Appendix A

Cost Effectiveness Test Results

Program	UCT	TRC	RIM	Partcipant
Residential Conservation and Energy Education	0.93	0.93	0.45	NA
Refrigerator Replacement	1.03	1.03	0.46	NA
Residential Home Energy House Call	3.38	3.38	1.02	NA
Residential Comprehensive Energy Education Program (NEED)	1.57	1.57	0.64	NA
Power Manager	3.32	3.98	3.32	NA
Energy Star Products	9.75	7.92	0.66	18.13
Energy Efficiency Website	1.95	2.49	0.57	NA
Personal Energy Report (PER)	5.78	10.76	0.71	NA
C&I High Efficiency Incentive (for Businesses and Schools)				
Lighting	4.73	2.69	0.84	3.6
HVAC	2.17	1.32	0.79	1.67
Motors	1.39	1.23	0.61	2.03
PowerShare	2.16	261.94	1.86	NA

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APPENDIX B

Low Income Refrigeration Program
Kentucky & Ohio
2006 Savings Analysis

August 1, 2007

Submitted by Rick Morgan

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Refrigerator Analysis 2006

Duke Kentucky and its Energy Collaborative proposed in the September 27, 2002 filing in Case No. 2002-358 and subsequently received approval to expand the low income weatherization program to include refrigerators as a qualified measure in owner occupied homes. This program is also offered in the Duke Ohio territory. This memo is to report the data analysis to determine the average savings for the Low Income Refrigerator replacement program in Ohio & Kentucky territories during 2006.

Field Protocol

To understand the data results, it is important to understand the field protocol to determine the existing refrigerator's efficiency and whether it qualifies for replacement. The refrigerators are tested in homes that are being weatherized through either the Duke Energy Low Income Weatherization program and its delivery contractor, or the State Weatherization program delivery by the state weatherization agency in the area. When an delivery contractor auditor comes to the home to determine weatherization requirements, they install a digital power meter directly to the refrigerator. The refrigerator plugs into the power meter, manufactured by Brand Electronics, which then plugs into the wall. The auditor calibrates the unit and then lets it run for two hours at a minimum. Two hours is required so that the unit can stabilize and cycle. While more time would be optimal for increased accuracy, two hours has been shown to be able to determine poorly operating units that need replaced. [1]

The Protocol which follows specifies the steps that are taken by the auditor in the home and the applicable data entered.

Protocol Steps

1. *Clean refrigerator coils and Check seal on door gasket.*
2. *Check to see that the refrigerator closes tightly.*

[1] *SELECTION OF HIGH USAGE REFRIGERATORS AND FREEZERS* by Jim Mapp April 16, 1998. & *Low-Income Refrigerator Replacement – Selection Criteria for High Usage Refrigerator Replacement* by Jim Mapp Ph. D. Wisconsin Division of Energy, Kathy Schroder, Program Manager Cinergy Corp, and Rick Morgan, President Morgan Marketing Partners, 2001 IEPEC

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3. *Open door and take data:* *Brand* ____________________
   Model Number ____________________ *Size* ____________________
   Serial Number ____________________
4. *Close Door when compressor comes on and note wattage. (remember to zero the watt meter before you start) Running Wattage:* ____________ *watts*
5. *Let operate normally for two hours or more with door closed and take the total minutes and the kWhY reading (kWh per year estimate).*
   Total Minutes: ____________ *kWhY reading:* ____________
6. *Record peak running wattage at end of the test.* *Peak Watts* ____________
7. *If Peak Wattage is less than 325 watts and the refrigerator has an estimated annual energy usage over 1315 kWhY –* ***Replace the unit.***
8. *If Peak Wattage is more than 325 watts and the refrigerator has an estimated annual energy usage over 1565 kWhY –* ***Replace the unit.***

Additional Information Collected

- Customer Name
- Address Where Unit Installed
- Customer Duke Energy Electric Account Number
- Number in Family
- Square Feet of dwelling
- Replacement Unit Size in ft3
- Special Conditions in the home
- Date New Unit Ordered
- Date New Unit Delivered
- Old Unit Removed by
- A second refrigerator used by the customer to be removed
- Auditor Name

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The meter calculates the annual kWh consumption based on the watts used over the period of the test. If the refrigerator is calculated by the meter to consume over 1315 kWh year (kWhY) it is replaced at no charge to the customer. However, defrost cycles sometimes initiate over the two hour test period which would skew consumption estimates. When a defrost cycle is occurs the meter measures a higher peak watt consumption during the test which is seen in the data. If the unit shows higher than 325 peak watts during the test, it is assumed that the unit has gone into defrost mode. The 325 was chosen as most compressors use 250 watts or less to operate and then with the lights included, would equal 300 peak watts or less. When the unit shows this high wattage demonstrating defrost mode, the kWh per year must equal 1565 kWh or more to be replaced. Units that have bad seals as determined by the auditor can be replaced in special cases even if the meter wattage is below the requirement.

If a unit is found to need replacement, the auditor orders a unit from the specified vendor providing the Energy Star unit. Three sizes are available, 21 cubic feet, 18 cubic feet and 15 cubic feet. The auditor determines the size for the replacement. The auditor is allowed to go to larger sizes under special circumstances. Of the total units replaced in both states, 40% were 21 ft3, 58% were 18 ft3 and 2% were 15 ft3.

Old units are required to be removed by the refrigerator supplier at the time of the delivery of the new unit and the old unit is environmentally recycled. This assures that the old refrigerator does not continue to be used by the customer or get resold in the secondary market thus taking it permanently off the grid. If there is a second refrigerator on the premise that is working and the customer does not want it anymore, the program will remove and recycle the unit for free. The program has not been successful in getting second units removed as no second units were picked up during 2006. This may be an area that the program wants to work on in future years.

Field data is then entered into a database and was reviewed for this analysis. Savings is determined by taking the metered consumption estimate for the year (kWhY) minus the energy consumption rating for the specific Energy Star refrigerator replacing the original unit. These Energy Star consumption estimates are determined by the standardized manufacturer testing in accordance with Energy Star guidelines. Those consumption estimates are:

- 443 kWh/yr for 21 cubic foot
- 434 kWh/yr for 18 ft3
- 372 kWh/yr for 15 ft3

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Results

The program data shows that there were 666 units tested in Ohio and Kentucky programs and 291 replaced. That is 43.7% replacement rate. By state information is listed below.

State	Tested	Replaced	Percent
Ohio	517	227	44%
KY	149	64	43%
Totals	666	291	43.7%

Based on the 2006 data from the field protocol outlined above, savings is on average 1089 kWh for all the units replaced. The highest savings was over 3300 kWh per year and the lowest 6 kWh. There were 43 units with less than the minimum savings (1315 kWhY minus 443 kWh of the 21 ft3 unit = 872 kWh). A majority had broken seals or other problems however these installations should be reviewed by Duke to assure that the protocols are being followed by all auditors.

State	Average Savings kWh/yr
Ohio	1105
KY	1033
Total	1089

The data used for analysis is within the attached spreadsheet. Due to privacy, customer names have been removed.

DSMore Analysis

To complete the DSMore analysis of cost effectiveness, savings should be applied across all hours with an annual savings of 1089 kWh. By using the two hour meter test, natural diversity of load is automatically included, thus using Mode 3 standard testing will work. Life of the measure is related to how early the unit is being replaced. Effective useful life of the new unit is 8 years based on research completed in California on a long term

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recycling program. [2] This reflects the time the unit would be normally replaced with a new unit and the time that the replaced unit might be used as a secondary refrigerator before ultimate operations failure.

Duke should note additional non-energy environmental benefits in the consideration of the program. The refrigerator that is recycled gains non-energy environmental benefits by ensuring that the collected refrigerators are processed and recycled in a manner that meets and exceeds both federal and state environmental laws and regulations. Ozone-depleting chlorofluorocarbon refrigerants and foam insulation blowing agents (CFCs/HCFCs/HFCs), mercury, used oils, plastics, metals, and glass are recovered and recycled. Polychlorinated biphenyls (PCBs) are also recovered for disposal.

Cost for the program is approximately $1000 per replaced refrigerator which includes the refrigerator delivered cost, recycling, testing and administration. These costs vary slightly by size, but for modeling the $1000 average cost is appropriate.

[2] *Residential Refrigerator Recycling Ninth Year Retention Study* Study ID Nos. 546B, 563 prepared for Southern California Edison Company by KEMA July 22, 2004

APPENDIX C

Power Manager Impact Evaluation Study

Duke Energy Indiana
Duke Energy Kentucky

2007 Event Year

Impact Modeling/Metering
conducted by Duke Energy staff/contractors

Report Compilation and Review
conducted by Integral Analytics

Table of Contents

Independent Review and Assessment of the 2007 Duke Energy Kentucky Power Manager Impact Estimates

Dr Michael Ozog, Vice President, Integral Analytics

In September/ October, 2007, I reviewed the enclosed text, findings, datasets, conclusions and load reduction estimates related to the Duke Energy Kentucky Power Manager program. The objective of this review was to provide an expert and independent third party assessment of the reliability and validity of the load reduction estimates and overall evaluation activities and findings contained within this report. Given that the Power Manager program evaluation efforts significantly depend on Duke Energy meters, staff, sampling and operations, this third party review and assessment is an important exercise to glean not only an independent perspective on the evaluation effort and load reduction estimates, but to also offer possible improvements and recommendations for subsequent evaluation activities.

Overall, I found the 2007 Duke Energy Kentucky load reduction estimates to be reasonable and accurate. The sampling protocols, coverage of load research meters across the service territory, paging and operational testing, duty cycle modeling, regression methods and load reduction estimations were satisfactory and reasonable. Sufficient sample sizes were employed to yield the desired precision and accuracy in load reduction forecasts, and considerable attention was afforded to correcting the switch, operating and paging problems previously identified in the 2006 Duke Energy Kentucky Power Manager evaluation study. The past year's efforts and attention to quality control and assessment appear to have increased the load reduction capability and reliability of the program significantly. As such, I am confident that the average household load reduction forecast of 1.04 KW is a reasonable and accurate load impact for the program, given this 2007 group of customers. This level of impacts is comparable to impacts I have found for similar programs in other areas of the country.

For future evaluations, I recommend the following possible improvements or enhancements to help improve program effectiveness and load reduction forecast precision. First, it would be useful to migrate load research meters from current year sample to new homes for the 2008 season. This sample migration will insure that any potential sampling bias is mitigated and does not confound the load reduction impact estimates. Second, continued, and perhaps expanded use of, supplementary logger and instantaneous demand measures are relatively inexpensive ways to boost sampling power and improve load reduction forecasts at a reasonable cost. Third, expanded use of a "nested" sample of logger and interval end-use meters to better understand the relationship between duty cycle and air conditioner load. In all cases, additional sample points would be desirable, though not required.

And finally, the approach used in this analysis relied upon the average duty cycle (per unit) to estimate run time. This is a reasonable assumption. However, there may be significant benefits to developing statistical models that relate the individual run-time to such things as the time of day, day of week, month, and weather, or other influential variables. This approach may produce more meaningful estimates of the program effect. Therefore, future analysis should look into using more advanced statistical methods to estimate of the impacts of the Power Manger program.

DR. MICHAEL OZOG

AREAS OF QUALIFICATION

Econometrics, energy economics, energy policy modeling, program evaluation

EMPLOYMENT HISTORY

- Integral Analytics, Fort Collins, CO 2007-present
- Senior Consultant, Summit Blue Consulting, LLC, Boulder, CO, 2002-2007
- Senior Associate, Stratus Consulting Inc., Boulder, CO, 2001-2002
- Senior Consultant, E Source, Boulder, CO, 2000

EDUCATION

- Boston College, PhD, Economics, 1991
- Pennsylvania State University, MS, Mineral Economics, 1985
- Massachusetts Institute of Technology, BS in Geology, 1982

PROFESSIONAL EXPERIENCE

At Integral Analytics (IA), Dr. Ozog is the leader of economic evaluation practice, which develops innovative statistical analysis techniques which can be used by the energy industry to understand and predict the behavior and preferences of their customer's. Dr. Ozog is also responsible for the support and improvement of IA's existing product base, including DSMore.

While at Summit Blue, Dr. Ozog was leading the quantitative research efforts into the impacts of energy efficiency programs, demand response and innovative pricing. He evaluated Sacramento Municipal Utility District's mass-market DR programs, Idaho Power Company's load management programs, and Com Ed/Chicago Cooperative Real Time Pricing program. A list of his recent projects includes:

- Multi-year evaluation of the Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP). ESPP is a large-scale residential real-time pricing program in the Chicago area that uses market-based hourly electricity prices.

- Multi-year evaluation of PSE&G's residential and small commercial direct load control programs

- Multi-year valuation of KCP&L's residential air conditional load control program.

- Multi-year evaluation of Idaho Power Company's (IPCo) Residential Air-Conditioning Cycling Pilot Program.

- Evaluation of IPCo's Irrigation Peak Clip program, a program which uses switches to curtain irrigation during peak demand periods.

- Evaluation of Louisville Gas & Electric Company (LG&E) residential direct load control program for water heating and air conditioning.
- Evaluation of California Working Group 2 (WG2) demand response. The WG2 evaluation investigated the demand impacts associated with industrial demand response programs.
- A multi-year impact Evaluation of Sacramento Municipal Utility District's (SMUD's) PowerStat and PowerChoice programs.
- Multi-utility evaluation of New Hampshire's Home Energy Solutions (HES). The HES program is a residential retrofit program that is implemented by all electric utilities in New Hampshire (i.e., Granite State, New Hampshire Electric Cooperative, Unitil, and Public Service of New Hampshire).
- Evaluation of LG&E WE Care low-income weatherization program.

PUBLICATIONS

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"Modeling Overnight Recreation Trip Choice: Application of a Repeated Nested Multinomial Logit Model" (with W. Shaw). *Environmental and Resource Economics.* October 1998.

"Residential Electricity Use and the Potential Impacts of Energy Efficiency Options in Pakistan" (with Mark Eiswerth). *Energy Policy.* March 1998.

"Decomposing Energy Conservation into Natural and Incentive-Induced Components" (with D. Waldman). *Southern Economic Journal* April 1996.

"Model Specification and Treatment of Outliers in the Evaluation of a Commercial Lighting Program" (with R. Davis). *Energy Services Journal.* Vol. 1, No. 1, September. 1995.

"Weighing Enriched Samples in Voluntary Energy Conservation Program Evaluation" (with D. Waldman). *The Energy Journal.* Vol. 15, No. 1, March. 1994.

Introduction

Duke Energy offers residential customers a load control program called Power Manager. This program offers customers a monetary incentive for reducing their air conditioning during peak demand periods. This report presents the load impact analysis for 2007 Power Manager control periods. The first two sections below are devoted to estimating the potential average (i.e., per-participant) impact from Power Manager load control; the first section describes data collection and the next section focuses on models derived from this data. The following section presents the operability study conducted in 2007 to identify an explicit de-rating factor for Power Manager load control. This is an important difference from the 2006 load impact analysis, where de-rating was implicit in the impact estimates and not separated from other influential factors such as weather. Hourly load impact estimates for Power Manager control days are given in the next section, in Tables 5-12(d). The maximum impact was 39 MW for Duke Energy Indiana and 8 MW for Duke Energy Kentucky on August 8. It should be noted that Duke Energy Indiana impacts during August were reduced about 4 MW by an IT change unrelated to the program, and this problem is now resolved. The final section describes Duke Energy's plan for diagnostic field testing to be conducted over the next few weeks at customer locations identified in the operability study where switches failed to shed during control periods this summer. Results from these tests will be used to improve future load impacts.

To ensure that Duke Energy maximizes the impacts of the program a quality assurance action plan was put in place prior to the 2007 control season. An assessment of the accuracy of the data and quality of the equipment and procedures being used to evaluate the program was done. One of the factors for the evaluation was the low impacts that were discovered during the 2006 control season. The impact estimates for the 2006 control season were significantly below the targeted load reduction. Details of the quality assurance plan and the impacts measured in 2006 are found in appendix 8.

Load Research Sample

A fresh load research sample ("RS" group) was recruited for summer 2007, with no holdovers from 2006. For each RS participant, HOBO U-9 state data loggers were installed on all AC units and the household kWh meter was replaced with an interval meter. Data logger's records times at which the AC unit turns on or off, allowing duty cycle to be constructed at any desired temporal resolution. To enable efficient collection of logger data, prospective candidates for the research sample were randomly selected with a two stage cluster sampling method. The clusters are based upon zip code, and required to contain at least 120 Power Manager customers to provide an adequate pool for recruitment. Prior to sampling (in January, 2007), small zip codes were combined with adjacent zip codes into a single cluster, so that all clusters meet the minimum size requirement. In the first stage of sampling, eight clusters were randomly selected in Indiana and four clusters in Kentucky. These clusters were drawn in such way that the probability of selection for a cluster was proportional to the number of Power Manager participants in that cluster.

In the second stage of sampling, customers were classified as high, medium, or low users based upon billed kWH for the months June – September of 2006. The kWH breakpoints used for classification were determined at the state level, so that equal numbers are assigned to each category in both Indiana and Kentucky. Clusters selected in the first stage were separated into six groups based upon kWH usage level and program option (1.5 kW or 1.0 kW). Using randomized selection within these groups, two participants were recruited from each 1.5 kW group and one participant from each 1.0 kW group, for a total of nine recruits in each cluster.

Due to a mistake in the preparation of randomized lists for recruiting, several customers were recruited from a zip code cluster that had not been selected in the stage 1 random draw. This cluster was substituted for a nearby cluster which had been selected in the random draw but where no recruits had yet been obtained.

Load Impacts with the Duty Cycle Method

The duty cycle method will be used to estimate load impacts during Power Manager control periods. Air-conditioner (AC) natural duty cycles are measured with HOBO data loggers for the Power Manager load research samples during 2006-2007 summer seasons. Together with connected loads for research sample AC units, the natural duty cycle data enables evaluation of the average load reduction achieved by a cycling strategy within the research sample. Hourly models have been constructed for average load reduction within the research sample as a function of weather conditions and cycling strategy. The potential load impact during a Power Manager control period is determined by evaluating these models with the cycling strategy employed and weather conditions during the control period. The potential load impacts estimated in this manner represent the load reduction which would be achieved if all switches controlled as expected.

Validation of Logger Data

We have found that HOBO U-9 state data loggers, when properly installed record the start and end times of AC duty cycles with good reliability. Installation procedures are given Appendix 1. Nevertheless, it is to be expected that some logger data will not accurately reflect AC cycles, and should be discarded. Premise interval kWh (15-minute) collected for customer sites where data loggers are installed is used to validate the logger data. The validation process is accomplished with a sequence of computer programs that: 1) convert the time stamp data collected from U-9 data logger into interval duty cycle; 2) display time series plots of premise kWh and duty cycle with control over time resolution enabling visual comparison of plot detail; 3) calculate cross-correlation between interval kWh and interval duty cycle and display cross-plots of kWh vs. duty cycle. Every logger data file collected from a customer site is reviewed in this fashion, and added to the duty cycle model database when the interval kWh provides confirmation of the AC cycles in the logger data.

Connected Load

Connected load is the average power demand (kW) of a running AC unit over a full cycle. It determines the load reduction (kWH) achieved when AC run time is reduced. Connected load is specified for research sample AC units through the basic engineering formulas,

Apparent Power (kVA) = (Compressor Amps + Fan Amps) * 240 Volts / 1000
Connected Load (kW) = Power Factor * Apparent Power

Rated amps for the compressor (FLA) and fan (RLA) are typically listed on the AC faceplate, and were obtained for 107 of the 112 research sample AC units.

Power factor in this formula is actually different for different AC units, and even varies somewhat for different cycles of the same unit, increasing at high temperature and humidity. However, we can use the synchronous AC duty cycle and interval kWH data obtained from the research sample to estimate a single, best-fitting power factor within the research sample. The first step is a regression, for each sample participant with adequate data, of interval kWH on duty cycle,

$$kWH_t = a + b^* DC_t + \varepsilon_t$$

Notice that if the AC unit runs for an entire 15-minute interval, so that $DC_t = 1$, then the regression coefficient b equals the kWH attributed to the unit during that interval. Dividing by the length (in hours) of the interval converts to kW, so 4^*b is the appropriate estimate of the unit's connected load. Next, the results for connected load obtained in the pervious step become the independent variable, and are regressed on Apparent Power (from faceplate FLA and RLA) . The slope computed in this regression (Apparent Power vs. connected load) is the best-fitting power factor for the group. The power factor obtained for the 2006 research sample was 0.834, and for the 2007 research sample it was 0.826.

For AC units where information on rated amps is not available, the first regression above provides an estimate of connected load for the unit which can be used instead.

Hourly Models for Load Reduction

The key parameter to a Power Manager control strategy is the shed percentage, the percentage of time within a control interval that AC units are prevented from running. When the natural duty cycle of an AC unit exceeds the complement of the shed percentage within a control interval, then run time for the unit is reduced and load reduction is realized. For shed percentage and natural duty cycle expressed as fractions between zero and one, hourly load reduction can be calculated as follows:

Run time reduction = MAX[Duty cycle - (1 - Shed percentage), 0]

Load reduction = Connected load * Run time reduction

These calculations can be performed in any hour of any day (i.e., hour 16 on June 13) for all AC units of the RS group with valid natural duty cycles in that hour to get average load reduction within the RS group for that particular hour. Hourly average load reductions computed in this manner comprise the dependent variable data in the load reduction models.

Hourly weather is represented in the load reduction models with heat index, which combines temperature and humidity into a single variable. Appendix 2 describes how heat index is calculated from temperature and relative humidity. Separate models for load reduction as a function of heat index are fit for each combination of shed percentage and hour of the day needed in the impact evaluation. The heat index variable in the models is a composite based on weather observations from Cincinnati airport, Indianapolis airport, and Louisville airport. Further detail on model fits is given in appendix 3.

Operability Study

Some switches fail to perform as expected when load control is initiated. A study has been conducted during summer 2007 to estimate the proportion of Power Manager switches in Indiana and Kentucky (Model ACP/F032803 manufactured by Corporate Systems Engineering) that shed the AC unit for the prescribed length of time during Power Manager load control events. The operability study involves about 250 Power Manager participants selected randomly, but in such a way as to ensure adequate geographic representation. The RS group described above is included, and 150 additional Power Manger participants (the "OP" group) were selected randomly from zip codes not represented by the RS group. A large proportion (100-200) of these customer sites were visited after each control day (or group of consecutive control days), and the contents of switch registers downloaded into a Palm PC device designed for this purpose. Switch data is transferred to a PC and aggregated into spreadsheet files for analysis. The de-rating factor (or net-to-gross ratio) obtained from the operability study is incorporated into the load impacts reported for the Power Manager program in this report. The remainder of this section describes in detail the switch data collected and how this data is used to obtain a statistically reliable estimate for the de-rating factor.

