Final Report for the myPower Pricing Segments Evaluation

Submitted To:

Public Service Electric and Gas Company

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TABLE OF CONTENTS

PREFACE

This report was prepared as a cooperative effort by staff from PSE&G and Summit Blue Consulting. Summit Blue advised PSE&G on the program design, the structure of the tariffs, the type, timing and sample sizes for customer surveys, and reviewed and advised on the type, number, and wording of questions included in customer surveys. The Technical, Rates and Regulatory, Operations, Billing, and Customer Assessments and Bill Impact Assessment were prepared by PSE&G staff and reviewed by Summit Blue. The section regarding the scaling of results to PSE&G's general residential service territory was also prepared by PSE&G staff and reviewed by Summit Blue. Summit Blue staff wrote the Executive Summary, conducted the Impact Analysis, wrote the Impact Assessment section, and integrated each of the pieces into this consolidated final report.

E EXECUTIVE SUMMARY

E.1 Program Overview

The myPower Pricing pilot program was created to test two-way communication technologies to the customer's meter in order to understand the potential to create opportunities for changing the way customers think about energy delivery and consumption. The Pilot utilized two-way communications to transfer energy pricing and interval consumption data and allowed PSE&G to test customer response to various pricing signals. Interval meters and in-home technology assisted with understanding the customer energy consumption cause-and-effect relationship.

The Pricing segments of the Pilot tested two approaches to encouraging customer responses to energy prices labeled myPower Connection and myPower Sense. Both approaches included a Time-of-Use rate with a critical peak price (CPP) component. Both included information to participants about methods for saving energy during peak and critical peak hours. Both approaches also included advance communication to participants the day before CPP events. myPower Connection participants were given programmable thermostats that could be programmed to respond to TOU and CPP tiers and to receive notice of CPP events. The thermostats could be programmed to automatically adjust set points for CPP events eliminating the need for participants to take action for each event. myPower Sense participants did not receive the communicating thermostats and thus responded to TOU rates and CPP events in other ways.

The myPower Sense segment is referred to as the TOU/CPP Educate Only segment. The myPower Connection segment is referred to as the TOU/CPP Technology Enabled segment.

The myPower Pricing segments were targeted at residential customers in Cherry Hill and Hamilton Township, NJ. Customers were recruited into one or the other segment; they were not given a choice between the two segments. Both groups of customers received an interval electric meter and were put on the same TOU rate with a CPP component. The TOU rate provided participants with different prices for electricity depending upon the time of day (essentially a base rate with a night discount and an on-peak adder). There were several sets of rates utilized during the Pilot. The rates changed from summer 2006 to the non-summer months of 2006/2007 and again for summer 2007. The rates were based upon the relationships between hourly energy costs over various times and seasons of the year in the PJM Day-Ahead LMP energy market. The CPP aspect of the rate was a significant adder to customer bills applied during CPP event periods. Participants were notified the night before a CPP event was called. The program was designed to call a maximum of eight events per year, five in the summer and three in the non-summer months.

For the first summer of the pilot during 2006, two events were called on August 1st and 2nd. In the summer of 2007, five CPP events were initiated on July 9th and 10th and August 2^{nd,} 3^{rd,} and 7th. There were additional CPP events called during non-summer months of the pilot. During the shoulder period an event was initiated on May 25th 2007 and during the winter period events were initiated on January 30th and February 6th, 2007.

A control population, with characteristics comparable to the treatment groups, received electric interval meters but no other treatment. The control group was chosen to facilitate a detailed impact analysis of the energy and demand savings. In general, it is difficult to find estimates of energy savings for TOU programs since a large, matched control group is needed to answer the question of what customers would have done if they had not been on the TOU rate. Large control groups are necessary to get a sufficient sample size to measure the small energy savings reliably. Since it can be a costly undertaking to collect hourly data for large control groups, it is rarely done. The myPower pilot undertook the effort of collecting hourly data for a large control group and is one of only a few studies that can present reliable energy savings estimates for TOU rates.

TOU/CPP Technology Enabled – myPower Connection

myPower Connection participants received a programmable thermostat which could be programmed to adjust the central air conditioner temperature during the various myPower price periods to help reduce usage at times of high and critical prices. The thermostats received signals sent by PSE&G to indicate price period changes including CPP events. The thermostats reacted to the signal and automatically implemented specific temperature adjustments programmed by the customer. Thus the thermostats allowed participants to program an aggressive response to high and critical peak prices.[1]

Potential myPower participants received educational recruitment materials about the program. At the time of the in-home equipment installation (myPower Connection customers only), the installers provided customers with information regarding the operation of the thermostat and assisted them in the initial programming for price response set-up. Both myPower Sense and myPower Connection customers received packages of educational materials including energy savings tips, pricing plan information and website information. Prior to CPP events, customers were informed of the event via telephone and/or e-mail to allow them to take action to reduce and/or shift their electric usage.

TOU/CPP Educate Only – myPower Sense

As stated previously, myPower Sense participants received electric interval meters, the TOU/CPP pricing plan, and program educational materials. However, they did not receive the free thermostat and in-home education that came with its installation, and therefore their response to high price periods and CPP events was not assisted by a program-provided thermostat. myPower Sense customers had to decide on their own how to respond and implement actions to adjust their usage during the high priced periods.

Participation

At the end of the program, 379 customers were participating in myPower Sense and 319 in myPower Connection as of (Table 1).

Table 1. myPower Pricing Program Participants

Segment	Actual Segment Size (9/30/07)
myPower Sense – TOU/CPP Educate Only	379
myPower Connection – TOU/CPP Technology Enabled	319
Control Group	450
Total	1,148

[1] Additionally, 7 customers with an in-ground pool and one with an electric water heater received additional equipment to help them manage their energy usage. Load Control Relays (LCRs) that communicated with the programmable thermostat were installed at the pool pump and electric water heater. At time of high and/or critical prices, the thermostat sent a signal to the LCR shutting off the pool pump and water heater.

E.2 Technical Assessment

The Technical Assessment reviewed the design and operation of the technical components of the myPower pilot program.

Three equipment manufacturers were selected to provide equipment for the Control Group and Pricing Segments. They were DCSI, Itron and Comverge.

- DCSI provided the Two-Way Automated Customer System (TWACS) system. DCSI communication technology is via a powerline carrier.

- The Itron equipment in the myPower pilot utilized a fixed network radio frequency communication technology.

- Comverge's Maingate product allowed for deployment of two-way communication. Comverge's equipment in the pilot utilized a paging system and customer phone lines.

Table 2 summarizes the equipment utilized in each segment of the myPower pilot program.

Table 2. Equipment Utilized in the myPower Pilot Program

Segment	Thermostat	Meter	Communication Equipment	Communication Medium	Actual Segment Size 9/30/07
Control Group	No change	Itron Centron Interval Electric Meters	DCSI	Powerline Carrier	450
TOU/CPP Education Only (myPower Sense)	No change	Itron Electric and Gas Meters	Itron Repeaters and Central Collection Units (CCUs)	RF	379
TOU/CPP Technology Enabled (myPower Connection)	Smart Thermostats (Honeywell) for HVAC and Load Control for Water Heater and Pool Pump	Itron Gas Meters Comverge Electric Interval Meters	Comverge Maingate Home	Paging to the Gateway in the customer's home. PLC within the home. Data back to PSE&G via customer's phone.	288
TOU/CPP Technology Enabled (myPower Connection REMS)	Honeywell Programmable Thermostat	Itron Gas devices Itron Centron Interval Electric Meters	Itron Residential Energy Management Systems (REMS). RF Gateway on customer's computer	RF between meter, thermostat, and Gateway. Customer's broadband Internet from Gateway to Itron	31

Meter Data and Billing. Meter data was transmitted and collected by each host system on a daily basis. Problems occurred in transmitting data throughout the pilot, however system monitoring helped to manage the problems and most were corrected. Interval meter data was used to generate customer bills using the myPower Time-of-Use (TOU) rate. A lack of consistent interval meter data at program start-up required manual intervention in order to create a customer bill on the TOU rate. Improvement to the collection of the interval data helped to improve billing.

Technology I - DCSI TWACS. DCSI technology was selected for use in the myPower Control Group. DCSI provided the Two-Way Automated Customer System (TWACS) via a Powerline carrier to provide automated meter reading of interval data. The DCSI technology was easy to install. The systems operated smoothly throughout the pilot, with minimal interaction on the part of PSE&G. However, on days with high heat and humidity, coupled with the high customer load, the DCSI system was prone to data loss from noise or harmonics injected on the line. DCSI engineers continued to work with PSE&G to ascertain if equipment and line filters could be utilized to assist in the data communications during critical periods to eliminate the gaps in the data received. Unfortunately there were no filters available to eliminate or reduce the noise generated on those days, therefore data loss was experienced.

Technology II – Itron. Itron electric meters were used for the Control Group, for myPower Sense participants, and the Itron myPower Connection REMS participants (discussed below). Participants with PSE&G gas service had their gas meters upgraded to Itron equipment to enable remote gas reads (in addition to the electric meter reads) for the pilot. All of the Itron electric meters met or exceeded ANSI specifications, tested within acceptable limits, and were easy to install. There were six meter failures (blank displays) throughout the duration of the pilot in all pilot sectors with the exception of the High Powered (HP) meters.

For myPower Sense, Itron installed a two-way fixed-network radio frequency communication technology. The technology used communication over radio frequency (RF) from meters and devices to a pole top mounted data collectors. The data collectors communicated to the host end data collection systems via digital cellular radio transmissions.

The Itron technology was installed as required, however fixed network communications problems were identified. Modifications were made to the network including the re-location of equipment. As a result, the system performance leveled-off near the end of July 2006 and produced better results. The number of intervals received with a bad status was the other measure used to assess system performance and the reliability of data provided. All data intervals that were marked with a bad status flag (i.e., questionable due to missing or sporadic interval data) were measured. These flags started off fairly high but improved and leveled-off near the end of July 2006 as the system matured. Once the fixed network system was in place and the start-up issues resolved, system performance could be effectively tracked and functionality tested throughout until the completion of the pilot.

