour of Day
Comparison
Re-Set

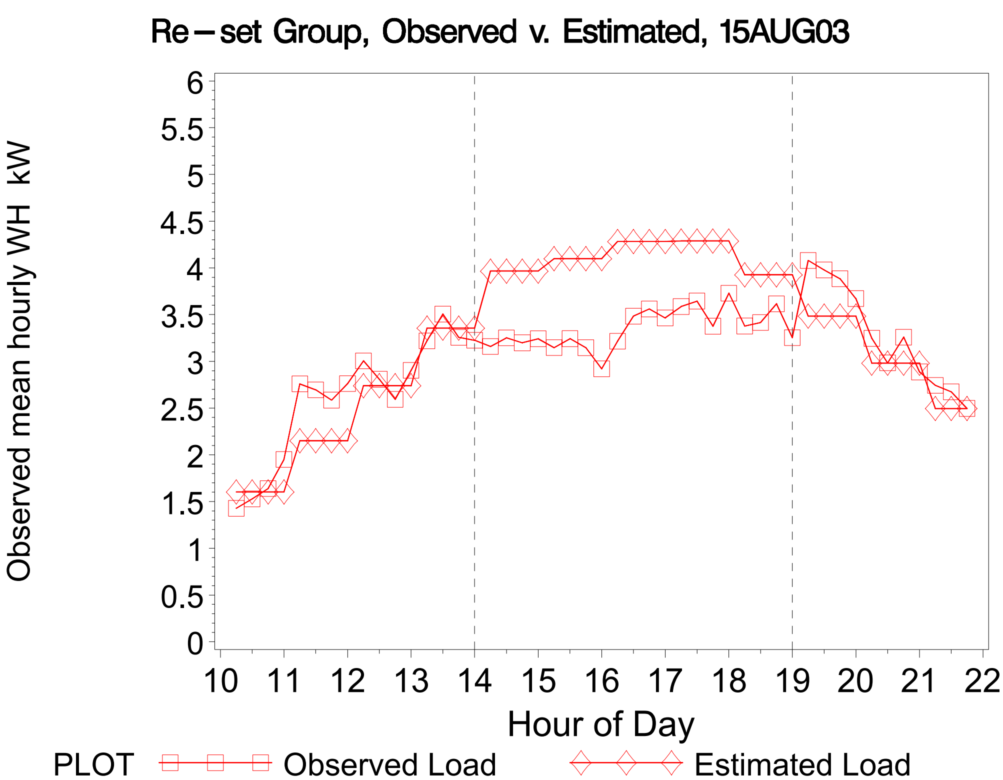

Re−set Group, Observed v. Estimated, 08AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

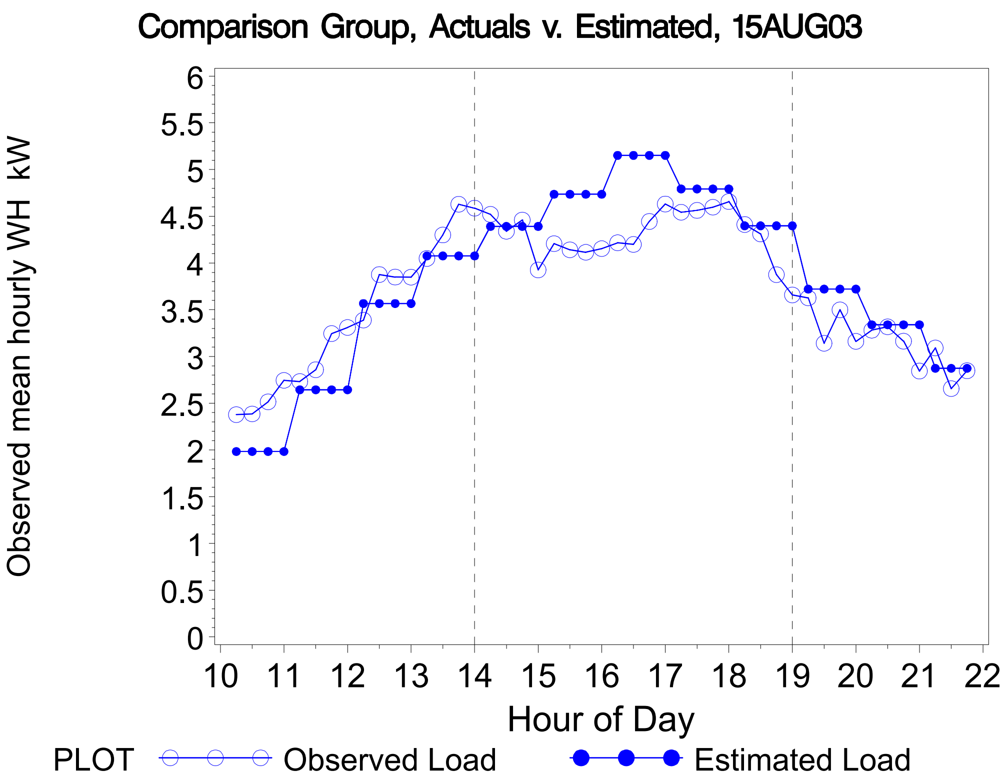

Comparison Group, Actuals v. Estimated, 08AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

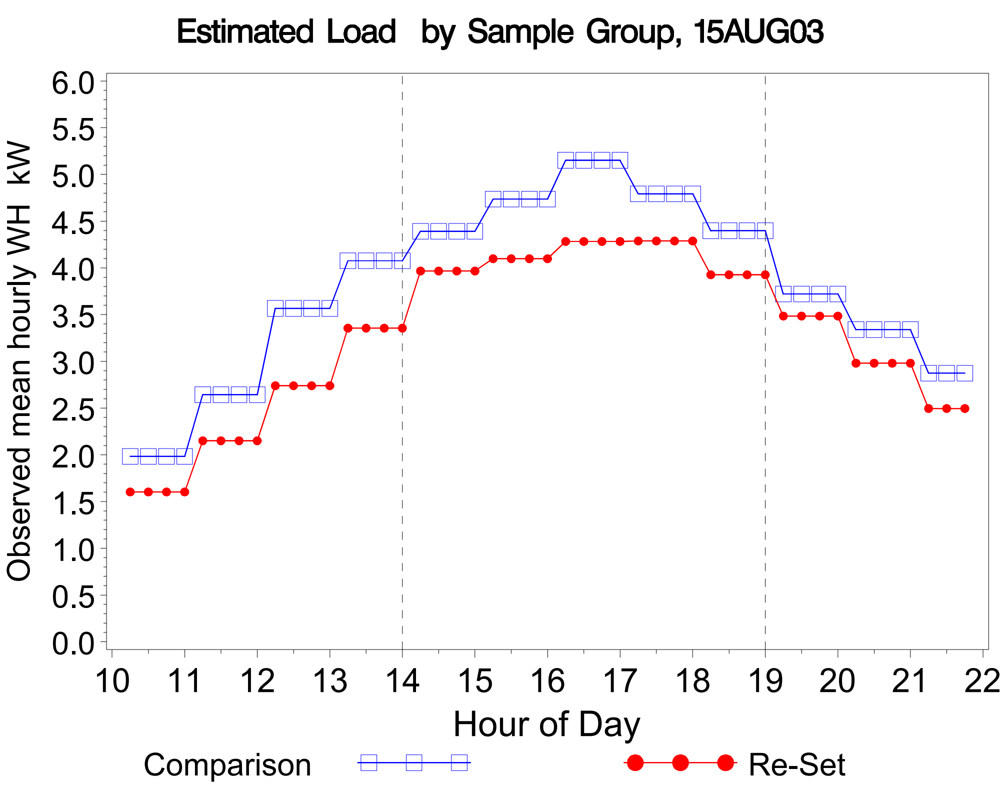

Estimated Load by Sample Group, 08AUG03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

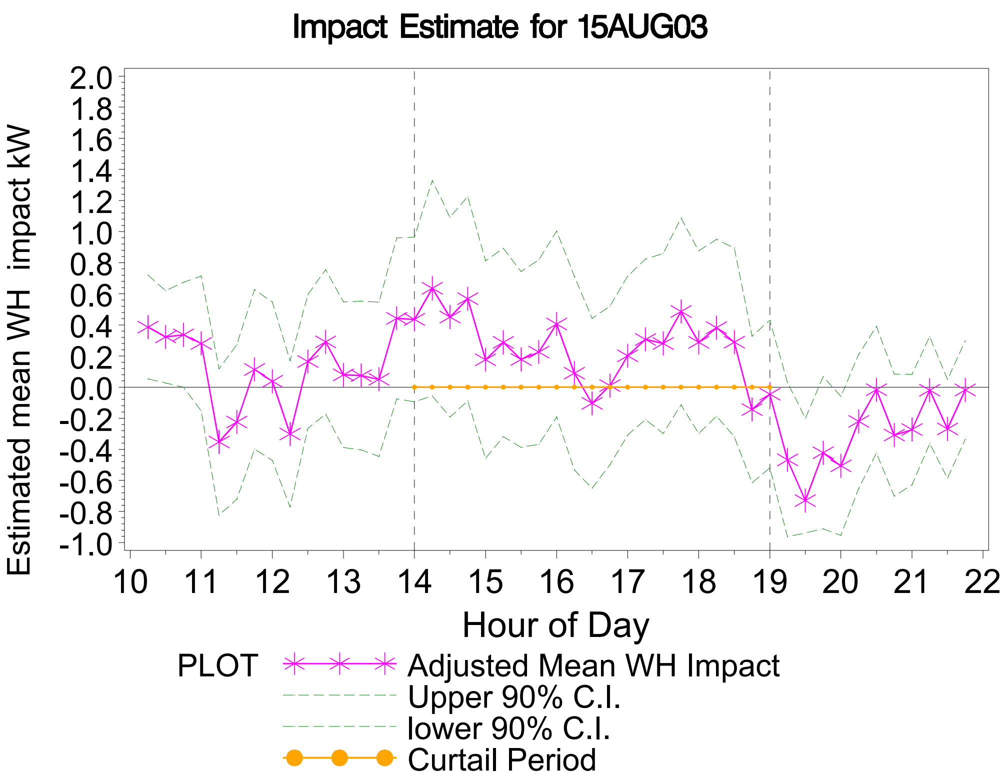

Impact Estimate for 08AUG03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

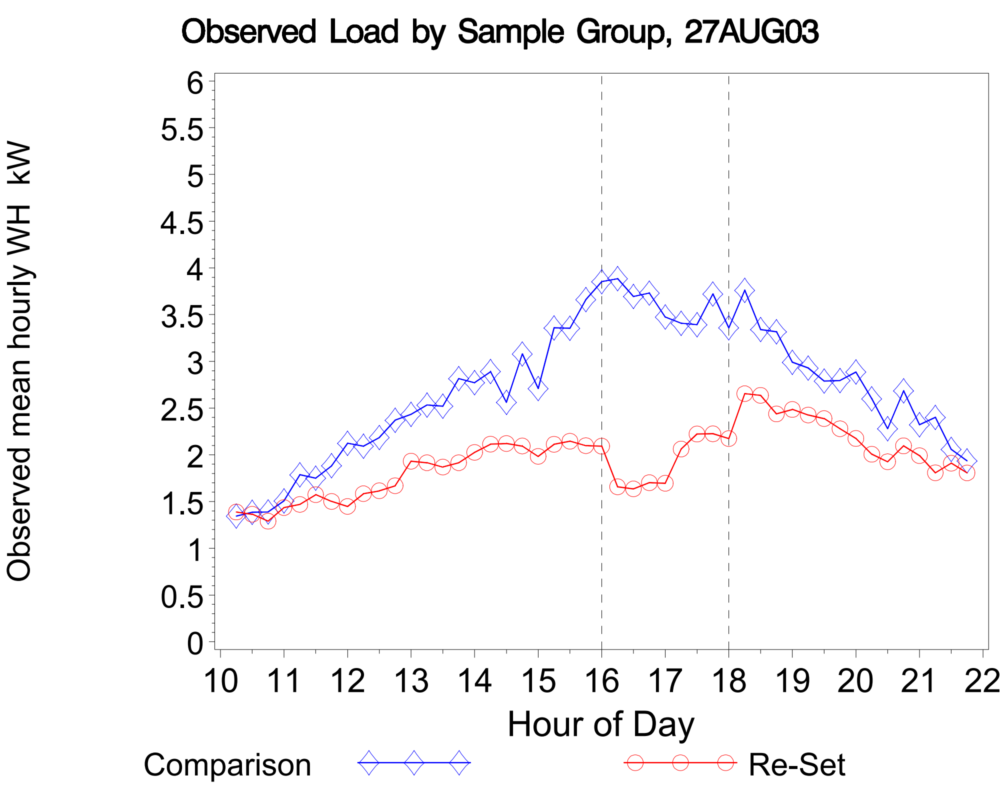

Observed Load by Sample Group, 15AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

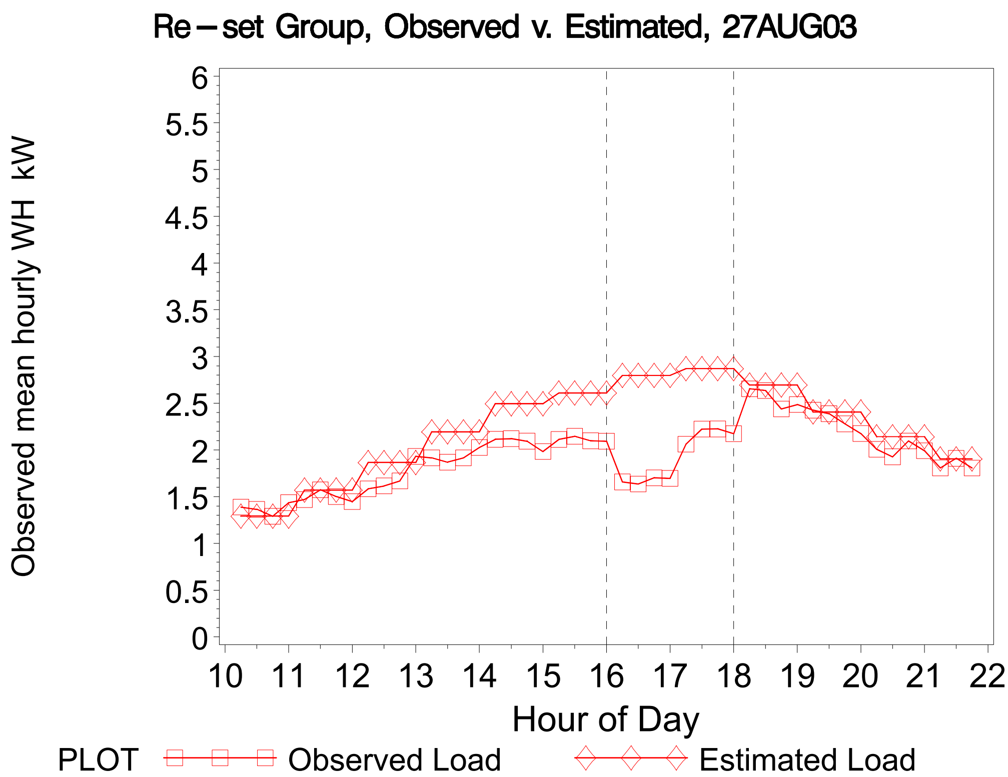

Re-set Group, Observed v. Estimated, 15AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

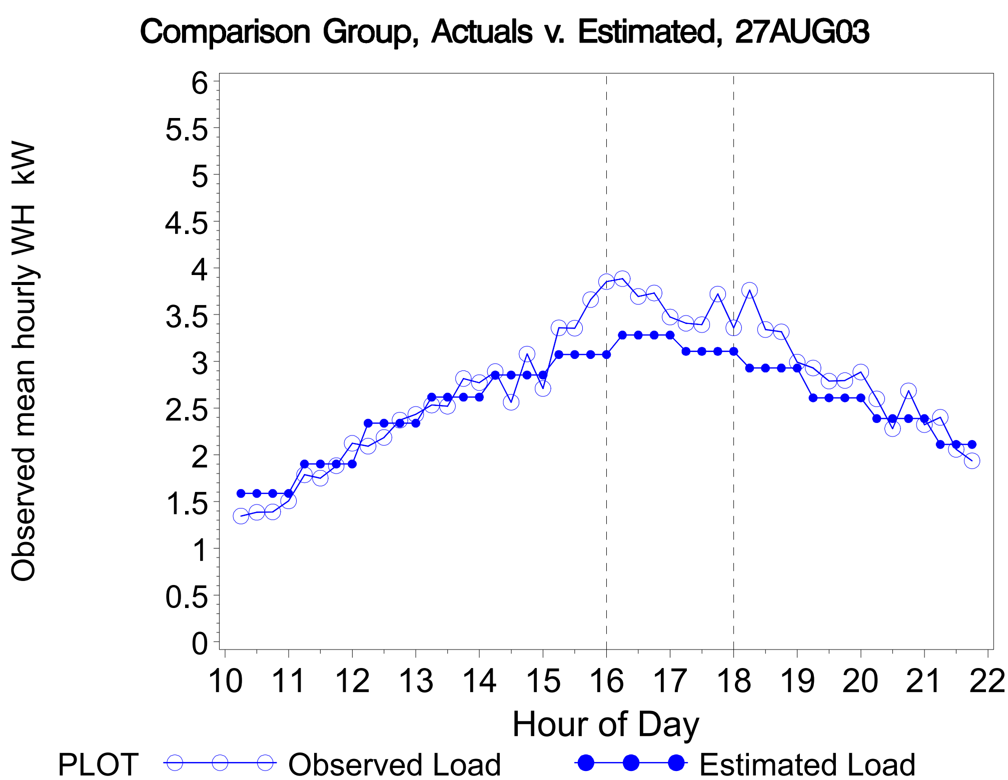

Comparison Group, Actuals v. Estimated, 15AUG03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10
11
12
13
14
15
16
17
18
19
20
21
22
Hour of Day
PLOT
Observed Load
Estimated Load