Based upon the structure of switch registers and the operation of the Power Manager program, the de-rating factor is constructed as a product of two distinct components: the programming factor and the shed factor. In general terms, the programming factor involves switch register settings that can be established prior to a control day and need not be modified from one control day to the next, while the shed factor measures correct switch response to paging signals sent immediately prior to and during a load control event.

The switch registers which are examined to set the value of the programming factor are shown in Table 1.

Table 1. Switch data for programming factor

Register Identifier	Register Value	Power Manager Code
OpReg1 (upper:lower)	1:3	DEI
	1:1	DEK
	2:37	RS group
OpReg5 (upper:lower)	1:2	1.5 kW
	1:1	1.0 kW
	1:3	0.5 kW
Wildcard (hh:mm:ss)	00:22:12	1.5 kW
	00:16:12	1.0 kW
	00:09:18	0.5 kW

Intended values for these registers are shown in column 2 of this table, and column 3 shows what determines correct values for a particular switch. Correct values depend upon the customer's choice of program option, the customer's location , and whether the customer is in the RS group. The wildcard register sets the amount of shed time within a 30-minute control period, so the correct values in Table 1 correspond to shed percentages of 74% for the 1.5 kW option, 54% for 1.0 kW, and 31% for 0.5 kW. If values of the three registers in switch data collected from a customer site match the correct values for that customer, then the programming factor for that observation is set to one. If there is any discrepancy in the register values, then the programming factor for that observation is usually zero, although there are infrequent cases with values between zero and one (discussed further below).

The shed factor is a conditional statistic, conditioned on correct programming, or more precisely programming factor greater than zero. Aside from this, the switch registers examined to determine a value for the shed factor are the activation counter and cumulative shed time. The activation counter records the number of times that the switch has shed since the last clear counters command was received. For example, a three hour control event with 30 minute control period should increment the activation counter by six. The cumulative shed time records the total minutes that the switch has shed since the last clear counters command was received, where shed time during a control period is rounded to the nearest minute for accumulation in this register. Table 2 gives the expected increments to these registers associated with each control day of summer 2007. Table 2 also indicates if counters were cleared immediately prior to a control day.

Table 2. Increments to Activation Counter and Cumulative Shed Time

Control Date	Groups Controlled	Control Period (min)	Counters Cleared	Activation Counter Increment	Cumulative Shed Increment (min) 1.5 kW | 1.0 kW
May 30	RS	30	Yes	4	88 | 64
June 7	DEI; DEK	30	Yes	6	132 | 96
June 21	RS	30	Yes	6	132 | 96
July 17	DEK	30	Yes	4	88 | 64
Aug 1	DEI; DEK; RS	30	Yes	8	176 | 128
Aug 8	DEI; DEK	30	Yes	6	132 | 96
Aug 9	DEI; DEK; RS	30	No	4	88 | 64
Aug 16	DEI; DEK; RS	45	Yes	4	120 | 90
Aug 23	DEI; DEK; RS	30	Yes	4	88 | 64
Aug 29	DEI; DEK	30	No	4	88 | 64

For switch data collected on a given date from a particular customer site, the information in Table 2 is sufficient to determine the expected contents of the activation counter and cumulative shed time registers. If the collected data values match these expected values (and programming factor is nonzero), then the shed factor for this observation is set to 1. The most common discrepancy encountered is when the activation counter and cumulative shed time collected from a switch are zero, and in this case the shed factor is set to zero. Other cases require further inspection to determine an appropriate shed factor for the observation, and occasionally result in a value between zero and one.

A computer program has been constructed to process switch data and identifies observations for which values in registers described above do not match the values expected for that observation. Because of rounding issues, the value for cumulative shed time is considered to match if it is at least as large as the appropriate value from Table 2, and no larger than that value plus one minute for each expected activation. Observations not matching expected values were examined individually to determine if the observation should be retained (i.e., not off-program due to a dropout or tenant change), and to assign appropriate programming and shed factors.

Results for Programming Factor

The RS group has special programming, as shown in Table 1, to enable it to be controlled independent of the general population. Special attention was devoted to achieving proper programming of the RS group. For these reasons, it is not appropriate to include switch data from the RS group in determining a programming factor for the general population. Results described below for the programming factor are based entirely on data from the OP group.

Although there were multiple observations for more than half of the OP switches, only three showed a change in the program factor over the summer. For all three switches, an incorrect factor observed after June 7 was corrected in subsequent observations. Normal programming changes to switch registers, such as tenant transfers, were excluded from the analysis. Programming factor data is aggregated by switch for statistical analysis, using the average value for the few switches with observations not all identical. Of 151 OP switches, 121 were correctly programmed (factor = 1) in all observations and 27 were incorrectly programmed in all observations (factor = 0). Table 3 shows statistical results.

Table 3. Programming factor statistics
(OP switch data only)

Switch count	151
Sample mean	0.809
Standard error	0.032
90% confidence	0.757 – 0.861

A variation adopted in the analysis of the programming factor for 1.5 kW switches in Indiana requires some further explanation. Early in the 2007 control season, it was decided to refresh the programming of all Power Manger switches. To do this efficiently, a global command was issued on June 27 to reprogram all Power Manager switches in Indiana and Kentucky, and this command set the program option in all switches to 1.0 kW. The plan was to reset appropriate switches to program option 1.5 kW with individual paging commands. This process was completed July 9 for Kentucky switches, but stalled midway through the list of Indiana switches. The reason was eventually identified and corrected – a Duke Energy IT change unrelated to the Power Manager program. But for control days in August approximately 50% of Indiana 1.5 kW customers were actually programmed to 1.0 kW (see OpReg5 in Table 1). This discrepancy was temporary in nature and not related to switch performance, and so it was disregarded in setting the programming factor. The discrepancy is incorporated into the impacts reported for August control days by modifying the Indiana participant counts for 1.5 kW and 1.0 kW in Tables 7-12(a) below.

Results for Shed factor

The registers examined for the shed factor (activation counter and cumulative shed time) function in exactly the same manner for correctly programmed RS and OP switches, so it is appropriate to use switch data from both groups to derive shed factor statistics. The shed factor for a single observation is normally zero or one, although there are a few observations with activations and cumulative shed greater than zero but less than expected for the control period. It is much more common for multiple observations of a switch to result in a shed factor of one on some control days and zero on other control days. Nevertheless there is correlation between multiple observations of the same switch. To allow for this correlation, a random effects model has been adopted to analyze shed factor observations, which allows for distinct variances within and between switches. Statistical results with this model are given in Table 4.

Table 4. Shed factor statistics
(OP and RS switches correctly programmed)

Observation count	566
Switch count	208
MS between	0.282
MS within	0.062
Sample mean	0.823
Standard error	0.023
90% confidence	0.785 – 0.861

August 16 Shed Avoiding the Wildcard Register

Incorrect wildcard register settings have been identified as a persistent problem for a significant proportion of switches in the OP group, and are the principal source of deficit in the programming factor. Shedding with the wildcard register enables complete flexibility in specifying the shed percentage that is imposed, and for this reason Power Manager protocols have relied upon configuring the wildcard register. However, the switches allow an alternate shed mechanism which involves selecting from a limited number of fixed shed times, with no need to configure the wildcard register. This alternate mechanism was used on August 16, and data was collected from more than 20 switches with incorrect wildcard registers. Careful examination of the activation counts and cumulative shed time in this data found no evidence any shed on August 16 among those switches with incorrect wildcard registers. In view of these findings, the de-rating factors derived above (Tables 3 and 4) are used for the August 16 load impacts in spite of the different shed mechanism employed.

Load Impacts for 2007 Control Days

In all control periods of 2007 except on August 16, the shed percentages were 74% for program option 1.5 kW, 54% for 1.0 kW, and 31% for 0.5 kW. These shed percentages were chosen to achieve the corresponding load reduction target under typical (median) weather conditions at the summer peak, which correspond to a temperature of 93 deg-F and dew point of 73 deg-F (heat index about 103) .

Hourly weather observations from three weather stations are used in the impact evaluation; Cincinnati airport (CVG), Indianapolis airport (IND), and Louisville airport (SDF). Power Manager customers are assigned to weather region by zip code. Kentucky zip codes and zip codes in southeast Indiana are assigned to CVG, zip codes in south-central and southwest Indiana to SDF , and in central Indiana to IND (Indianapolis airport). Indiana zip codes assigned to CVG or SDF are listed in appendix 4. The blended heat index for Duke Energy Indiana in Tables 5-12(b) is calculated as a weighted average of the corresponding hourly heat index in these weather regions. The weights used for each program option correspond to the counts of Power Manager customers for that program option in the three weather regions.

Average shed kW in Tables 5-12(c) is computed with the hourly load reduction models described in that section and appendix 3. The model developed for the indicated hour and shed percentage is evaluated at the appropriate heat index for the prior hour shown in Tables 5-12(b). The CVG heat index is used to compute shed kW for Duke Energy Kentucky, and blended heat index for the corresponding program option is used to compute shed kW for Duke Energy Indiana.

Hourly potential load impacts in Tables 5-12(d) are computed with the participation counts in Tables 5-12(a) and the average shed kW in Tables 5-12(c). A de-rating factor is applied to these potential impacts to get the de-rated impacts appearing in Tables 5-12(d). This factor is 0.666, the product of sample means obtained for the programming factor (0.809, from Table 3) and shed factor (0.823, from Table 4) in the section discussing the Operability Study. August hourly impacts for Duke Energy Indiana in Tables 7-12(d) were reduced about 4 MW by the reprogramming problem discussed in the previous section. The weather normalized, de-rated, per-participant impact is 1.22 kW for option 1.5, 0.80 kW for option 1.0, and 0.39 kW for option 0.5 (hour 17, heat index 103).

Table 5. Load Impacts for June 7

(5a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20539	13675	23
DEK	4445	2784	2

(5b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	92.6	91.5	93.8	91.8	91.9	91.7
15	92.6	91.0	93.8	91.4	91.5	91.3
16	93.8	91.5	95.5	92.1	92.2	91.9
17	93.3	91.5	94.9	92.0	92.1	91.9

(5c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	1.12	0.65	0.28	1.16	0.68	0.30
16	1.17	0.69	0.30	1.24	0.74	0.32
17	1.30	0.79	0.35	1.38	0.85	0.39

(5d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	24.0	5.3	16.0	3.5
16	33.5	7.5	22.3	5.0
17	37.4	8.5	24.9	5.7

Table 6. DEK Load Impacts for July 17

(6a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	-	-	-
DEK	4447	2816	2

(6b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	92.6	91.5	93.8	-	-	-
15	92.6	91.0	93.8	-	-	-
16	93.8	91.5	95.5	-	-	-
17	93.3	91.5	94.9	-	-	-

(6c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	-	-	-	1.16	0.68	0.30
16	-	-	-	1.24	0.74	0.32
17	-	-	-	1.38	0.85	0.39

(6d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	-	5.3	-	3.5
16	-	7.6	-	5.0
17	-	8.5	-	5.7

Table 7. Load Impacts for August 1

(7a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20563	13993	23
DEK	4442	2812	2
DEI Reprogram	10282	24274	23

(7b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	91.4	89.9	93.9	90.5	90.6	90.3
15	90.6	89.9	95.0	90.6	90.7	90.4
16	92.0	92.5	96.1	92.9	93.0	92.8
17	93.0	92.0	94.0	92.3	92.4	92.3

(7c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	1.06	0.61	0.26	1.10	0.64	0.28
16	1.13	0.66	0.28	1.13	0.66	0.28
17	1.34	0.82	0.37	1.29	0.78	0.35
18	1.38	0.85	0.38	1.41	0.87	0.40

(7d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	22.7	5.0	15.1	3.3
16	32.6	6.9	21.7	4.6
17	39.0	7.9	26.0	5.3
18	40.2	8.7	26.8	5.8

Table 8. Load Impacts for August 8

(8a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20554	13987	23
DEK	4439	2819	2
DEI Reprogram	10277	24264	23

(8b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	102.9	103.0	109.4	103.9	104.0	103.6
15	108.1	104.0	107.9	104.6	104.8	104.5
16	104.2	105.4	109.2	105.9	105.9	105.7
17	91.9	106.8	109.7	106.8	106.6	106.4

(8c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	1.71	1.08	0.50	1.66	1.05	0.49
16	1.85	1.21	0.56	2.02	1.33	0.63
17	1.97	1.32	0.65	1.89	1.25	0.62

(8d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	37.8	7.8	25.2	5.2
16	54.8	12.7	36.5	8.5
17	58.9	11.9	39.2	7.9

Table 9. Load Impacts for August 9

(9a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20533	13968	25
DEK	4442	2815	2
DEI Reprogram	10267	24234	25

(9b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	105.5	101.6	109.7	102.8	103.0	102.4
15	105.1	98.9	108.8	100.3	100.6	99.9
16	104.6	98.9	108.8	100.3	100.6	99.9
17	105.1	100.2	106.7	101.2	101.4	101.0

(9c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
16	1.63	1.05	0.47	1.87	1.22	0.57
17	1.70	1.11	0.52	1.90	1.27	0.62

(9d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
16	36.0	8.8	24.0	5.9
17	50.4	12.0	33.6	8.0

Table 10. Load Impacts for August 16

(10a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20495	13942	29
DEK	4433	2813	4
DEI Reprogram	10248	24189	29

(10b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	107.2	101.6	107.8	102.6	102.8	102.4
15	104.2	97.5	106.0	98.8	99.1	98.5
16	104.7	104.1	107.8	104.6	104.7	104.4
17	99.7	92.2	93.2	92.5	92.7	92.8

(10c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	1.43	0.93	0.31	1.64	1.07	0.37
16	1.34	0.88	0.29	1.60	1.06	0.36
17	1.68	1.15	0.41	1.68	1.15	0.42

(10d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	31.7	7.7	21.1	5.1
16	39.7	10.1	26.5	6.7
17	50.5	10.7	33.6	7.1

Table 11. Load Impacts for August 23

(11a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20456	13946	32
DEK	4428	2801	5
DEI Reprogram	10228	24174	32

(11b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	100.8	98.0	103.0	98.8	98.9	98.5
15	101.3	99.3	103.5	99.9	100.0	99.7
16	101.4	98.6	103.5	99.3	99.4	99.0
17	100.8	98.6	102.7	99.2	99.3	99.0

(11c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
15	1.46	0.90	0.41	1.56	0.97	0.45
16	1.60	1.02	0.46	1.68	1.07	0.49

(11d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
15	31.9	7.2	21.2	4.8
16	47.1	10.4	31.3	7.0

Table 12. Load Impacts for August 29

(12a)

	Participant Count		
	1.5 kW	1.0 kW	0.5 kW
DEI	20453	13937	33
DEK	4429	2796	6
DEI Reprogram	10227	24163	33

(12b)

	Heat Index			Blended Heat Index for DEI		
Hour	CVG	IND	SDF	1.5 kW	1.0 kW	0.5 kW
14	97.9	95.1	95.8	95.3	95.4	95.3
15	96.1	96.1	101.1	96.8	96.9	96.4
16	96.7	94.5	101.3	95.5	95.6	95.0
17	98.0	95.8	95.5	95.8	95.8	95.9

(12c)

	Duty Cycle Model Average Shed kW					
	DEI			DEK		
Hour	1.5 kW	1.0 kW	0.5 kW	1.5 kW	1.0 kW	0.5 kW
16	1.45	0.90	0.40	1.41	0.87	0.39
17	1.46	0.92	0.42	1.52	0.96	0.45

(12d)

	Potential Impact (MW)		De-rated Impact (MW)	
Hour	DEI	DEK	DEI	DEK
16	31.6	6.5	21.1	4.3
17	42.7	9.4	28.4	6.3

Action Plan for Improving Load Impact

The operability study has identified many customer sites where switches have not been effectively configured with paging signals (62 in Indiana, 16 in Kentucky), or where properly configured switches appear not to have not shed during any of the 2007 control intervals (8 in Indiana, 6 in Kentucky). Diagnostic testing of these sites and switches will begin immediately, to identify the cause of these problems and determine whether the problems are associated with the customer site (e.g., a problem with the paging signal or switch installation) or with the switch itself. The customer locations are displayed in appendix 5 and 6.

A technician will visit several of these customer sites with problematic switch performance. The technician will communicate by phone with someone using the paging software and document results of several switch tests. He will also use the handheld device to observe and download the results of the tests. The type of additional testing on the switches will include:

- Observing whether or not our test on/test off commands are being transmitted to the switch
- Sending a test paging command to a different paging device at the same location as the switch to determine if the page can be transmitted successfully
- Plugging in a special test switch to an outside outlet if available at the site and sending commands to it to determine if the paged commands get transmitted.
- Open/close the disconnect and repeat the paging tests and record results
- Observe and record any indication of tampering
- Record location of possible physical structures that could impede paging commands

A checklist showing actions to be performed during site visits for diagnostic testing is attached as appendix 7. Switches that appear to be completely non-functioning will be removed at a later time and taken to the switch vendor for internal component testing. A technical resource from the switch vendor has already been assigned to this project.

In addition to these tests, we will revisit a sampling of switches that were found to be incorrectly reprogrammed last year. Again the registers will be read with the hand-held device and the data downloaded. The purpose of this will be to assess the success of the reprogramming effort.

Appendix 1. HOBO U9 Logger Installation and Data Retrieval Procedure for 2007

HOBO U9 Logger

The HOBO U9-001 logger records the change of state of the compressor by direct connection. Each time the compressor starts or stops, the logger records the new state, along with the date/timestamp. The logger directly reads the continuity of a set of relay contacts that close when the compressor is started. The relay is field installed at the time of the logger installation. The relay has a 240 volt coil wired in parallel with the compressor and when the compressor is energized by the compressor contactor, the relay coil is simultaneously energized, pulling in the contacts. The logger interprets this as a change of compressor state (the start of the compressor). When the contactor deenergizes the compressor windings, the relay contacts open and the logger interprets this as another change of state (the end of the compressor run cycle).

The loggers will be installed in a weatherproof enclosure to keep them dry.

Definitions:

HOBOware – the software application that is used to launch and readout the HOBO loggers.

Launch – Process that turns on the logger, checks its battery and prepares it to begin logging data. A logger must be launched initially and after each data readout. Launching deletes all on/off state data in the logger.

Readout – off-loads the data from the logger. When reading out a logger, it is possible to either stop the logging process or to continue logging. The data in the memory is not deleted simply by reading out the logger. You must launch the logger to delete the old data.

Procedures

Update your HOBOware version. The version on the CD is out of date. You need to update to HOBOware Pro.

PC Time Set

Each HOBO U9 logger is launched by the HOBOware application on the PC – this sets the clock in the logger. Set the PC time each day before connecting the PC to a logger. This can be done by either the time-syncing feature of the Microsoft operating system (if your version supports that feature) or by connecting over the Internet to a site to sync with the atomic clock. Here are links to free utilities that can sync the PC to the atomic clock.
http://www.analogx.com/contents/download/network/ats.htm
http://www.worldtimeserver.com/atomic-clock/

During the initial launch, install new battery in all loggers.

Replacing Batteries

1. Remove logger from weather proof case
2. Unplug grey wire from logger
3. Remove battery using a pencil.
4. Install new battery with positive side facing up.
5. Plug the grey wire back into the logger.

Installation

Suggested tools: Nut driver, screw drivers, small diagonal cutters.
Materials: Logger, relay, 2 conductor wire, nylon cable ties, extra sheet metal screws.

1. Do not install on rainy days or when humidity approaches 95% (near dewfall).
2. Set the PC time before leaving home.
3. Open disconnect switch or pull fuses.
4. Open A/C unit.
5. Determine which relay to use.
    a. If voltage is present on the load side of the contactor, a 24 volt coil relay must be used (Part number 90-293q). To energize this relay, low voltage from the contactor must be connected to 1 and 3. The black and white wire from the logger should be connected to numbers 2 and 4 on the relay (normally open).
    b. If voltage is NOT present on the load side of the contactor, a 240 volt coil relay must be used (Type 91 relay). To energize the Type 91 relay, connect wires on the load side of the contactor to each side of the coil on the relay. The logger should be connected to 1 and 3 (normally open).
    c. If voltage is NOT present and there are clearance issues, the part number 90-295q should be used. To energize this relay, connect two wires from the load side of the contactor to 1 and 3 on the relay. The logger should be connected to 2 and 4 (normally open).
6. Mount the relay in the control compartment of the A/C unit, near the contactor.
7. Mount the black case outside of the ac unit. Attach black case to the conduit between the Power Manager switch and the air conditioning unit with a wire-tie. Locate the black case containing the logger in the shade and out of direct rainfall if possible.
8. Run the gray wire from the logger along the conduit and through a grommet leading to the air conditioning unit control compartment.
9. Connect the black and white wires from the logger to the relay as described above in step 5.
10. Secure all wiring with cable ties.
11. Connect the logger to the PC with the USB cable and launch the logger by clicking the Launch Logger icon.
12. HOBOware Launch Logger screen. These fields are to be completed at time of launch:

    Description: must be set to **serial number**

    State channels S-1: name = State Sensor, open = State Off, closed = State On

Channels to log: **UN-check** Logger's Battery Voltage
Launch Options: **Now**.

13. After all fields have been set, click **Launch**.
14. After the logger has been relaunched, click the Logger status icon and verify that the current status is "Launch, Logging" and the proper state of compressor running, On or Off, is being displayed.
15. While in the logger status mode, verify that the logger is correctly recording the compressor starts and stops. To do this, close the disconnect switch, manually engage the contactor to force the compressor to start, taking care to avoid the high voltage terminals on the contactor or start capacitor. Verify the state sensor display on the screen indicates State On when the compressor is running and State Off when the compressor is off. If you are not getting the correct response, see the **Troubleshooting** section below.
16. After verifying proper operation, disconnect the USB cable, close the logger enclosure, remount the logger.
17. Close A/C unit, replacing any lost or damaged sheet metal screws.
18. If still open, close disconnect switch or replace fuses. Make sure fuse holder is properly oriented.

Readout/Relaunch
The readout schedule for U9 loggers is every four weeks.

Do not readout the logger during a Power Manager event. You can call 877-392-4848 to see if there it an event under way. If the red LED on the Power Manager device is lit, there is an event under way and you should wait until a non-event day to readout the loggers.

Loss of good data will be minimized if you can avoid readouts during afternoon hours (12:00 - 6:00 PM), especially when temperature exceeds 85 deg-F. However, this is not an essential requirement, and can be disregarded when it would significantly complicate data collection.

Suggested tools: Nut driver, screw drivers, small diagonal cutters.
Materials: nylon cable ties, extra sheet metal screws, logger batteries

1. Do not readout on rainy days or when humidity approaches 95% (near dewfall).
2. Set the PC time before leaving home.
3. Connect logger to PC using the USB cable.
4. Using HOBOware, click the Readout logger icon. It will ask if you want to stop logging. Click **Stop**.
5. While doing the readout, HOBOware will suggest a file name based on the Description that was defined at the time of last launching. This file name should be the logger serial number perhaps with additional numerical suffixes if you are saving to a folder with other files with the same name. Click **Save**.
6. The Plot Setup screen will now appear. Click Cancel.
7. You must relaunch the logger to clear its memory. Click the Launch Logger icon.
8. HOBOware Launch Logger screen.