Technology II – Itron REMS. The pilot program included a sub-segment of myPower Connection customers provided with the Itron REMS technology. REMS utilized broadband Internet communications to the customer's programmable smart thermostat. Only customers having broadband Internet were eligible for this sub-segment. The technology allowed customers to program their thermostat remotely over the Internet. The REMS technology also allowed the thermostat to respond to price signals from the host system to control thermostat settings based on pre-determined price tiers.

PSE&G gas technicians installed a Honeywell programmable thermostat at the customer's home, as well as a Gateway device that connected to the customer's computer.

Technology III – Comverge. Comverge was selected to provide their Maingate product to 90% of the myPower Connection homes. The Comverge system is considered a hybrid because it uses various communication technologies. The Maingate appliances receive commands from the host system via radio frequency (RF). The Maingates communicate with appliances throughout the house via power line carrier

(PLC). Finally, the Maingates send data back to the host network and receive price data over the customer's telephone line.

Honeywell manufactured the thermostat utilized by Comverge. The thermostat was programmable and responded to pricing signals to automatically adjust the temperature in the customer's home, according to a pre-determined set-up as selected by the customer and based on their lifestyle. Pricing information was sent to the smart thermostats the night prior over the phone lines. A full 24 hours of pricing information was provided.

The thermostat could also manage electric water heaters and in-ground pool pumps by shutting them off according to a pre-determined price response selected by the customer. For example, if the thermostat received a pricing signal for a high or CPP time period, the thermostat could send a signal to the load control device installed on the pool pump or water heater to shut the equipment off.

Customers could program their thermostat remotely over the Internet through the Comverge website or through the myPower website linked to the Comverge site. Customers used their own Internet provider and logged-in to the Comverge site with a user ID and password.

Field site turndowns were encountered because the thermostat was not compatible with some of the conditions found in the customer's homes, despite upfront customer screening over the telephone to identify those conditions. Field site turndowns included customers with multi-staged, dual, and multi zoned HVAC systems, heating systems with too few or too many wires to connect to the thermostat, and customers having Voice Over Internet Provider (VOIP) telephone service rather than the required standard phone line.

One of the system performance indicators was the number of gaps in interval data received, per unit, per day. The Comverge system had relatively few gaps and the trend decreased over the course of the first summer. On the other hand, the metering hardware and data collectors (Gateways) had 53 failures as of program's end (14% of the initial number of participants). The devices that did not fail recorded data very well and appeared to be robust in all weather conditions.

PSE&G Systems. Several systems were built by PSE&G's System Integration/Measurement Group to enable the data collection, validation and reporting of information for myPower customer participants. The systems developed also supported the myPower billing process. All of the systems developed were solutions for the myPower pilot program only and were not designed to be scalable for a rollout to the general population. PSE&G systems included the following:

- Databases for interval meter data
- Several integrated systems to provide the required functionality necessary to administer and execute the pilot program billing

E.3 Rates and Regulatory Assessment

Rate Design

A specific rate structure was developed for the CPP/TOU pricing segments of the myPower pilot program. In addition, some modifications were made to the Rate Schedule RS (the standard residential delivery service rate) for use as the delivery rate for all test customers in this pilot program.

The CPP rate was a standard fixed Time-of-Day rate with the addition of a variable adder in certain periods. This variable adder was only applied on days of high energy prices or expected high supply loads. The CPP rate was designed to be revenue neutral on a seasonal basis.

The CPP rate was structured as a four part time-of-day rate. During the summer months (the calendar months of June through September) a Base charge was applied for all electricity used during the month. During weekday nights, from 10 p.m. to 9 a.m., a Night Discount to the Base charge was applied. During the weekday period from 1 p.m. to 6 p.m., an On-Peak Adder was applied on top of the Base charge. When market prices were very high, the On-Peak Adder was replaced by a much higher Critical Peak Adder. The structure of the rate was the same during the remainder of the year; however, there were variations in the time frames for the various periods.

The rates and time period definitions for the TOU portion of the CPP rate (those charges other than those in effect during a critical price event) were based upon an analysis of the historic PJM Day-Ahead hourly Locational Marginal Price (LMP) energy market. The analysis determined the optimized time period definitions and related rates, based on historic market conditions. The additional charges in effect during a CPP event were based upon recovering the costs associated with the highest energy market prices, as well as 50% of the costs of the Generation and Transmission Obligations. The remainder of the obligation costs was spread throughout the summer High Period price.

The layout of these charges follows in Table 3 and Table 4 below:

Table 3. CPP Rate – Summer Months (June to September) All charges per kWh

Period	Charge June 1, 2006	Charge July 15, 2006	Charge June 1, 2007	Applicable
Base Price	9.1279¢	9.2032¢	8.6675¢	All Hours
Night Discount	-5¢	-5¢	-5¢	10 p.m. to 9 a.m. Daily
On-Peak Adder	8¢	8¢	15¢	1 p.m. to 6 p.m. Weekdays
Critical Peak Adder	68¢	69¢	$1.37	When called 1 p.m. to 6 p.m. Weekdays. When called is added to the Base Price.

Table 3 note: The increase in 2007 in the Critical Peak Adder and the On-Peak Adder was due to a more than 5 fold increase in Generation Obligation costs while lower forward prices resulted in a slight decrease in the Base Price. Also, all charges are shown with NJ Sales and Use Tax (SUT).

Table 4. CPP Rate – Non-Summer Months (October to May) All charges per kWh

Period	Charge October 1, 2006	Charge January 1, 2007	Applicable
Base Price	8.6670¢	8.6741¢	All Hours
Night Discount	-4¢	-4¢	10 p.m. to 6 a.m. Daily
On-Peak Adder	3¢	3¢	5 p.m. to 9 p.m. Weekdays, November to March
Critical Peak Adder	23¢	23¢	When called 5 p.m. to 9 p.m. Weekdays in November to March; or 1 p.m. to 6 p.m. Weekdays in October, April, and May. When called is added to the Base Price.

Table 4 note: All charges are shown with NJ Sales and Use Tax (SUT)

Criteria for Designating Critical Peak Pricing Days

The number of critical period events for Critical Peak Pricing (CPP) Basic Generation Service was limited by tariff to a maximum of eight per year. The Company planned to call five events each summer of the pilot (from 1 p.m. to 6 p.m.), one in the shoulder season (from 1 p.m. to 6 p.m.), and two in the winter season (from 5 p.m. to 9 p.m.). Selection of the CPP days was based on predetermined price and weather criteria. The pricing criterion references the forecast wholesale price (the day ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day) and the weather criterion references the expected weather conditions (as measured by the forecast next day 4 p.m. weighted THI). The criterion was such that it could be modified during a summer period to reflect actual conditions that were experienced.

Due to technology challenges at program start-up, the program was not able to initiate any CPP events until mid July 2006. CPP events were called on August 1st and 2nd, 2006, with August 3rd (a potential CPP day) reserved for baseline analysis. As the program moved through August 2006, there were no more extreme weather days and prices declined resulting in no additional CPP days that month. Since it was generally agreed that significant data for 2006 had been gathered from the August 1st and 2nd events, and the end of the 2006 summer season was approaching, the price and weather criteria were not changed and there were no CPP events in September 2006.

The goal for the winter of 2006-2007 was to designate two CPP days across the months of December, January and/or February. Selection of these days was based on a predetermined price criterion that could have been modified as the winter progressed to reflect actual conditions that were experienced. The pricing criterion was the forecasted 6 p.m. wholesale price (specifically the day-ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day). The hour of 6 p.m. was selected since it was generally the time of the highest daily winter LMP, and it fell within the 5 p.m. to 9 p.m. CPP period. Weather was not used as a criterion for designating winter CPP days as the relationship between cold weather and high LMP values was not consistent and the timing of CPP days needed to correspond to days with high prices (i.e., high LMPs).

The program also had a goal to initiate one shoulder month CPP day in the month of April or May 2007. Selection of this day was based on predetermined price and weather criteria that could have been modified as the period progressed to reflect actual conditions that were experienced. The pricing criterion was the forecast 5 p.m. wholesale price (specifically the day ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day). The hour of 5 p.m. was selected since it was generally the time of the highest April and May LMP and it fell within the 1 p.m. to 6 p.m. CPP period. Since the shoulder period CPP day was expected to occur on a hot day with a correspondingly high LMP, weather and day ahead LMP were both used as criteria for designating the CPP day.

The program was able to initiate all three non-summer CPP events. The two winter CPP events were called on January 30th and February 6th 2007 while the shoulder CPP event was initiated on May 25th, 2007.

For the second summer of the program, the maximum of five CPP days were initiated. CPP events were called on July 9th and 10th, and August 2nd, 3rd and 7th 2007, with additional days (potential CPP days) reserved for baseline analysis. Due to the weather and pricing conditions experienced in the summer of 2007, the weather criteria was not changed, however, the pricing criteria was. LMPs were lower than expected during the summer of 2007. Therefore, the pricing criterion to call a CPP event was changed from $190 or greater to $140 or greater.

E.4 Operational Assessment

The Operational Assessment presents the operational processes that were developed to support the implementation of the myPower pilot program Pricing Segments. These processes required the coordination of various areas within PSE&G and with program contractors and vendors as well.

Operational Processes

Recruit and Market. PSE&G staff ranked communities by the percent of residents on standard rates and by predicted penetration of central air conditioners. Cherry Hill and Hamilton Township, the two highest ranking townships having these criteria, were chosen for the pilot program. Pilot recruitment was then targeted to 39,170 residential customers in these two townships.

PSE&G utilized direct mail with follow-up telemarketing as the primary marketing channels to solicit customer participation. Customers were selected for participation in specific pilot segments and were not offered the opportunity to choose between segments. Customers had the ability to respond to the direct mail campaign via a toll-free telephone number or a business reply card (BRC). The direct mail was supplemented with telemarketing to ensure adequate enrollment.

Recruitment incentives were utilized to drive customer participation to meet the program schedule. Incentives were structured to be paid to customers in two phases, at the start of the pilot and at its conclusion. The technology-enabled segment (myPower Connection) also received a free smart thermostat and, where applicable, a load control device to help them manage their energy use.