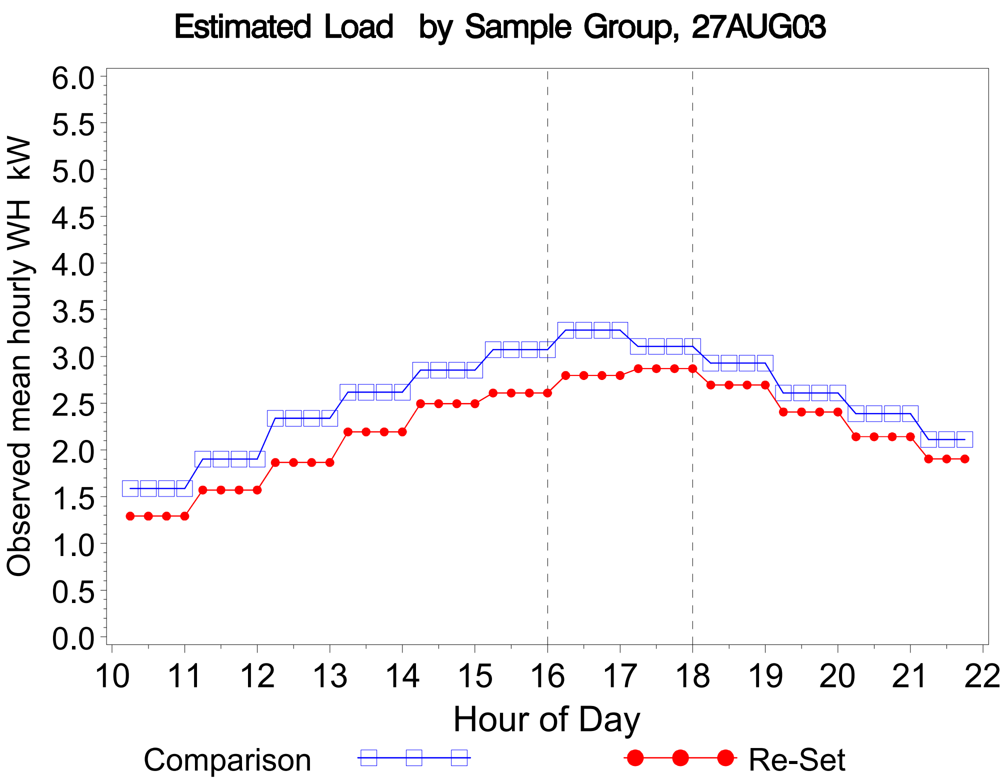

Estimated Load by Sample Group, 15AUG03
Observed mean hourly WH kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
10
11
12
13
14
15
16
17
18
19
20
21
22
Hour of Day
Comparison
Re-Set

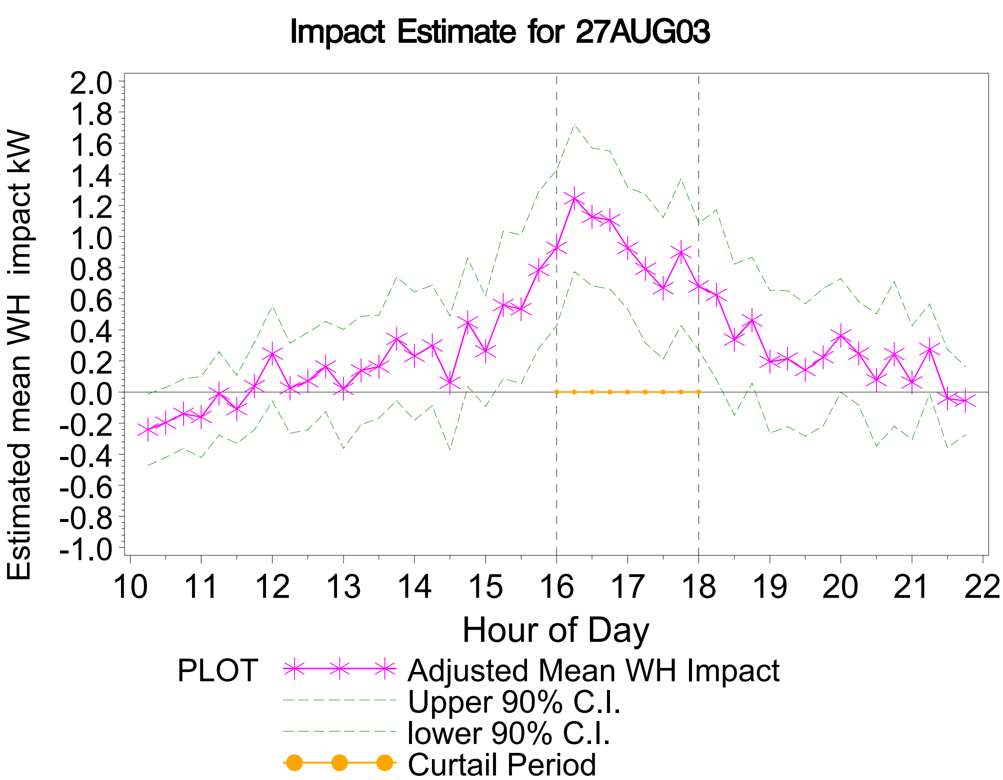

Impact Estimate for 15AUG03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

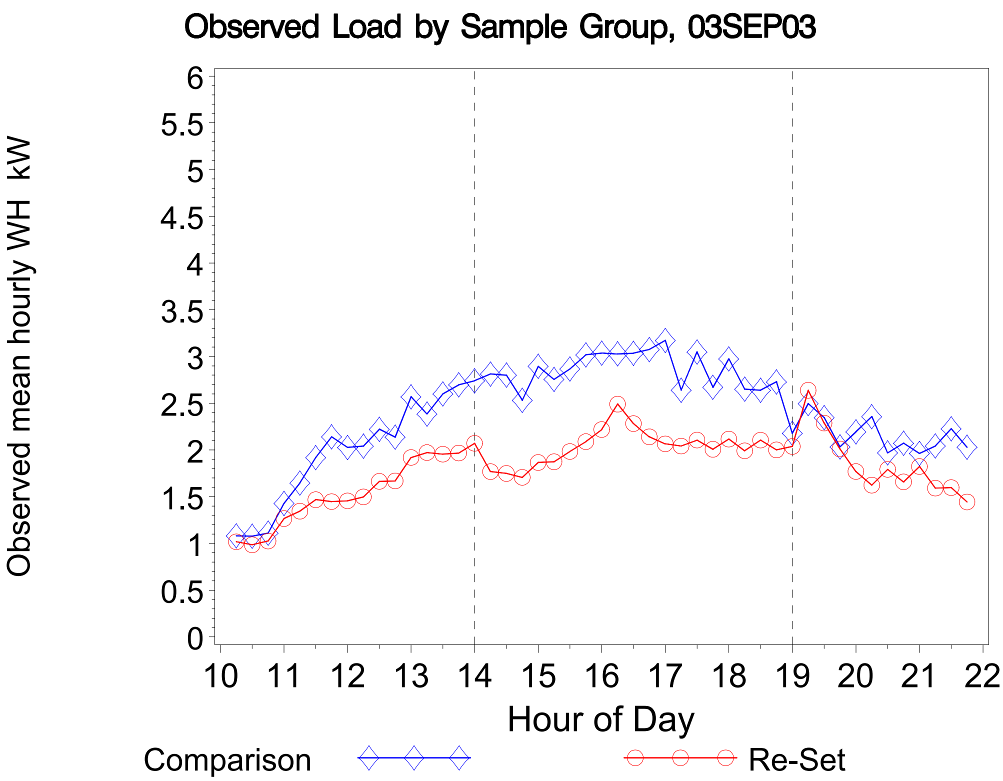

Observed Load by Sample Group, 27AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

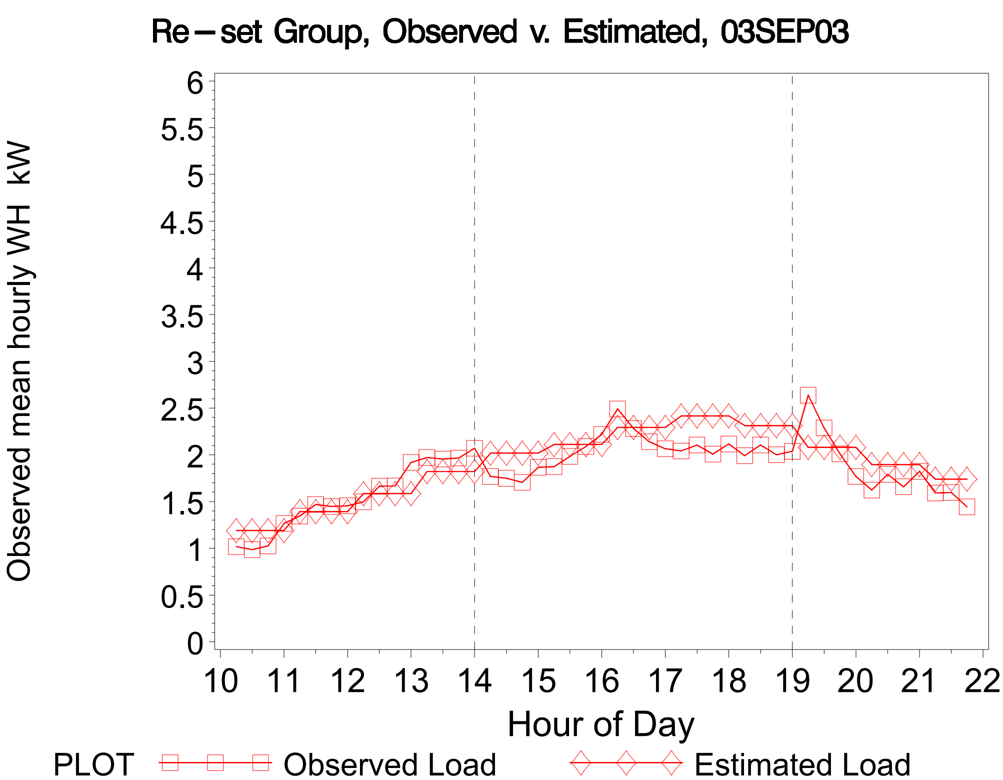

Re−set Group, Observed v. Estimated, 27AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

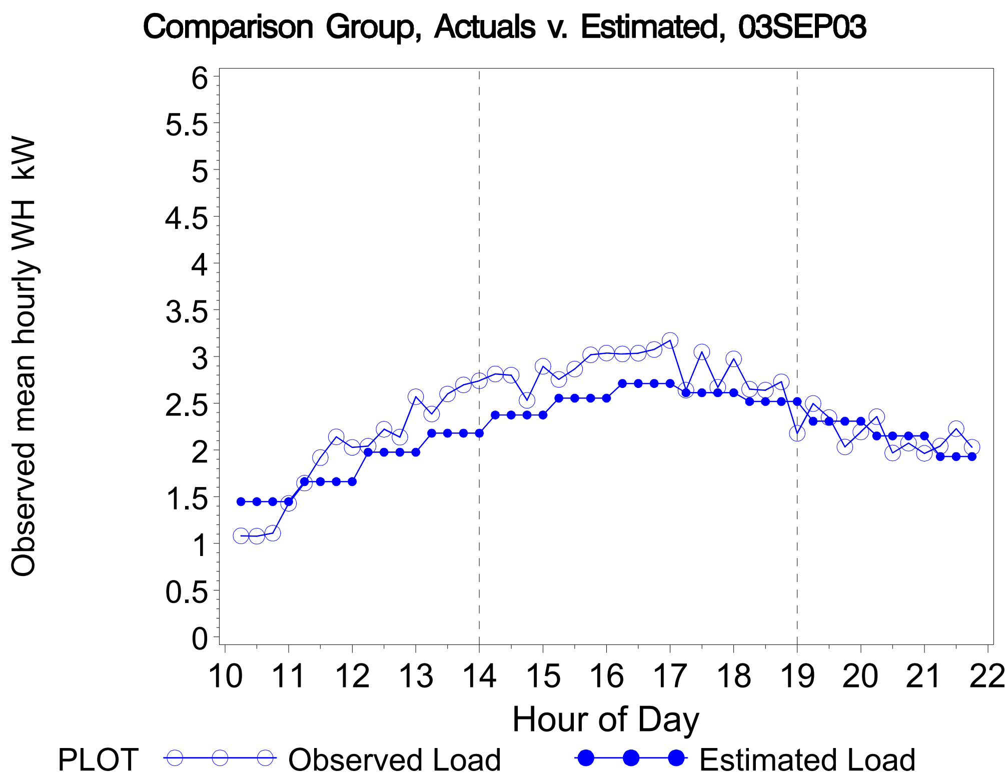

Comparison Group, Actuals v. Estimated, 27AUG03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

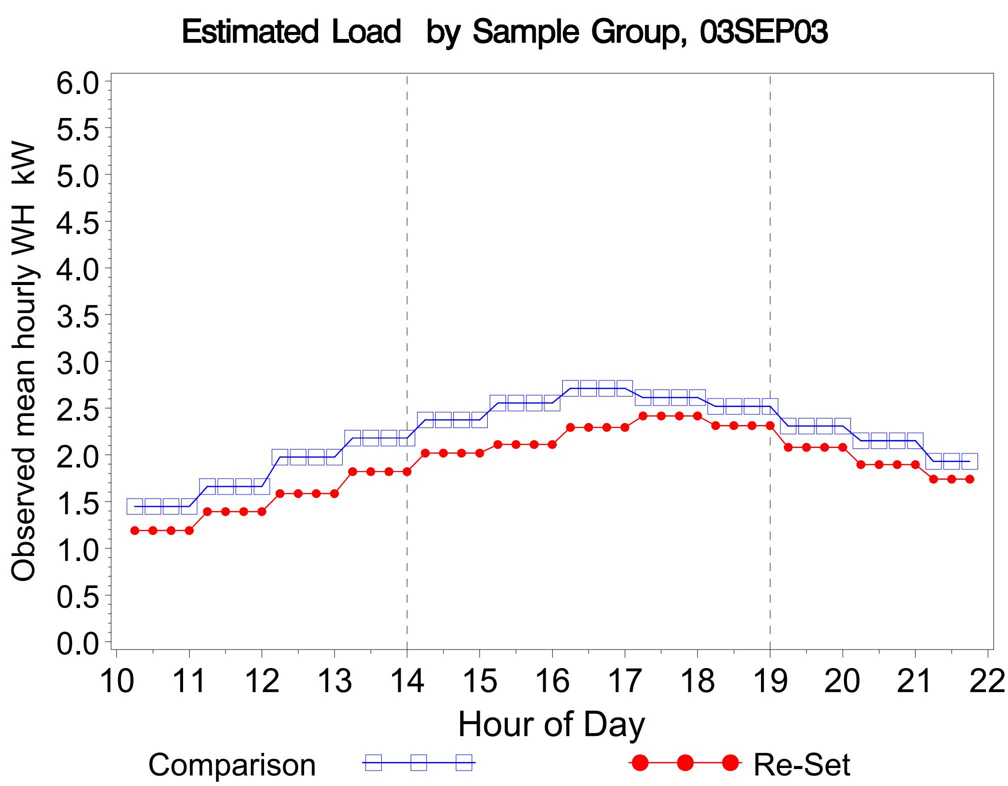

Estimated Load by Sample Group, 27AUG03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

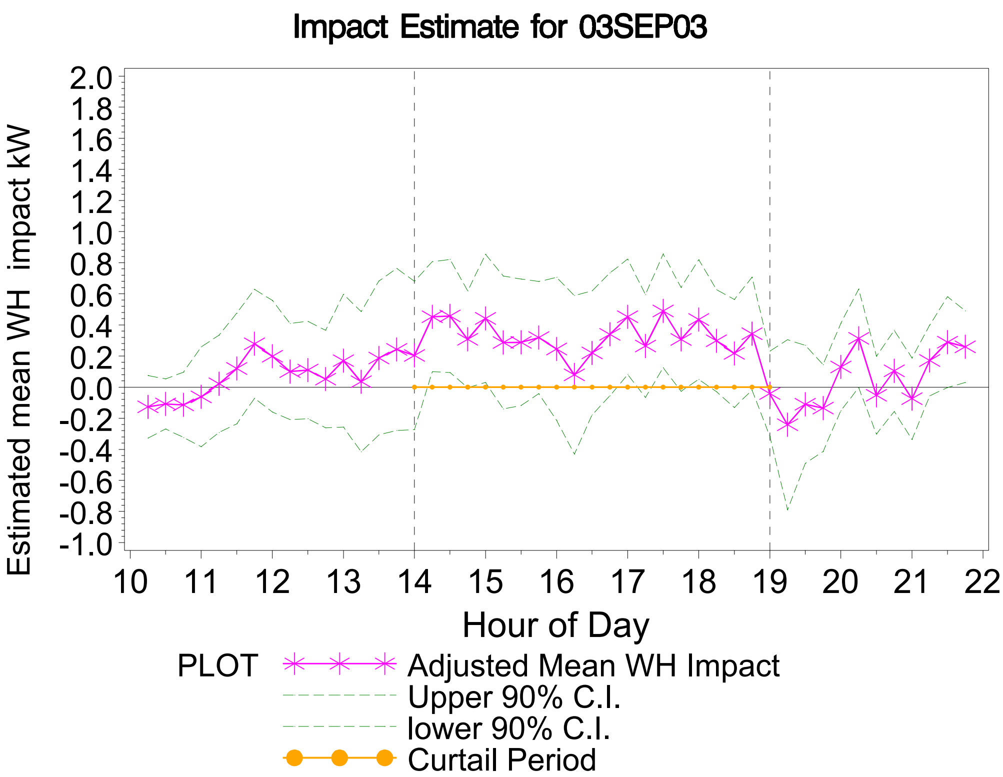

Impact Estimate for 27AUG03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

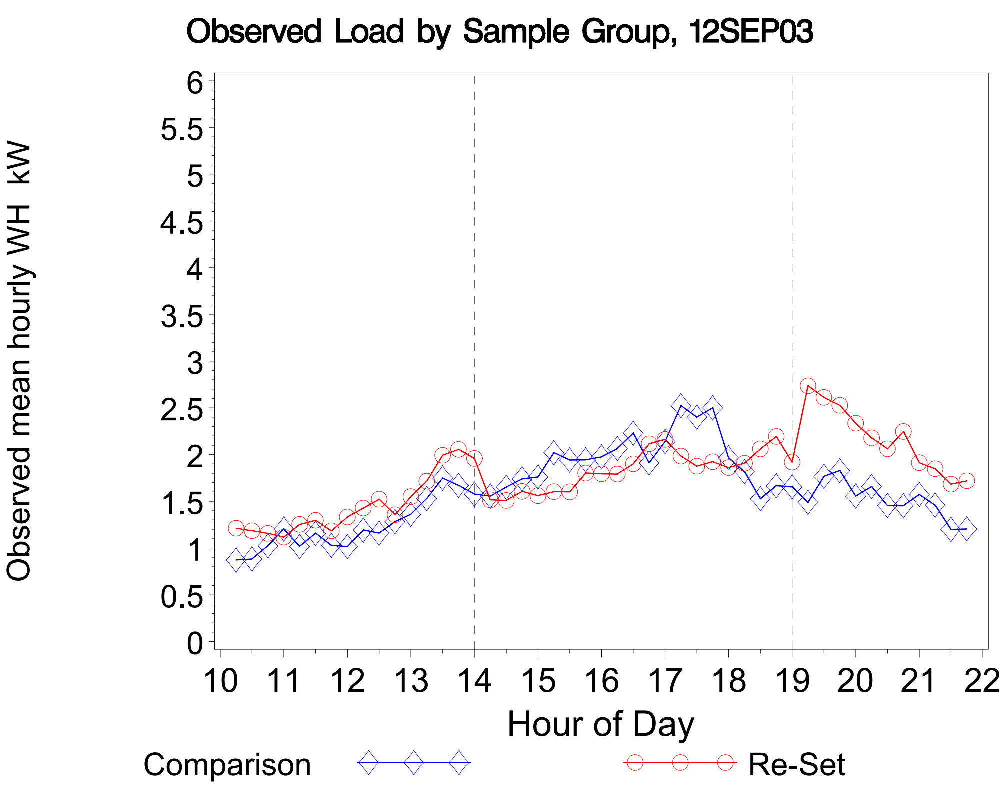

Observed Load by Sample Group, 03SEP03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