9. If the battery level is 25% or less, you must replace the battery in the logger.
10. To replace battery, remove logger from weather-proof case.
11. Unplug grey wire from logger.
12. Remove battery.
13. Install new battery with positive side facing up.
14. Plug the grey wire back into the logger.
15. These fields to be completed at time of launch:
    Description: must be set to **serial number**
    State channels S-1: name = State Sensor, open = State Off, closed = State On
    Channels to log: **UN-check** Logger's Battery Voltage
    Launch Options: Now.
16. After all fields have been set, click **Launch**.
17. After the logger has been relaunched, click the Logger status icon and verify that the current status is "Launch, Logging" and the proper state of compressor running, On or Off, is being displayed.
18. After verifying proper operation, disconnect the USB cable, close the logger enclosure, remount the logger.
19. Helpful tip on closing weather-proof case: Place logger in case such that grey wire is on the hinge side of the case lid. The length adjustment of grey wire can be accomplished by loosening the outside nut on the case and adjusting the wire so that the lid of the case closes easily. A 2 ½ inch length of grey wire on the inside of the case will allow the lid to close easily.

Email the all data files to Carol Burwick at amanda.goins@duke-energy.com . Save a backup copy of the data files to a diskette or CD.

Troubleshooting
You can check the green LED to see if the logger is recording the A/C start but in sunlight it will probably be easier to look at the Logger Status screen in HOBOware. The status should be Launched, Logging and the State should be On when the compressor is running and Off when the compressor is off.

If the logger is not logging, it needs to be launched.

If the State does not change to On when the compressor starts, the problem is either with relay or the wiring. Make sure the relay contacts close when the compressor starts and they open when the compressor stops. You can do this by checking the stereo plug with an ohm meter. Connect the meter to the tip and sleeve of the plug (the middle ring is not connected to anything) and measure the resistance when the compressor is off and again when the compressor is running. When the compressor is running, the resistance should be near zero (less than 5 ohms). When the compressor is off, the resistance should be infinity. If this is not the case, make the same check at the terminals of the relay contacts to determine if the problem is with the relay or the cable. Also verify that the relay coil is energized with 240 vac when the unit is running. If not, rewire it.

Appendix 2. Heat Index

The basic formula we use to calculate heat index is a 16 element polynomial in temperature (T, deg-F), and relative humidity (H, 0-100),

```
HI = 1.6923e+1 + 1.85212e-1 * T + 9.41695e-3 * T^2
   - 3.8646e-5 * T^3 + 5.37941 * H + 7.28898e-3 * H^2
   + 2.91583e-5 * H^3 - 1.00254e-1 * (T * H)
   + 3.45372e-4 * T^2 * H + 1.42721e-6 * T^3 * H
   - 8.14971e-4 * T * H^2 + 1.97483e-7 * T * H^3
   + 1.02102e-5 * T^2 * H^2 - 2.18429e-8 * T^3 * H^2
   + 8.43296e-10 * T^2 * H^3 - 4.81975e-11 * T^3 * H^3
```

This formula is not used for temperature below 70, and in this case we define heat index to be identical to temperature. To achieve a smooth transition, we use the following definition for temperature between 70 and 80,

$$\text{Heat index} = 0.1 * (T - 70) * HI + 0.1 * (80 - T) * T$$

For temperature above 80, the heat index is HI.

Appendix 3. Hourly Load Reduction Model Fits

The model specification for hourly load reduction is of the form

$$LR = a + b * MAX[(HI - HI_0), 0]$$

Coefficients a, b and the knot point HI_0 are model parameters to be determined through the model fit procedure. Data for average load reduction (LR) used in the model fit procedure was obtained from the RS group as described in section 2.3. The data for hourly heat index (HI) is a composite of heat index computed from hourly weather observations at the weather stations CVG, IND, SDF. Each RS group participant is associated with a weather station, as described in Section 4 (see also Appendix 4). The relative weighting of each weather station in the composite HI is determined on an hourly basis according to the counts of valid RS duty cycles in that hour associated with the three weather stations. Weather observations are collected near the end of an hour. Since we want HI in the above formula to be heat index at the beginning of the hour of the LR data, HI must correspond to the weather observations for the prior hour.

For impact evaluation during 2007 control periods, models are needed for hours 15-18 and shed percentages 74%, 54%, 31%, 67%, 50%, 22% (not all combinations are required). The general approach of the model fit procedure is to perform a sequence of regressions with the equation given above, resulting in values for parameters a and b, as the knot point HI_0 varies over a grid. The model with highest R-square is selected. Model parameters obtained with this procedure are given in the table below:

Load Reduction Model Parameters

Shed%	Hour	Knot	a	b	R-sq
74	15	85.9	0.831	0.490	0.711
74	16	87.2	0.958	0.509	0.685
74	17	85.2	0.960	0.487	0.637
74	18	85.2	1.015	0.507	0.609
54	15	85.9	0.441	0.356	0.714
54	16	87.2	0.525	0.387	0.713
54	17	85.2	0.525	0.382	0.655
54	18	85.2	0.564	0.397	0.607
31	15	86.3	0.183	0.184	0.667
31	16	87.2	0.215	0.198	0.673
31	17	85.2	0.209	0.214	0.644
31	18	87.3	0.269	0.227	0.567
67	15	85.9	0.676	0.451	0.712
67	16	87.2	0.791	0.475	0.700
67	17	85.2	0.794	0.456	0.647
50	15	86.0	0.385	0.326	0.712
50	16	87.2	0.456	0.354	0.710
50	17	85.2	0.456	0.354	0.656
22	15	86.0	0.110	0.122	0.626
22	16	87.2	0.136	0.134	0.665
22	17	85.2	0.127	0.149	0.638

Appendix 4. Indiana Weather Regions

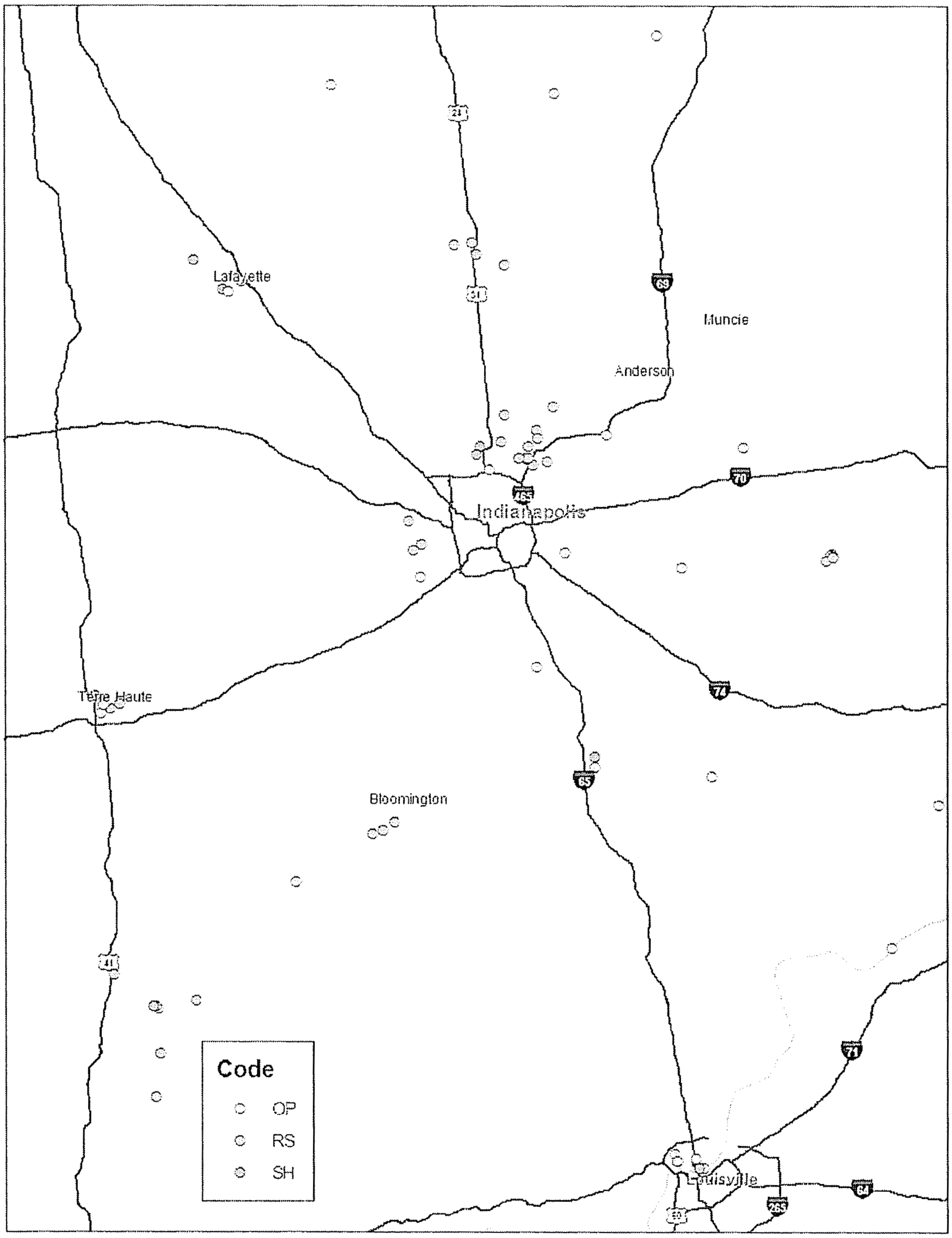
Indiana Zip Codes Assigned to Weather Region CVG:

47001	47023	47036
47003	47024	47037
47006	47025	47041
47010	47030	47042
47012	47031	47043
47016	47032	47060
47018	47034	47223
47022	47035	47250

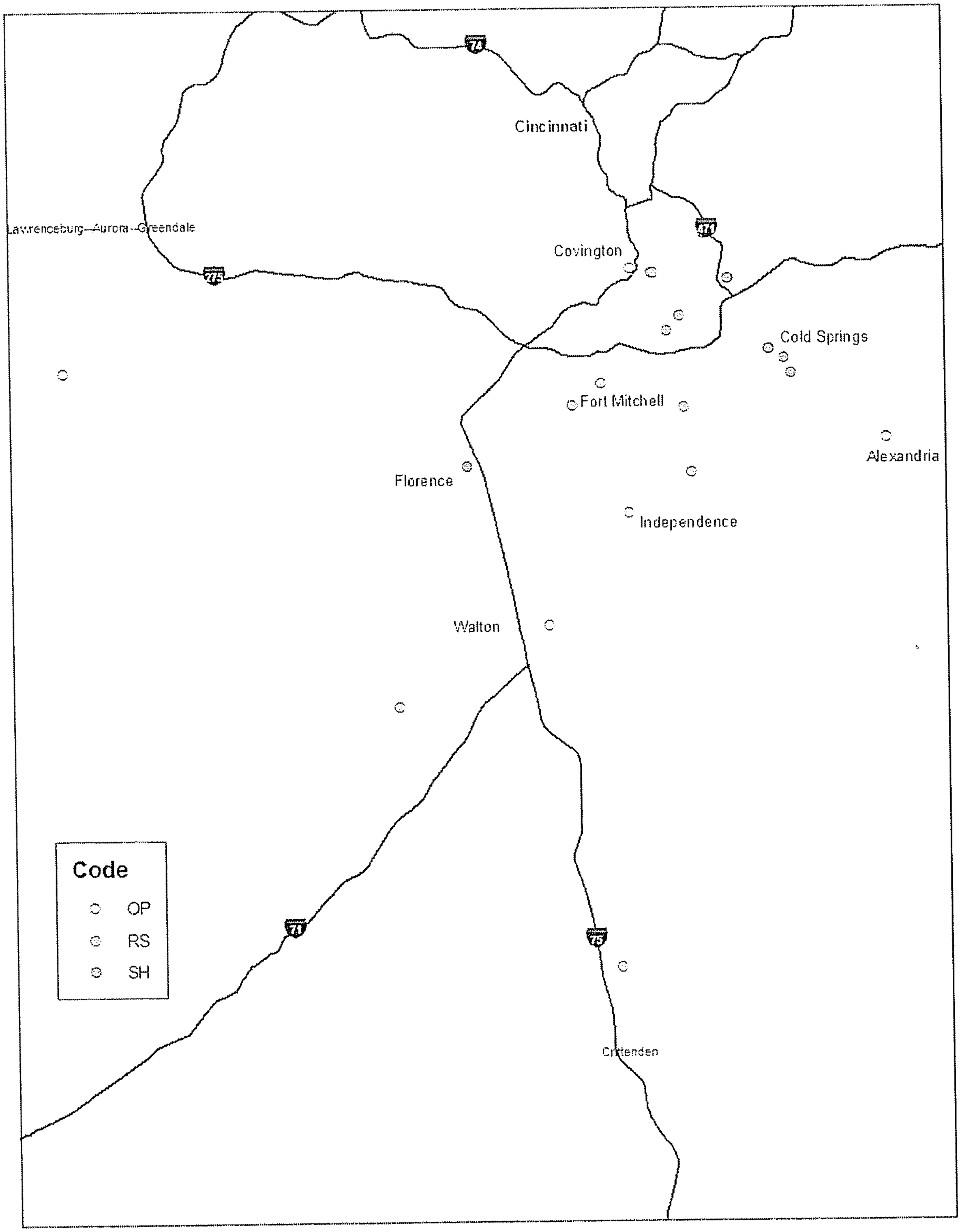
Indiana Zip Codes Assigned to Weather Regions SDF:

47102	47161	47524
47104	47162	47553
47106	47164	47557
47108	47165	47567
47111	47166	47581
47112	47167	47584
47114	47172	47591
47115	47220	47597
47118	47227	47612
47119	47229	47613
47120	47230	47616
47122	47231	47619
47123	47243	47633
47124	47260	47639
47125	47270	47640
47129	47281	47647
47130	47282	47649
47136	47432	47654
47137	47446	47660
47138	47452	47665
47140	47454	47666
47145	47469	47670
47147	47470	47683
47150		

Appendix 5. Indiana - Field Testing Locations



Appendix 6. Kentucky- Field Testing Locations



Appendix 7. Power Manger QC Field Test Check List

Date ___________ **Address** _______________
Time___________ **Temperature**______________

Switch ID__________

- ❑ Once at the house have Rose send the test to the plug in switch.
- ❑ Plug into the switch and read the register information:

Switch Data	
Option (Register 5)	
Opco (Register 1)	
Substation (Register 3)	
Feeder (Register 4)	
Group (Register 8)	

Activation Information	
Relay #1 Activation Counter	
Relay #1 Cumulative Shed	
Frequency	

General Inspection

- ❑ Verify that the switch is still connected to the air conditioner
  - ❑ Yes
  - ❑ No

- ❑ Check if the amber light is flashing on the switch
  - ❑ Yes
  - ❑ No

- ❑ Check the test on/ off light- (Green is on)
  - ❑ On
  - ❑ Off

- ❑ Verify the Paging signal 1…..2……3

- ❑ Call Rose and have the switch put in the special test group

- Plug into the switch and read the register information

Switch Data	
Option (Register 5)	
Opco (Register 1)	
Substation (Register 3)	
Feeder (Register 4)	
Group (Register 8)	

- If the switch was verified in group ______ have Rose send a short event to the switch. Plug into the switch and read the register information

Switch Data	
Option (Register 5)	
Opco (Register 1)	
Substation (Register 3)	
Feeder (Register 4)	
Group (Register 8)	

Activation Information	
Relay #1 Activation Counter	
Relay #1 Cumulative Shed	
Frequency	

- If the switch responds to one or both of the tests above, move on to the next switch
- If the switch doesn't respond to the tests, open and close the disconnect and retry both tests.

Disconnect opened and closed:

- Call Rose and have the switch put in the special test group

- Plug into the switch and read the register information

Switch Data	
Option (Register 5)	
Opco (Register 1)	
Substation (Register 3)	
Feeder (Register 4)	
Group (Register 8)	

- If the switch was verified in group ______ have Rose send a short event to the switch. Plug into the switch and read the register information

Switch Data	
Option (Register 5)	
Opco (Register 1)	
Substation (Register 3)	
Feeder (Register 4)	
Group (Register 8)	

Activation Information	
Relay #1 Activation Counter	
Relay #1 Cumulative Shed	
Frequency	

Appendix 8: Power Manger Customer and Impact Evaluation Study 2006

Power Manager Customer and Impact Evaluation Study

Duke Energy Indiana
Duke Energy Kentucky

2006 Event Year

Impact Modeling/ Metering
conducted by Duke Energy staff/ contractors

Customer Evaluation
conducted by Integral Analytics

Report Compilation and Review
conducted by Integral Analytics

Quick Summary

Duke Energy currently offers a residential load control program called Power Manager to qualifying residential customers. This program offers customers a monetary incentive for reducing their air conditioning during peak demand periods. Duke is evaluating the current program to find ways to increase participation, insure customer satisfaction and improve the impact of the program. Several different methods of analysis were used to evaluate the program. A mail satisfaction survey was conducted with current participants. A conjoint study was conducted with participants as well as non-participants to discover what attracts customers to sign up for the program. Finally, a load research impact evaluation was completed using data loggers, end use metering and whole house metering equipment.

The Power Manager satisfaction survey revealed that the participant's satisfaction with the phone representative that handled their call was the most important indicator of overall satisfaction of the Power Manager program. The survey also revealed that the level of the participant's comfort during a control event was the second most important factor of participant's satisfaction. This important finding suggests that Duke needs to pay just as much attention to the process and operational aspects of participant sign up as it does on the program design and/or financial incentives.

Further, It was discovered through the conjoint analysis that the current program incentive offering of $25 and $35 was the most attractive incentive to customers to participate in the program. Alternatives like free thermostats held less appeal. It was also uncovered that a per event incentive is the most important feature to customers when they are considering signing up for the program. Presumably, this event savings is attractive in that it is shared with customers, and it increases as the level of potential interruptions increases.

Finally, It was discovered through the impact evaluation of the program that load impact estimates of the load control events done during the summer were substantially below the targeted load reduction. However, the report details possible reasons for the low impacts, cites a plan to diagnose the source of the problem, and fix it. At present, it is believed that the most likely reason for the low impacts is due to operational problems experienced with the signaling software tested among just the metered homes, and perhaps did not occur to the same extent, or perhaps not at all, among the population participants at large.

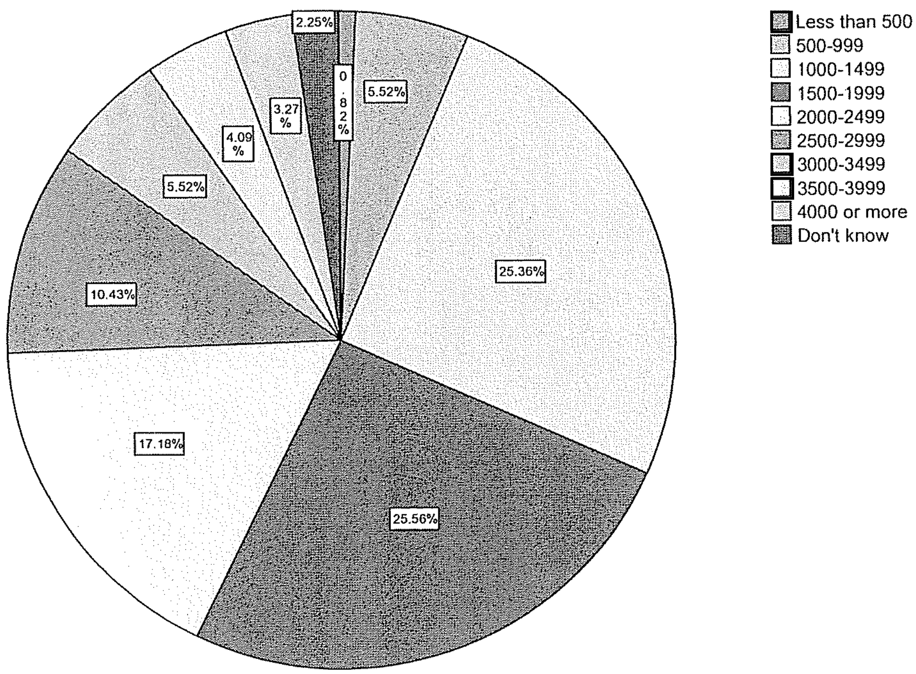
Although, the load impact estimates were substantially below the targeted load reduction expected, the program still passed cost-effectiveness tests. The Utility Cost Test result was 2.38.

Power Manager Satisfaction Survey

A Power Manager Satisfaction study was conducted in September 2006. A survey was sent to a random sample of 3,000 current Power Manager customers, 2,000 Indiana and 1,000 Kentucky. Of the 3,000 surveys that were sent out 1,392 customers responded for a 46% response rate. The intent of the study was to discover ways to increase the number of customers signing up for the program as well as to increase the satisfaction of the customers currently on the program.

Power Manager Participants Square Footage

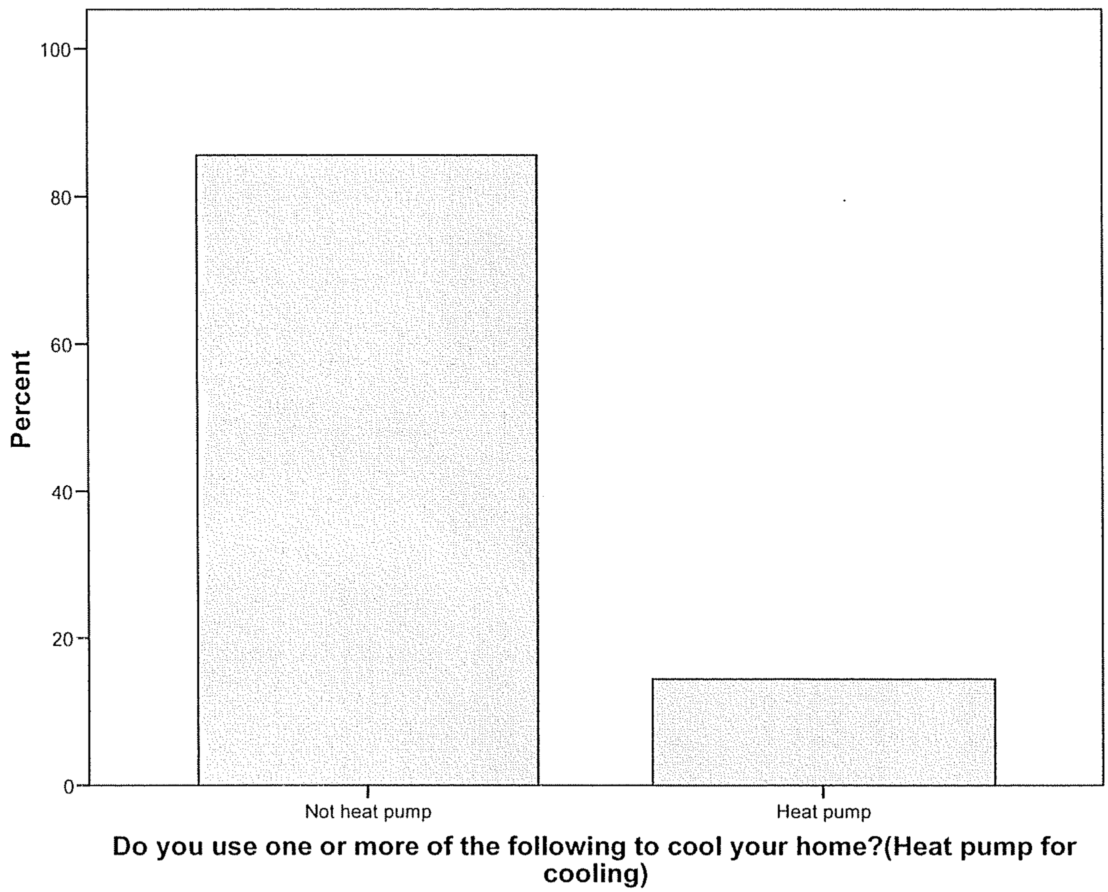
More than 50% of respondents live in a house between 1,000 and 2,000 square feet. Less than 1% lives in home smaller than 500 square feet. About one quarter of the population lives in homes between 2,000 and 2,999 square feet.