Recruitment Results. 1,527 customers responded to the direct mail campaign, which was equal to a 4% response rate. (This response was well above the average residential response rate of 1% used as an industry standard for similar mail campaigns.) Of the 1,527 respondents, 50% (or 763 responses) came from business reply cards, and 50% (or 764 responses) came from customer call-ins.

Campaign leads were screened to determine the presence of central air conditioning in the home, electric house heating, broadband Internet access, in-home standard telephone lines, and other measures. During this initial telephone screening, 154 customers declined to participate or were found ineligible for program participation. Additional potential participants were unable to participate in myPower due to conditions found at the customer's home at the time of the field installation site visit. To understand how the number of program participants varied over the life of the pilot, see the comparison in Table 5 below.

Table 5. myPower Pricing Target and Actual Participants

Segment	Segment Size Goal	Beginning Segment Size	Actual Segment Size (11/3/06)	Actual Segment Size (9/30/07)	Percent From Goal Remaining in Program
Control Group	450	450	450	450	100%
myPower Sense – TOU/CPP Educate Only	550	536	459	379	69%
myPower Connection – TOU/CPP Technology Enabled	400	424	377	319	80%
Totals	**1,400**	**1,410**	**1,286**	**1,148**	**82%**

Customer Removals. Throughout the course of the pilot, participants were removed from the myPower program for various reasons including incompatible technology due to changes at the customer's home, incompatibility with other PSE&G programs, customers who moved, etc. Table 6 below details the customer removals.

Table 6. myPower Pricing Plan Customers Removed

Reasons	myPower Sense	myPower Connection
Technology Issues	22	28
Billing or Incompatible Program	33	18
Customer Moved	42	17
Special Circumstance	1	3
Totals	**98**	**66**

Specific reasons for participant removals included in the main categories in the table above are as follows:

- **Technology Issues include –** Installation related problem, Installing Solar or Net Metering, Installed new 2-stage HVAC, New HVAC System, Changed to VOIP, Technology Incompatible, Communication Issues
- **Billing or Incompatible Program includes –** Signed-Up for USF,[2] Stay on Auto Pay,[3] Stay on Equal Payment Plan,[4] cannot bill un-metered services
- **Customer Moved includes –** Moved, Not Primary Residence
- **Special Circumstance –** Illness, Death in family

Customer Drop-Outs. A number of customers dropped-out of the program during the course of the program for various reasons.

Table 7. myPower Pricing Plan Customer Drop-Outs

Reasons	myPower Sense	myPower Connection
Technology Issues		24
Billing	28	8
Miscellaneous	31	7
Totals	**59**	**39**

Specific reasons included in the main categories in the table above are as follows:

- **Technology Issues includes –** Does not like T-Stat, Does not like Technology

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[2] Customers receiving Universal Service Fund (USF) benefits could not remain on the program, since the USF program in effect limits the amount of the customer's energy bill. Pilot results would be affected since the customer bill is reduced by USF benefits.

[3] Since this is a pilot program, it was not set up to enable participation in PSE&G's AutoPay program, which automatically deducts the amount due from the customer's bank account.

[4] Customers in the pilot program were not allowed to participate in PSE&G's Equal Payment Plan. The EPP could affect pilot results since customers might not notice the bill impacts resulting from program participation.

- **Billing includes –** Did Not Like Pricing Plan, Does Not Like Billing, Not Saving
- **Miscellaneous includes** - Changed mind, No reason given, Not happy with program, Unable to shift usage into low cost periods

Customer Education and Communication

At the time of the program equipment installation, the installation contractors reviewed the pricing tiers at a high level with the customers while explaining to them the thermostat programming process. The contractors also collected customer HVAC information including the initial thermostat settings at the time of the installation.

Program Education Materials. Following program installation and just prior to program start, customers were mailed a package of program educational materials to assist them in their program participation. The educational materials were customized for each segment and technology, and included:

- Program welcome letter with program updates
- FAQ informational sheet
- Summer 2006 Pricing Plan information (rates sheet)
- Energy Savers Guide
- Refrigerator magnet with toll-free program phone number

myPower Website. A myPower website was developed for customers to provide them easy access to their energy usage and myPower bills online so they could compare program savings to what they would have paid on the traditional RS rate structure, and to provide general program information and energy savings tips. Website navigation guides customized for each segment and technology were mailed to the customers, along with a cover letter providing website log-in instructions, user ID, and initial website password.

Continuing Support. As the pilot progressed, participants received program updates and information via postal mail and/or e-mail. Customers were provided with the new myPower pricing plan information (rates sheets) for the non-summer months and for summer 2007, and were reminded of steps they could take to save energy and shift their usage to lower priced time periods. Prior to summer 2007, customers were sent summer reminder letters and asked to verify and/or update their CPP contact information and myPower Connection customers were provided with their thermostat set-points for cooling to enable them to review their settings and program their thermostat to maximize savings during the summer high and CPP periods. This was particularly important for summer 2007, as the cost of electricity increased overall for residential electric customers and those costs affected myPower participants as well, resulting in significantly higher cost during the High and CPP periods for 2007.

Customer Care

PSE&G contracted with Honeywell Utility Solutions (HUS) to handle the customer support for the myPower Pricing Segments. Services HUS provided include:

- Participant inquiries, compliments, and complaints
- Equipment trouble calls including scripted, over the phone trouble shooting
- 24 x 7 customer service using a live answering service off-hours, which directed emergency service calls to the appropriate installation vendor as required
- Customer equipment removal requests
- Customer billing inquiries

- All other calls as required

Critical Peak Price Event Execution

Once it was determined that a CPP event would be initiated, all applicable internal parties were notified the night prior to an event so that they could respond to any customer inquires that might occur. Customers were notified by 6 p.m. the night before an event by home, office, or cell phone as well as e-mail. Customers were asked to provide their two preferred methods of contact. Customer telephone notifications were made through an outbound dialer, utilizing pre-recorded messages. The myPower e-mail mail box was also utilized to notify customers of CPP events using segmented e-mail lists with the appropriate customer message.

E.5 Billing Assessment

A stand-alone billing system was created specifically for the myPower pilot program. The system enabled PSE&G to bill myPower pilot participants on Time-of-Use (TOU) rates with Critical Peak Pricing (CPP). The billing system provided pilot program participants with a branded myPower billing statement and also supported data inputs required for the myPower customer website.

Because the myPower billing system was developed as an adjunct system to the legacy PSE&G Customer Information System (CIS), it required manual intervention and non-standard billing processes. Customer bills had to be diverted from the CIS billing process and forwarded to dedicated myPower billing staff who in-turn prepared the myPower monthly billing statements. As such, the myPower billing system could not be used for a full scale program deployment.

For the myPower program, electric interval meters were installed at the customer homes to facilitate the collection of data remotely for the pilot. PSE&G meter readers continued to obtain on-site meter readings and entered the data into their handheld meter reading devices for myPower data validation purposes. Because of the specialized nature of the myPower billing process, myPower billing staff provided training sessions for meter readers and customer service representatives; Customer Inquiry, Billing, Credit and Collection, Customer Relations and Construction Inquiry.

A number of issues were encountered during the billing process that had a negative impact on the ability to produce a myPower bill. These issues, such as gaps in interval data, required manual review and intervention on a case-by-case basis. As the interval data collection issues improved, less manual intervention was required.

As the myPower program progressed, it became evident that a number of billing system conflicts needed to be addressed. Specifically, customers who either participated-in or signed-up for various billing related programs (in addition to participating in myPower) required individual billing attention and intervention. Customers were screened-out during the recruitment phase of myPower if they participated in particular programs such as Universal Service Fund (USF), Auto Pay, and the Equal Payment Plan (EPP). Unfortunately, throughout the course of the myPower pilot program, customers inadvertently enrolled in billing related programs, which affected the program's ability to create accurate myPower bills and in many cases prevented a myPower bill from being generated. These billing issues had to be resolved on a customer-by-customer basis.

Due to potential billing conflicts identified by the myPower billing team, a Billing Validation Process (BVP) was established. On a daily basis, the myPower billing team identified and documented all database and system conflicts requiring additional investigation in order to ensure accurate billing.

The close-out of the myPower billing process, resulted in split bills comprised of both TOU and RS rates. The October 2007 myPower bills were produced using interval data collected through September 30th, and billed on a TOU rate, coupled with usage data from October 1st up to the customer's October meter reading date and billed on the standard RS rates. The split bills were necessary to reflect the end of the myPower pricing plan and the customer's return to the normal RS rates.

Key findings: In a wide-scale program deployment, a billing system must:

- Be developed and implemented in an efficient process for mass bill production considering Time-of-Use rates and multiple data systems;
- Identify all programs that require special billing design, i.e., Auto-Pay, EPP, TPS, etc.;
- In partnership with business leads and the Information Technology department, make certain all billing system requirements support required functionality across the business both internal and external;
- Insure that system design adheres to Sarbanes Oxley requirements and all security protocols, as did the myPower process.

E.6 Customer Assessment

The Customer Assessment portion of the myPower program evaluation was designed to evaluate the overall effectiveness of the pilot program by measuring changes in participant attitudes and behaviors. The assessment measured myPower program participants' pre- and post-program attitudes toward energy usage and conservation and measured participants' experience with myPower program equipment, equipment installation, program recruitment and educational materials.

Methodology

The Customer Assessment consists of six surveys:

Pre-Program Survey:	Conducted November 2005 through February 2006 via telephone as part of the customer screening process.
Installation Survey:	myPower Connection only – Conducted via a paper survey, which was mailed to participants after equipment installation. The participants filled-out the paper survey and returned it in a postage paid, pre-addressed envelope directly to PSE&G's Marketing Department.
2006 Annual Survey:	Conducted October 19th through 25th, 2006 via telephone through an independent market research vendor Schulman, Ronca, & Bucuvalas, Inc. (SRBI).
2007 Winter CPP Event Survey:	Conducted January 31st through February 1st, 2007 via telephone through SRBI to measure awareness of and actions taken during the January 30th CPP event.
2007 Summer CPP Event Survey:	Conducted August 4th and 5th, 2007 via telephone through SRBI to measure awareness of and actions taken during the August 2nd and 3rd CPP events. Detailed cost savings questions were added during this survey to get a baseline for the end-of-program survey.