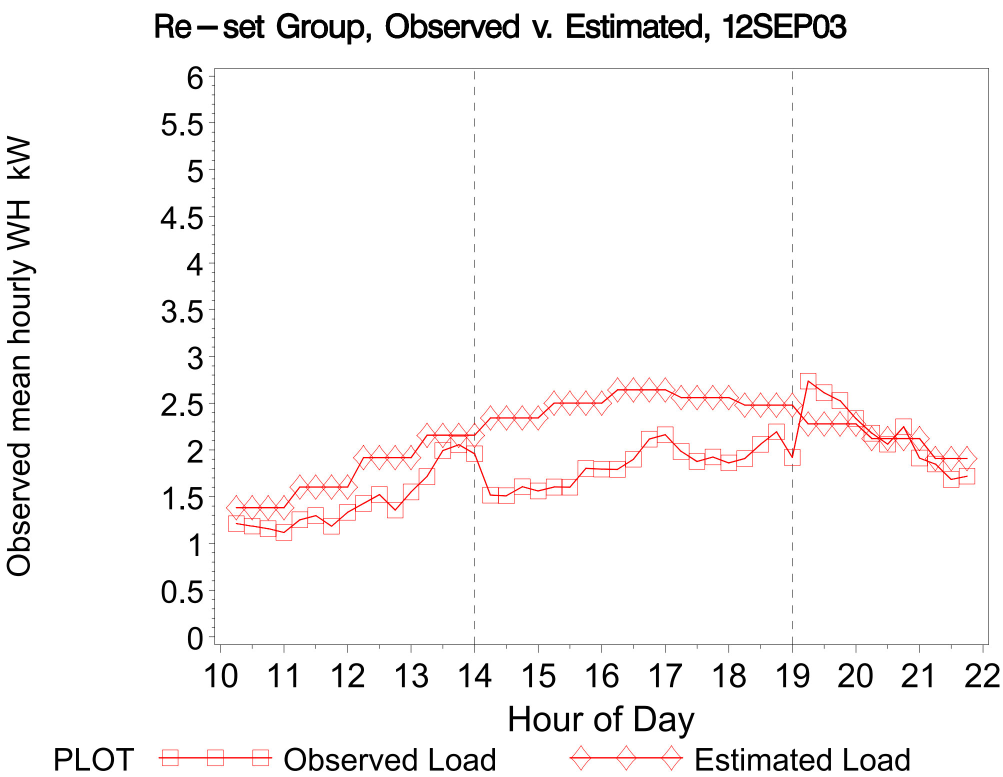

Re-set Group, Observed v. Estimated, 03SEP03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

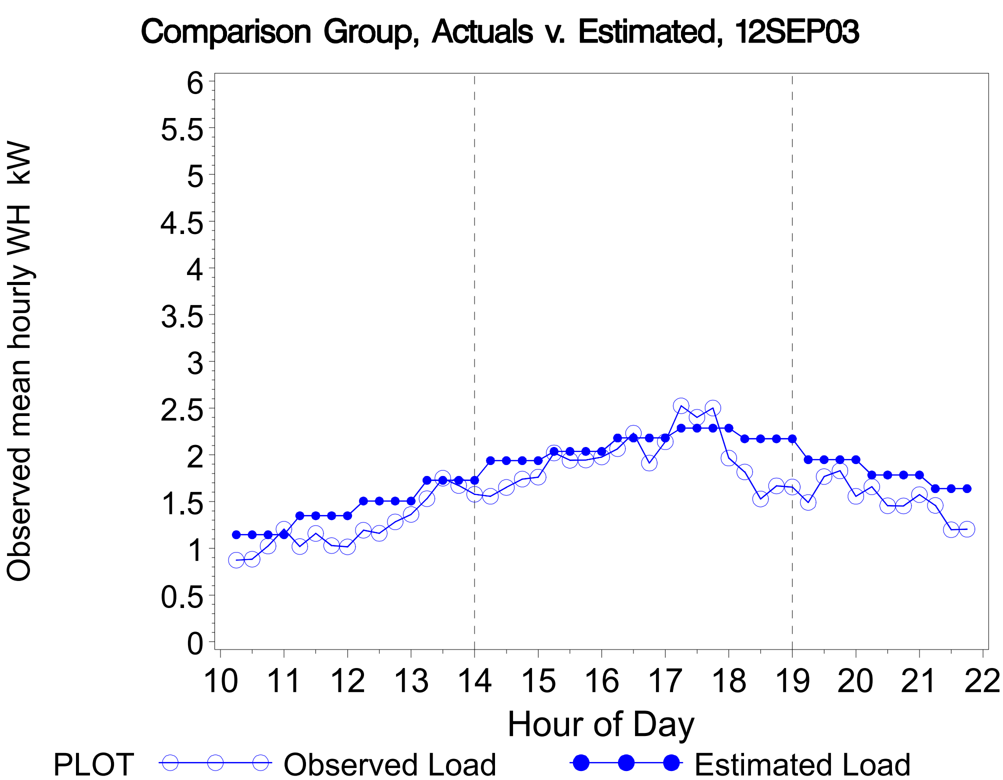

Comparison Group, Actuals v. Estimated, 03SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

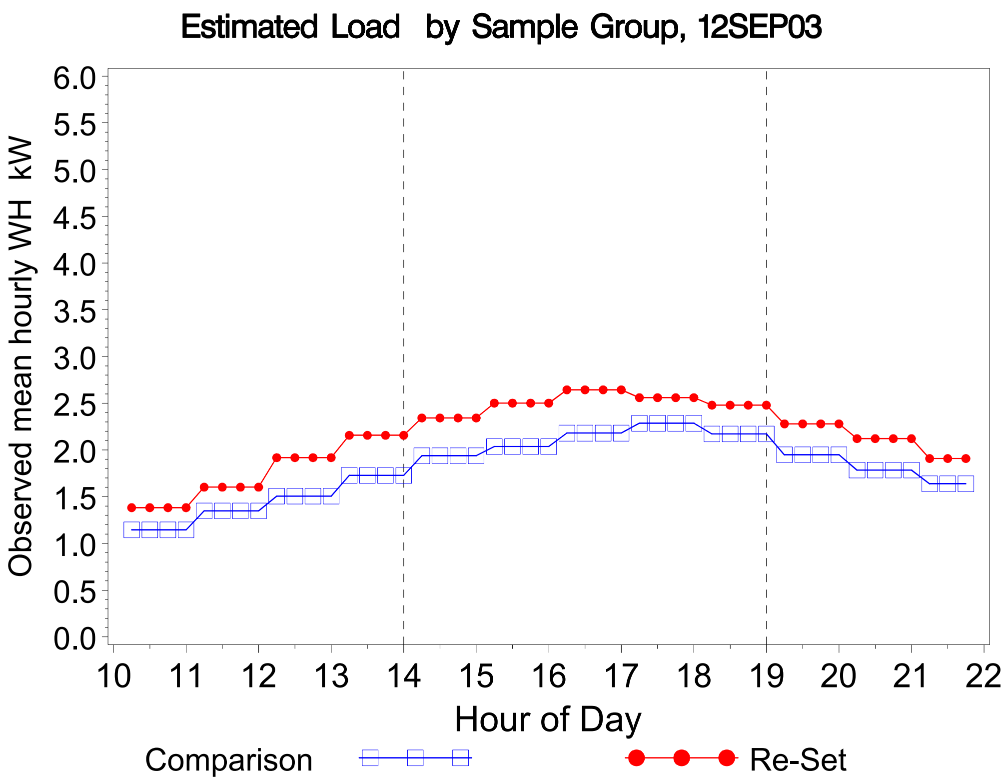

Estimated Load by Sample Group, 03SEP03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

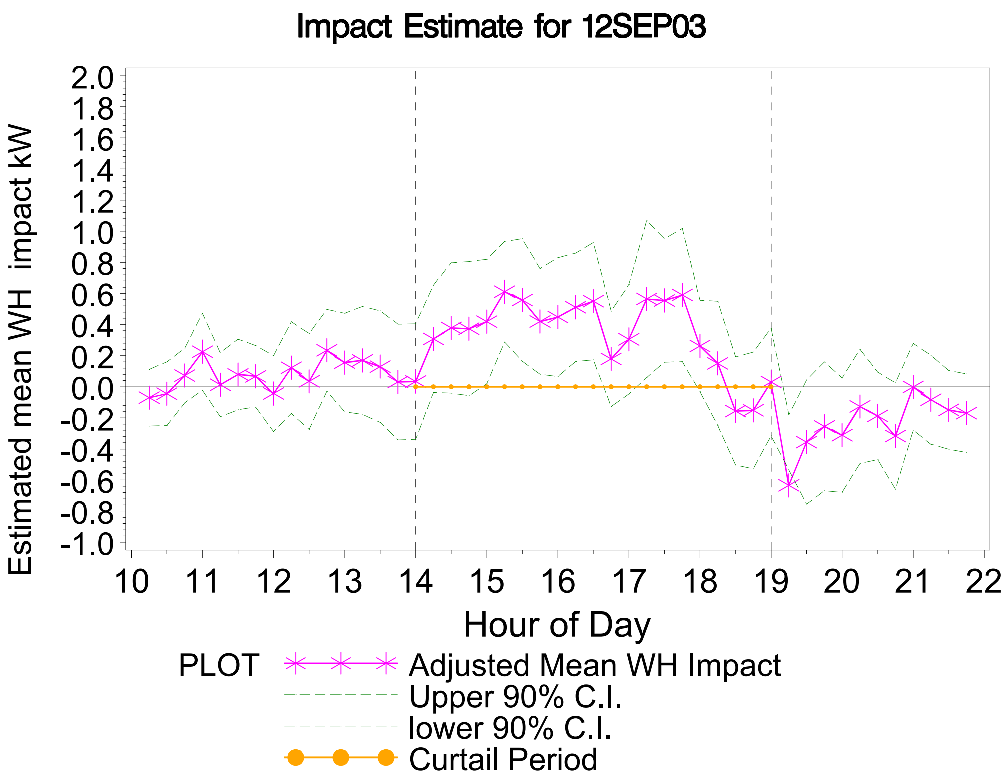

Impact Estimate for 03SEP03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

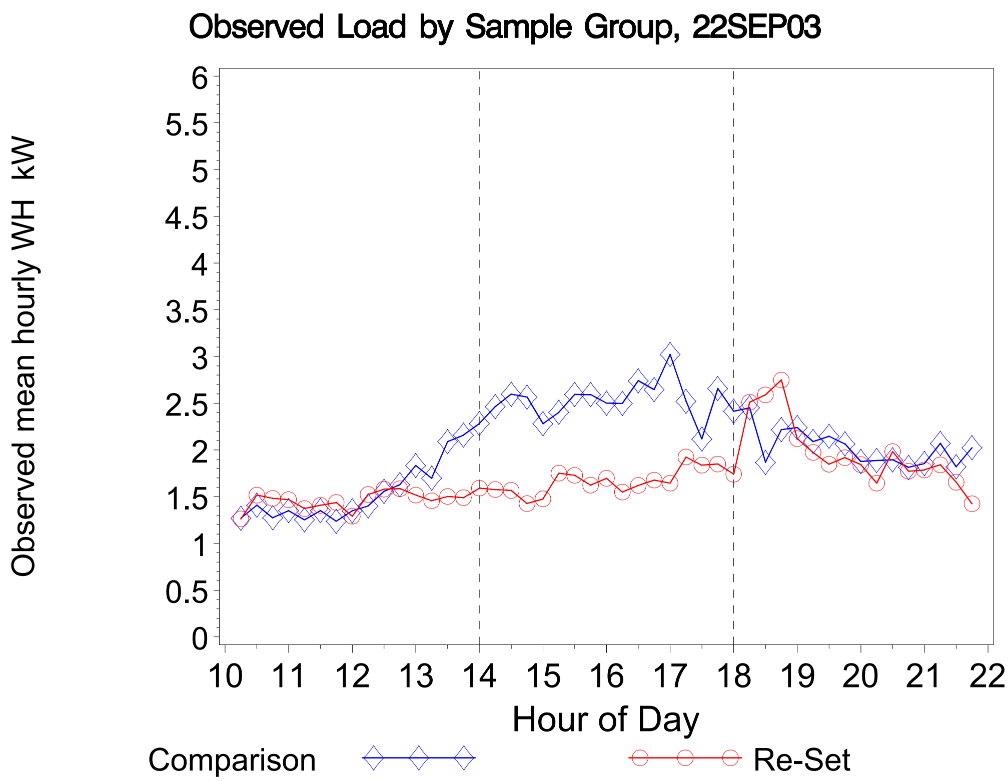

Observed Load by Sample Group, 12SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

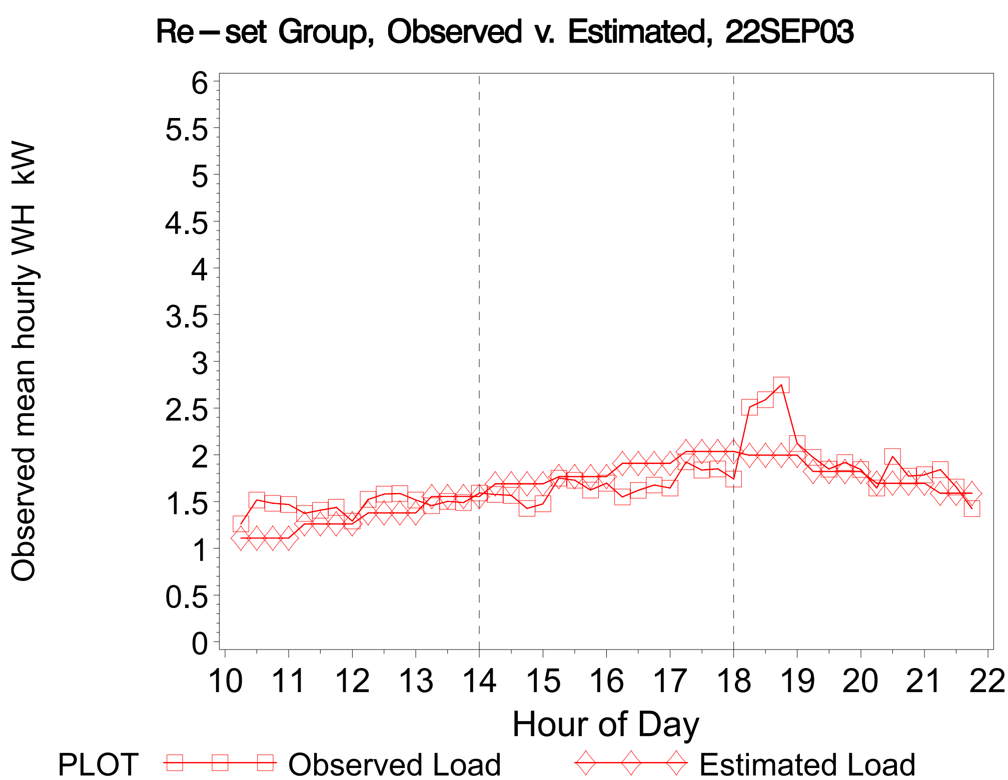

Re – set Group, Observed v. Estimated, 12SEP03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