About how many square feet of living space are in your home?

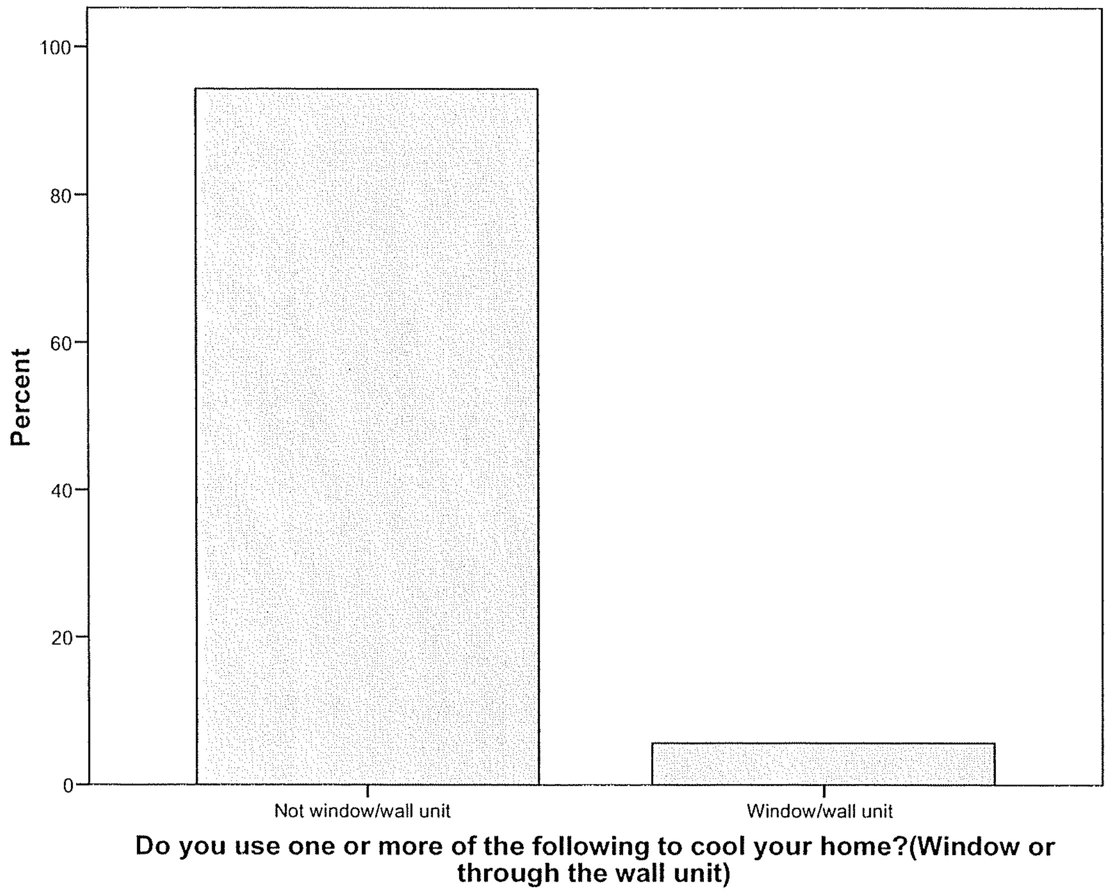
Heat Pump Participants vs. Central Air Participants

The primary source of cooling among participants currently is central air systems. Only 14.4% of the respondents use heat pumps for cooling their homes.



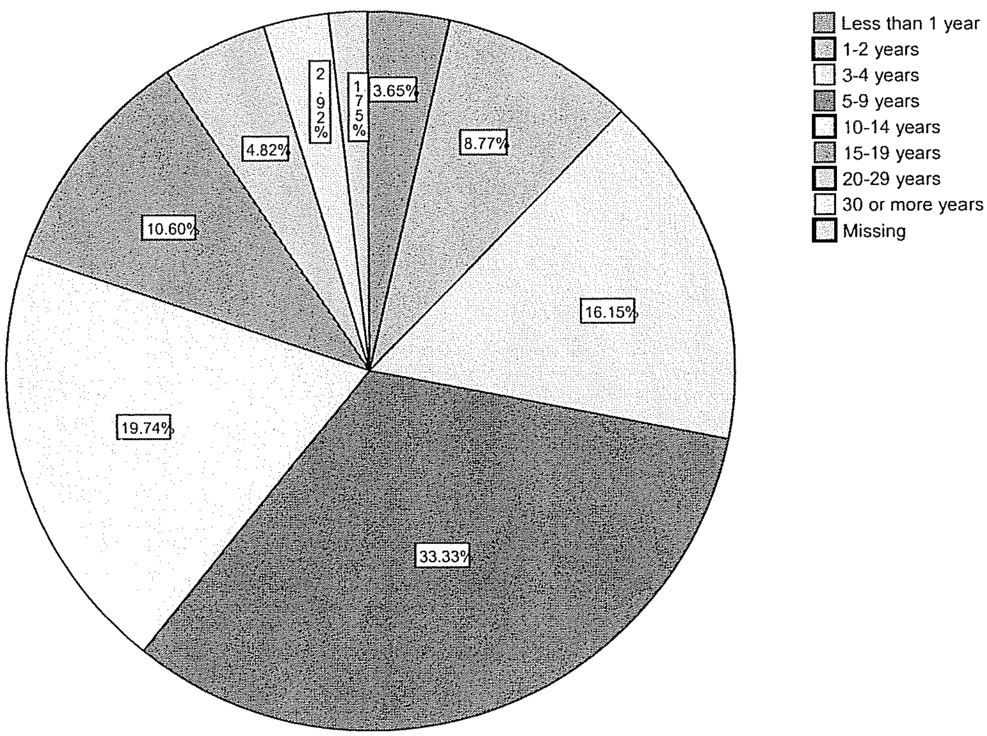
Window Unit Participants vs. Other Cooling System Participants

Although window unit cooling systems are not usually as efficient 5.7% of participants use window/wall units (sometimes in conjunction with AC). This group would make a good candidate for participation in the program due to high usage during peak hours.



Age of Cooling System

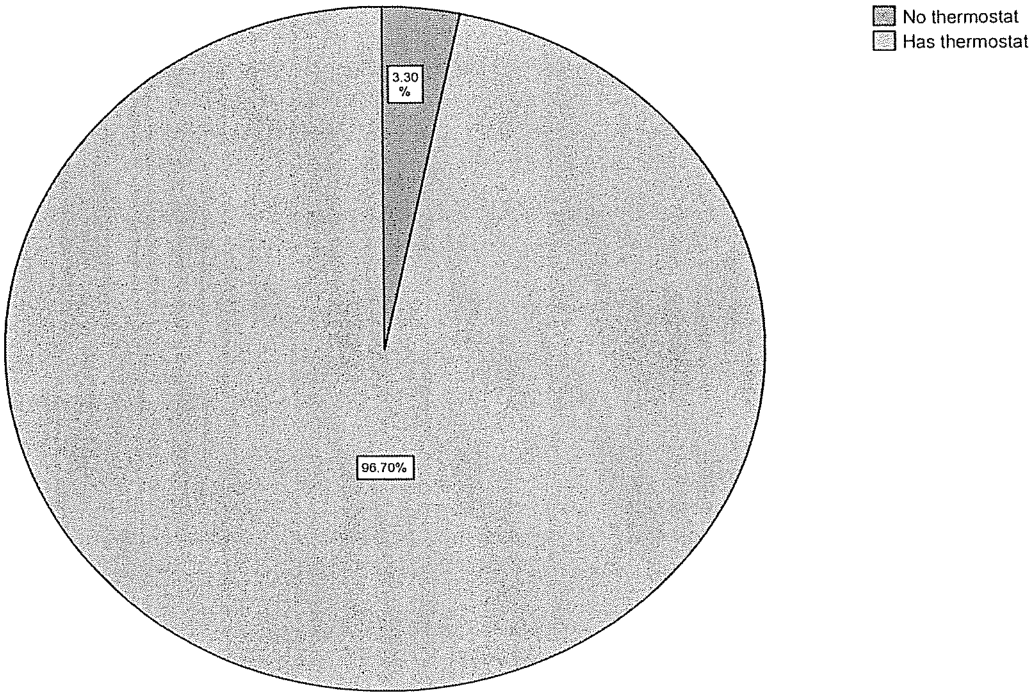
More than half of the sample population has cooling systems that have been installed between 5 and 14 years ago. One third of the cooling systems were about 5 to 9 years old. 18.34% of participants had cooling systems that were 10-30 years old or more. Only about 12.42% are using newer high efficient cooling systems that have been installed during the past two years. It is suggested to try and not target customers with high efficient cooling systems.



How old is your cooling system?

Thermostat Participants vs. No Thermostat Participants

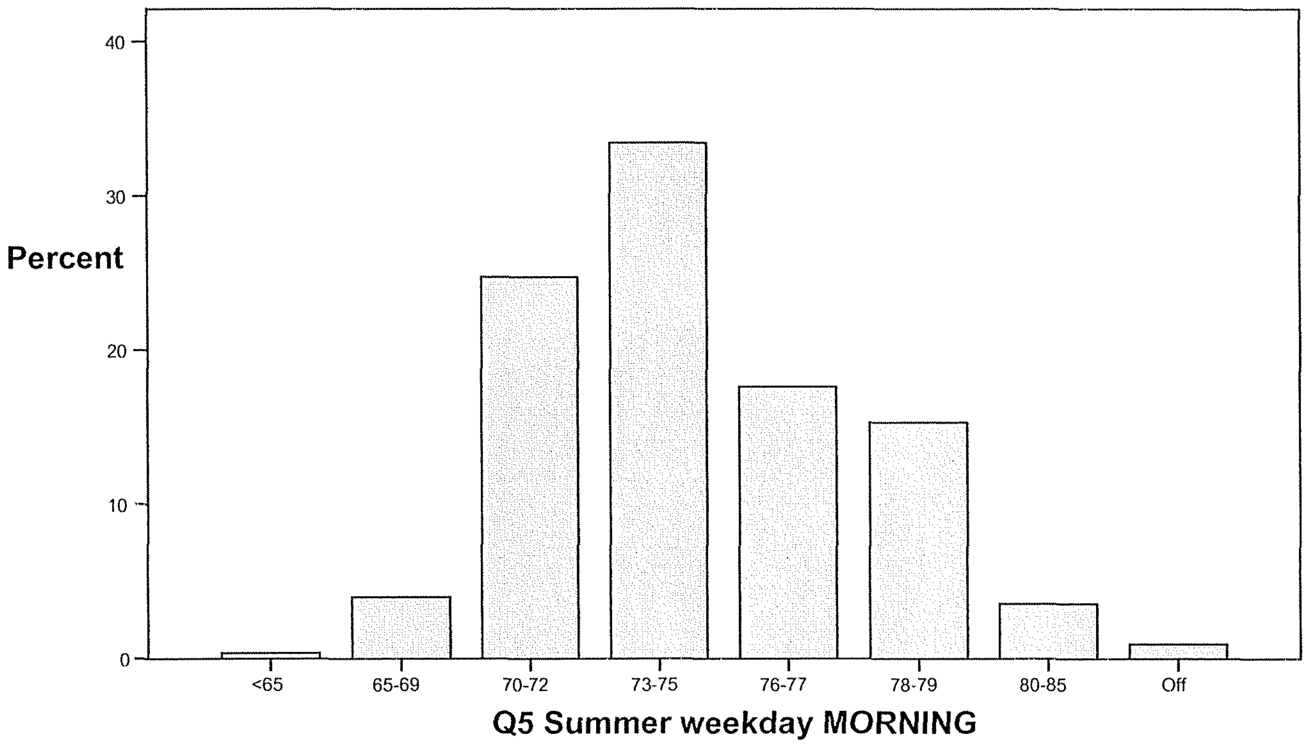
Only about 3.3% of participants have no thermostat. Not having a thermostat is a good indication of an older cooling system. Older systems with no thermostat are less efficient.



Do not have a thermostat

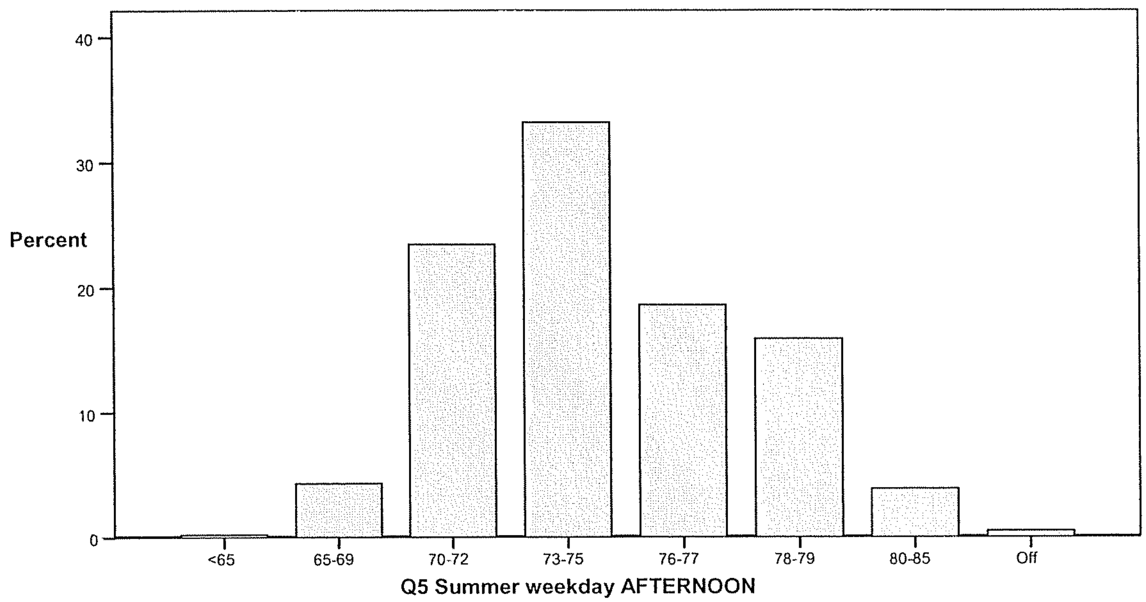
Temperature of Thermostat Summer Weekday Morning

About one third of respondents set their thermostat between 73 to 75 degrees in summer weekday mornings. 37.1% of customers set their thermostat above 76 degrees with .9% of which turn it off during summer morning weekdays.



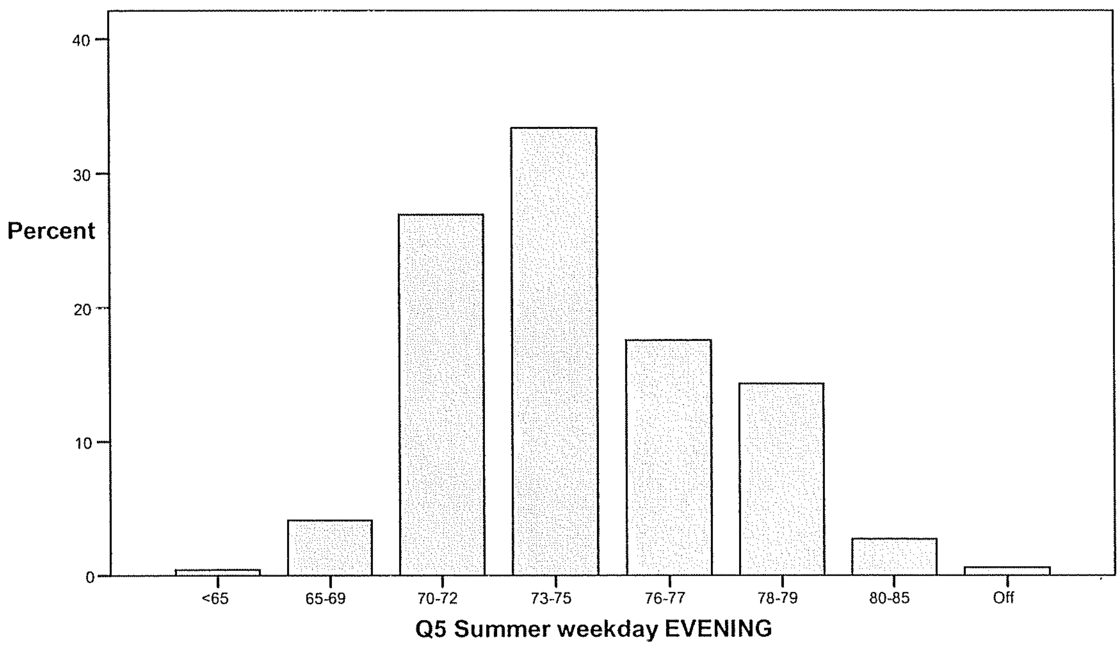
Temperature of Thermostat Summer Weekday Afternoon

About one third of respondents set their thermostat between 73 to 75 degrees. 38.9% of customers set their thermostat above 76 degrees with .5% of which turn it off during summer afternoon weekdays.



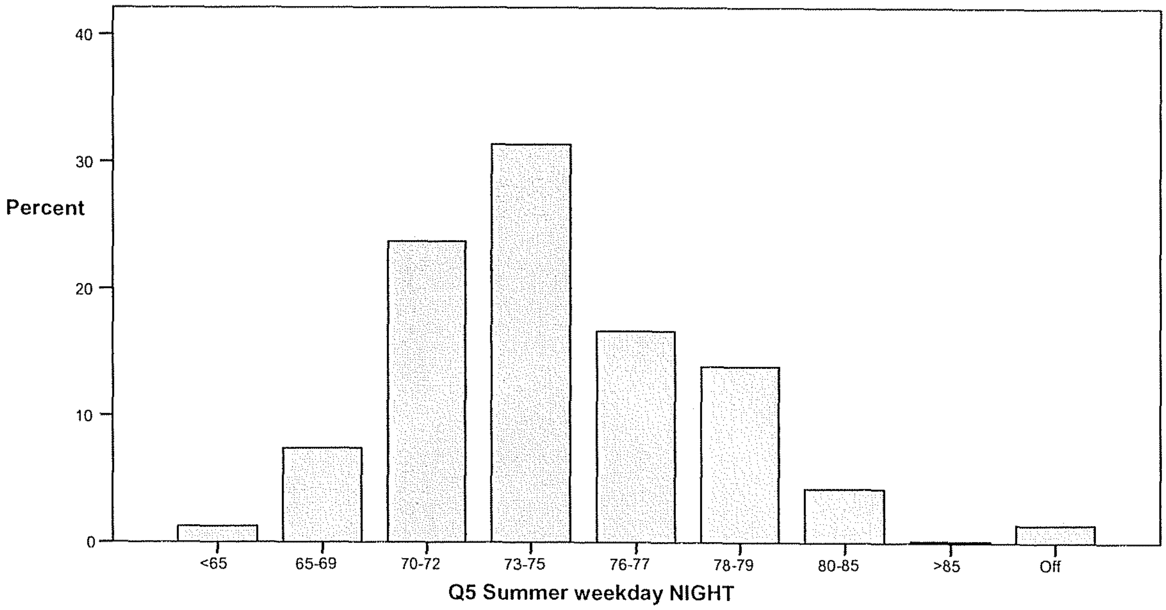
Temperature of Thermostat Summer Weekday Evening

About one third of respondents set their thermostat between 73 to 75 degrees. 35.1% of customers set their thermostat above 76 degrees with .6% of which turn it off during summer evening weekdays.



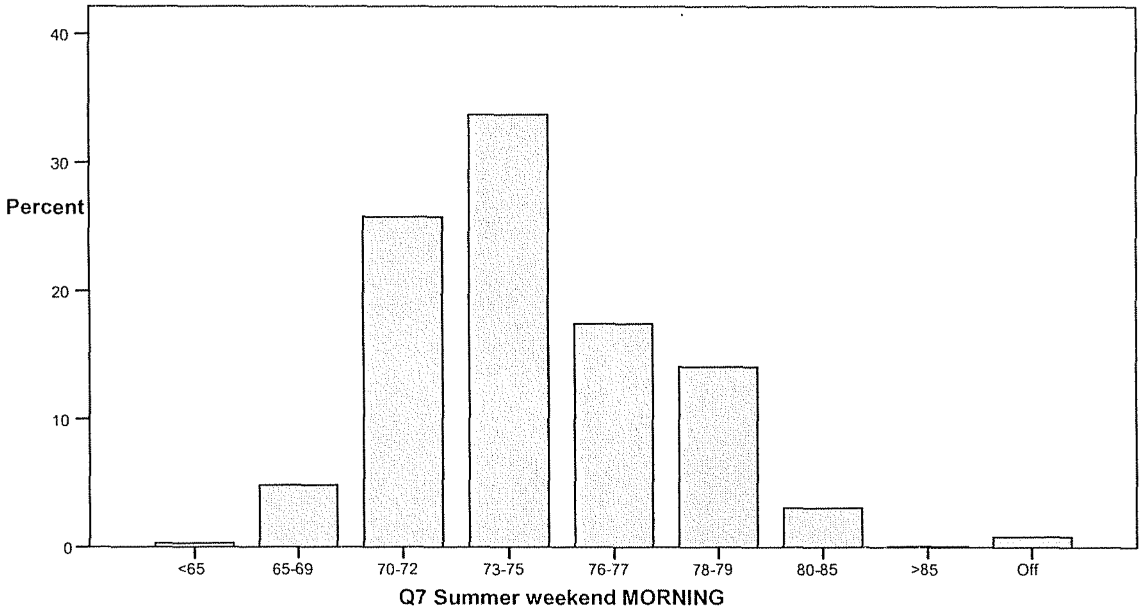
Temperature of Thermostat Summer Weekday Night

Less than one third (31.3%) of respondents set their thermostat between 73 to 75 degrees. 36.4% of customers set their thermostat above 76 degrees with 1.4% of which turn it off during summer night weekdays.