End-of-Program Survey: Conducted October 8th through 13th, 2007 via telephone through SRBI.

The total number of completed interviews for each survey is shown in the following table.

Table 8. Survey Completions

Survey	myPower Sense	myPower Connection
Pre-Program	481	397
Installation	NA	301
2006 Annual	100	100
2007 Winter CPP Event	100	100
2007 Summer CPP Event	100	100
End-of-Program	150	150

Results

Overall results and outcomes include the following:

- 91% of myPower Connection and 85% of myPower Sense participants agree that PSE&G should offer more programs similar to myPower to customers.

- Roughly eight out of ten myPower Connection (77%) and myPower Sense (81%) participants would recommend myPower to a friend or relative.

- The majority of myPower Connection (84%) and myPower Sense (83%) participants believe that programs such as myPower benefit the environment.

- 71% of both myPower Connection and myPower Sense participants believe they saved money.

- Satisfaction with the myPower program remained consistent throughout the pilot. Satisfaction with the myPower Connection program overall at the end of the program (7.4) was essentially the same as the level achieved in 2006 (7.5) while myPower Sense participants satisfaction improved at the end of the program (7.7) compared to 2006 (7.4).

Program Strengths:

- The majority of participants myPower Connection (80%) and myPower Sense (84%) became more knowledgeable about energy consumption reduction as the myPower program progressed (vs. 71% who reported being more knowledgeable in 2006 for both programs).

- Most program participants took action to reduce their energy consumption during High Price Hours and CPP events.

- Program communications were positively received by participants, including CPP event communications.

- Bills were easy to read and understandable.

- Overall, participants were favorable to PSE&G offering this type of program in the future as a voluntary program and would recommend the program to others.

- myPower Connection participants were highly satisfied with the knowledge, professionalism, and courtesy of the myPower equipment installers (Comverge and Itron subcontractors). They were also satisfied that the work was performed neatly.

Opportunities for Improvement:

- Bill savings – On average all participants reported that they had saved money with myPower, although a number of participants did not achieve the electricity bill savings they expected.[5] myPower Connection participants reported saving an average of $188 on the program vs. an expected average savings of $222; myPower Sense participants reported saving an average of $105 on the program vs. an expected average savings of $132.

- Up-front communications – Customers may benefit from more in-depth communications at program sign-up.

- Program equipment – myPower Connection participants experienced some difficulty in programming the thermostat as this was a main area of program dissatisfaction and they gave lower ratings to the installers' explanation of how to operate the thermostat than for other attributes.

- Integrating PSE&G's Equal Payment Plan (EPP) – The majority of participants who were on EPP prior to myPower intended to return to it post myPower.

CPP Events. Only 6% of myPower Connection and 9% of myPower Sense participants accurately reported that PSE&G called eight Critical Peak Price (CPP) events in 2007. The vast majority of participants did not think there had been more CPP events than had actually occurred. Just 6% of myPower Connection participants and no myPower Sense participants overestimated the number of CPP events in the 2007 End of Program Survey.

Satisfaction with the number of CPP events called was generally high in both 2007 and 2006. It declined in 2007 (from 8.0 to 7.0 on a 10 point scale for myPower Connection participants and from 7.9 to 7.5 for myPower Sense participants), which is not surprising given that there were 8 CPP events in 2007 vs. only 2 CPP events in 2006. Comfort during the CPP events varied over the pilot.

E.7 Impact Assessment

Summit Blue performed an impact analysis to estimate the per-participant reduction in load and any load shifting created by the myPower Pricing program. This evaluation addressed both the Time-Of-Use (TOU) and Critical Peak Pricing (CPP) aspects of the myPower program during 2006 and 2007. Two summer periods, one winter period and three shoulder months were covered during this timeframe. Each season had a different pricing structure so impacts were estimated separately for each season. The focus of this impact evaluation was to determine the effect on participants' load shape going from a flat rate to

[5] The CPP rate was designed to be revenue neutral, on a seasonal basis, when compared with the otherwise applicable Basic Generation Service (BGS) charges for the average residential customer (on delivery Rate Schedule Residential Service or RS). See Section 2.1.1 of this report.

the myPower time differentiated rate and to determine the effect of the CPP rate. The analysis also investigated whether or not there was any difference between the impacts from both the TOU and CPP aspects of the program between the myPower Sense participants and the myPower Connection participants. Several different areas of impacts were analyzed:

- Summer Peak Day Impacts
- Summer kWh Shifts
- Summer Energy Conservation
- Summer Elasticities
- Winter and Shoulder Month Impacts

Summer Peak Day Impacts. TOU rates created a reduction in demand during the on-peak period of 1:00 p.m. to 6:00 p.m. throughout the summer for all participant groups. The technology-enabled segment (myPower Connection) performed significantly better than those who received education only (myPower Sense). Table 9 shows that myPower Connection customers regularly reduced their on-peak demand on summer peak days by 21%, while myPower Sense customers reduced their demand by 3 to 6%. Table 9 also shows that CPP events created additional demand reductions. myPower Connection customers reduced their demand by an additional 26%, creating a total demand reduction of 47%. This is equivalent to an average reduction of 1.33 kW over the on-peak period.

Table 9. myPower TOU and CPP Demand Reduction on Summer Peak Days

Segment	Baseline Avg On Peak kW	TOU Only		CPP		Total	
		kW	%	kW	%	kW	%
myPower Connection	2.85	-0.59	-21%	-0.74	-26%	-1.33	-47%
myPower Sense with Central AC	2.6	-0.07	-3%	-0.36	-14%	-0.43	-17%
myPower Sense without Central AC	1.61	-0.09	-6%	-0.23	-14%	-0.32	-20%

Source: Summit Blue analysis of PSEG myPower data

Summer kWh Shifts. Participants face TOU prices every day and so TOU rates inspire load impacts that stretch across the entire summer season. This is reflected in how much load is shifted from one price period to another over the whole summer. Summer kWh shift impacts for each participant group are summarized in Table 10. In general, myPower Connection customers showed the greatest shifting. myPower Sense customers also showed shifting, but the volume of shifting was about half of that achieved in the myPower Connection group. There was little difference in the volume of shifting between myPower Sense customers with central air conditioning and myPower Sense customers without central air conditioning.

Table 10. TOU Summer KWh Shift Impacts by Size of Participant

Participant Group	Rate Period	Very Small	Small	Medium	Large	All Participants	Percent of Summer kWh
myPower Connection	Night	-29	46	148	218	135	1.6%
	Base	32	6	-10	1	0	0.0%
	On-peak	-3	-52	-138	-219	-134	-3.2%
myPower Sense with Central AC	Night	-28	25	52	114	55	0.8%
	Base	41	-3	-17	-31	-11	-0.1%
	On-peak	-13	-22	-35	-83	-44	-1.2%
myPower Sense without Central AC	Night	66	4	70	138	73	1.1%
	Base	-2	11	-46	-105	-41	-0.6%
	On-peak	-64	-15	-24	-33	-32	-1.2%

These impacts show the expected kWh change during a summer season (June through September) for a single residential customer that switches from a regular rate to the myPower TOU rate. Percent changes are based on Control Group average summer kWh for the given rate period.
Source: Summit Blue analysis of PSEG myPower data

Summer Energy Conservation. This analysis looked to see if is possible that overall energy use changed when customers participate in the TOU rate. Comparing the differences between the participant groups and the Control Groups, the best estimates of summer energy savings from the myPower Pricing program is 3.3% for myPower Connection customers, 3.7% for myPower Sense customers with central air conditioning, and 4.3% for myPower Sense customers without central air conditioning. These savings, shown in Table 11, are in comparison to what the participants would have used if they had not been on the TOU rate.

Table 11. myPower Pricing TOU Summer Energy Savings Estimates

Variable	Control Group Change in Use		Participant Group Change in Use		Summer Energy Savings from TOU (Percent)		Total Summer Energy Savings from TOU (kWh per Cust)
myPower Connection	**5.2%**	**-**	**1.9%**	=	**3.3%**		**139**
myPower Sense with Central AC	**5.2%**	**-**	**1.5%**	=	**3.7%**		**144**
myPower Sense without Central AC	**6.4%**	**-**	**2.1%**	=	**4.3%**		**127**

Source: Summit Blue analysis of PSEG myPower data

Summer Elasticities. The analysis presented to this point discusses shifts in kWh and changes in demand induced by the TOU rate. These analyses showed how customers responded to the actual prices they faced in the myPower TOU rate and expressed those results in kW, kWh, and percent change. In order to predict customers' demand response to different TOU rates, we need a different metric. The elasticity of substitution provides that metric. It provides a scalable measure of participants' response to changes in prices. Combining data from the 2006 and 2007 summers in a single elasticity model gives a good summary of the elasticity of substitution for the myPower program. Table 12 presents the results of these combined year models for each customer segment of interest.

Table 12. Comparison of Summer Substitution Elasticities for myPower Customer Segments

Variable	myPower Connection Coefficient (t-value)	myPower Sense with Central AC Coefficient (t-value)	myPower Sense without Central AC Coefficient (t-value)
Substitution Elasticity	**-0.125** **(-44.9)**	**-0.069** **(-21.9)**	**-0.063** **(-14.6)**

Source: Summit Blue analysis of PSEG myPower data

myPower Connection customers had a much higher elasticity of substitution than either of the myPower Sense customer groups, and elasticities for the two myPower Sense groups are very similar. Table 13 shows that the difference between myPower Connection customers and myPower Sense customers is both large and statistically significant. However, there is no significant difference between the two myPower Sense customer groups.