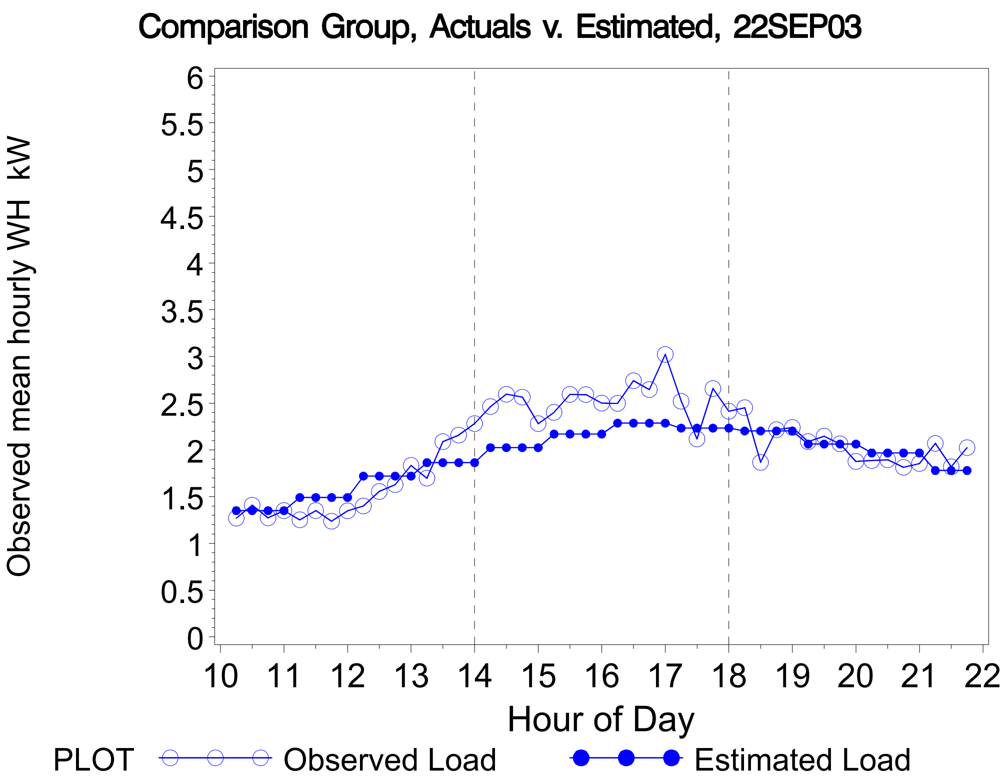

Comparison Group, Actuals v. Estimated, 12SEP03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

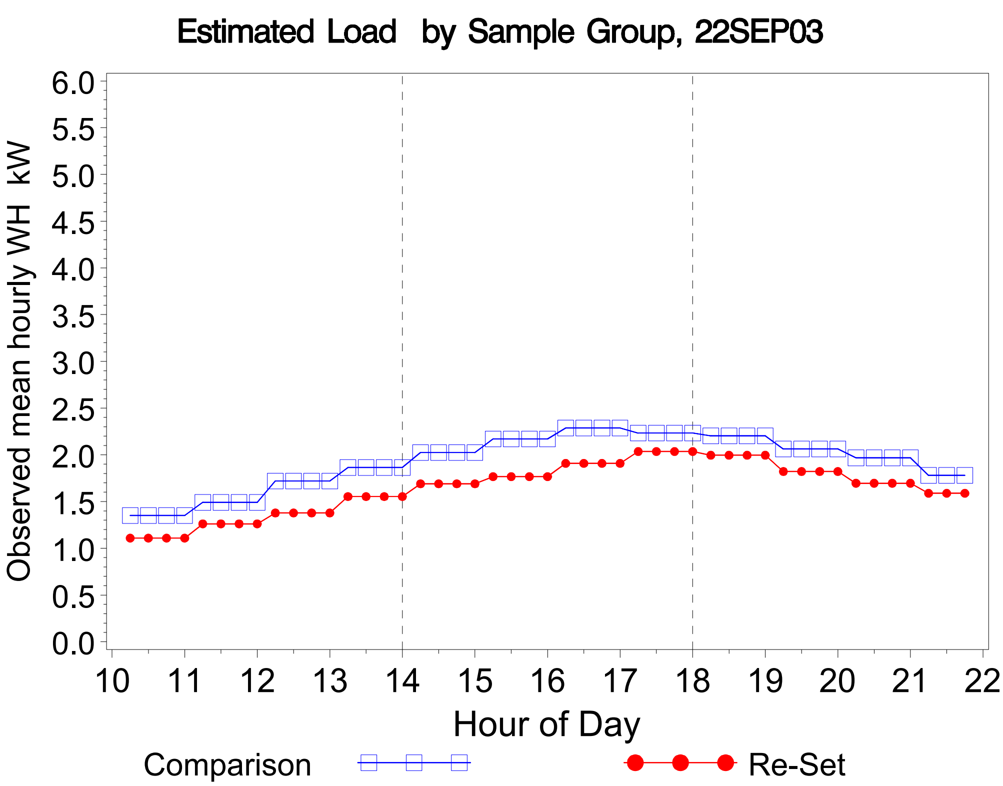

Estimated Load by Sample Group, 12SEP03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

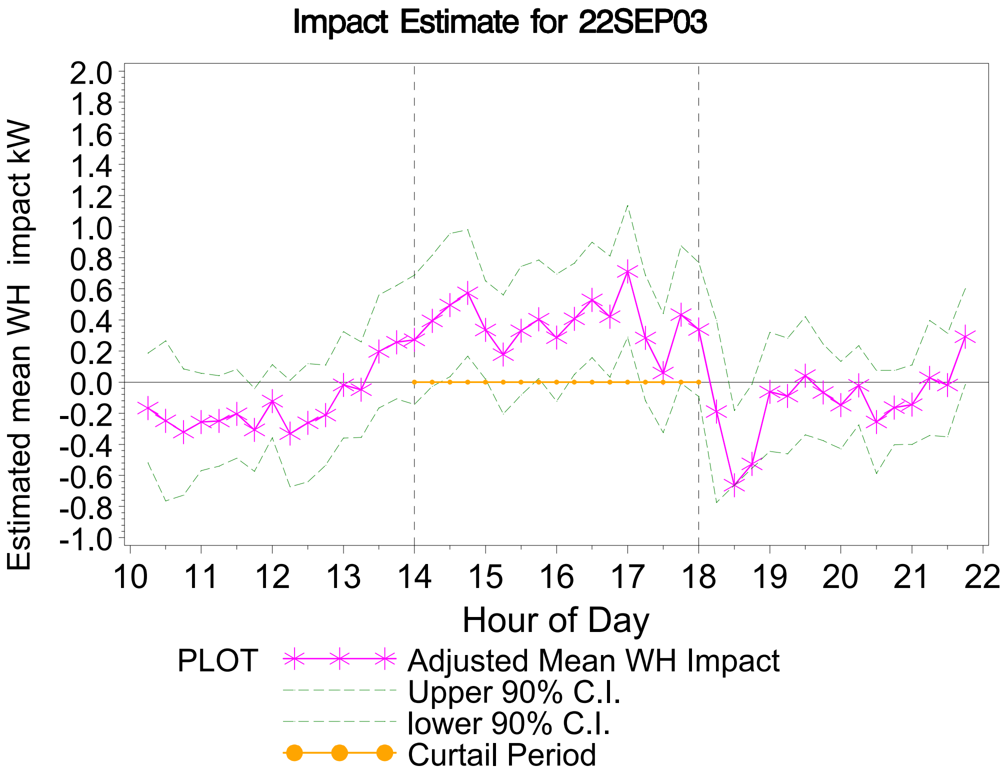

Impact Estimate for 12SEP03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

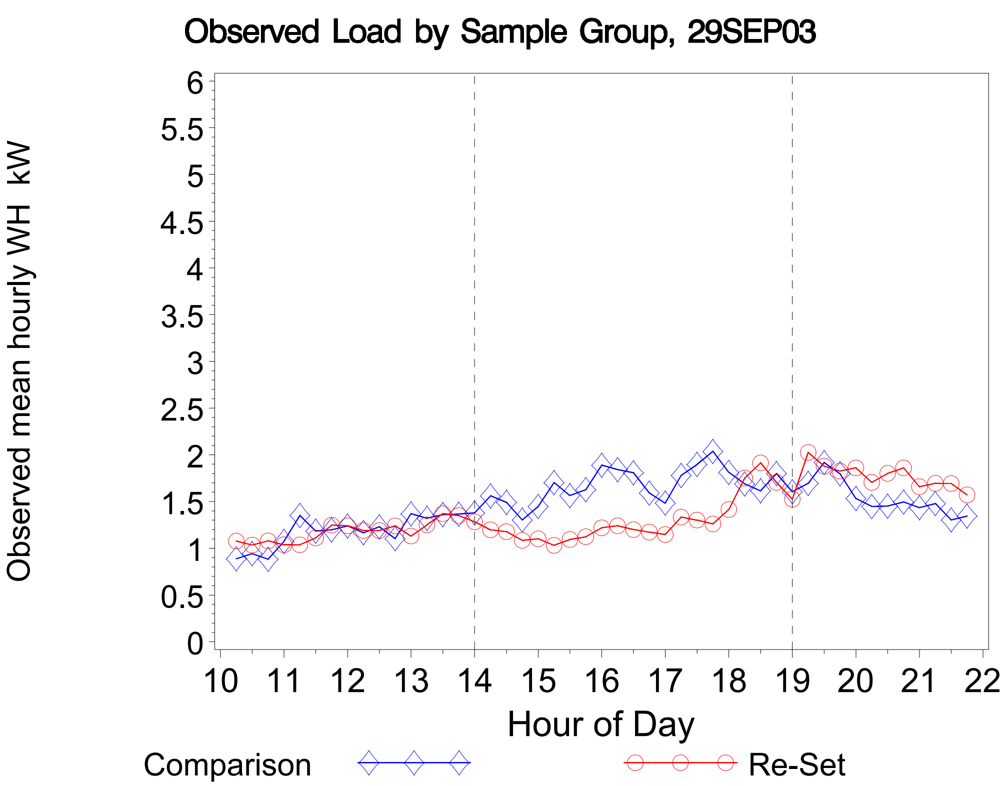

Observed Load by Sample Group, 22SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

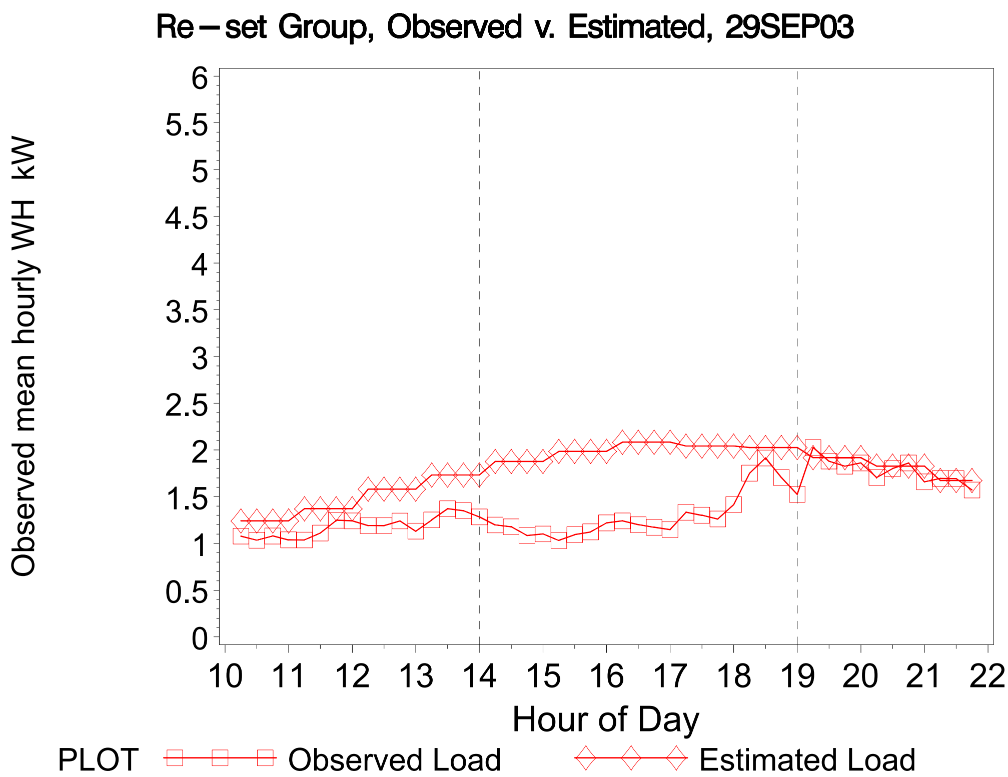

Re-set Group, Observed v. Estimated, 22SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

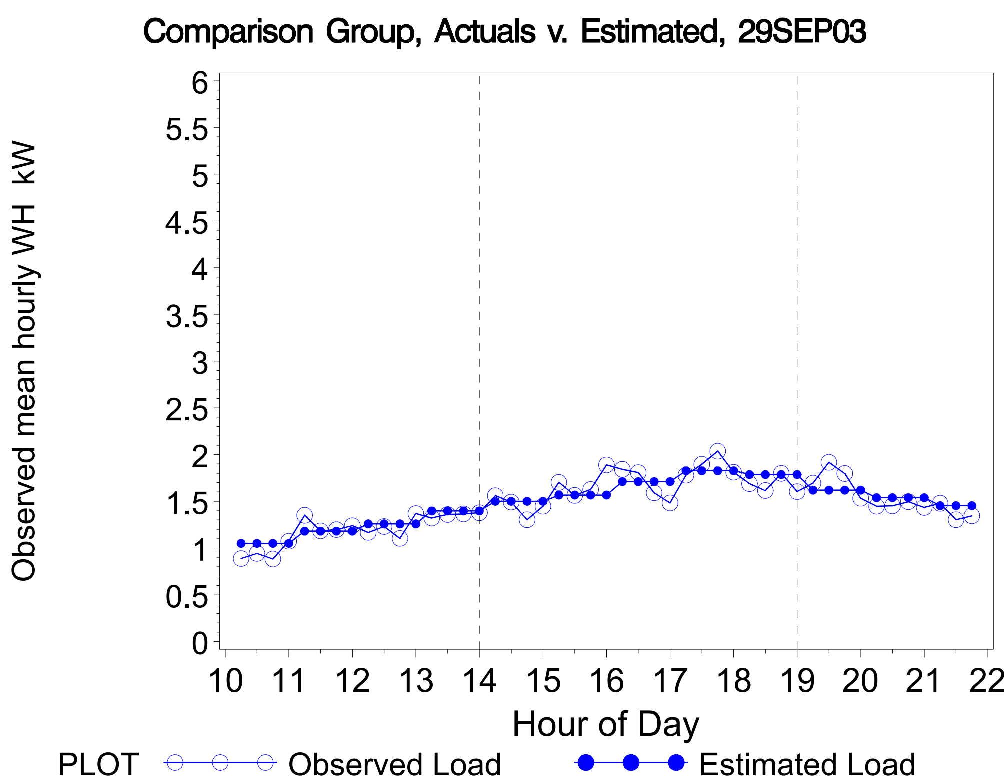

Comparison Group, Actuals v. Estimated, 22SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

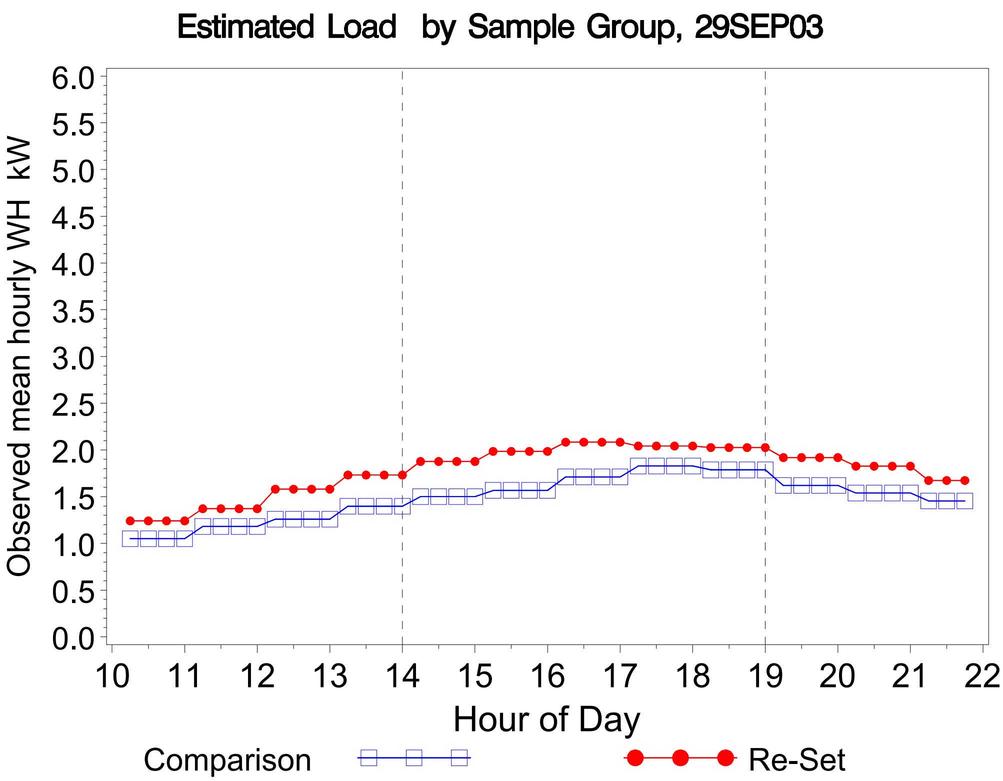

Estimated Load by Sample Group, 22SEP03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