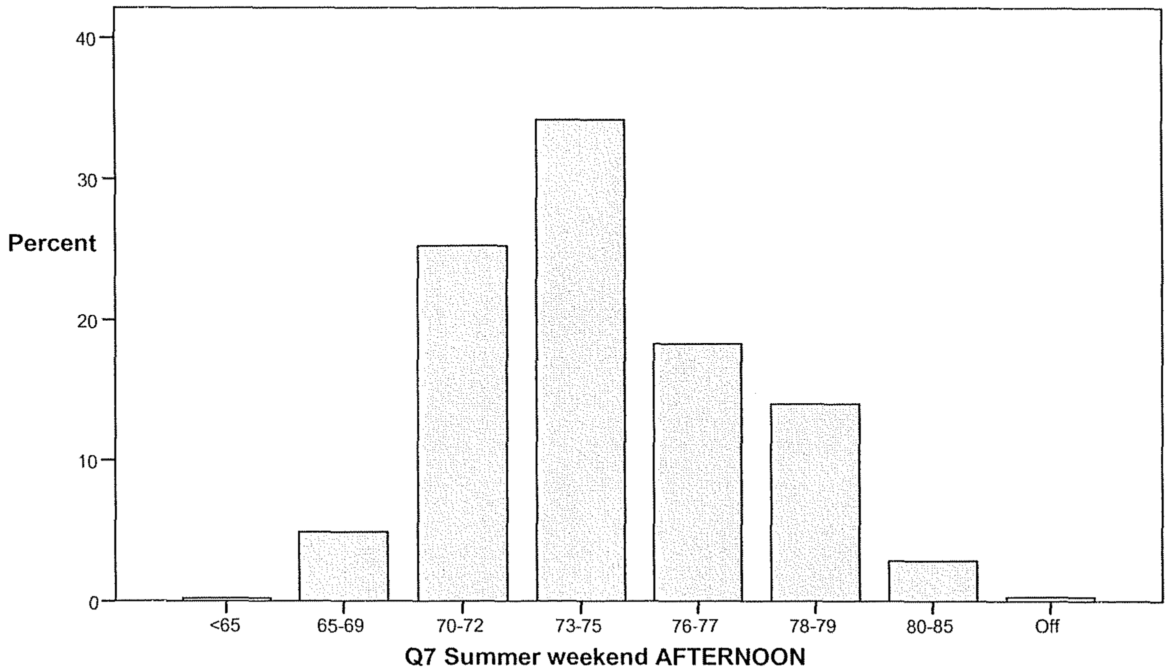
Temperature of Thermostat Summer Weekend Morning

About one third of respondents set their thermostat between 73 to 75 degrees. 35.5% of customers set their thermostat above 76 degrees with .9% of which either set it on higher than 85 degrees or turn it off during summer weekend mornings.



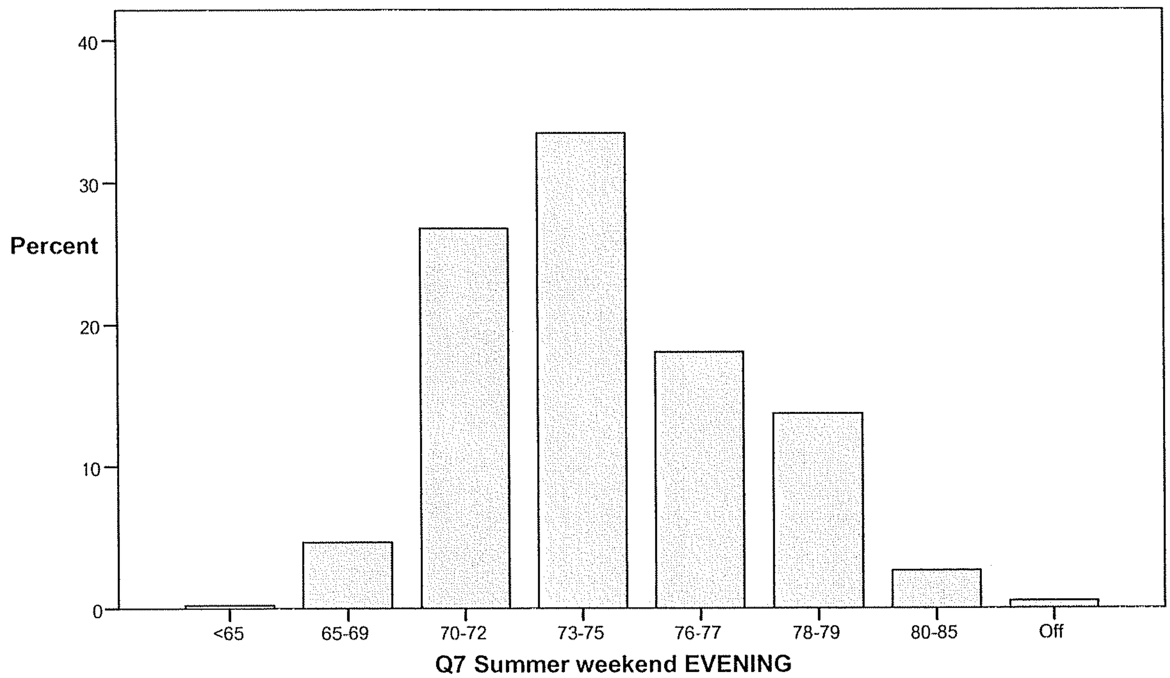
Temperature of Thermostat Summer Weekend Afternoon

More than one third of respondents set their thermostat between 73 to 75 degrees. 35.5% of customers set their thermostat above 76 degrees with .3% of which turn it off during summer weekend afternoons.



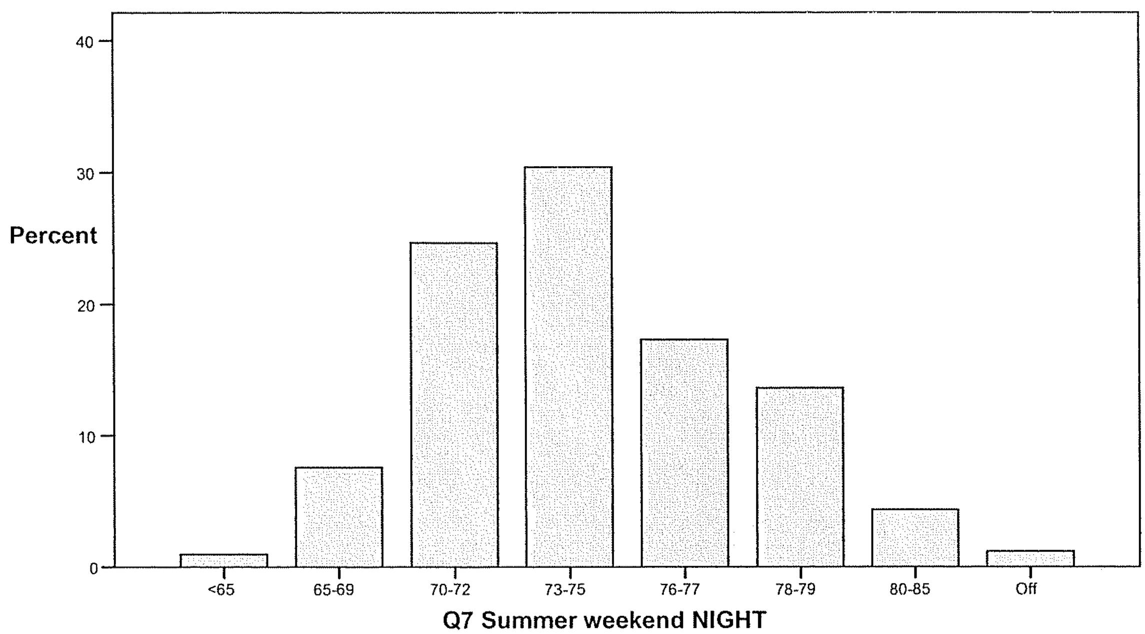
Temperature of Thermostat Summer Weekend Evening

About one third of respondents set their thermostat between 73 to 75 degrees. 35% of customers set their thermostat above 76 degrees with .5% of which turn it off during summer weekend evenings.



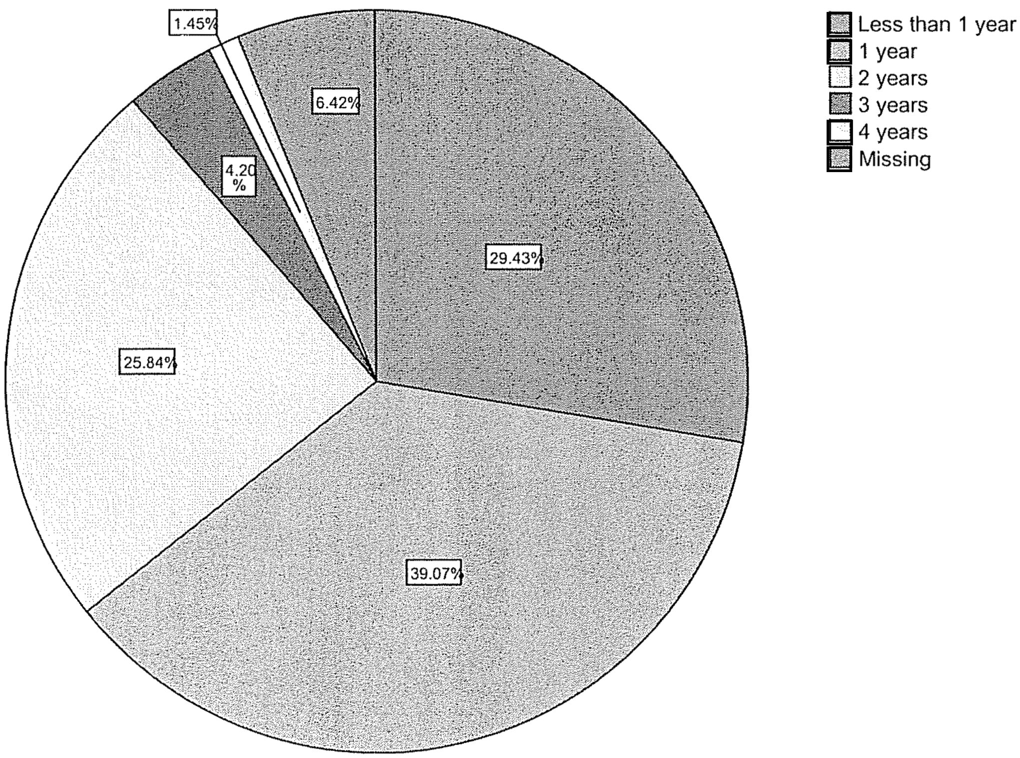
Temperature of Thermostat Summer Weekend Night

Less than one third of respondents set their thermostat between 73 to 75 degrees. 36.4% of customers set their thermostat above 76 degrees with 1.2% of which turn it off during summer weekend nights. It is recommended to target customers with thermostats set in cooler degrees during peak hours of weekdays.



Length of Participation in Power Manager Program

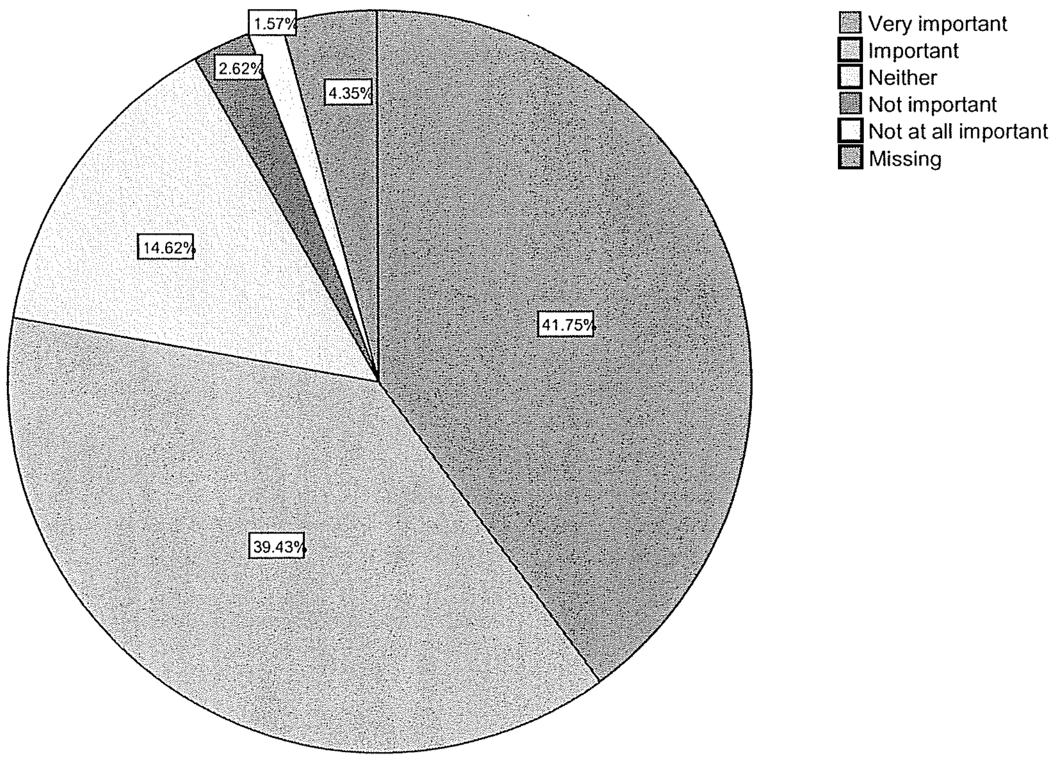
Less than one third of the customers have been participating in the program for less than 1 year, while 39.07% have been in the program for one year. One fourth of participants have been with the program for two years and less than 6% have been with the program for three to four years. It might be a good idea to send an appreciation note to customers who are in their first or second year of participation.



How long have you participated in the Power Manager Program?

Importance of Monetary Incentive

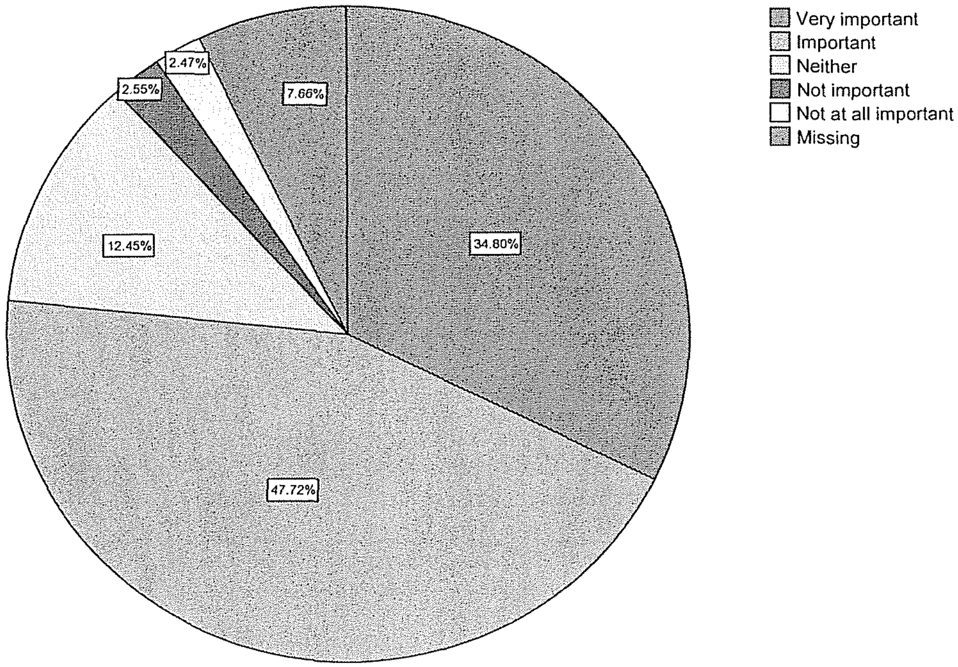
Money is a significant factor for more than 80% of participants while only less then 4% of participants claim that money is not an important factor for them. Depending on budget limitations, increasing monetary rewards would satisfy most participants.



Q10 Factors - MONEY

Importance of Environment

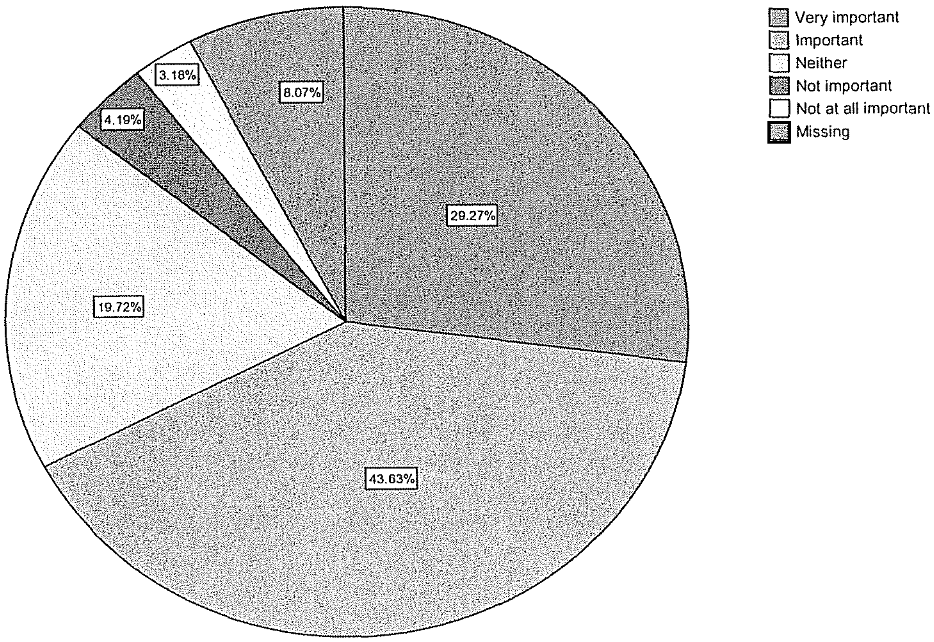
More than 82% of participants consider environment as an important or very important factor while only about 5% claimed that environment is not an important factor for them. Improving the environment is as strong of a factor as monetary rewards. It is recommended to send participants information on the impact their participation in the program is making on the environment.



Q10 Factors - ENVIROMENT

Importance of Not Building Power Plants

For almost two third or 67.5% of participants "Not Building a Power Plant" is either important or very important. About 20% of participants are indifferent. While only 7.37% of participants believe that "Not Building a Power Plant" is not important. It could be beneficial to send participants information on the impact that their participation in the program has on plans to build additional power plants since for the majority of participants not building a Power Plant is an important factor.



Q10 Factors - NOT BUILD POWER PLANTS

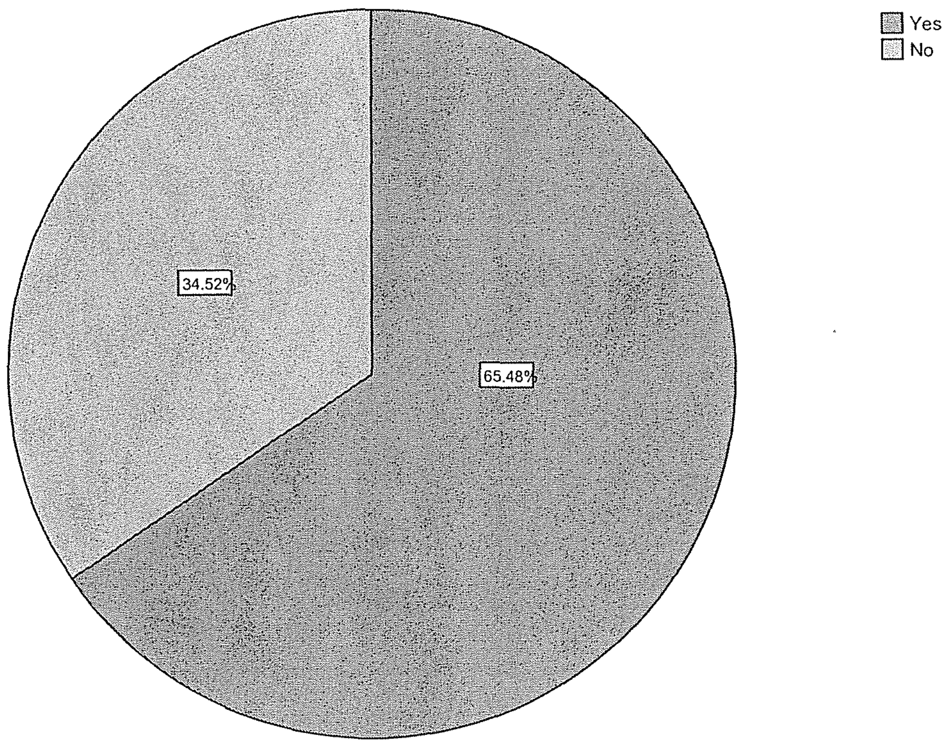
Option to Opt out of Control Event

Only about 1.77% of participants would choose to opt out of one of the control events.

Did you ever choose to opt out of one of the control events?

Participants that were Home during Control Events

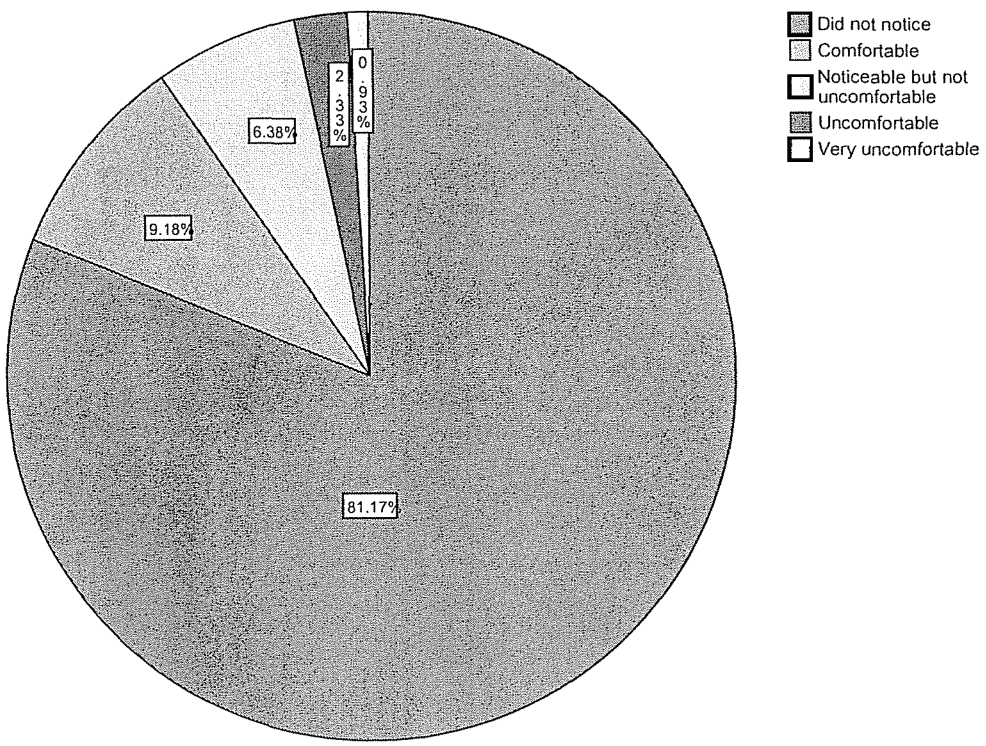
About two third of participants were home during the control events. 30.22% of participants did not answer this question suggesting that they might not have noticed when the control event happened, indicating they did not experience any discomfort.