Table 13. 95% Confidence Interval About Elasticity Estimates

	Lower Bound	Substitution Elasticity	Upper Bound
myPower Connection	-12.0%	-12.5%	-13.1%
myPower Sense with Central AC	-6.3%	-6.9%	-7.5%
myPower Sense without Central AC	-5.5%	-6.3%	-7.2%

Source: Summit Blue analysis of PSEG myPower data

Winter and Shoulder Month Impacts. The TOU rate applied the whole year and CPP events were called in non-summer months as well as summer months. As a result, the impact analysis included an analysis of winter and shoulder month impacts. Customers did respond to price signals on winter peak days and shift usage out of the on-peak period. However, as expected, winter kW impacts were lower than summer kW impacts. For example, myPower Connection customers had average on-peak winter impacts of –0.41 kW compared to –1.33 kW during summer. This is largely because there is less electric load being used in residential households during the winter. However, if the achieved impacts are considered as a percent of load, the summer and winter impacts are very comparable.

There was only one CPP event during the shoulder months, on Friday, May 25th, 2007, the Friday before Memorial Day. Selection of this day was based on predetermined price and weather criteria. myPower Connection customers showed a -0.27 average kW demand reduction in response to the shoulder month's CPP event. This event was on a very hot day and there was air conditioning load that responded to the control signal. Neither of the myPower Sense customer groups demonstrated a change in usage in response to this event. This is not surprising, given that it occurred on the Friday before a holiday weekend. Customer attention was probably not focused on energy use during that single event.

Moving beyond peak day analyses and looking at entire seasons, there was little overall kWh shifting for any of the customer groups during winter months and even less during the shoulder months. There was also little total energy savings in the winter and shoulder months. The one exception is the myPower Sense with central air conditioning group. They showed a 1.65% decrease in energy use during winter months which was statistically significant at the 90% confidence level. It appears that their conscious attention to energy demand and load shifting during the summer may have become habit and carried over into the winter months.

Findings. In summary, the major findings from the analysis include the following:

- myPower participants consistently lowered their on-peak demand in response to price signals across two summers.
- During the summer there were daily reductions in demand from 1:00 p.m. to 6:00 p.m. on weekdays due to the on-peak prices in the TOU rate.
- When critical peak days were called, customers reacted to the CPP rates and created even more demand reduction during the 1:00 p.m. to 6:00 p.m. period.
- Customers who received enabling technology as part of the program (myPower Connection customers received programmable, communicating thermostats) showed greater reductions in demand, both in response to the TOU rates and the CPP events.
- On the hottest summer days, myPower Connection customers reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 21% (0.59 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 26% (0.74 kW) if a CPP event was called. This is a total reduction of 47% (1.33 kW).
- On the hottest summer days, myPower Sense customers with central air conditioning reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 3% (0.07 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 14% (0.36 kW) if a CPP event was called. This is a total reduction of 17% (0.43 kW).
- Many customers used less air conditioning during the high price periods. This created snapback demand after 6:00 p.m. when prices returned to base levels and air conditioners started running at full capacity to bring down indoor air temperatures.
- Snapback occurred on all hot weekdays due to the on-peak TOU rate. The snapback effect was highest from 6:00 p.m. to 7:00 p.m. and diminished over the next few hours.
- On critical peak days, there was additional snapback adding to what normally occurred on regular TOU days. There was a limiting factor on the amount of snapback that occurred in the first hour after the end of the control period, suggesting that many air conditioners were running at 100% of their capacity.
- myPower customers were able to reduce their total summer energy use by 3-4% compared to Control Group customers.
- The elasticity of substitution ranged from –13.7% to -8.8% for myPower Connection customers over the two summers of the study, and from –8.5% to –6.1% for myPower Sense customers. The on-peak to off-peak rate differential changed from 4.1 to 6.5 over this same period.
- Customers also responded to price signals on winter peak days, but winter kW demand reductions were smaller than summer kW demand reductions. For example, myPower Connection customers had average on-peak winter impacts of –0.41 kW compared to –1.33 kW during summer.
- myPower Connection customers did not show any reduction in their total winter energy use. However, myPower Sense customers showed a 1.65% decrease in energy use during winter months which was statistically significant at the 90% confidence level. It appears that their

conscious attention to energy demands and load shifting during the summer may have become habit and carried over into the winter months.

E.8 Bill Impact Assessment

An analysis was also performed to understand the bill impacts experienced by customers participating in the pricing segments of the pilot. The CPP rate was designed to be revenue neutral for the average residential customer. An average hourly load shape was constructed for the RS rate class and the critical peak prices were established such that over each summer period and, separately, over the non-summer period, a customer using electricity according to this average load shape would have experienced a zero bill impact if billed on the CPP rate and the customer took no action to modify his energy use pattern.

A summary of the bill impacts is provided in Table 14 below. This summary provides several different views of the bill impacts. These views are considered logical slices of time of the myPower program during 2006 and 2007. The table shows the percentage of customers in both the myPower Sense and myPower Connection segments that saved and/or lost money from the program, the average savings/loss for customers in each segment, and the maximum and minimum savings/loss.

Table 14. Bill Impacts

	Higher Bills				Lower Bills			
Participant Group	**%**	**Average**	**Max**	**Min**	**%**	**Average**	**Max**	**Min**
myPower Connection - 12 Months Ending September 2007	13%	$35.77	$136.92	$0.22	87%	($101.68)	($421.67)	($0.60)
myPower Sense - 12 Months Ending September 2007	32%	$34.78	$196.12	$0.53	68%	($68.14)	($501.12)	($0.62)
myPower Connection - Entire Program	14%	$44.41	$201.82	$0.67	86%	($156.91)	($639.20)	($2.17)
myPower Sense - Entire Program	29%	$44.36	$238.25	$0.53	71%	($95.88)	($601.82)	($0.62)
myPower Connection - Summer 2007	16%	$33.91	$113.85	$1.56	84%	($88.93)	($347.89)	($1.61)
myPower Sense - Summer 2007	33%	$36.98	$126.15	$0.05	67%	($57.33)	($483.82)	($0.12)
myPower Connection - Non Summer October 2006 through May 2007	23%	$6.67	$26.68	$0.27	77%	($20.05)	($187.32)	($0.03)
myPower Sense - Non Summer October 2006 through May 2007	26%	$6.25	$69.97	$0.08	74%	($13.41)	($61.15)	($0.01)

The percent of customers with higher bills vs. lower bills appears to be fairly consistent across each of the different time periods analyzed with higher savings consistently experienced by the myPower Connection customers. The percent of customers that did not save in the pilot also remained consistent across all views. It is also noteworthy that by far, most of the savings occurred during the summer periods.

The impact analysis component focusing on the summer kWh shifts due to the TOU rate provides data for another view of the bill savings the participants achieved. Table 15 shows the value of the electricity savings priced out at the summer 2007 TOU rates.

Table 15. Summer kWh Shifting Expressed in Dollars (per Participant)

Participant Group	Rate Period	Very Small	Small	Medium	Large	All Participants
myPower Connection	On-Peak	($0.71)	($12.31)	($32.66)	($51.83)	($31.71)
	Base	$2.77	$0.52	($0.87)	$0.09	$0.00
	Night	($1.06)	$1.69	$5.43	$8.00	$4.95
myPower Sense with Central AC	On-Peak	($3.08)	($5.21)	($8.28)	($19.64)	($10.41)
	Base	$3.55	($0.26)	($1.47)	($2.69)	($0.95)
	Night	($1.03)	$0.92	$1.91	$4.18	$2.02
myPower Sense without Central AC	On-Peak	($15.15)	($3.55)	($5.68)	($7.81)	($7.57)
	Base	($0.17)	$0.95	($3.99)	($9.10)	($3.55)
	Night	$2.42	$0.15	$2.57	$5.06	$2.68

In addition to savings achieved by shifting energy usage from On-Peak to Base and Night hours, the participants in the pilot also achieved some energy savings during the summer months as evidenced in Table 8 of the Impact Assessment section of this report. Table 16 shows the value of the savings in terms of energy and delivery bill reductions at the current residential RS Rate.

Table 16. Summer Energy Savings (kWh per Participant)

Participant Group	Percent Saved	kWh Saved	Energy Bill Savings	Delivery Bill Savings	Total Savings
myPower Connection	3.3%	139	$15.84	$7.30	$23.14
myPower Sense with Central AC	3.7%	144	$16.41	$7.56	$23.97
myPower Sense without Central AC	4.3%	127	$14.48	$6.67	$21.15

E.9 Summary

The myPower Pricing pilot demonstrated the benefits of implementing a small-scale program before starting a full-scale rollout. Those benefits included:

- Design and debug all processes needed to implement the program; including communication systems, installation protocols, and operating protocols.
- Identify the range of issues that will have to be dealt with to ensure that the billing system will meet the program's needs when the program is scaled-up.
- Test options for equipment to determine customer response, as well as installation and operations issues.
- Work with vendors to ensure the equipment meets the program and participant needs before large quantities are ordered.

The myPower Pricing pilot demonstrated the benefits and drawbacks of the particular approach and technology chosen before starting a full-scale program. The relevant issues and findings are as follows:

- Customer response to the mail marketing campaign was high, indicating a significant interest in the program's approach, but significant effort was needed from the telemarketing effort to obtain qualified participants.

- Technical barriers (e.g., incompatible air conditioners) and other PSE&G rates or programs (e.g., Universal Service Fund, Auto Pay, Equal Payment Plan) disqualify a significant number of interested customers. A significantly higher percent of sites were disqualified at the field installation step than originally anticipated. All of these types of issues would need to be addressed prior to a full-scale program deployment.

- On the whole, participants were satisfied with the program. They were generally pleased with the participation process, the installation process (for myPower Connection), and the myPower bills. The vast majority thought that PSE&G should offer more programs similar to myPower to customers and the vast majority also would recommend myPower to a relative or friend. Almost three quarters thought they saved money with the program although one half of the participants expected to save more money than they did. Over three quarters of participants thought the program had made them more knowledgeable about saving energy. Some myPower Connection participants would appreciate more information and assistance in programming their thermostats.

- Most participants thought there were fewer CPP events than there actually were and very few thought there were more events so the participants were not significantly affected by the CPP events. Most were reasonably comfortable on CPP days.