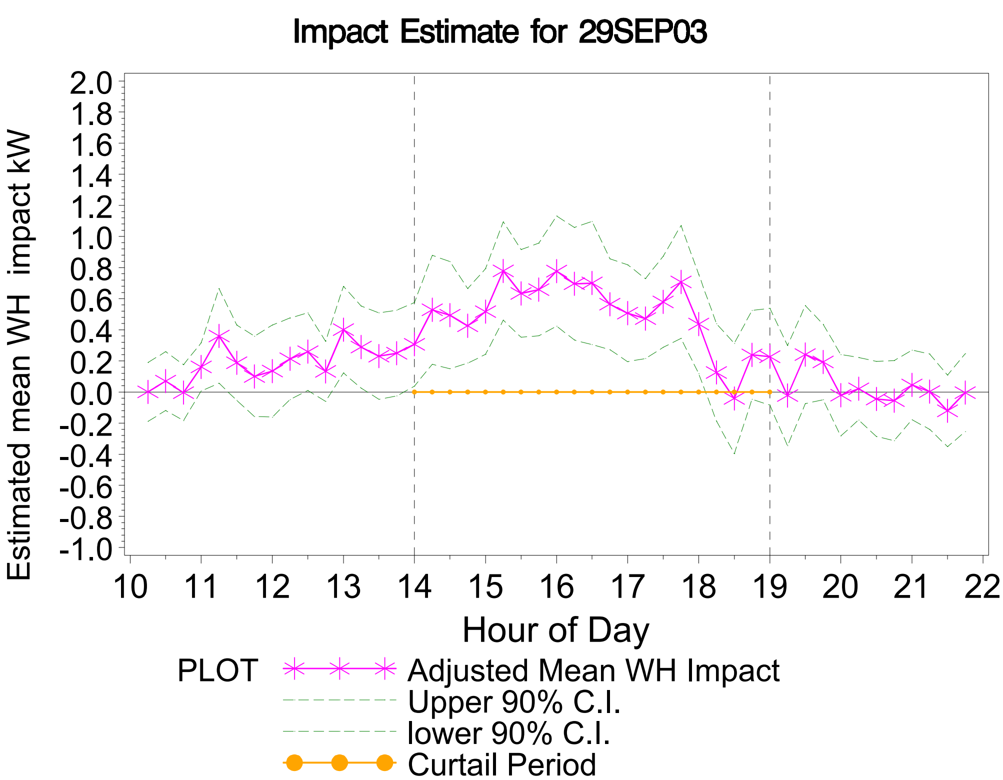

Impact Estimate for 22SEP03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

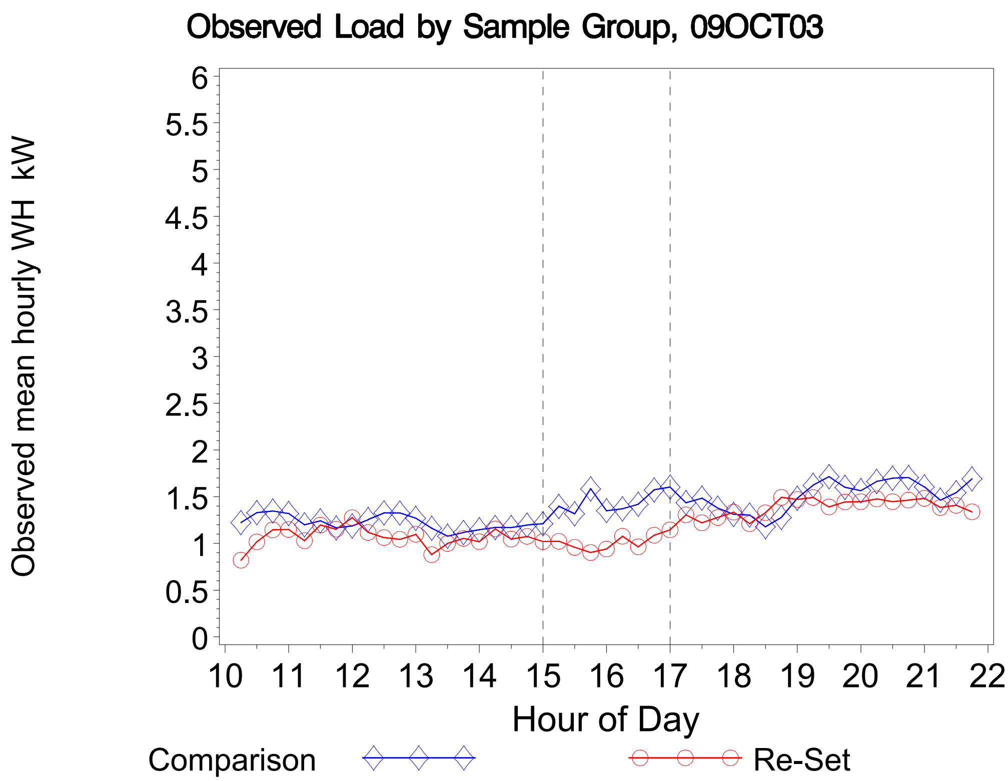

Observed Load by Sample Group, 29SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

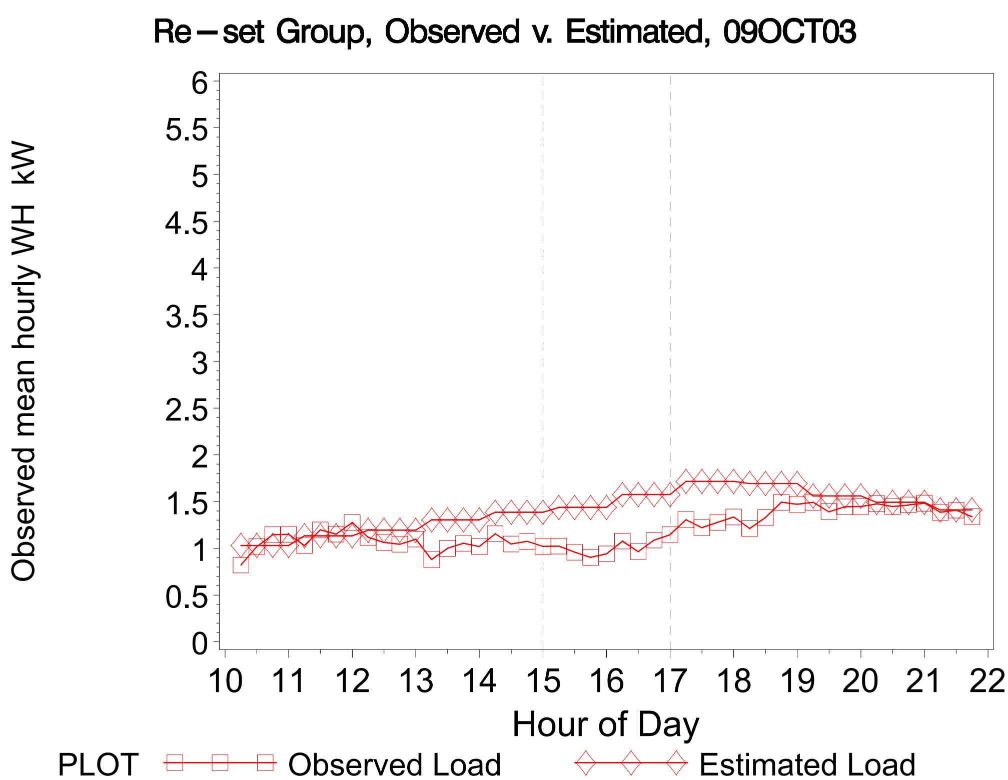

Re-set Group, Observed v. Estimated, 29SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

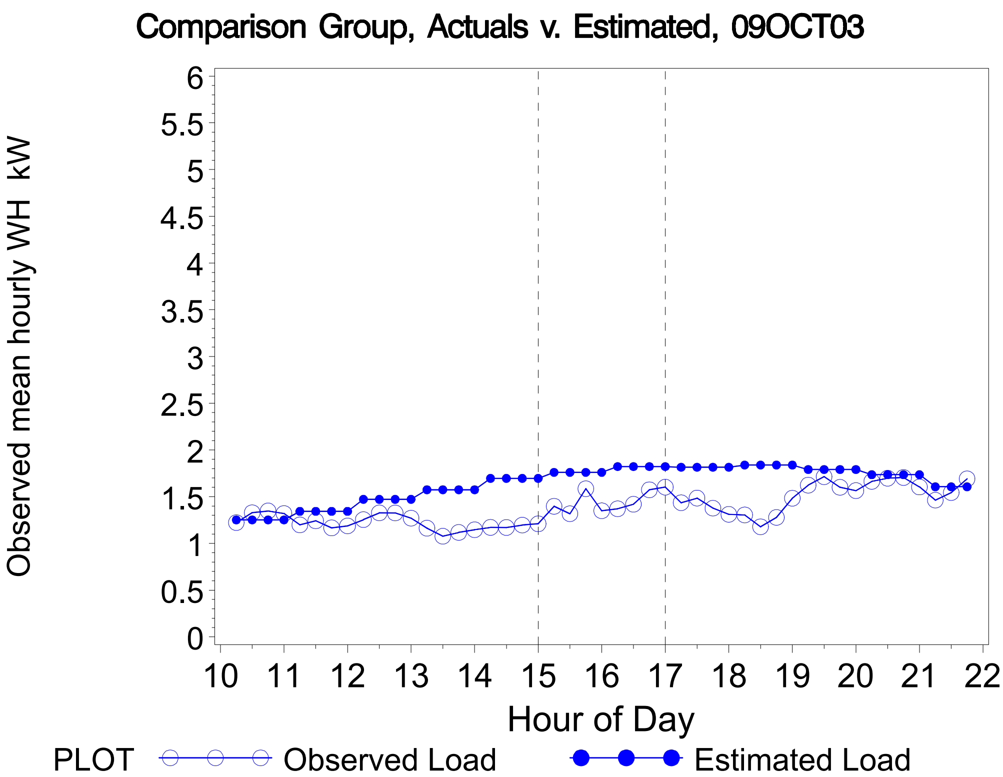

Comparison Group, Actuals v. Estimated, 29SEP03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

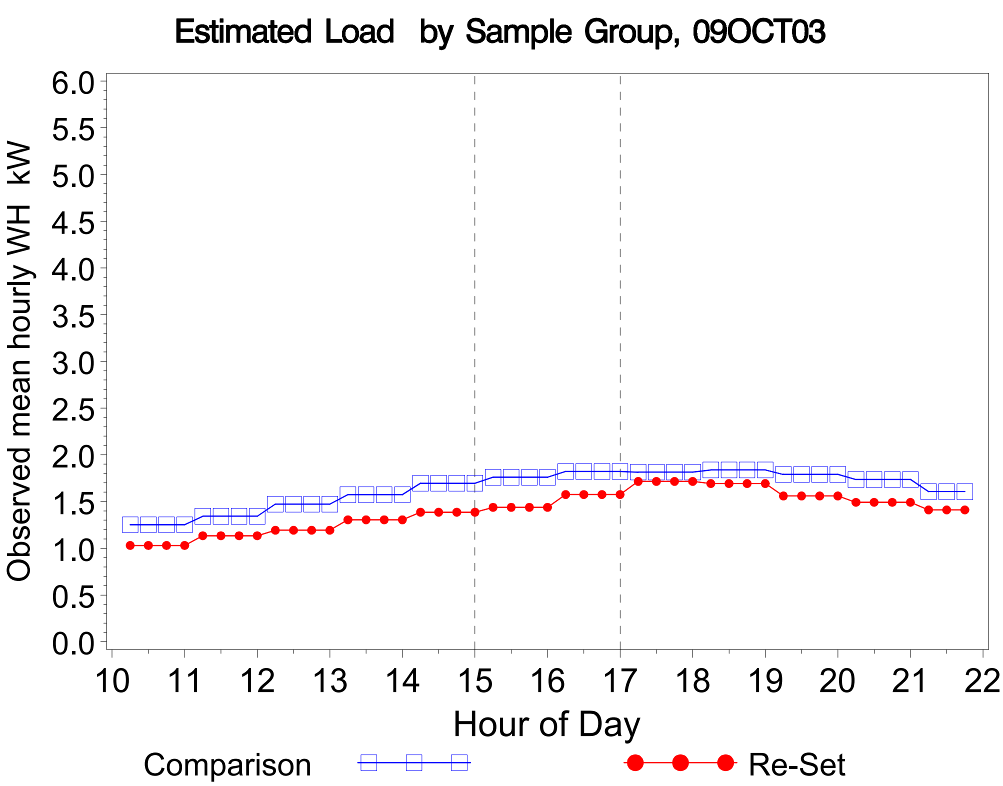

Estimated Load by Sample Group, 29SEP03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

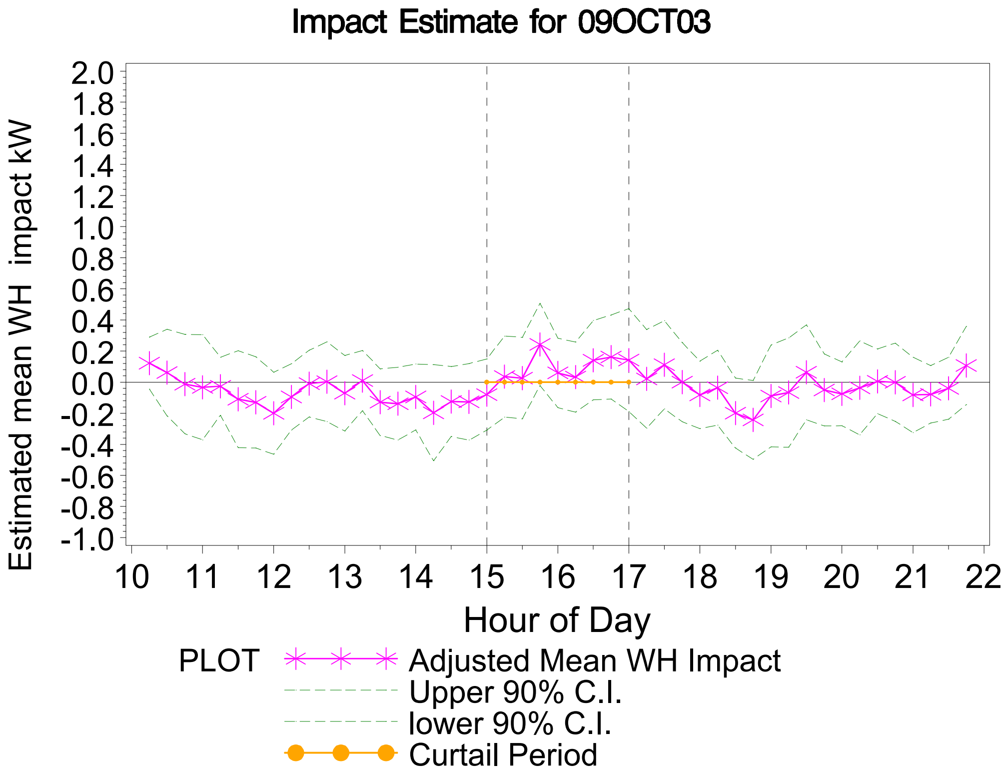

Impact Estimate for 29SEP03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

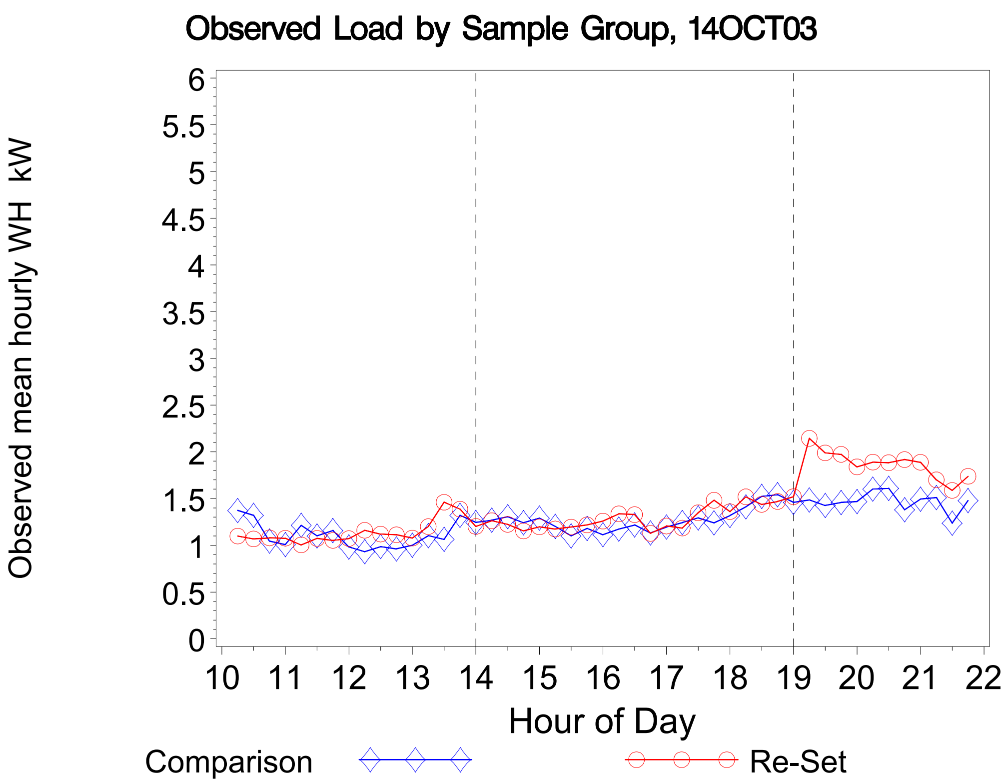

Observed Load by Sample Group, 09OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

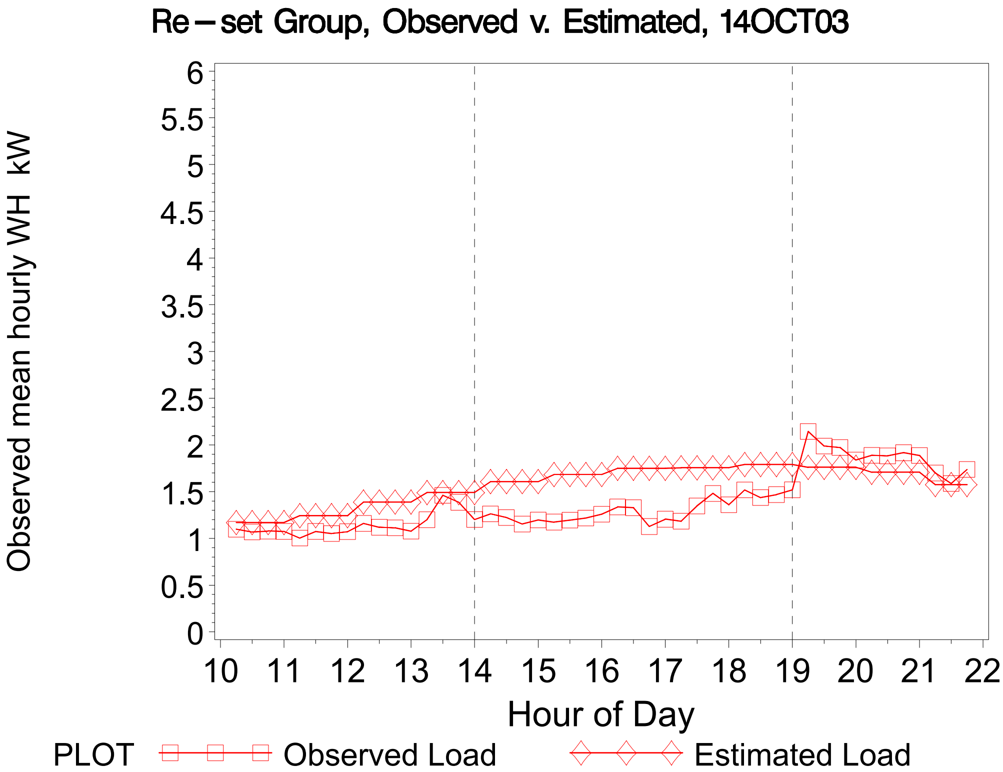

Re−set Group, Observed v. Estimated, 09OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