Were you usually home during control events that occurred?

How Comfort Level was Affected during Control Event

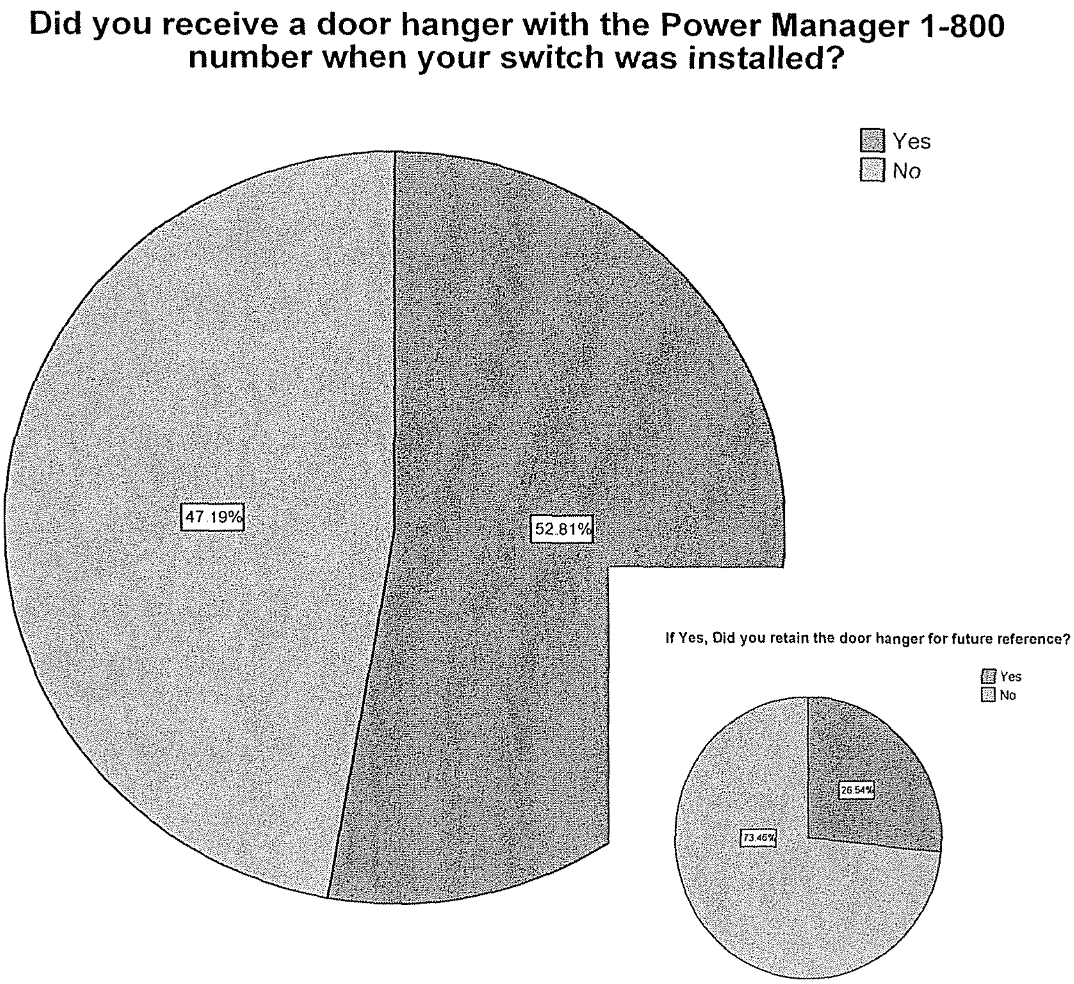
More than 90% of participants either did not notice or were comfortable during the control event.
Only less than 1% of participants were very uncomfortable while 3.2% were either uncomfortable or very uncomfortable. It could be recommended to give the people who are uncomfortable the option to receive a notice a day in advance about the control event occurring and give them the option to opt out.



How much did the control event affect your comfort level?

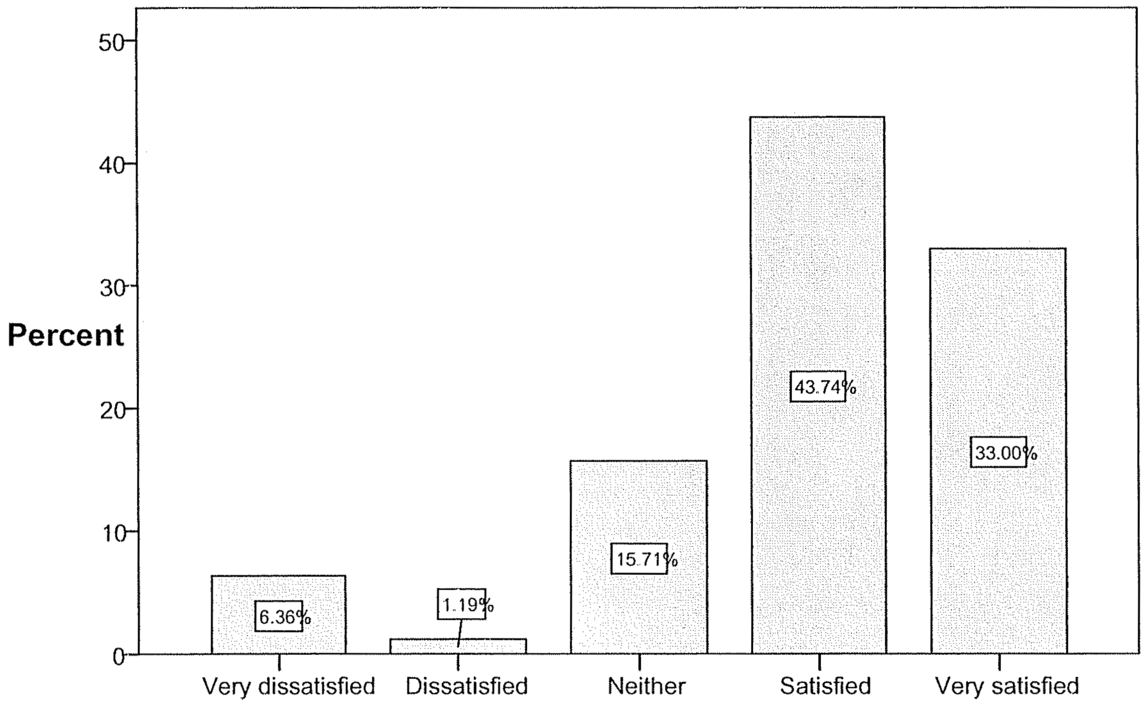
Retention of Informational Door Hanger

More than half of the participants received a door hanger with the power manager 1-800 number on it, more than one fourth of which kept it.



Satisfaction with Power Manager Phone Representative

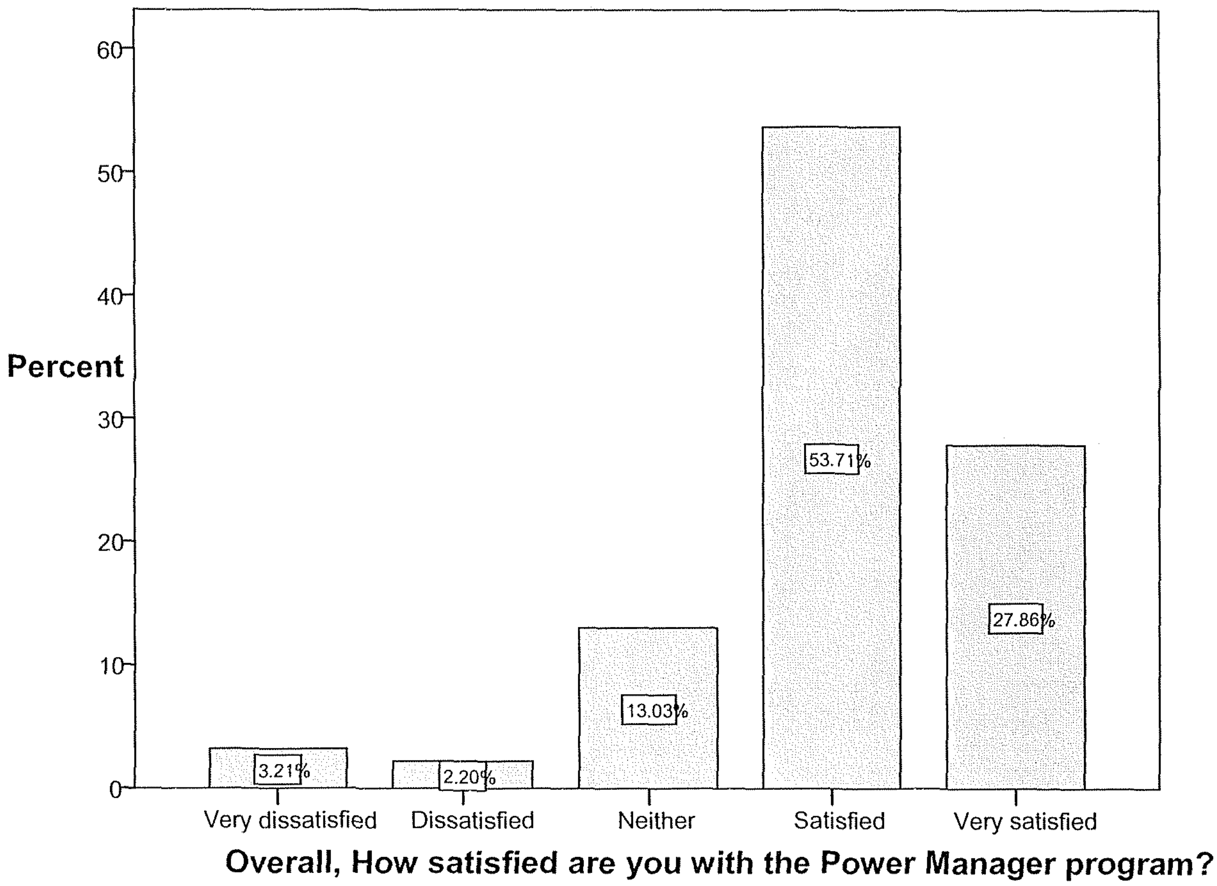
76.74% of participants were either satisfied or very satisfied with the Power Manager phone representative whereas 7.55% were dissatisfied or very dissatisfied with phone representatives. More research could be done to uncover what made them unsatisfied with the phone representative. Based on the research the phone representative could than be trained better in those areas.



Overall, how satisfied were you with the Power Manager phone representative who handled your questions?

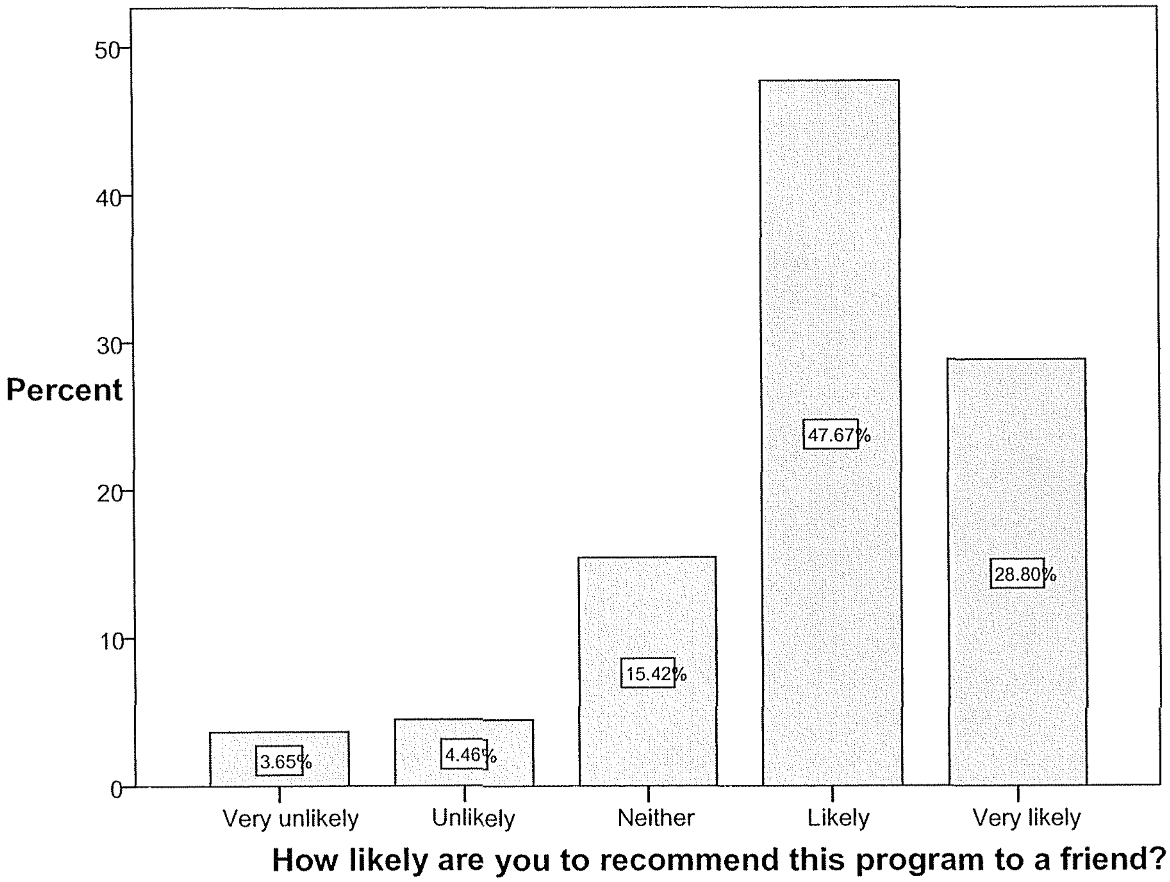
Overall Satisfaction with Power Manager Program

81.57% of participants were either satisfied or very satisfied with the Power Manager program whereas only 5.41% were dissatisfied or very dissatisfied.



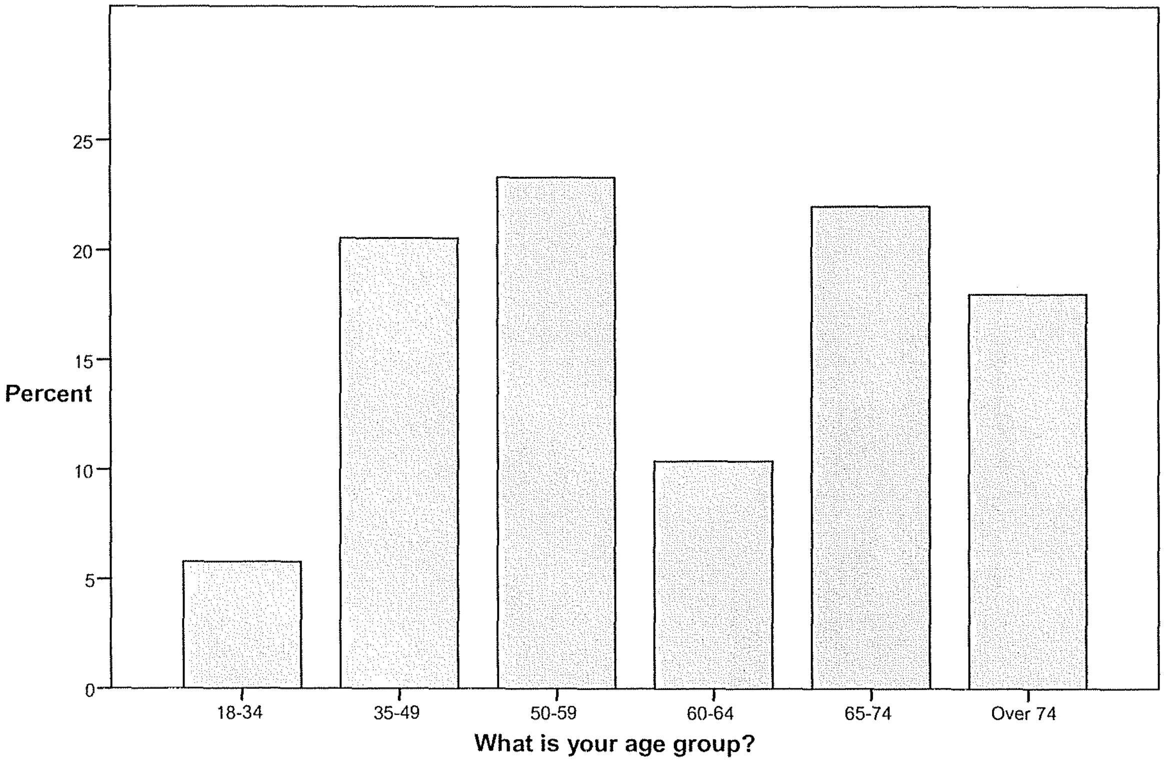
Likelihood to recommend Power Manager to a Friend

76.47% of participants are either likely or very likely to recommend this program to a friend whereas 8.11% of them are unlikely or very unlikely to do so. To increase the word of mouth about the program, a monetary reward to get a friend to sign up could be implemented.



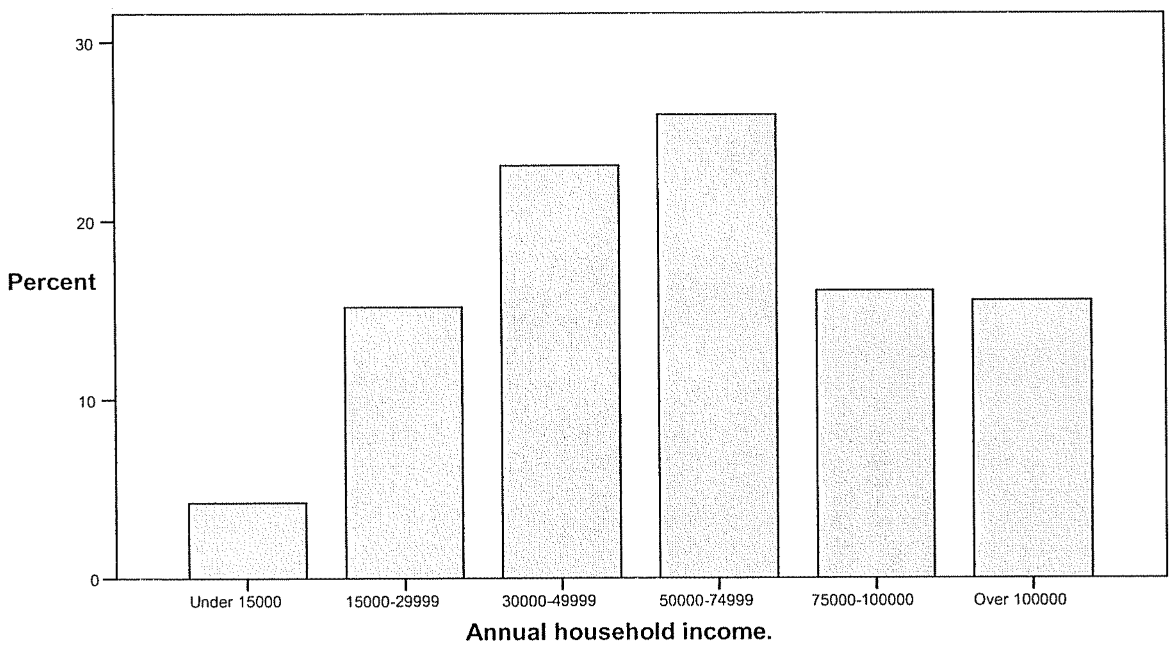
Age of Participants

More than half of the participants (53.8%) are between 35 and 59 years of age while 40% of them are 65 and over.



Annual Income of Participants

About 49% of the participants had annual income of 30,000 to 74,999. While 19.4% of people had annual income of less than 30,000, over 31% of participants have an annual income of 75,000 or more.



Drivers of the Power Manager Program Participant's Satisfaction

A regression analysis was done to discover which variables are the most important attributes at contributing to satisfaction of the Power Manager program. The following is the results of the analysis.

Participant's satisfaction of how the power manager phone representative handled their questions is the most important indicator of overall satisfaction of the power manager program. This may suggest:

- Special attention to training phone representatives is viable.
- Constant tracking of the performance of phone representatives is important.
- Placing courtesy thank you calls after control events may sustain/increase satisfaction.

To what extent participants become uncomfortable during control events is the second most important indicator of participant's satisfaction. The more uncomfortable they become the greater the dissatisfaction. Recommendations are:

- Targeting younger customers may increase participation as they are less sensitive to change in temperature during control events.
- Targeting customers who are not at home during control events is recommended.

Helping the environment is an important factor in satisfying participants. Recommendations are:

- Emphasizing on environmental outcomes in marketing campaign is an effective tool in obtaining customers in the program.
- Reminding participants of the environmental benefits when they call the 800 number.

There is a relationship between temperature settings and summer weekend nights. This indicates that participants who have the habit of setting their thermostat on higher degrees during the summer are generally more satisfied with the program since they have a higher tolerance for heat. This may suggest:

- Targeting customers with such habits as turning their thermostat up in the summer.

Target Marketing Recommendations

A correlation analysis was performed on the most important Power Manager attributes from the regression analysis to discover how those attributes related to each other. Using focused cluster and regression analysis makes it possible to have a better understanding of causes of satisfaction and dissatisfaction of participants and will provide more effective ways to promote and keep these participants.

Details regarding the correlation analysis can be found in Appendix A.

Grouping the participants based on income and age provides very accurate results for deciding which groups to target for future marketing in the program.

Participants with lower income are more likely to witness the control event and call the 1-800 number and in general feel more uncomfortable during the event. On the other hand the very wealthy people are more likely to have newer and more efficient cooling system and are less likely to have heat pumps in their homes. In general, the wealthy people are less concerned about the Power Manager Program. So we could conclude that the very low income and very high income households would not make a good candidate for the program while the middle income households (income between 30,000 and 100,000) would be the best candidates.