- myPower Critical Peak Pricing does produce measurable and statistically significant reductions in participants' energy use during high and critical price periods. myPower Connection customers regularly reduced their on-peak demand on summer peak days by 21%, while myPower Sense customers reduced their demand by 3 to 6%. myPower Connection customers reduced their demand by an additional 26% on CPP days, creating a total demand reduction of 47%. This is equivalent to an average reduction of 1.33 kW over the on-peak period.

- Customers who received enabling technology as part of the program (myPower Connection customers received programmable, communicating thermostats) showed greater reductions in demand, both in response to the TOU rates and the CPP events.

- On the hottest summer days, myPower Connection customers reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 21% (0.59 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 26% (0.74 kW) if a CPP event was called. This is a total reduction of 47% (1.33 kW).

- On the hottest summer days, myPower Sense customers with central air conditioning reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 3% (0.07 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 14% (0.36 kW) if a CPP event was called. This is a total reduction of 17% (0.43 kW).

1 TECHNICAL ASSESSMENT

1.1 Introduction

The myPower Pricing pilot program was created to test two-way communication technologies to the customer's meter in order to understand the potential to create opportunities for changing the way customers think about energy delivery and consumption. The Pilot utilized two-way communications to transfer energy pricing and interval consumption data and allowed PSE&G to test customer response to various pricing signals. Interval meters and in-home technology assisted with understanding the customer energy consumption cause-and-effect relationship.

The Technical Assessment presents the technology that was selected for the Control Group and Pricing Segments of the myPower pilot program, as well as the implementation processes associated with the technologies. These processes required tight coordination between multiple parties including PSE&G personnel and third party contractors, vendors and suppliers. The technical assessment also addresses the various data systems utilized in myPower. Data collected and analyzed includes outage timestamps, circuit voltage readings, vendor website data, and customer overrides. Other types of data were also mined and analyzed as applicable throughout the project.

Three equipment manufacturers were selected to provide equipment for the Control Group and Pricing Segments. They were DCSI, Itron, and Comverge.

- DCSI provided the Two-Way Automated Customer System (TWACS) system. DCSI technology communicated via a Powerline carrier.

- The Itron equipment in the myPower pilot utilized a fixed-network radio frequency communication technology.

- Comverge's Maingate product allowed for deployment of two-way communication. Comverge's equipment in the pilot utilized a paging system and customer phone lines.

Table 17 summarizes the equipment utilized in each segment of the myPower pilot program.

Table 17. Equipment Utilized in the myPower Pilot Program

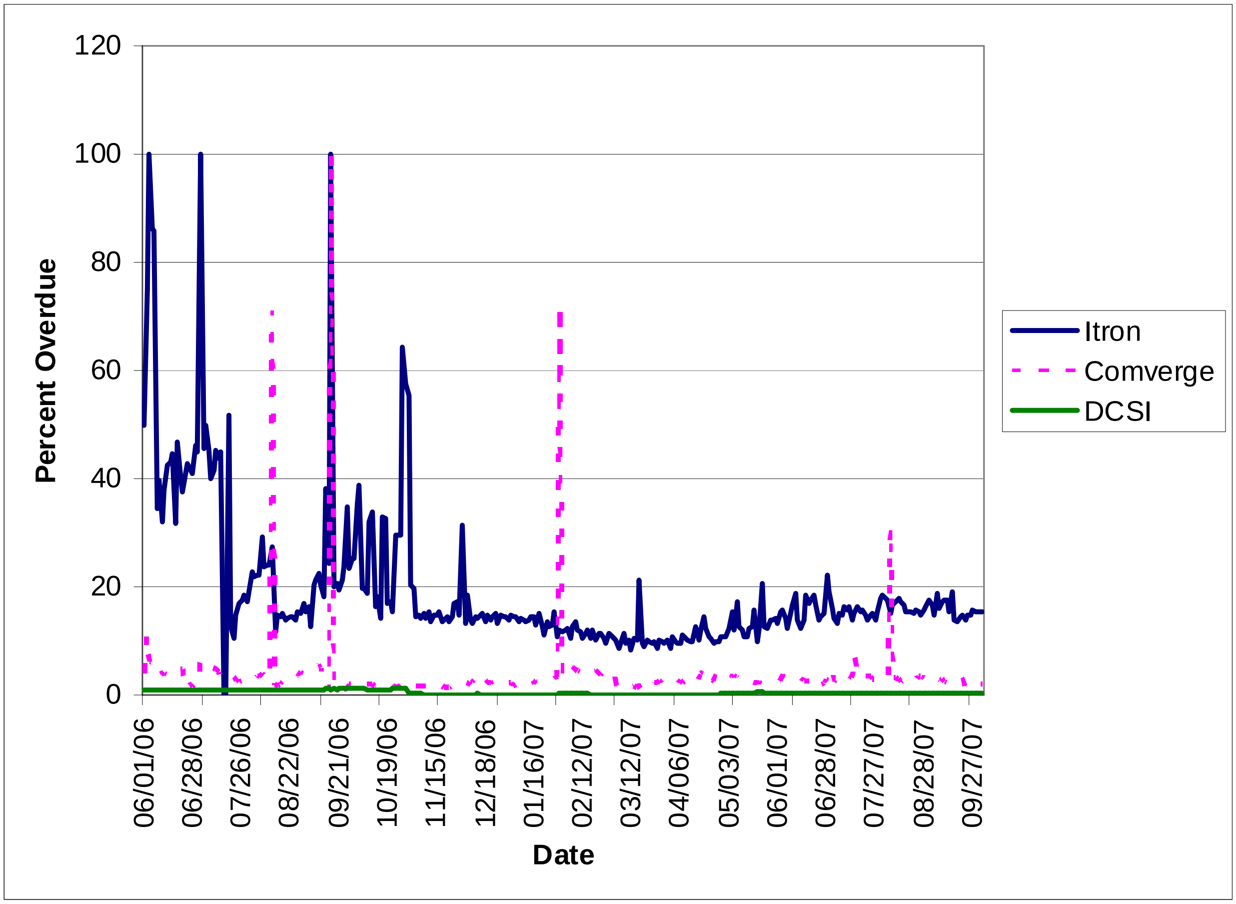
Segment	Thermostat	Meter	Communication Equipment	Communication Medium	Actual Segment Size 9/30/07
Control Group	No change	Itron Centron Interval Electric Meters	DCSI	Powerline Carrier	450 Customers
TOU/CPP Education (myPower Sense)	No change	Itron Electric and Gas Meters	Itron Repeaters and Central Collection Units (CCUs)	RF	379 Customers
TOU/CPP Technology (myPower Connection)	Smart Thermostats (Honeywell) for HVAC and Load Control for Water Heater and Pool Pump	Itron Gas Meters Comverge Electric Interval Meters	Comverge Maingate Home	Paging to the Gateway in the customer's home. PLC within the home. Data back to PSE&G via customer's phone.	288 Customers
TOU/CPP Technology (myPower Connection REMS)	Honeywell Programmable Thermostat	Itron Gas devices Itron Centron Electric Interval Meters	Itron Residential Energy Management Systems (REMS). RF Gateway on customer's computer	RF between meter, thermostat, and Gateway. Customer's broadband Internet from Gateway to Itron	31 Customers

1.2 Summary

1.2.1 System Operation

Meter data was transmitted and collected by each host system on a daily basis. System performance was measured by tracking daily the number and percent of meter devices that were overdue, i.e. when data was not received by the host (see Figure 1 below that illustrates the percent of meter devices that were overdue). In reviewing the data for each system, there are several sharp peaks that are indicative of host system problems that resulted in the failure of the delivery of the daily data file. However, the data was recovered through a backup process. The results for the Itron technology reflect the timing of infrastructure deployment and the associated fixed network issues experienced during the early days of implementation. Performance improved as the infrastructure was deployed and the fixed network was improved. The Comverge spikes illustrate data collection issues on the host end. Refinements to the system were made including the establishment of a more robust monitoring system for both PSE&G and each vendor. None of the spikes occurred on CPP days. Since the system was monitored through a daily report, most of the problems were quickly identified and alleviated. Data collection and quality was continuously evaluated throughout the duration of the pilot and the overall data trend improved.

Figure 1. Percentage of Meter Data Overdue on a Daily Basis

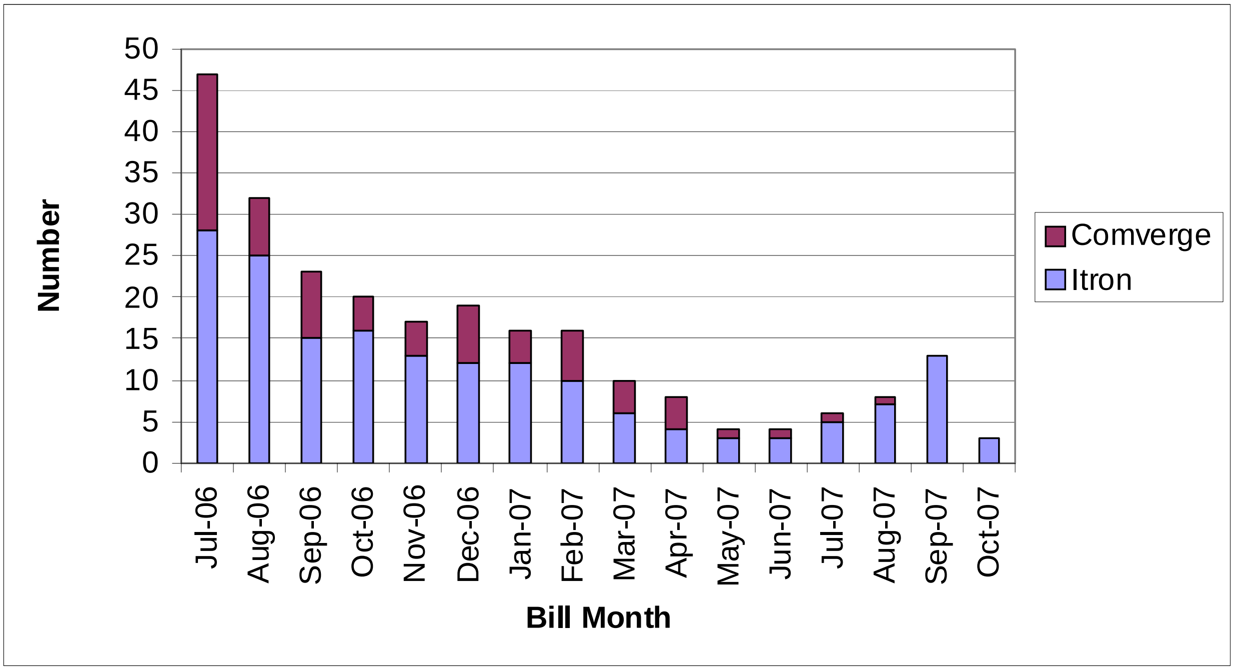


1.2.2 Billing Data

Interval meter data was used to generate customer bills using the myPower Time-of-Use (TOU) rate.