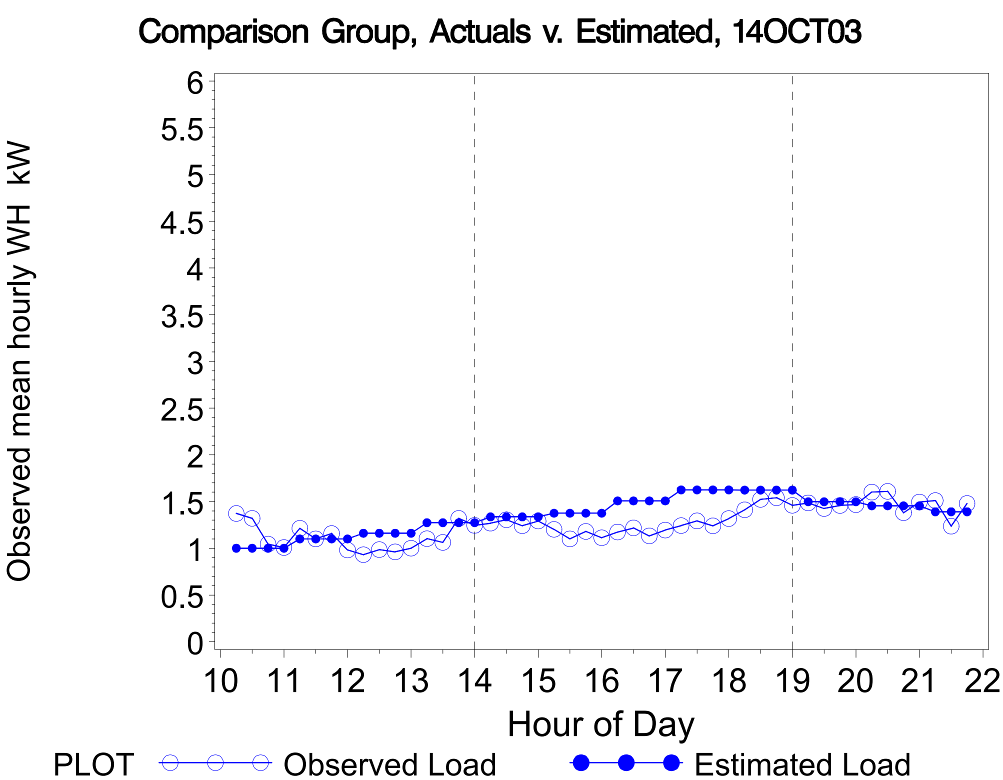

Comparison Group, Actuals v. Estimated, 09OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

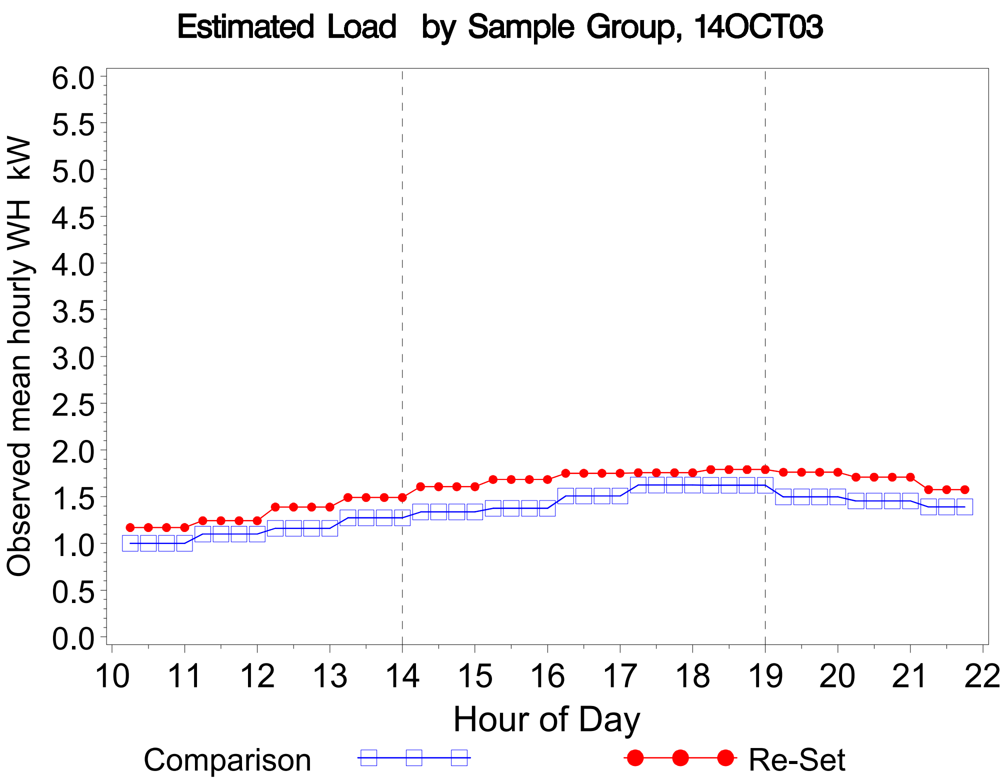

Estimated Load by Sample Group, 09OCT03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

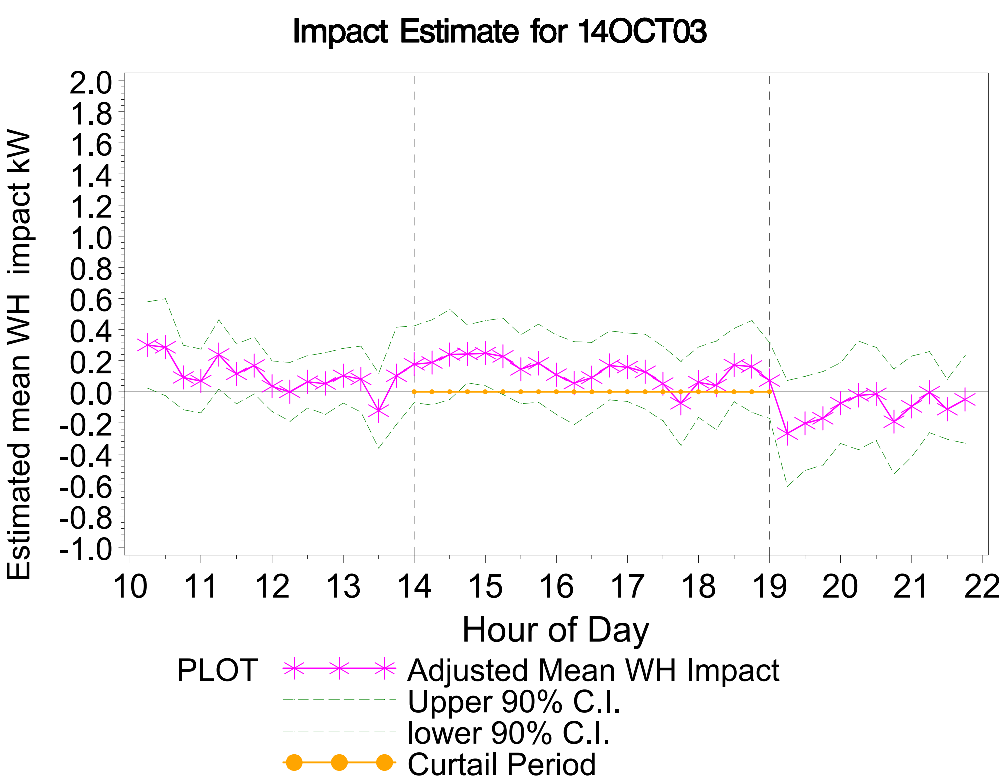

Impact Estimate for 09OCT03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

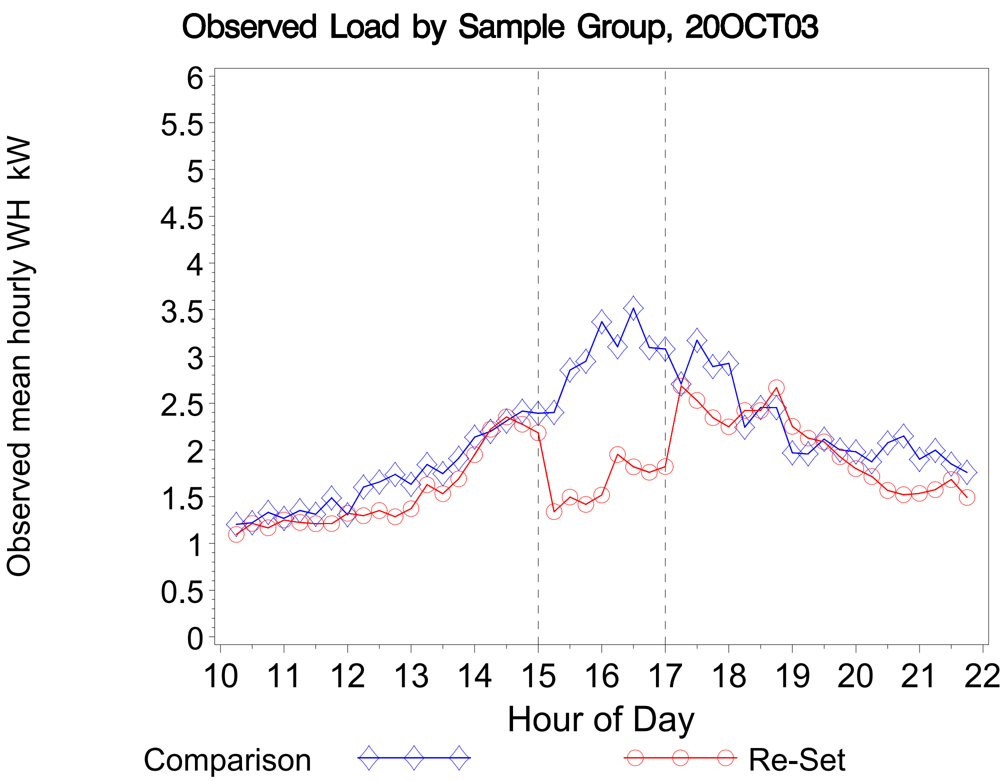

Observed Load by Sample Group, 14OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

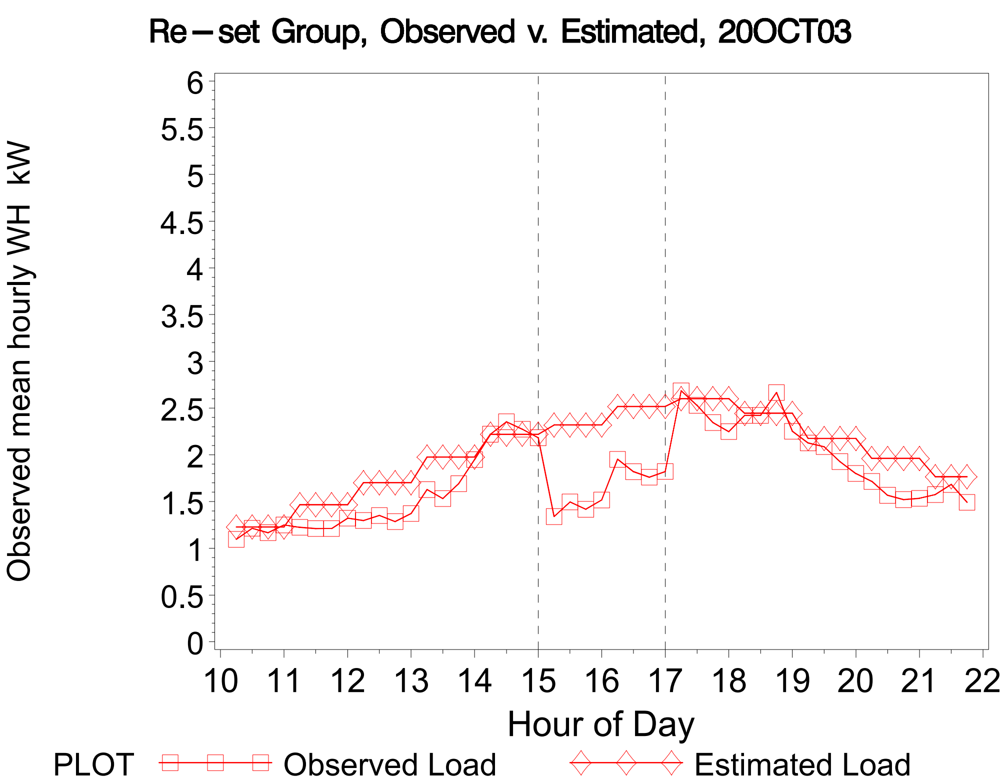

Re – set Group, Observed v. Estimated, 14OCT03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 14OCT03
Observed mean hourly WH kW
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

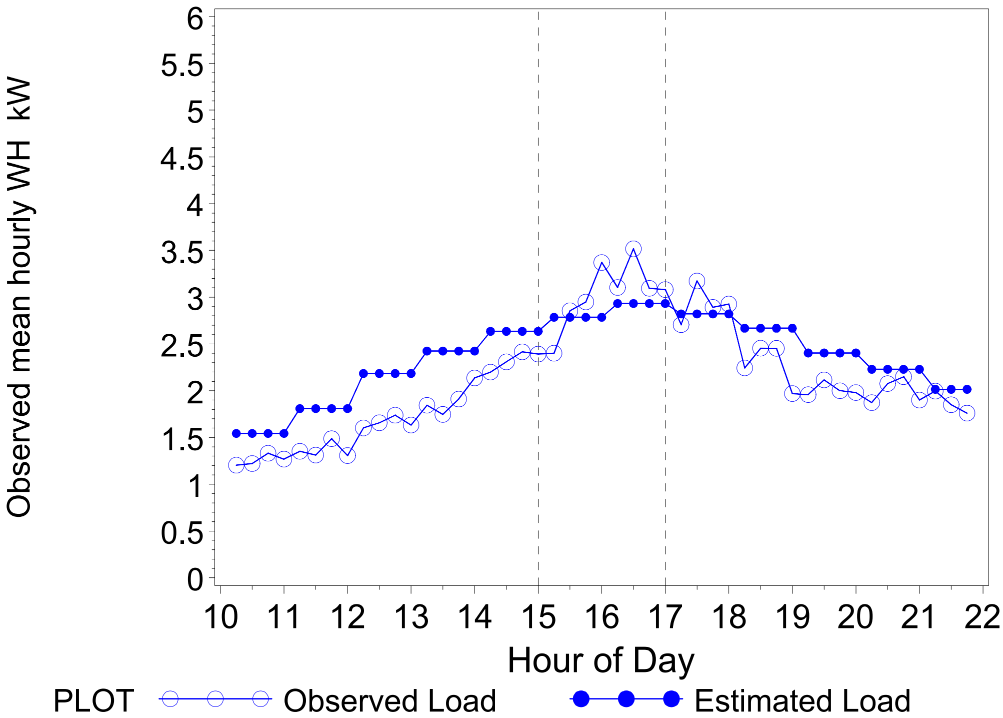

Estimated Load by Sample Group, 14OCT03
Observed mean hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set


Impact Estimate for 14OCT03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

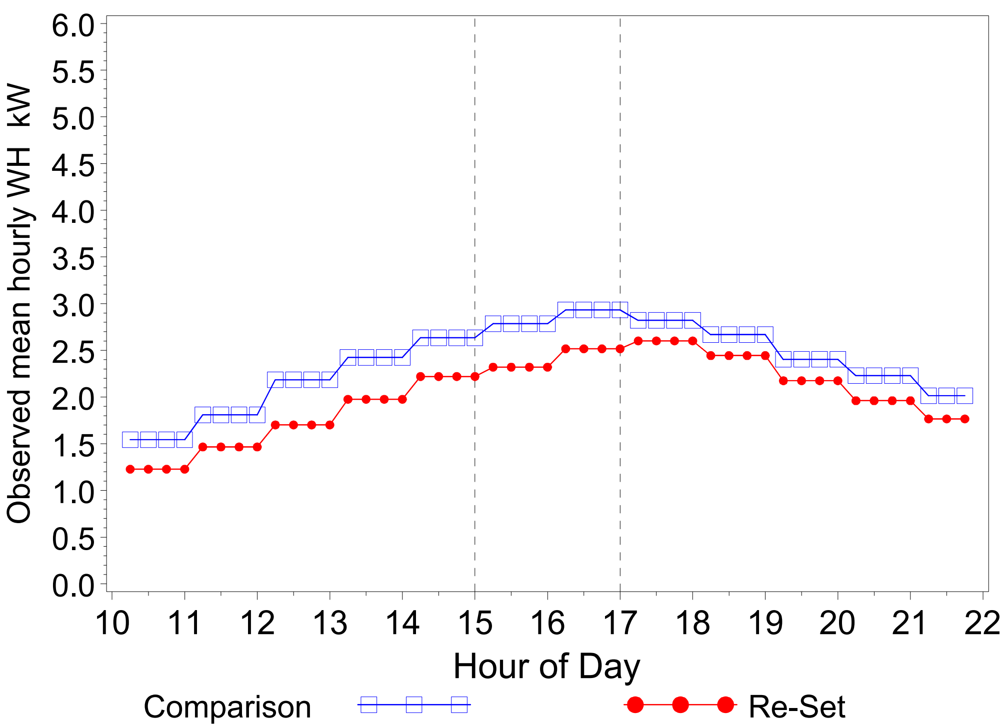

Observed Load by Sample Group, 20OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Comparison
Re-Set