Older people are more likely to own older cooling systems as well as using window unit as cooling systems. Older people are also more likely to have less income and to keep the informational door hanger. They are also less likely to call the 1-800 numbers and they tend to stay in the program longer. Despite the fact that in general participants who were home during control events experienced more discomfort and would leave the program, the older group of participants tend to stay longer in the program even though they were more likely to be home more often during control events than the younger participants.

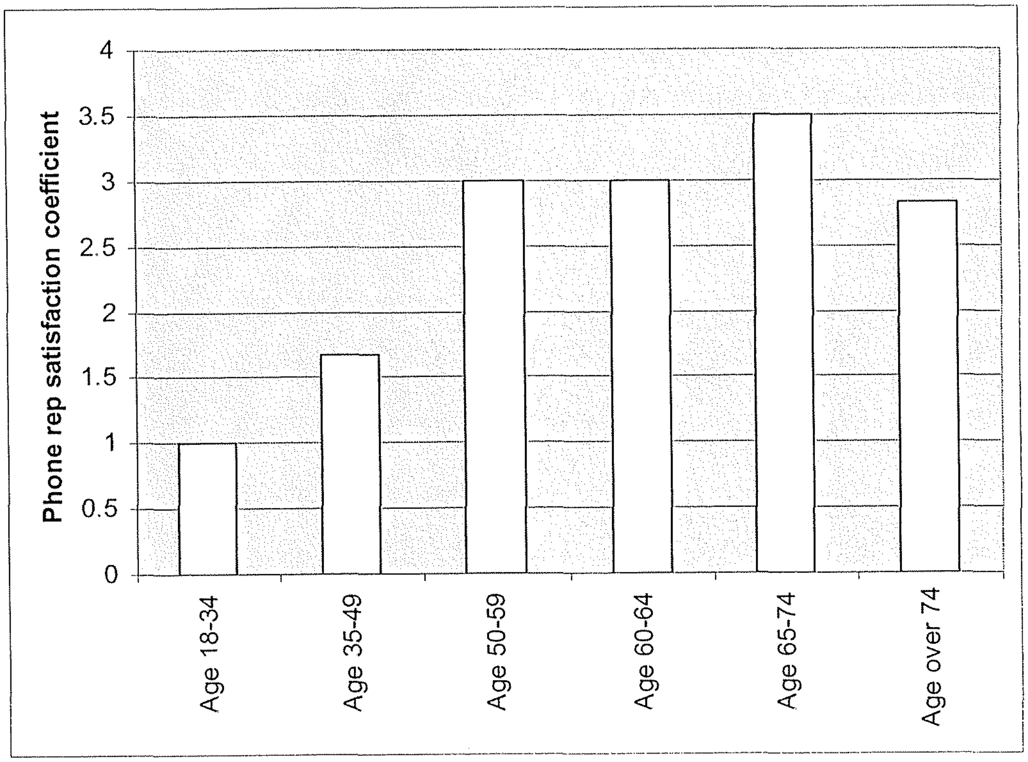
In order to maximize participation in the future, the study also suggests a closer look at people with homes between 1,000 and 2,999 square feet. Customers with homes in the above mentioned range make up 75% of total participants in the program thus a significant target for any promotional campaign. Targeting residents of smaller homes (less than 500 square feet) does not seem to be effective since these are low usage customers also make up less than one percent of participants in the program.

Satisfaction of the Power Manager Phone Representatives

The most important indicator of overall satisfaction was the participant's satisfaction of the power manager phone representative that handled their call. Due to this attributes importance further analysis was done on the satisfaction of the phone representative and overall satisfaction.

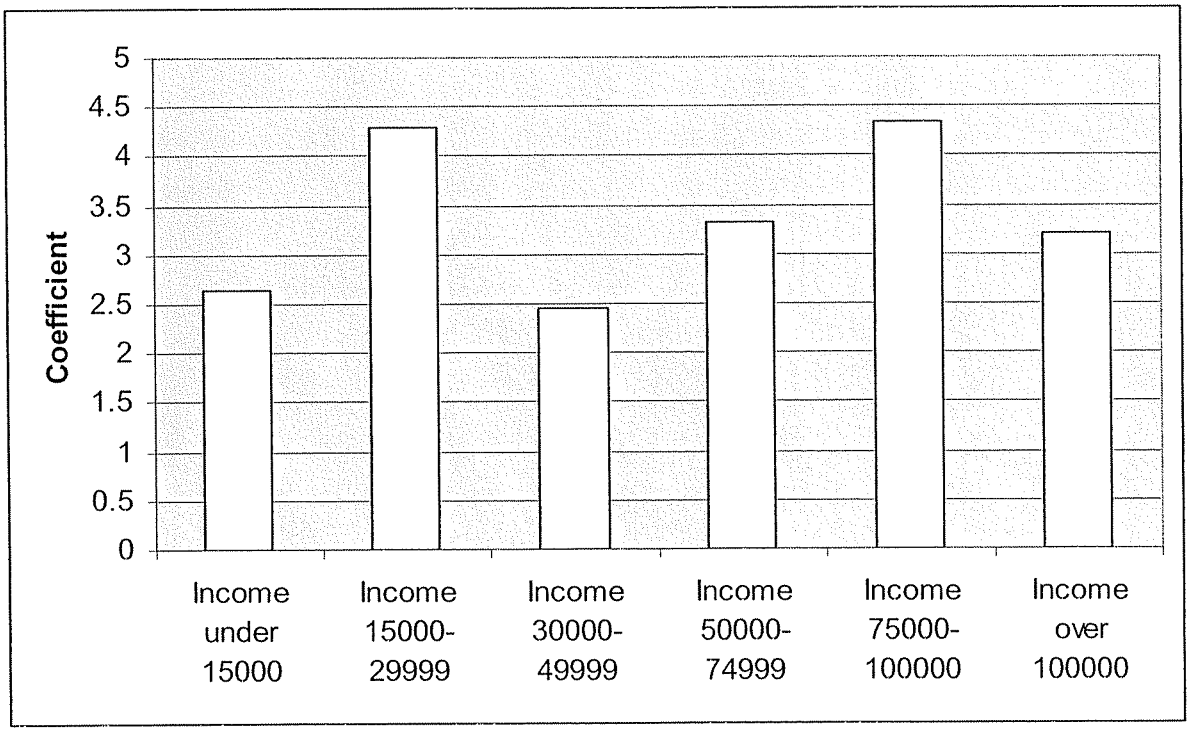
Satisfaction of Power Manager Phone Representative by Age Groups

Regressing overall satisfaction against satisfaction of phone representatives for different age groups for those customers who called power manager phone representative shows a lower coefficient for younger customers. This suggests that participants younger than 50 years, especially age 35 and below, are less satisfied with the service they received from the Power Manager phone representative.



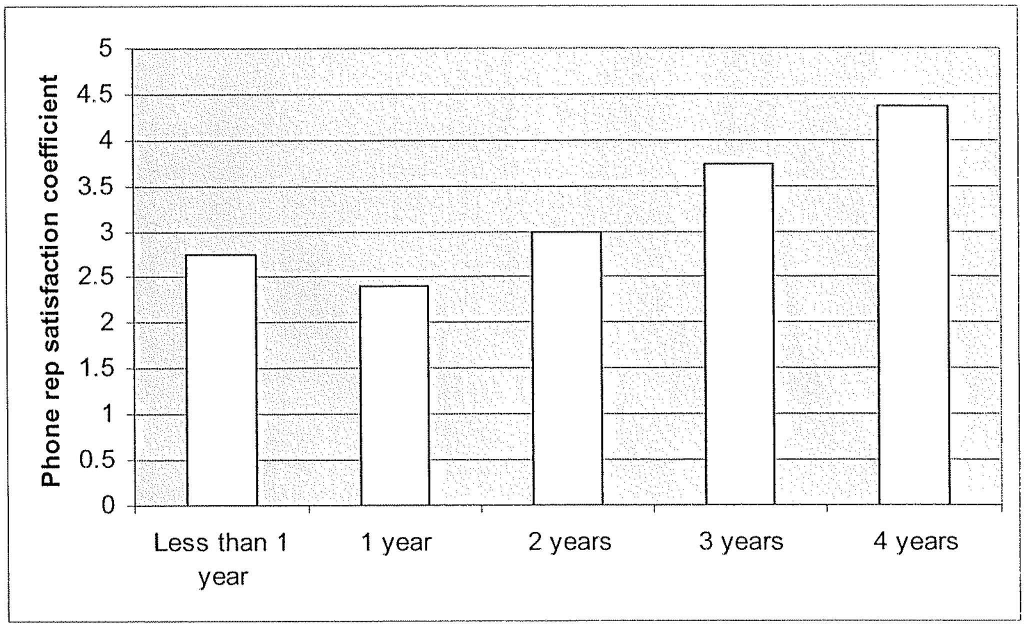
Satisfaction of Power Manager Phone Representative by Income Groups

Regressing overall satisfaction against satisfaction of phone representatives for different household income groups shows a lower coefficient for customers with annual income of 50K to 30K as well as customers having lower income of fewer than 15K suggesting these income groups are less satisfied with the service they received from the Power Manager phone representative.



Satisfaction of Power Manager Phone Representative by Length of Participation

The results of regressing overall satisfaction against satisfaction of phone representatives for different participation time period shows a higher coefficient for customers who have been with the program longer. This might suggest that participants who stay longer with program find the phone representatives more helpful or the upward coefficient trend is because satisfied participants stay longer in the program.

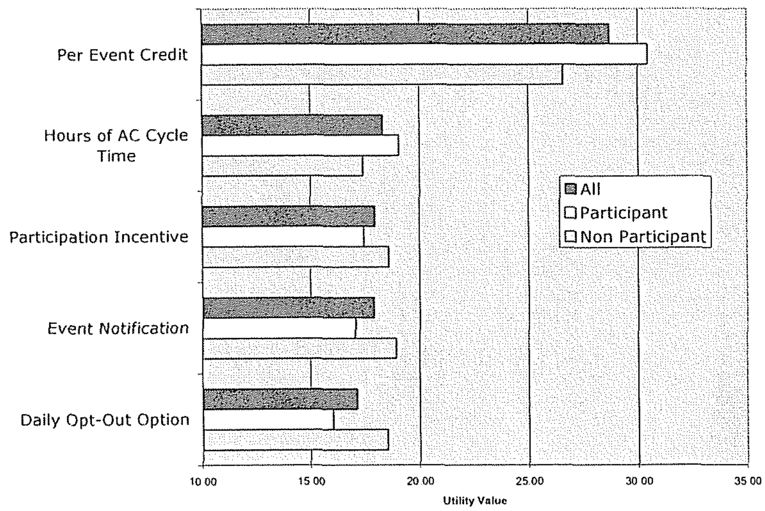


Additional insight on increasing participation in the Power Manager Program

To gain further insight on ways to increase participation in the Power Manager program a conjoint study was conducted was conducted in November 2006 in the Duke Energy Midwest Region to over 100 respondents. Respondents included a blend of current Power Manager Customers, and non-Power Manager Customers. All customers surveyed were eligible for the Power Manager program.

Results indicate that the current program offering sign up incentive of $25 (and $35) obtain the highest participation likelihood scores compared to a proposed free thermostat as a participation incentive. The free thermostat sign up incentive was still a viable option, but would need a considerable amount of marketing to communicate the benefits and value of a programmable thermostat, as well as educational material and additional features such as a toll free technical assistance phone number for operational questions. Over 60% of the customers indicate they do not adjust their thermostats settings (programmable or non-programmable) throughout the day.

Additional results indicate a per event incentive is the most important feature to customers considering signing up for a Power Manager program option, compared to features such as sign-up incentive, event credit, notification, and opt-out options.



(How important the attribute is compared to the others)

The current program offering includes a $25 sign-up incentive for a 1 kW reduction in load, and a $35 incentive for 1.5 kW reduction in load. Average AC cycle times for 2006 in total were around 3 hours. Event credits were given on a per kW basis. Customers were offered a 1 time per month opt-out option. This current opt-out offering is preferred by customers, and increases participation. Offering more than 1 opt-out option is not recommended, as it will not increase participation likelihood significantly.

Based on the conjoint results, three (3) hours of AC cycle time obtained a positive utility value. Increasing the cycling time from three (3) hours to five (5) hours reduces the probability of participation from 37% to 27%. But adding program feature enhancements will offset this difference.

Increased sign-up likelihood can come from program enhancements such as an email notification of an event occurring 1 day ahead, which moreover would be the least cost notification method. Respondents preferred email notification to phone call notification, and some notification to no event notification.

Additional suggestions include a per event credit instead of a per kW credit. Per Event is defined as any day that Duke Energy cycles a customer's AC unit on and off.

	Option A	**Option B**	
Sign Up Incentive	$25	$35	
Hours Cycle Time	3	3	
Event Credit	1	2	
Event Notification	None	None	
Monthly Opt-Out	1	1	
CURRENT OFFERINGS	10%	15%	**Relative Share**
Increase Cycle Time to 5 hours	7%	13%	**New Relative Share**
Add Event Notification	**11%**	**17%**	**Final Relative Share**

Relative Share of preference can be thought of as how many consumers would chose one option over another in the same menu. Share of Preference scores capture information about what product is most preferred and also the relative desirability of the remaining products. Share of preference does not represent market share potential. However, to some extent it can be viewed as a relative gauge, if both programs were offered by Duke Energy to every eligible customer and external effects were applied. An external effects multiplier can be included to better represent a market share potential, but again does not represent market share, as it is missing factors such as level and effectiveness of advertising, length of time on the market, and competitive or similar programs on the market. External Effects have been applied above to obtain the relative share estimates based on current share of participants to eligible customers. Current share of eligible customers is .047 for Option A and .082 for Option B.

Temperature Settings

- On average, respondents set their thermostats in the summertime to between 73 and 75 degrees.

- Regardless of temperature setting, it can be determined that having a thermostat set at 2 degrees warmer than current setting, customers will experience no difference in comfort level.
- 4 degrees warmer, causes customers to feel slightly less comfortable, except those setting their temperatures initially at 65 – 69.

Evaluating the impacts of the Power Manager Program

To evaluate the impacts of the program a load research study was conducted during summer 2006 of Power Manager. During summer 2006, nearly 29,000 Duke Energy Indiana residential customers in Indiana and 5,900 Duke Energy Kentucky residential customers in Kentucky participated in Power Manager load control events. The main purposes of the load research study is to evaluate how well load reduction targets were achieved during load control events and provide data for modeling purposes to support the program in future years. A new control model was developed for the 2006 Power Manager program based on data captured during 2005. This model called for substantially greater cycling percentages to achieve 1.0 or 1.5 kw target reduction levels than were in effect in the 2005 model. Overall load reduction achieved in 2005's program was generally too low according to the impact evaluation. The difference in the model is largely due to better capturing the "flattening" of the AC KW curve at higher temperatures. The summer of 2005 had many days with temperatures above 89 degrees; so this flattening was well represented in the dataset. This was not the case for the summer of 2004, the basis for 2005's model.

The results from this study are estimates of the load impact of the Power Manager program during five load control events conducted in summer 2006. These estimates are significantly below the targeted load reduction. Potential sources of this discrepancy include failures in paging communication and incorrect programming of switches, both of which have been encountered in spot field tests. A QA plan addressing how these problems will be investigated and remedied is presented. It may also be that expected load reductions from the Power Manager control model are too high for the moderate to low temperatures that prevailed during control periods this summer (see Table 2 below). To address this possibility, model methodology and data sources will be carefully reviewed and model results will be compared to studies in other areas. Lastly, model error in estimating realized shed kWh within the research sample during load control periods may also contribute to the discrepancy. Other results in this study include a small study with apartments, and estimates of payback during the two hours immediately following Power Manger load control events.

Power Manager Control Events

In a Power Manager control event, air conditioner units on the program are cycled off for a portion of each 30-minute interval; a random delay of up to 30 minutes at the beginning of the control period is used to stagger the off and on periods. The cycling percentage (i.e., percentage off) is chosen to achieve a specific load reduction target. This is accomplished with the Power Manger control model, which uses forecasted weather for the control period to calculate the cycling level needed to achieve a specified target reduction, on average, over the program population. A choice of program options with different target reduction levels is offered. The two commonly used program options are identified by typical target levels, "1.0 kW" and "1.5 kW," but other load reduction targets can be specified for either program option.

Power Manager load control was implemented on five days during summer 2006; July 17, 19, 26 and August 2, 7. The time period for each load control event was 2:00 – 5:00 PM (EDT). A simplified cycling strategy was adopted this year. Rather than modifying the cycling in each hour to achieve a fixed hourly load reduction, a fixed cycling percentage was imposed in all hours of an event. This cycling percentage was calculated with the Power Manager control model to achieve the load reduction target over the event as a whole, but not necessarily in each hour of the event. The load reduction targets (total kWh for the three hour event) and corresponding cycling percentages specified for the control events of summer 2006 are shown in Table 1. Cycling percentages for Duke Energy Kentucky were calculated with the CVG weather forecast, and cycling percentages for Duke Energy Indiana were calculated with the IND weather forecast.

Table 1. Control Event Cycling

	1.5 kW			1.0 kW		
	Target	DEK %	DEI %	Target	DEK %	DEI %
July 17	3.3	62	58	3.0	58	52
July 19	3.6	65	65	3.0	58	58
July 26	3.9	76	73	3.0	63	60
August 2	4.5	71	71	3.0	48	48
August 7	4.5	75	75	3.0	56	56

An initial estimate of load impact after a control event can be obtained with the control model algorithm, using actual weather during the control period together with the cycling percentages imposed. Deviation of actual weather from the weather forecast results in a total impact estimate different than the load reduction target. These estimates are the starting point for load impact results developed later in this report (see Table 6-a). Table 2 provides an overview of the weather experienced during Power Manager load control events f summer 2006, showing average hourly temperature and heat index during the control period. Notice the very low temperature at IND during the August 7 event.

Table 2. Temperature and Heat Index (deg-F) during Control Periods

	CVG		IND		SDF	
July 17	90	93	89	93	91	95
July 19	91	97	89	95	93	100
July 26	86	89	83	88	88	95
August 2	91	99	91	99	94	104
August 7	90	96	77	80	94	101

Load Research Sample

The 2006 load research sample consists of 159 single-family residences in the main load impact study, and 12 apartments in a side study of the effectiveness of Power Manager for multi-tenant properties. Interval KWH (15-minute) is collected for all research sample participants. State data loggers were installed on the air-conditioner units for about half (83) of the main study and all in the apartment study, which allow air-conditioner duty cycles to be constructed. The research sample for the main study was chosen to achieve reasonable geographic representation of the Power Manager population in Indiana and Kentucky, while also allowing for reasonably efficient data collection (residences with data loggers were visited every 4 weeks for data collection). Participants with data loggers are distributed in clusters in the Indianapolis area (32), Kokomo (10), Terre Haute (9), Jeffersonville-New Albany (9), and Cincinnati area (23). The rest of the sample for the main study, with interval meters only, was selected from areas not represented in the clusters.

Research sample participants with data loggers were separated into two control groups, RS1 and RS2, with about an equal split in each cluster. In Power Manager events, one group was controlled along with the general population and the other group was not controlled, and so provided information on the natural duty cycle. For evaluation of load impact, participants in the main study are grouped according to weather region (CVG, IND, SDF), and control group. The control group is RS1 or RS2 for participants with data loggers, or MET for participants with interval meters only. Table 3 below shows the breakdown into these evaluation groups.

Table 3. Evaluation Groups

Weather Region	Control Group	Participants
CVG	RS1	11
CVG	RS2	12
CVG	MET	17
IND	RS1	26
IND	RS2	25
IND	MET	49
SDF	RS1	5
SDF	RS2	4
SDF	MET	10

Weather regions are assigned by zip code. All Kentucky zip codes are assigned to CVG (Cincinnati airport). Zip codes in southeast Indiana are assigned to CVG, in south-central and southwest Indiana to SDF (Louisville airport), and in central Indiana to IND (Indianapolis airport). Appendix E lists Indiana zip codes assigned to CVG or SDF.

The research sample was also chosen to achieve balanced representation of high and low kWh usage. Quartile statistics of monthly kWh during summer 2005 were used to divide (separately for DEI and DEK) Power Manager participants into low (below Q25), medium (between Q25 and Q75), and high (above Q75) usage segments. About 25% of the research sample participants were drawn from each of the low and high segments, and the remaining 50% were drawn from the medium segment. Table 4 illustrates this balance, comparing quantiles of overall 2006 summer usage for the research sample (main study) and the Power Manager population in each weather region. The numbers in Table 4 are total monthly KWH for June – September, 2006 billing cycles.

Table 4. Quantile Statistics for Summer-2006 KWH

	CVG		IND		SDF	
Q	Population	Sample	Population	Sample	Population	Sample
0.1	3312	3020	3154	2758	3106	3571
0.2	3853	3794	3786	3586	3782	3786
0.3	4351	4199	4266	3930	4215	4050
0.4	4819	4580	4743	4488	4721	4744
0.5	5315	5518	5259	5099	5255	4822
0.6	5828	6160	5832	5616	5902	6600
0.7	6505	6807	6529	6032	6569	8114
0.8	7446	7139	7446	7465	7552	8803
0.9	8824	8564	9024	9678	9164	10011

Load Reduction within Research Sample

This section describes the method used to estimate load reduction within the portion of the research sample controlled during each Power Manager event of summer 2006. Group MET was controlled on all event days, group RS1 was controlled July 17, 26 and August 2, and group RS2 was controlled July 19 and August 7.

Impact evaluation is based on separate models for average 30-minute interval KWH within each of the evaluation groups in Table 3. Explanatory variables in these models are linear temperature splines based at 66, 77, and 88 deg-F, a humidity adjustment factor, the hour of the day, and interventions for intervals during control events. The humidity variable in the model depends upon both temperature and humidity, and is defined as the natural logarithm of the ratio of heat index to temperature. The models are estimated with research sample interval KWH for 1:00–7:00 PM (EDT) on non-holiday weekdays from Memorial Day to Labor Day (May 30 – September 1, 2006). By including the hour prior to control period and two hours subsequent to the control period in the model, it will be possible to investigate additional effects such as autocorrelation and payback. Interaction variables between temperature splines and hour of the day were investigated but discarded from all models. The temperature spline at 88 deg-F was retained in IND models, but was not significant and was dropped from CVG and SDF models.

The load reduction achieved within each evaluation group of Table 3 during load control is estimated by coefficients of corresponding intervention variables in the model for this group. A unique intervention variable is specified for each 30-minute interval during a control event, and so the models estimate average load reduction within each group during every 30-minute interval of the control event. Intervention variables are also specified for the intervals subsequent to a control event (four 30-minute intervals for the period 5:00 – 7:00), and coefficients of these variables estimate payback, which will be discussed further later in the report.