At program start-up the lack of consistent interval meter data required manual intervention in order to create a customer bill on the TOU rate. In some cases a myPower bill could not be produced because of inconsistent data and a regular bill was sent to customers. Improvement to interval data collection helped to improve customer billing. Figure 2 below summarizes the interval data billing errors by billing month. The data illustrates the number of accounts that did not have the required interval data to bill due to missing data. As the collection of the interval data that supported the myPower billing systems improved, errors were reduced and customer billing performance on the myPower TOU rate increased.

Figure 2. Interval Error Summary by Billing Month



1.3 Technology Characteristics and Data Collection

Several technologies were utilized in the Pricing Segments of the myPower Pilot program and numerous types of data were collected from each of the technologies employed. This section of the Technology Assessment will review the technologies used by vendor and the associated data collection.

1.3.1 Technology I - DCSI TWACS

DCSI technology was selected for use in the myPower Control Group. DCSI provided the Two-Way Automated Customer System (TWACS) using Powerline carrier technology.

Preliminary Engineering

Two electric circuits in PSE&G's southern division were selected for the Control Group. DCSI and PSE&G engineers met several times and together designed the equipment requirements for the two identified circuits. Meter and customer locations were selected by PSE&G along those circuits, to emulate the makeup of customers in the myPower Pricing Segments. This allowed comparison of data between Pricing Segment and Control Group customers for program evaluation. Because the DCSI technology was utilized for the blind Control Group, no design considerations were necessary for downstream customer interface devices such as thermostats.

Equipment Hardware

Control and Receiving Unit (CRU)

The Control and Receiving Units (CRUs) provided the communications and data storage links for the two circuits in the Control Group. The CRUs were mounted on poles outside of the substations feeding each of the two identified circuits. Mounting was fairly simple and went according to plan and design. After approximately one month of operation, it was determined that one of the circuit installations was too low and could pose a potential safety issue for pedestrians. The modification to raise it on the pole was completed within a week with no issues. The Host-End communication system was installed using a modem and a standard Telco line.

Outbound/Inbound/Modulation Units (OMU/IPU/MTU)

The Outbound/Inbound Modulation Units (OMU, IPU and MTUs) enabled the Power Line Carrier (PLC) to initiate calls to the meters in order to gather data from the meters.

Meters

DCSI Communication devices were installed in the Itron Centron meters. All devices were inside the meter, under glass, and easy to install. There were only three known communication device failures.

Data Collection

Data collection systems were hosted by PSE&G in their Springfield, NJ office. The data collection systems operated via Structured Query Language (SQL) and a Graphical User Interface (GUI) from DCSI. In order to collect the necessary data for the myPower pilot program, DCSI adopted the PSE&G required multi speak XML format for data transfer. Initial data collection is summarized below.

Application Issues

- Database and host software operated with no issues

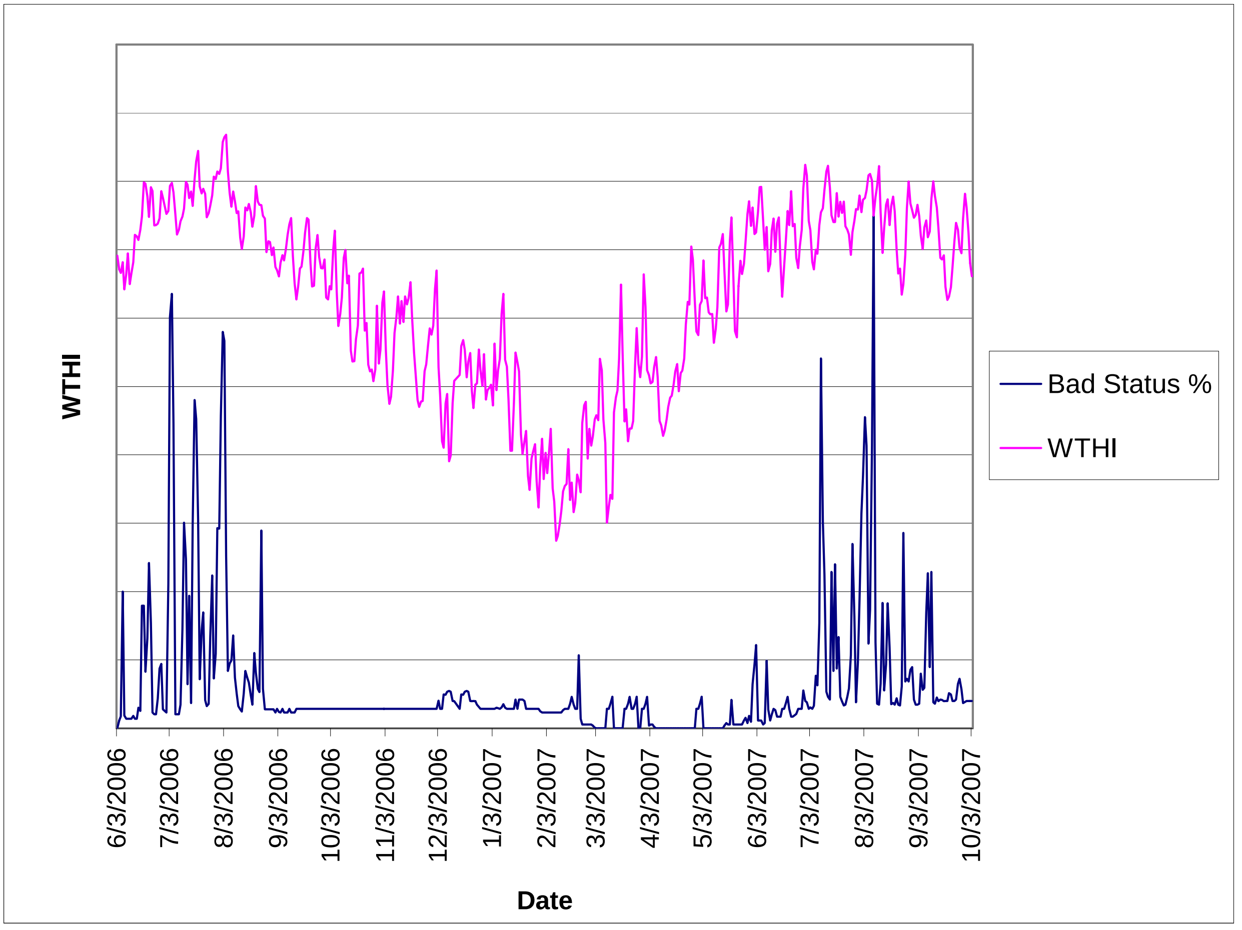
Data Quality Issues

- Acceptable overdue percentage.
- Major problem gathering interval data through peak summer periods. As part of the ongoing data analysis, it was identified that there was a large data loss on days when temperatures started to peak. (See summary below).
- Outage detection on the two identified circuits for the Control Group were technically enhanced to detect outages before a customer notified PSE&G. Initially, a printer was established in electric dispatch to support the early detection process to enable PSE&G to detect outages at the customer level using the DCSI technology. After the mid-year evaluation of this process, it was determined that the printer concept was too cumbersome. Since there was no direct interface to the PSE&G Outage Management System (OMS) system (due to the time and cost required to build the interface), an alternate method was developed to compare datasets of OMS and myPower outages. The data gathered from this system enhancement was used to evaluate the technology and its value to early outage detection.

Summary – Project to Date

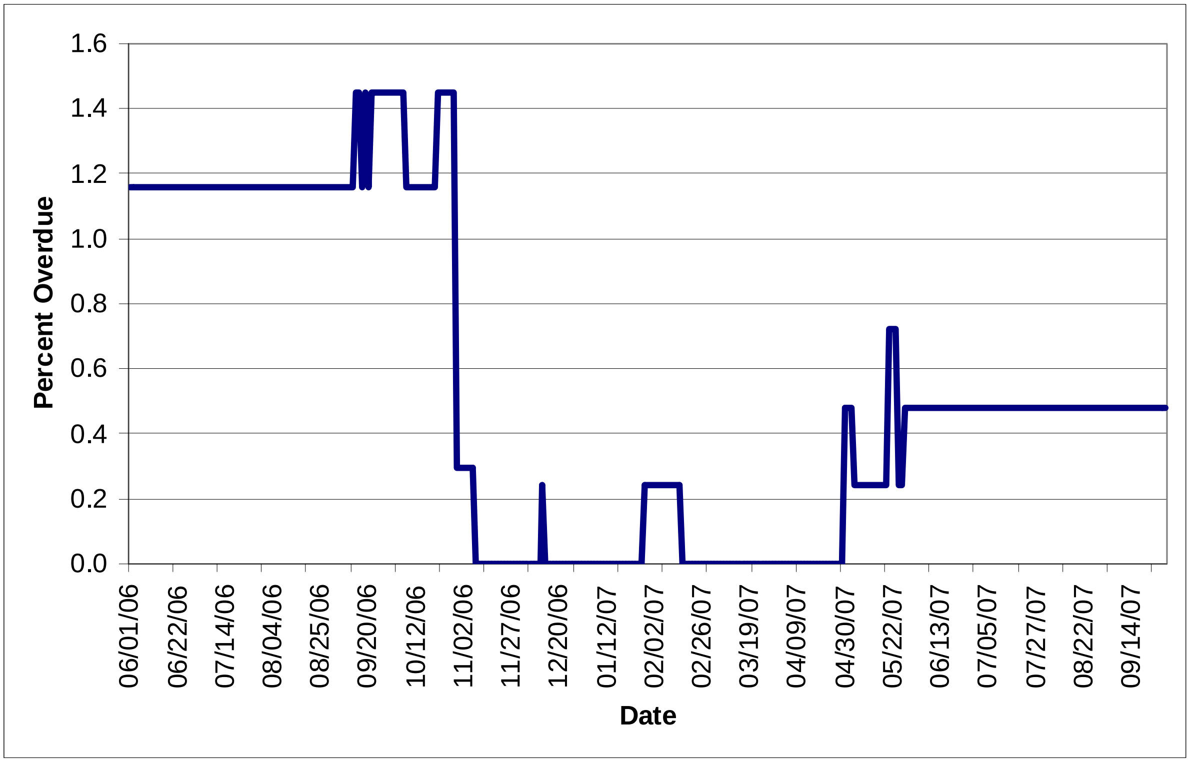
The DCSI technology was easy to install. Meters were set (phase 1) before the infrastructure was in place. When the host systems were activated, all meters were instantly recognized and accounted for. The systems operated smoothly throughout the pilot, with minimal interaction on the part of PSE&G. However, when the data was analyzed for the CPP events (summer 2006 and 2007) an unexpected trend was identified. Although there was communication to the devices each day, data was missing under certain conditions. The missing data seemed to occur during high heat and humidity days with high Weighted THI (WTHI) values, when most customers had their AC and other cooling related equipment operating at maximum levels. A discussion with DCSI engineers revealed that in times of high heat and humidity, coupled with high customer load, the DCSI system is prone to data loss from noise or harmonics injected on the line. Figure 3 displays the dates of missing data as compared to the WTHI for that day.