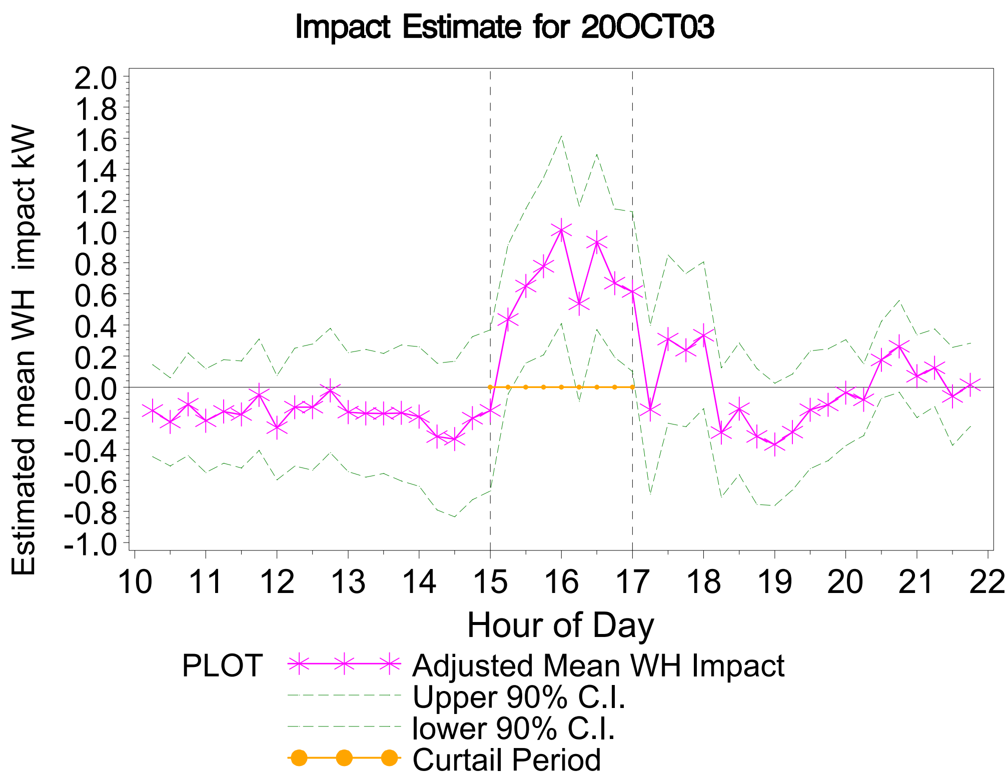

Re–set Group, Observed v. Estimated, 20OCT03
Observed mean hourly WH kW
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

Comparison Group, Actuals v. Estimated, 20OCT03



Estimated Load by Sample Group, 20OCT03




Impact Estimate for 20OCT03
Estimated mean WH impact kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Adjusted Mean WH Impact
Upper 90% C.I.
lower 90% C.I.
Curtail Period

C

UNADJUSTED PROJECTED SAVINGS PER UNIT

These tables show results for potential contributors only. These are units that respond to the re-set, do not over-ride, and have non-zero AC use over the course of the summer. After a re-set event has occurred, these unadjusted results can be adjusted based on actual re-set day response and over-ride rates and an assumed zero AC use percent.

Table C-1
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 1°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.01	0.02	0.02	0.03	0.03	0.02	0.02
66	0.01	0.01	0.02	0.03	0.04	0.04	0.04	0.03
67	0.01	0.03	0.04	0.05	0.05	0.06	0.06	0.05
68	0.03	0.04	0.06	0.07	0.08	0.09	0.08	0.06
69	0.04	0.07	0.09	0.11	0.12	0.13	0.12	0.11
70	0.06	0.08	0.10	0.12	0.14	0.15	0.14	0.12
71	0.06	0.08	0.11	0.13	0.14	0.16	0.14	0.13
72	0.06	0.09	0.11	0.13	0.15	0.17	0.15	0.13
73	0.06	0.09	0.12	0.14	0.16	0.17	0.16	0.14
74	0.06	0.10	0.13	0.15	0.17	0.18	0.17	0.15
75	0.07	0.10	0.13	0.16	0.17	0.19	0.18	0.15
76	0.07	0.12	0.15	0.18	0.20	0.21	0.19	0.17
77	0.07	0.12	0.15	0.18	0.20	0.21	0.19	0.17
78	0.07	0.12	0.15	0.18	0.20	0.21	0.19	0.17
79	0.07	0.12	0.15	0.18	0.20	0.21	0.19	0.17
80	0.07	0.12	0.15	0.18	0.20	0.21	0.19	0.17
81	0.10	0.17	0.21	0.22	0.25	0.28	0.26	0.24
82	0.10	0.17	0.21	0.22	0.25	0.28	0.26	0.24
83	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
84	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
85	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
86	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
87	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
88	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
89	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
90	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
91	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
92	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
93	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
94	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24
95	0.10	0.17	0.21	0.22	0.25	0.28	0.27	0.24

Table C-2
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 2°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.03	0.04	0.05	0.06	0.07	0.06	0.05
67	0.02	0.04	0.06	0.08	0.09	0.10	0.09	0.08
68	0.04	0.07	0.10	0.12	0.13	0.15	0.13	0.11
69	0.07	0.11	0.15	0.18	0.20	0.22	0.20	0.17
70	0.10	0.15	0.19	0.23	0.26	0.29	0.26	0.23
71	0.11	0.17	0.21	0.25	0.28	0.31	0.29	0.25
72	0.12	0.18	0.22	0.26	0.29	0.32	0.30	0.26
73	0.12	0.18	0.24	0.28	0.31	0.34	0.31	0.28
74	0.12	0.19	0.25	0.30	0.33	0.35	0.33	0.29
75	0.13	0.20	0.26	0.31	0.34	0.37	0.35	0.30
76	0.14	0.22	0.28	0.33	0.37	0.40	0.37	0.33
77	0.15	0.23	0.30	0.35	0.39	0.42	0.39	0.35
78	0.15	0.23	0.30	0.35	0.39	0.42	0.39	0.35
79	0.15	0.23	0.30	0.35	0.39	0.42	0.39	0.35
80	0.15	0.23	0.30	0.35	0.39	0.42	0.39	0.35
81	0.17	0.29	0.36	0.40	0.44	0.49	0.46	0.42
82	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
83	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
84	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
85	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
86	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
87	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
88	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
89	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
90	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
91	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
92	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
93	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
94	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49
95	0.19	0.35	0.43	0.45	0.49	0.56	0.53	0.49

Table C-3
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 3°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.05	0.06	0.05	0.04
66	0.02	0.03	0.05	0.07	0.08	0.09	0.08	0.07
67	0.03	0.06	0.08	0.10	0.12	0.13	0.12	0.10
68	0.05	0.09	0.12	0.15	0.17	0.19	0.17	0.15
69	0.08	0.14	0.19	0.23	0.26	0.28	0.25	0.22
70	0.13	0.19	0.25	0.30	0.34	0.37	0.34	0.30
71	0.16	0.24	0.30	0.36	0.41	0.44	0.41	0.36
72	0.17	0.26	0.32	0.38	0.44	0.48	0.44	0.39
73	0.18	0.27	0.34	0.40	0.45	0.49	0.46	0.40
74	0.18	0.28	0.36	0.43	0.48	0.52	0.48	0.43
75	0.19	0.30	0.38	0.45	0.50	0.54	0.51	0.45
76	0.20	0.32	0.41	0.49	0.54	0.58	0.54	0.48
77	0.21	0.33	0.43	0.51	0.57	0.61	0.56	0.50
78	0.22	0.35	0.45	0.53	0.59	0.63	0.58	0.52
79	0.22	0.35	0.45	0.53	0.59	0.63	0.58	0.52
80	0.22	0.35	0.45	0.53	0.59	0.63	0.58	0.52
81	0.25	0.40	0.51	0.58	0.64	0.70	0.65	0.59
82	0.27	0.46	0.58	0.62	0.69	0.77	0.72	0.66
83	0.29	0.52	0.64	0.67	0.74	0.84	0.79	0.73
84	0.29	0.52	0.64	0.67	0.74	0.84	0.79	0.73
85	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
86	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
87	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
88	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
89	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
90	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
91	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
92	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
93	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
94	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73
95	0.29	0.52	0.64	0.67	0.74	0.84	0.80	0.73

Table C-4
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 4°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
66	0.02	0.04	0.06	0.08	0.09	0.10	0.09	0.08
67	0.03	0.06	0.09	0.11	0.13	0.15	0.13	0.11
68	0.05	0.10	0.14	0.17	0.20	0.22	0.19	0.17
69	0.09	0.15	0.21	0.26	0.29	0.32	0.29	0.25
70	0.14	0.22	0.29	0.35	0.40	0.44	0.39	0.34
71	0.18	0.28	0.36	0.43	0.49	0.53	0.48	0.42
72	0.22	0.33	0.41	0.49	0.56	0.61	0.56	0.49
73	0.23	0.35	0.45	0.53	0.59	0.65	0.60	0.53
74	0.24	0.37	0.47	0.56	0.62	0.68	0.63	0.55
75	0.25	0.39	0.50	0.59	0.65	0.71	0.66	0.58
76	0.26	0.41	0.53	0.63	0.70	0.75	0.70	0.62
77	0.28	0.43	0.56	0.66	0.74	0.79	0.74	0.65
78	0.29	0.45	0.58	0.69	0.77	0.82	0.76	0.68
79	0.29	0.46	0.59	0.71	0.79	0.85	0.78	0.69
80	0.30	0.46	0.60	0.71	0.79	0.85	0.78	0.69
81	0.32	0.52	0.66	0.75	0.84	0.91	0.85	0.77
82	0.34	0.58	0.72	0.80	0.89	0.98	0.92	0.84
83	0.37	0.63	0.79	0.85	0.94	1.05	0.99	0.91
84	0.39	0.69	0.85	0.89	0.99	1.12	1.06	0.98
85	0.39	0.69	0.85	0.89	0.99	1.12	1.06	0.98
86	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
87	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
88	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
89	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
90	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
91	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
92	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
93	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
94	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98
95	0.39	0.69	0.85	0.90	0.99	1.12	1.06	0.98

Table C-5
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
66	0.02	0.04	0.06	0.08	0.09	0.11	0.09	0.08
67	0.03	0.06	0.10	0.12	0.14	0.17	0.15	0.12
68	0.06	0.10	0.15	0.19	0.21	0.24	0.21	0.18
69	0.10	0.17	0.23	0.28	0.32	0.35	0.32	0.27
70	0.15	0.24	0.31	0.38	0.43	0.48	0.43	0.38
71	0.20	0.31	0.40	0.48	0.54	0.59	0.54	0.47
72	0.24	0.37	0.48	0.56	0.64	0.70	0.64	0.56
73	0.28	0.42	0.53	0.63	0.72	0.78	0.72	0.63
74	0.30	0.45	0.57	0.68	0.76	0.83	0.77	0.68
75	0.31	0.47	0.60	0.71	0.80	0.86	0.80	0.71
76	0.32	0.50	0.65	0.77	0.85	0.92	0.85	0.75
77	0.34	0.53	0.68	0.81	0.90	0.96	0.90	0.79
78	0.35	0.55	0.71	0.84	0.93	1.01	0.93	0.83
79	0.36	0.57	0.73	0.86	0.96	1.03	0.95	0.85
80	0.37	0.58	0.74	0.88	0.98	1.06	0.97	0.87
81	0.39	0.63	0.81	0.93	1.03	1.13	1.04	0.94
82	0.42	0.69	0.87	0.98	1.08	1.19	1.11	1.01
83	0.44	0.75	0.94	1.02	1.13	1.26	1.18	1.08
84	0.46	0.81	1.00	1.07	1.18	1.33	1.25	1.15
85	0.49	0.86	1.06	1.12	1.23	1.40	1.32	1.22
86	0.49	0.86	1.06	1.12	1.24	1.40	1.33	1.22
87	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
88	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
89	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
90	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
91	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
92	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
93	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
94	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22
95	0.49	0.87	1.06	1.12	1.24	1.40	1.33	1.22

Table C-6
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 6°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
66	0.02	0.04	0.06	0.08	0.09	0.11	0.09	0.08
67	0.03	0.06	0.10	0.13	0.15	0.17	0.15	0.13
68	0.06	0.11	0.16	0.20	0.22	0.25	0.22	0.19
69	0.10	0.17	0.24	0.29	0.33	0.37	0.33	0.28
70	0.15	0.25	0.33	0.41	0.46	0.51	0.46	0.40
71	0.20	0.32	0.42	0.51	0.58	0.63	0.58	0.50
72	0.26	0.40	0.51	0.61	0.69	0.76	0.69	0.60
73	0.30	0.46	0.60	0.71	0.80	0.87	0.80	0.70
74	0.34	0.52	0.66	0.79	0.89	0.96	0.89	0.78
75	0.36	0.55	0.71	0.84	0.94	1.02	0.94	0.83
76	0.38	0.59	0.75	0.89	0.99	1.07	1.00	0.88
77	0.40	0.62	0.80	0.94	1.05	1.13	1.05	0.93
78	0.41	0.64	0.83	0.98	1.09	1.18	1.09	0.97
79	0.42	0.66	0.86	1.02	1.13	1.22	1.13	1.00
80	0.43	0.68	0.88	1.04	1.16	1.25	1.15	1.02
81	0.47	0.75	0.96	1.11	1.23	1.34	1.24	1.11
82	0.49	0.81	1.02	1.15	1.28	1.41	1.31	1.18
83	0.51	0.86	1.09	1.20	1.33	1.47	1.38	1.26
84	0.54	0.92	1.15	1.25	1.38	1.54	1.45	1.33
85	0.56	0.98	1.21	1.29	1.43	1.61	1.52	1.40
86	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
87	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
88	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
89	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
90	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
91	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
92	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
93	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
94	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47
95	0.58	1.04	1.28	1.34	1.48	1.68	1.59	1.47

Table C-7
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 7°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
66	0.02	0.04	0.06	0.08	0.09	0.11	0.09	0.08
67	0.03	0.06	0.10	0.13	0.15	0.17	0.15	0.13
68	0.06	0.11	0.16	0.20	0.23	0.26	0.23	0.19
69	0.10	0.18	0.25	0.30	0.35	0.39	0.34	0.30
70	0.15	0.26	0.34	0.42	0.48	0.53	0.47	0.41
71	0.21	0.33	0.44	0.53	0.60	0.66	0.60	0.52
72	0.26	0.41	0.53	0.64	0.73	0.80	0.73	0.64
73	0.32	0.49	0.63	0.76	0.85	0.93	0.85	0.75
74	0.37	0.56	0.73	0.86	0.97	1.05	0.97	0.85
75	0.41	0.62	0.80	0.95	1.06	1.15	1.07	0.94
76	0.44	0.67	0.86	1.02	1.13	1.23	1.14	1.01
77	0.45	0.70	0.90	1.07	1.19	1.29	1.19	1.05
78	0.47	0.73	0.94	1.12	1.24	1.34	1.24	1.10
79	0.48	0.76	0.98	1.16	1.29	1.39	1.29	1.14
80	0.50	0.78	1.01	1.19	1.33	1.43	1.32	1.17
81	0.53	0.85	1.09	1.26	1.41	1.53	1.41	1.27
82	0.56	0.92	1.17	1.33	1.48	1.62	1.50	1.36
83	0.59	0.98	1.23	1.38	1.53	1.69	1.57	1.43
84	0.61	1.04	1.30	1.42	1.58	1.75	1.64	1.50
85	0.63	1.09	1.36	1.47	1.63	1.82	1.71	1.57
86	0.66	1.15	1.43	1.52	1.68	1.89	1.78	1.64
87	0.68	1.21	1.49	1.57	1.73	1.96	1.85	1.71
88	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
89	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
90	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
91	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
92	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
93	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
94	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71
95	0.68	1.21	1.49	1.57	1.73	1.96	1.86	1.71

Table C-8
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 8°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
66	0.02	0.04	0.06	0.08	0.09	0.11	0.09	0.08
67	0.03	0.06	0.10	0.13	0.15	0.17	0.15	0.13
68	0.06	0.11	0.16	0.20	0.23	0.26	0.23	0.19
69	0.10	0.18	0.25	0.31	0.35	0.39	0.35	0.30
70	0.15	0.26	0.35	0.43	0.49	0.54	0.48	0.42
71	0.21	0.34	0.45	0.54	0.62	0.68	0.62	0.54
72	0.27	0.42	0.55	0.67	0.76	0.83	0.75	0.66
73	0.33	0.51	0.66	0.79	0.89	0.97	0.89	0.78
74	0.38	0.59	0.76	0.91	1.02	1.11	1.02	0.90
75	0.43	0.67	0.86	1.02	1.14	1.24	1.14	1.00
76	0.48	0.74	0.95	1.12	1.26	1.36	1.26	1.11
77	0.51	0.79	1.01	1.19	1.33	1.44	1.33	1.18
78	0.53	0.82	1.05	1.24	1.39	1.50	1.39	1.23
79	0.54	0.85	1.09	1.30	1.44	1.55	1.44	1.28
80	0.56	0.87	1.13	1.34	1.49	1.60	1.48	1.31
81	0.59	0.95	1.22	1.42	1.57	1.71	1.58	1.42
82	0.63	1.03	1.30	1.49	1.65	1.80	1.68	1.51
83	0.66	1.09	1.38	1.55	1.72	1.90	1.77	1.60
84	0.68	1.15	1.45	1.60	1.77	1.97	1.84	1.67
85	0.71	1.21	1.51	1.65	1.82	2.03	1.91	1.74
86	0.73	1.27	1.58	1.70	1.88	2.10	1.98	1.82
87	0.75	1.33	1.64	1.74	1.93	2.17	2.05	1.89
88	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
89	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
90	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
91	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
92	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
93	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
94	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96
95	0.78	1.38	1.70	1.79	1.98	2.24	2.12	1.96

D

ADJUSTED PROJECTED SAVINGS PER UNIT

These tables show the average per unit savings across all program units. Savings have been adjusted to reflect 2003 average rates of non-response and zero AC use as well as the temperature-based estimate of over-ride percent. These results provide the best means of projecting per unit savings prior to a re-set event.