For overall impact evaluation of the Power Manager program, we focus on the total load reduction achieved in evaluation groups on a control event day. This is the sum of intervention coefficients for the control period, 2:00 – 5:00 PM for all control days in summer 2006. In summing estimated intervention coefficients, a positive coefficient is treated as zero load reduction. Table 5 gives the results obtained for total load reduction within evaluation groups on control event days. In blocks with results, the middle row is the weighted average of total KWH reduction for two evaluation groups identified in the leftmost column. The top row gives the expected total KWH reduction calculated with the Power Manager control model using actual weather and event cycling levels, and reflecting the mix of program option (1.5 KW or 1.0 KW) in the evaluation groups. The bottom row shows the ratio of realized KWH reduction (middle row) to expected KWH reduction (top row). A complicating factor is that MET groups are subject to a random delay of up to 30 minutes in the start of the control period, the same as for the general program population. This means that initial MET intervention coefficients (for 2:00 – 2:30) will be somewhat reduced. The remaining MET intervention coefficients during the control period are not affected. RS1 and RS2 groups are not subject to random delay. To deal with this, sums were calculated both with and without the initial 30-minute interval of the control period. Results with the greater ratio appear in Table 5 and are used in the impact evaluation.

Table 5. Estimated load reduction within research sample by weather region.

Group	July 17	July 19	July 26	August 2	August 7
CVG RS1-MET	2.80 0.49 18%		3.41 1.06 31%	3.25* 1.42 44%	
CVG RS2-MET		2.82* 1.77 63%			3.63 1.32 36%
IND RS1-MET	2.42 0.35 14%		2.38* 1.36 57%	3.12* 1.90 61%	
IND RS2-MET		2.69* 1.35 50%			0.93 0.0 0%
SDF	2.34*		3.06*	3.55*	

RS1-MET	1.23 52%		0.74 24%	1.02 29%	
SDF RS2-MET		3.61 1.55 43%			3.75* 0.85 23%

* load reduction excludes initial half-hour of event period

Figures 1(a)-(c) provide a graphic representation of load reduction estimates within the research sample - Figure 1(a) shows estimates for the CVG weather region, Figure 1(b) for IND and Figure 1(c) for SDF. The horizontal axis in each individual graph corresponds to the period 1:00 – 7:00 PM, the hours covered by our model, on a Power Manager control day. The vertical axis corresponds to KWH within 30-minute intervals. The solid blocks show KWH at 30-minute intervals averaged over research sample groups controlled that day. The line with open blocks shows the composite model fit for the controlled groups, excluding intervention terms. Moving left to right in the graphs, the first two points (open or closed blocks) correspond to the hour prior to the control period, the next 6 points correspond to the three-hour control period, and the final 4 points correspond to the two hours immediately after control is released (ignoring random delay, which complicates the picture a bit for the first interval of the control period and the first interval after the control period). During the control period, the distance of the solid block below the line is the estimated load reduction. After the control period, the distance of the solid block above the line is the estimated payback. In both cases, since the estimate is for a 30-minute interval, it must be doubled to correspond to kWh.

Figure 1(a). Controlled Groups in CVG Weather Region

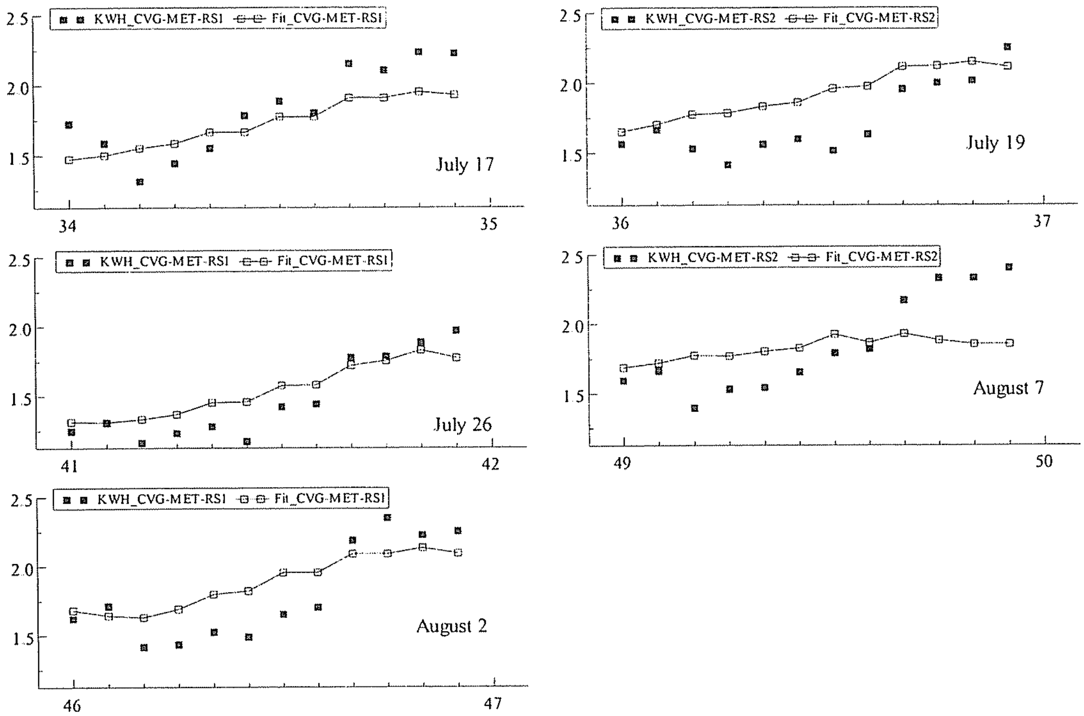


Figure 1(b). Controlled Groups in IND Weather Region

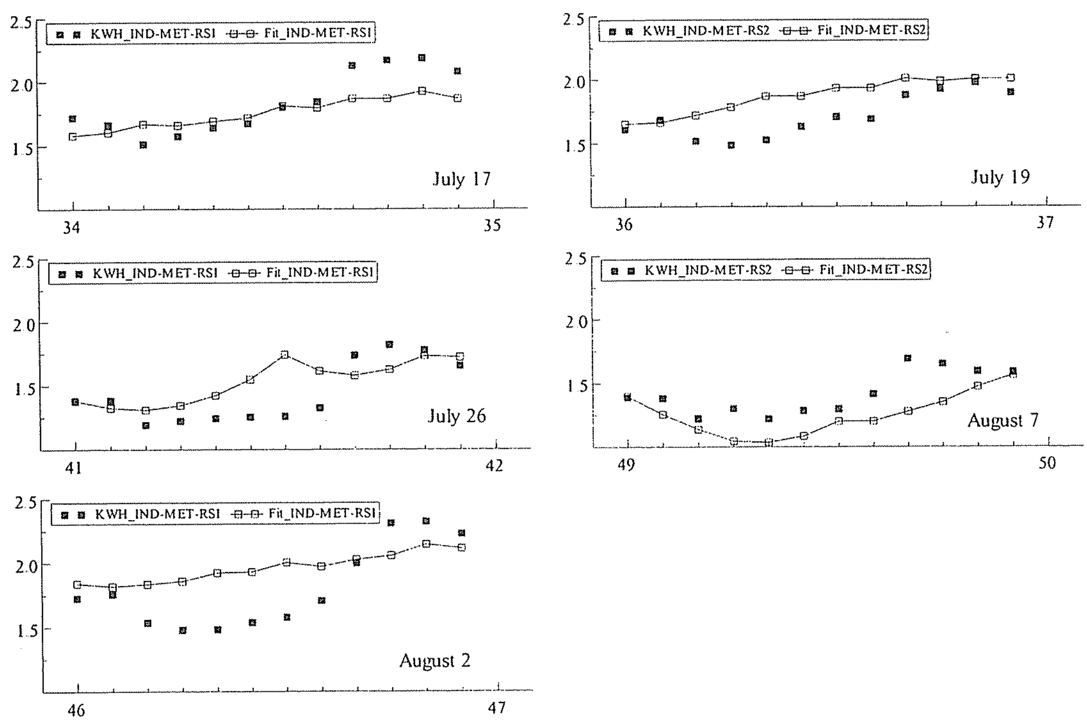
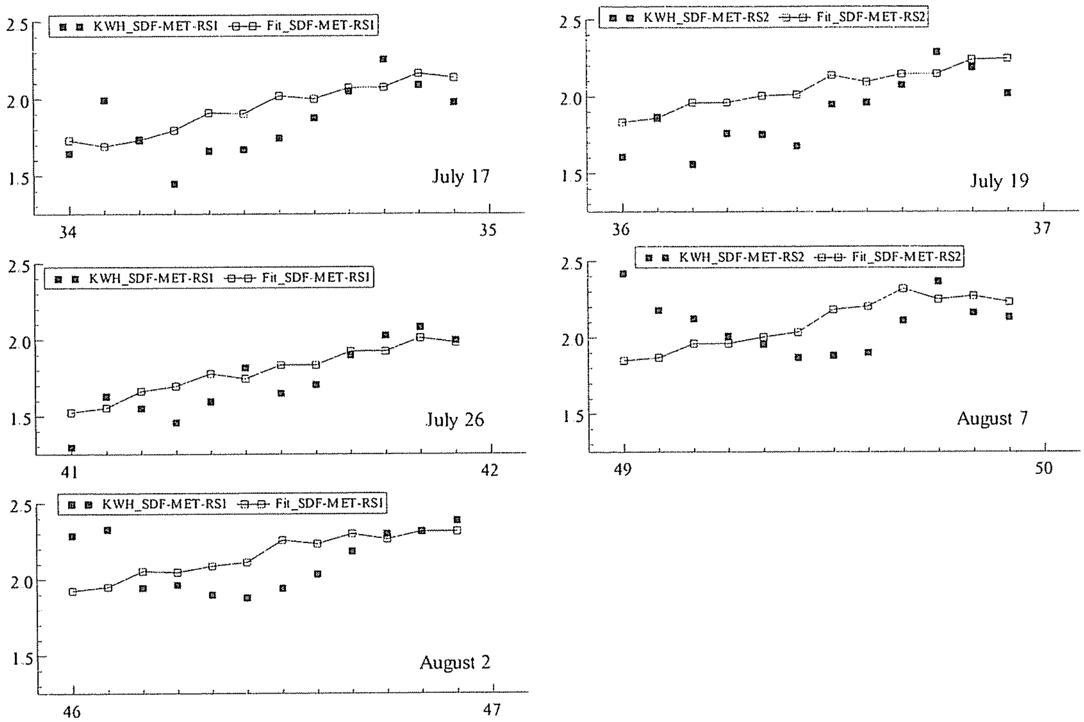


Figure 1(c). Controlled Groups in SDF Weather Region



Power Manager Program Load Impact

This section presents hourly impact estimates for Power Manager load control events of summer 2006. Tables 6(a)-(b) illustrate intermediate steps in the calculation of these estimates, and final impact results are in Table 6(c).

Table 6(a) shows separate estimates of average hourly shed kWh during control events for each weather region (CVG, IND, SDF) and program option (1.5 kW, 1.0 kW). These estimates were computed with the Power Manager control model algorithm using the control event cycling percentage (see Table 1) and actual weather during the control period. Also shown in Table 6(a) are participant counts by operating company (DEI, DEK) for each weather region and program option. Participants are assigned to weather regions according to their zip code.

In Table 6(b), the results from Table 6(a) are accumulated for each operating company. These numbers represent expected impacts immediately after an event, before any consideration of results from the research sample.

The upper section of Table 6(c) lists the adjustment factors from Table 5 of the previous section, derived from the research sample. The lower sections of Table 6(c) contain the final hourly impact estimates by operating company. These estimates start with the product of three factors which have been described:

1) Control model average kWh reduction with event cycling and actual weather;
2) Participant count by operating company;
3) Adjustment within weather regions based upon research sample results.

Factors 1 and 2 appear in Table 6(a) and factor 3 is from the upper section of Table 6(c) (and also Table 5). For each operating company, these products are summed over weather regions and program options to get overall hourly impact estimates.

Table 6(a). Expected Hourly Shed with Control Model Algorithm

	Jul_17	Jul_19	Jul_26	Aug_2	Aug_7
CVG-DEK 1.5_kw					
Model Shed - Hr 15	0.85	1.00	1.08	1.22	1.18
Model Shed - Hr 16	0.94	1.14	1.18	1.35	1.36
Model Shed - Hr 17	1.06	1.27	1.31	1.48	1.40
Count	4210	4215	4228	4264	4260
CVG-DEK 1.0_kw					
Model Shed - Hr 15	0.77	0.84	0.77	0.71	0.77
Model Shed - Hr 16	0.86	0.97	0.86	0.82	0.90
Model Shed - Hr 17	0.98	1.10	0.98	0.92	0.92
Count	1465	1470	1482	1565	1550
CVG-DEI 1.5_kw					
Model Shed - Hr 15	0.77	1.00	0.99	1.22	1.18
Model Shed - Hr 16	0.86	1.14	1.09	1.35	1.36
Model Shed - Hr 17	0.98	1.27	1.21	1.48	1.40
Count	483	483	483	480	480
CVG-DEI 1.0_kw					
Model Shed - Hr 15	0.67	0.84	0.69	0.71	0.77
Model Shed - Hr 16	0.75	0.97	0.78	0.82	0.90
Model Shed - Hr 17	0.85	1.10	0.89	0.92	0.92
Count	358	358	358	355	354
IND-DEI 1.5_kw					
Model Shed - Hr 15	0.73	0.99	0.82	1.23	0.24
Model Shed - Hr 16	0.85	1.08	1.17	1.38	0.37
Model Shed - Hr 17	0.92	1.20	0.96	1.42	0.44
Count	16568	16579	16596	16643	16623
IND-DEI 1.0_kw					
Model Shed - Hr 15	0.62	0.82	0.55	0.73	0.10
Model Shed - Hr 16	0.74	0.91	0.84	0.83	0.16
Model Shed - Hr 17	0.79	1.01	0.67	0.85	0.20
Count	6969	7059	7104	7316	7238
SDF-DEI 1.5_kw					
Model Shed - Hr 15	0.84	1.10	1.17	1.32	1.33
Model Shed - Hr 16	0.93	1.25	1.23	1.47	1.50
Model Shed - Hr 17	1.04	1.29	1.35	1.60	1.66
Count	2533	2552	2561	2575	2568
SDF-DEI 1.0_kw					
Model Shed - Hr 15	0.73	0.94	0.86	0.81	0.90
Model Shed - Hr 16	0.81	1.07	0.91	0.93	1.05
Model Shed - Hr 17	0.91	1.11	1.01	1.03	1.20
Count	1422	1463	1480	1529	1521

Table 6(b). Operating Company Total Expected Hourly Shed (MW)

	Jul_17	Jul_19	Jul_26	Aug_2	Aug_7
DEK					
Hr 15	3.5	4.1	4.3	4.7	4.7
Hr 16	5.2	6.2	6.3	7.0	7.2
Hr 17	5.9	7.0	7.0	7.8	7.4
DEI					
Hr 15	15.1	20.4	16.9	23.5	7.7
Hr 16	23.5	30.0	30.8	35.1	13.7
Hr 17	25.4	33.0	26.5	36.6	15.9

Note: First event hour reduced 25% to account for random delay

Table 6(c). Operating Company Hourly Impact Estimates (MW)

	Jul_17	Jul_19	Jul_26	Aug_2	Aug_7
Research Sample Adjustment					
CVG	18%	63%	31%	44%	36%
IND	14%	50%	57%	61%	0%
SDF	52%	43%	24%	29%	23%
DEK Impact					
Hr 15	0.6	2.6	1.3	2.1	1.7
Hr 16	0.9	3.9	1.9	3.1	2.6
Hr 17	1.1	4.4	2.2	3.4	2.7
DEI Impact					
Hr 15	3.0	10.0	8.4	13.1	1.1
Hr 16	4.6	14.8	15.8	19.6	1.6
Hr 17	5.1	16.3	13.2	20.3	1.8

Note: First event hour reduced 25% to account for random delay

Apartment Study

Twelve participants were recruited from apartment complexes in Franklin, IN (IND weather region) and New Albany, IN (SDF weather region) to investigate the suitability of multi-tenant properties for Power Manager program. Both state data loggers and interval meters were installed for the apartment sample, but data for the bulk of summer 2006 is available for only 8 of these participants. These apartment accounts are listed in Table 7 below, with apartment size and total kWH for June – September bill cycles. Notice the comparatively low KWH usage for two accounts, even though one is the largest apartment in the study.

Table 7. Apartment Research Sample Characteristics

Account	Size (Sq Ft)	Summer KWH
26502594	1066	3577
90602594	833	3311
79802594	962	3189
06202929	1360	3797
91602946	1000	3756
45602946	840	4740
93302929	1440	1943
96302929*	1080	1845

* tenant changes in July and August

Separating apartment accounts into evaluation groups and modeling average kWh usage within these groups is not feasible due to the small sample size. Instead, load reduction by apartment accounts is estimated individually for each account by comparing kWh usage during a control period to kWh usage during the same time period on days with similar weather. For each control event and account, three weekdays are selected to most closely match temperature and heat index during the control period, avoiding any days where load control was implemented or kWh data is not available for that account. Total kWh during the control period is subtracted from total kWh during the same time period, averaged for the three comparable days. Table 8 below gives results for each apartment account and Power Manger control event. The layout of Table 8 is similar to Table 5; the top row in each block is the estimated load reduction for the apartment, the middle row is the expected load reduction computed by the Power Manager control model (with 1.0 kw program option and appropriate weather region), and the bottom row is the ratio between the top and middle rows. The bottom row of Table 8 shows averages for all apartments controlled in each Power Manager control event.

Table 8. Estimated Load Reduction for Apartments

Account	July 17	July 19	July 26	August 2	August 7
26502594 IND-RS1	2.48 2.15 115%		1.29 2.06 63%	1.43 4.02 36%	
90602594 IND-RS1	0.00 2.15 0%		1.39 2.06 67%	0.00 4.02 0%	
79802594 IND-RS2		0.00 2.74 0%			0.00 0.46 0%
06202929 SDF-RS1	2.05 2.45 84%		0.55 2.78 20%	1.42 4.40 32%	
91602946 SDF-RS1	3.57 2.45 146%		1.06 2.78 38%	0.00 4.40 0%	
45602946 SDF-RS2		1.65 3.12 53%			0.00 3.15 0%
93302929 SDF-RS2		0.00 3.12 0%			0.00 3.15 0%
96302929 SDF-RS2		1.57 3.12 50%			0.00 3.15 0%
Event Average	2.03 2.30 88%	0.81 3.03 27%	1.07 2.42 44%	0.71 4.21 17%	0.00 2.48 0%

Payback

As discussed previously, the models used to measure average kWh impact within the evaluation groups during control events include intervention coefficients for four 30-minute intervals subsequent to each control event (the time period 5:00 – 7:00 PM). These intervention coefficients measure the increase in average kWh usage within evaluation groups above the expected level (i.e., the model) immediately after a control period, which is often referred to as payback. The sum of these intervention coefficients estimates the total payback during the two hours immediately after a control event, on average within the evaluation group. Payback results are given in the bottom row of blocks in Table 9. For comparison, the top row of these blocks contains the estimated total load reduction during the control period (the sum of intervention coefficients during the control period).

Table 9. Payback (kWh) over Two-Hour Period After Control

Group	July 17	July 19	July 26	August 2	August 7
CVG RS1-MET	-0.49 1.02		-1.06 0.34	-1.63 0.61	
CVG RS2-MET		-2.03 0.0			-1.32 1.83
IND RS1-MET	-0.35 1.04		-1.48 0.33	-2.20 0.54	
IND RS2-MET		-3.16 0.0			0.0 -
SDF RS1-MET	-1.23 0.0		-0.85 0.19	-1.13 0.10	
SDF RS2-MET		-1.55 0.0			-0.85 0.0

Power Manager Quality Assurance Action Plan

As a result of the Power Manager impact evaluation analysis, and in order to maximize the impact of the program, Duke Energy has developed the following action plan for 2006-7 to insure that the full program impacts can be realized prior to the execution of the 2007 control season. During November and December, 2006, discussions took place Duke Energy personnel and service provider partners, so that we could better understand control equipment performance issues. The lower than expected load reductions during the 2006 season could possibly have been due to somewhat milder peak temperatures than expected, but it is also possible that other structural causes may be the cause. To insure that all causes are systematically analyzed and corrected, where needed, prior to the 2007 season, Duke Energy intends to pursue the following quality assurance action plan.

Validate Data and Complete On-site Assessments

Work started in December 2006 is targeted to insure that the data used to complete the analysis of impacts is accurate and representative of the actual load reductions during the control events. Verification of the data received from the interval meters (measures actual energy usage in 15 minute intervals), data loggers (shows time stamped on/off cycling of A/C units) and weather data will be completed before Jan 2007. The modeling logic used to forecast load reduction potential will also be reviewed to ensure proper representation.

An on-site visit will be made to more than 100 homes that encompass the representative data sample. Technicians will visit each site with portable diagnostic equipment that will determine the operational condition of each switch. The inspection will evaluate the following:

- Switch programming
- Event history – did the switch receive the commands
- Signal strength
- Proper installation and functionality
- Switch tampering

If required, technicians will make repairs while on site and they will document their findings, so that the system integrity can be evaluated.

Analyze the results

The information gathered from the site visits will point the way to improving system performance and ultimate load reduction potential. The data will be analyzed and a list of prioritized initiatives will be developed and implemented to maximize performance for the 2007 Power Manager event season. A list of modification or repairs includes, but is not limited to the following:

- Programming enhancements to software (switch or command software)
- Changes in the paging or command protocol
- Paging company coverage improvements
- Antennae modifications
- Additional site visits assessments
- Switch replacement
- On site monitoring during a simulated command event

These options and others will be considered as opportunities to improve load reduction impacts. The items listed above have varied timeframes for implementation, so a comprehensive solution will incorporate short and long term solutions. Ideally, the chosen remedies will be implemented in parallel when possible and test will be conducted to verify results. The following chart represents the proposed timeline for implementing the action plan.

Actions	*Dec*	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*
Consult with experts											
Validate data											
On-site assessments											
Analyze the on-site data											
Develop an improvement plan											
Phase 1 improvements											
Phase 2 improvements											

Initial results

The initial stage of the Power Manger QA program involved site visits to 96 program participants in late December and early January. 45 of these were selected from the 2006 research sample, after analysis of interval load data indicated little or no load reduction from these households during load control events. 51 were selected from the general population of Indiana program participants. Key registers in the switches still contained values from the final Power Manger event of the summer, on August 7. Analysis of the switch register data collected in the test has identified two types of switch problems that contributed to lower than expected impact: some switches were not correctly programmed prior to the August 7 event, and many switches (24 from the research sample and 8 from the other group) apparently correctly programmed did not actually shed during the event period. The first problem will be addressed by re-programming all Power Manger switches (remotely, by paging) prior to next summer. Further QA tests will be conducted early in 2007 to identify the source of the second problem. No significant problems with paging signal strength, installation, or switch tampering were found in the site visits.