Table D-1
Adjusted Projected Savings per AC Unit (kW)
Re-set = 1°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.01
66	0.01	0.01	0.01	0.02	0.03	0.03	0.03	0.02
67	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.03
68	0.02	0.03	0.04	0.05	0.06	0.06	0.05	0.04
69	0.03	0.05	0.06	0.07	0.08	0.09	0.08	0.07
70	0.04	0.05	0.07	0.08	0.09	0.10	0.09	0.08
71	0.04	0.05	0.07	0.08	0.09	0.10	0.09	0.08
72	0.04	0.06	0.07	0.08	0.10	0.10	0.10	0.08
73	0.04	0.06	0.07	0.09	0.10	0.10	0.10	0.09
74	0.04	0.06	0.08	0.09	0.10	0.11	0.10	0.09
75	0.04	0.06	0.08	0.09	0.10	0.11	0.10	0.09
76	0.04	0.06	0.08	0.09	0.11	0.11	0.10	0.09
77	0.04	0.06	0.08	0.09	0.10	0.11	0.10	0.09
78	0.03	0.05	0.07	0.08	0.09	0.10	0.09	0.08
79	0.03	0.05	0.07	0.08	0.09	0.09	0.09	0.08
80	0.03	0.05	0.06	0.07	0.08	0.09	0.08	0.07
81	0.04	0.06	0.08	0.08	0.09	0.10	0.10	0.09
82	0.03	0.06	0.07	0.07	0.08	0.09	0.09	0.08
83	0.03	0.05	0.06	0.07	0.07	0.08	0.08	0.07
84	0.03	0.04	0.06	0.06	0.06	0.07	0.07	0.06
85	0.02	0.04	0.05	0.05	0.05	0.06	0.06	0.05
86	0.02	0.03	0.04	0.04	0.05	0.05	0.05	0.05
87	0.01	0.03	0.03	0.03	0.04	0.04	0.04	0.04
88	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03
89	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02
90	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
91	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-2
Adjusted Projected Savings per AC Unit (kW)
Re-set = 2°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.02
66	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.04
67	0.02	0.03	0.04	0.05	0.06	0.07	0.07	0.06
68	0.03	0.05	0.07	0.08	0.09	0.10	0.09	0.08
69	0.05	0.08	0.10	0.12	0.14	0.15	0.13	0.12
70	0.07	0.10	0.13	0.15	0.17	0.19	0.17	0.15
71	0.07	0.11	0.14	0.16	0.18	0.20	0.18	0.16
72	0.07	0.11	0.14	0.16	0.18	0.20	0.19	0.16
73	0.07	0.11	0.14	0.17	0.19	0.20	0.19	0.17
74	0.07	0.11	0.15	0.17	0.19	0.21	0.19	0.17
75	0.07	0.11	0.15	0.17	0.19	0.21	0.19	0.17
76	0.07	0.12	0.15	0.18	0.20	0.21	0.20	0.18
77	0.07	0.12	0.15	0.18	0.20	0.21	0.20	0.18
78	0.07	0.11	0.14	0.17	0.19	0.20	0.19	0.17
79	0.06	0.10	0.13	0.16	0.17	0.19	0.17	0.15
80	0.06	0.09	0.12	0.14	0.16	0.17	0.16	0.14
81	0.06	0.11	0.13	0.15	0.16	0.18	0.17	0.16
82	0.06	0.12	0.14	0.15	0.16	0.19	0.18	0.16
83	0.06	0.10	0.13	0.13	0.15	0.17	0.16	0.15
84	0.05	0.09	0.11	0.12	0.13	0.15	0.14	0.13
85	0.04	0.08	0.09	0.10	0.11	0.12	0.12	0.11
86	0.04	0.06	0.08	0.08	0.09	0.10	0.10	0.09
87	0.03	0.05	0.06	0.07	0.07	0.08	0.08	0.07
88	0.02	0.04	0.05	0.05	0.06	0.07	0.06	0.06
89	0.02	0.03	0.04	0.04	0.04	0.05	0.05	0.04
90	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03
91	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-3
Adjusted Projected Savings per AC Unit (kW)
Re-set = 3°F

Daily Average Temperature (°F)	Hour Ending 12	13	14	15	16	17	18	19
65	0.01	0.01	0.03	0.03	0.04	0.04	0.04	0.03
66	0.01	0.02	0.04	0.05	0.05	0.06	0.05	0.05
67	0.02	0.04	0.05	0.07	0.08	0.09	0.08	0.07
68	0.03	0.06	0.08	0.10	0.12	0.13	0.12	0.10
69	0.06	0.09	0.13	0.15	0.17	0.19	0.17	0.15
70	0.08	0.13	0.17	0.20	0.23	0.25	0.22	0.20
71	0.10	0.15	0.19	0.23	0.26	0.29	0.26	0.23
72	0.11	0.16	0.20	0.24	0.27	0.30	0.28	0.24
73	0.11	0.16	0.21	0.25	0.28	0.30	0.28	0.24
74	0.11	0.17	0.21	0.25	0.28	0.30	0.28	0.25
75	0.11	0.17	0.22	0.26	0.28	0.30	0.28	0.25
76	0.11	0.17	0.22	0.26	0.29	0.31	0.29	0.26
77	0.11	0.17	0.22	0.26	0.29	0.31	0.29	0.25
78	0.10	0.16	0.21	0.25	0.28	0.30	0.28	0.25
79	0.10	0.15	0.20	0.23	0.26	0.28	0.26	0.23
80	0.09	0.14	0.18	0.22	0.24	0.26	0.24	0.21
81	0.09	0.15	0.19	0.21	0.24	0.26	0.24	0.22
82	0.09	0.15	0.19	0.21	0.23	0.26	0.24	0.22
83	0.09	0.15	0.19	0.20	0.22	0.25	0.24	0.22
84	0.08	0.13	0.17	0.17	0.19	0.22	0.21	0.19
85	0.06	0.12	0.14	0.15	0.16	0.19	0.18	0.16
86	0.05	0.10	0.12	0.12	0.14	0.16	0.15	0.14
87	0.04	0.08	0.10	0.10	0.11	0.13	0.12	0.11
88	0.03	0.06	0.08	0.08	0.09	0.10	0.09	0.09
89	0.03	0.05	0.06	0.06	0.06	0.07	0.07	0.06
90	0.02	0.03	0.04	0.04	0.04	0.05	0.05	0.04
91	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.02
92	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-4
Adjusted Projected Savings per AC Unit (kW)
Re-set = 4°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.02	0.04	0.05	0.06	0.07	0.06	0.05
67	0.02	0.04	0.06	0.08	0.09	0.11	0.09	0.08
68	0.04	0.07	0.10	0.12	0.13	0.15	0.13	0.11
69	0.06	0.10	0.14	0.17	0.20	0.22	0.20	0.17
70	0.09	0.15	0.19	0.23	0.26	0.29	0.26	0.23
71	0.12	0.18	0.23	0.28	0.31	0.34	0.31	0.27
72	0.14	0.21	0.26	0.31	0.35	0.38	0.35	0.31
73	0.14	0.21	0.27	0.32	0.36	0.39	0.36	0.32
74	0.14	0.22	0.28	0.33	0.36	0.40	0.37	0.32
75	0.14	0.22	0.28	0.33	0.37	0.40	0.37	0.33
76	0.14	0.22	0.28	0.34	0.37	0.40	0.38	0.33
77	0.14	0.22	0.28	0.34	0.37	0.40	0.37	0.33
78	0.14	0.21	0.28	0.33	0.36	0.39	0.36	0.32
79	0.13	0.20	0.26	0.31	0.35	0.37	0.34	0.31
80	0.12	0.19	0.24	0.29	0.32	0.34	0.32	0.28
81	0.12	0.19	0.25	0.28	0.31	0.34	0.31	0.28
82	0.11	0.19	0.24	0.27	0.30	0.33	0.31	0.28
83	0.11	0.19	0.23	0.25	0.28	0.31	0.29	0.27
84	0.10	0.18	0.22	0.23	0.26	0.29	0.27	0.25
85	0.09	0.15	0.19	0.20	0.22	0.25	0.24	0.22
86	0.07	0.13	0.16	0.17	0.18	0.21	0.20	0.18
87	0.06	0.10	0.13	0.14	0.15	0.17	0.16	0.15
88	0.05	0.08	0.10	0.11	0.12	0.13	0.13	0.12
89	0.03	0.06	0.07	0.08	0.09	0.10	0.09	0.09
90	0.02	0.04	0.05	0.05	0.06	0.07	0.06	0.06
91	0.01	0.02	0.03	0.03	0.03	0.04	0.03	0.03
92	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-5
Adjusted Projected Savings per AC Unit (kW)
Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.03	0.04	0.06	0.07	0.08	0.07	0.06
67	0.02	0.04	0.07	0.09	0.10	0.12	0.10	0.09
68	0.04	0.07	0.10	0.13	0.15	0.16	0.14	0.12
69	0.07	0.11	0.15	0.19	0.22	0.24	0.21	0.18
70	0.10	0.16	0.21	0.25	0.29	0.32	0.29	0.25
71	0.13	0.20	0.26	0.31	0.35	0.38	0.35	0.30
72	0.15	0.23	0.30	0.35	0.40	0.44	0.40	0.35
73	0.17	0.26	0.33	0.39	0.44	0.48	0.44	0.39
74	0.17	0.26	0.34	0.40	0.45	0.49	0.45	0.40
75	0.17	0.27	0.34	0.40	0.45	0.48	0.45	0.40
76	0.17	0.27	0.35	0.41	0.46	0.49	0.46	0.40
77	0.17	0.27	0.34	0.41	0.45	0.49	0.45	0.40
78	0.17	0.26	0.34	0.40	0.44	0.48	0.44	0.39
79	0.16	0.25	0.32	0.38	0.43	0.46	0.42	0.38
80	0.15	0.23	0.30	0.36	0.40	0.43	0.40	0.35
81	0.15	0.24	0.30	0.35	0.38	0.42	0.39	0.35
82	0.14	0.23	0.29	0.33	0.36	0.40	0.37	0.34
83	0.13	0.22	0.28	0.30	0.34	0.37	0.35	0.32
84	0.12	0.21	0.26	0.28	0.31	0.34	0.32	0.30
85	0.11	0.19	0.24	0.25	0.27	0.31	0.29	0.27
86	0.09	0.16	0.20	0.21	0.23	0.26	0.25	0.23
87	0.07	0.13	0.16	0.17	0.19	0.21	0.20	0.19
88	0.06	0.10	0.13	0.13	0.15	0.17	0.16	0.14
89	0.04	0.08	0.09	0.10	0.11	0.12	0.12	0.11
90	0.03	0.05	0.06	0.07	0.07	0.08	0.08	0.07
91	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04
92	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-6
Adjusted Projected Savings per AC Unit (kW)
Re-set = 6°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.03	0.04	0.06	0.07	0.08	0.07	0.06
67	0.02	0.04	0.07	0.09	0.10	0.12	0.10	0.09
68	0.04	0.07	0.11	0.14	0.15	0.17	0.15	0.13
69	0.07	0.12	0.16	0.20	0.23	0.25	0.22	0.19
70	0.10	0.16	0.22	0.27	0.30	0.34	0.30	0.26
71	0.13	0.21	0.27	0.33	0.37	0.41	0.37	0.32
72	0.16	0.25	0.32	0.38	0.44	0.48	0.43	0.38
73	0.19	0.28	0.36	0.43	0.48	0.53	0.48	0.42
74	0.20	0.30	0.39	0.46	0.52	0.57	0.52	0.46
75	0.20	0.31	0.40	0.47	0.53	0.57	0.53	0.47
76	0.20	0.31	0.40	0.48	0.53	0.58	0.53	0.47
77	0.20	0.31	0.40	0.48	0.53	0.57	0.53	0.47
78	0.20	0.31	0.39	0.47	0.52	0.56	0.52	0.46
79	0.19	0.29	0.38	0.45	0.50	0.54	0.50	0.44
80	0.18	0.28	0.36	0.42	0.47	0.51	0.47	0.42
81	0.17	0.28	0.36	0.41	0.46	0.50	0.46	0.41
82	0.16	0.27	0.34	0.39	0.43	0.47	0.44	0.40
83	0.15	0.26	0.32	0.36	0.39	0.44	0.41	0.37
84	0.14	0.24	0.30	0.32	0.36	0.40	0.38	0.34
85	0.12	0.22	0.27	0.29	0.32	0.36	0.34	0.31
86	0.11	0.19	0.24	0.25	0.28	0.31	0.30	0.27
87	0.09	0.16	0.19	0.20	0.22	0.25	0.24	0.22
88	0.07	0.12	0.15	0.16	0.18	0.20	0.19	0.17
89	0.05	0.09	0.11	0.12	0.13	0.15	0.14	0.13
90	0.03	0.06	0.07	0.08	0.09	0.10	0.09	0.09
91	0.02	0.03	0.04	0.04	0.05	0.05	0.05	0.05
92	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-7
Adjusted Projected Savings per AC Unit (kW)
Re-set = 7°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.03	0.04	0.06	0.07	0.08	0.07	0.06
67	0.02	0.04	0.07	0.09	0.10	0.12	0.10	0.09
68	0.04	0.07	0.11	0.14	0.16	0.18	0.15	0.13
69	0.07	0.12	0.17	0.21	0.23	0.26	0.23	0.20
70	0.10	0.17	0.23	0.28	0.31	0.35	0.31	0.27
71	0.14	0.22	0.28	0.34	0.39	0.43	0.39	0.34
72	0.17	0.26	0.34	0.40	0.46	0.50	0.46	0.40
73	0.19	0.30	0.39	0.46	0.52	0.56	0.52	0.45
74	0.22	0.33	0.43	0.50	0.57	0.62	0.57	0.50
75	0.23	0.35	0.45	0.53	0.60	0.65	0.60	0.53
76	0.23	0.36	0.46	0.54	0.61	0.66	0.61	0.54
77	0.23	0.36	0.46	0.54	0.60	0.65	0.60	0.53
78	0.22	0.35	0.45	0.53	0.59	0.64	0.59	0.52
79	0.21	0.34	0.43	0.51	0.57	0.61	0.57	0.50
80	0.20	0.32	0.41	0.49	0.54	0.58	0.54	0.48
81	0.20	0.32	0.41	0.47	0.52	0.57	0.52	0.47
82	0.19	0.31	0.39	0.44	0.49	0.54	0.50	0.45
83	0.17	0.29	0.37	0.41	0.45	0.50	0.47	0.42
84	0.16	0.27	0.34	0.37	0.41	0.45	0.43	0.39
85	0.14	0.24	0.30	0.33	0.36	0.40	0.38	0.35
86	0.12	0.21	0.27	0.28	0.31	0.35	0.33	0.31
87	0.10	0.18	0.23	0.24	0.26	0.30	0.28	0.26
88	0.08	0.14	0.18	0.19	0.20	0.23	0.22	0.20
89	0.06	0.11	0.13	0.14	0.15	0.17	0.16	0.15
90	0.04	0.07	0.09	0.09	0.10	0.11	0.11	0.10
91	0.02	0.04	0.05	0.05	0.05	0.06	0.06	0.05
92	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-8
Adjusted Projected Savings per AC Unit (kW)
Re-set = 8°F

Daily Average Temperature (°F)	Hour Ending							
	12	13	14	15	16	17	18	19
65	0.01	0.02	0.03	0.04	0.04	0.05	0.04	0.03
66	0.01	0.03	0.04	0.06	0.07	0.08	0.07	0.06
67	0.02	0.04	0.07	0.09	0.10	0.12	0.10	0.09
68	0.04	0.07	0.11	0.14	0.16	0.18	0.15	0.13
69	0.07	0.12	0.17	0.21	0.24	0.26	0.23	0.20
70	0.10	0.17	0.23	0.28	0.32	0.36	0.32	0.28
71	0.14	0.22	0.29	0.35	0.40	0.44	0.40	0.35
72	0.17	0.27	0.35	0.42	0.47	0.52	0.47	0.41
73	0.20	0.31	0.40	0.48	0.54	0.59	0.54	0.47
74	0.22	0.35	0.45	0.53	0.60	0.65	0.60	0.52
75	0.24	0.37	0.48	0.57	0.64	0.70	0.64	0.56
76	0.26	0.40	0.51	0.60	0.67	0.73	0.67	0.60
77	0.26	0.40	0.51	0.60	0.67	0.73	0.68	0.60
78	0.25	0.39	0.50	0.59	0.66	0.71	0.66	0.58
79	0.24	0.38	0.48	0.57	0.64	0.69	0.64	0.56
80	0.23	0.36	0.46	0.54	0.61	0.65	0.60	0.54
81	0.22	0.35	0.45	0.53	0.58	0.63	0.59	0.53
82	0.21	0.34	0.44	0.50	0.55	0.60	0.56	0.51
83	0.20	0.32	0.41	0.46	0.51	0.56	0.52	0.48
84	0.18	0.30	0.38	0.42	0.46	0.51	0.48	0.43
85	0.16	0.27	0.34	0.37	0.41	0.45	0.42	0.39
86	0.14	0.24	0.29	0.32	0.35	0.39	0.37	0.34
87	0.11	0.20	0.25	0.26	0.29	0.33	0.31	0.29
88	0.09	0.16	0.20	0.21	0.23	0.26	0.25	0.23
89	0.07	0.12	0.15	0.16	0.17	0.20	0.18	0.17
90	0.05	0.08	0.10	0.10	0.12	0.13	0.12	0.11
91	0.02	0.04	0.05	0.06	0.06	0.07	0.07	0.06
92	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00