Figure 3. WTHI vs. DCSI Data Missing



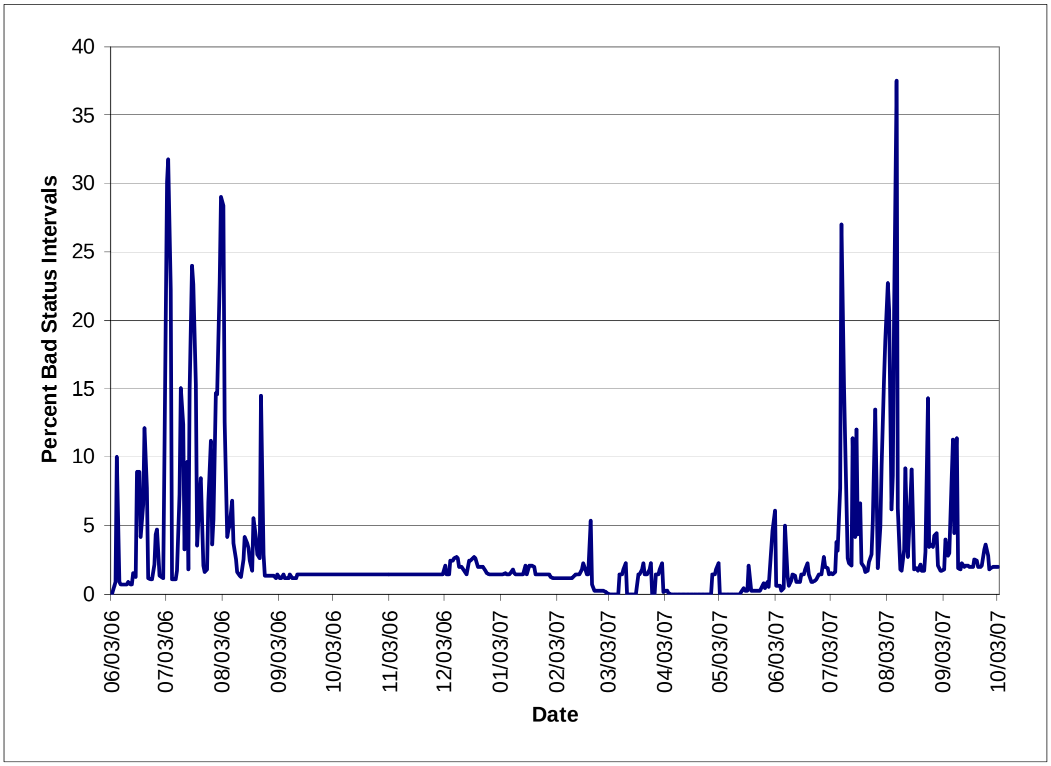
DCSI has a low overdue rate associated with its technology (See Figure 4 below). In addition, during the pilot there were only two meter failures that were not related to the communication devices. There were also three communication devices that failed.

Figure 4. Overdue Report DCSI



The other measure used to trend health of the system and the data provided, was the number of gaps associated per unit day. In Figure 5 below, both measures are portrayed in percentage of expected intervals received. As previously stated, the DCSI system encountered issues on days with heat and high humidity, and did not perform well on days with those conditions.

Figure 5. Bad Status – DCSI



DCSI engineers continued to work with PSE&G to ascertain if equipment and line filters could be utilized to assist in the data communications during critical periods to eliminate the gaps in the data received. At the end of the pilot, the system issues had not been resolved.

1.3.2 Technology II - Itron

Itron electric meters were used for the Control Group, for myPower Sense participants, and the Itron REMS myPower Connection participants. Participants with PSE&G gas service had their gas meters upgraded to Itron equipment to enable remote gas reads (in addition to the electric meter reads) for the pilot. For myPower Sense, Itron installed a two-way fixed network radio frequency communication technology. The technology used communication over radio frequency (RF) from meters and devices to pole top mounted data collectors. The data collectors communicated to the host-end data collection systems via digital cellular radio transmissions.

Preliminary Engineering

Itron requested and was provided with information from PSE&G for the purposes of upfront program planning and design. This information included customer data on potential program participants residing in both Cherry Hill and Hamilton Township, NJ, primarily to look at the population density and saturation of central air conditioning in the two towns. Itron also requested the Global Positioning System (GPS) data for each customer. That information was supplied by PSE&G from its Customer Information System (CIS), which provides estimated latitude and longitude information. Itron also requested PSE&G pole data with GPS coordinates, and that data was provided to them through a program that PSE&G's electric delivery group maintains for the electric distribution grid. Itron had difficulty reading and utilizing the data provided, as it was in a different format than they typically used. As a result, the data required to locate and install equipment was eventually gathered through onsite investigation and Radio Frequency (RF) range testing.

Itron engineers redesigned the RF network several times in order to address communications issues. There were issues with range and interference associated with the installation of the network. Central Collection Units (CCUs) and pole repeaters were relocated and additional infrastructure equipment was installed to improve the communications of the network system.

This experience demonstrated that onsite engineering work should be a base requirement for any installation of technology, especially one that is RF in nature.

Equipment Hardware

Central Collection Units (CCUs)

Central Collection Units (CCUs) were needed to collect interval data from the meter and transmit it by radio frequency to the host system. The CCUs used General Packet Radio Systems (GPRS) for host communications. PSE&G's electric delivery group installed the CCUs, utilizing mounting brackets and pre-wired power cords.

Sleeve Repeaters

Sleeve Repeaters are devices that provide a Radio Frequency (RF) signal boost for remote devices located a long distance from a Pole Repeater or CCU. These devices were housed in Marwell adaptors and inserted before PSE&G electric delivery technicians installed the meter. Sleeve repeaters were minimally required.

Pole Repeaters

Pole repeaters are signal boosters that enhance communications from the meter to the CCUs. They were needed to enhance the transmission of interval data. PSE&G's electric delivery installed the pole repeaters for myPower utilizing mounting brackets and pre-wired power cords. During the installation and testing of the pole repeaters, adjustments were made to the original engineering design to account for interference and adjust for range impact. During the installation of pole repeaters and CCUs, a newly developed broadband type pole repeater technology was introduced to address some of the communication challenges being experienced.

Electric Meters

Several types of Itron electric meters were installed by PSE&G's electric delivery group throughout the different segments of the pilot program. They included:

a. Centron meters with ERT technology
b. Sentinal meters with pulse capability
c. Centron meters with TWACS technology
d. Sentinal Meters with NERTEC technology
e. CENTRON HP (High Powered – group 1)
f. CENTRON HP (High Powered – group 2)

All of the meters met or exceeded ANSI specifications, tested within acceptable limits, and were easy to install. The meters had communication modules under the meter glass cover which were integrated within the meter. These same types of meters are also used on a daily basis at PSE&G, and have had a good track record for reliability and accuracy. There were three meter failures (blank displays) in all pilot sectors with the exception of the High Powered (HP) meters. The first group of HP meters was installed to provide stronger RF signals for remote points. Shortly after those installations, Itron identified a HP meter defect and notified PSE&G immediately. An issue in the meter logic caused the meter to lose track of the interval boundary, causing the creation of multiple time intervals. Itron investigated the problem to determine how the problem manifested, and the catalyst that caused the issue. It was determined that a bad component chipset was the root cause. Because these meters were required to provide TOU data for billing purposes, the defective meters were removed and replaced with a different type of HP meter.

Gas ERTS

During Pilot planning it was decided that customers having PSE&G gas service would have their gas meters upgraded to enable remote gas reads for the pilot (in addition to the electric meter reads). For the Itron REMS installations (myPower Connection REMS), PSE&G gas delivery technicians performed full gas meter replacements.

Fixed Network

There were problems identified throughout the installation and subsequent testing of these devices.

- There were eight failed power cords. This required a second visit to the site for replacement. It was determined that there was a short in one of the manufactured batches.

- Repeaters set in close proximity to CCU devices created interference between both devices resulting in two cases where repeaters had to be relocated.

- Repeaters did not perform as expected and were limited in their range ability. This was one of the equipment issues that had the largest program impact. Although the original engineering plan called for 140 pole repeaters, ultimately 302 pole repeaters were installed, twice the original number.

- In September 2006, a new broadband pole repeater with multi channels (eight) was introduced. This bandwidth increased reliability and repeatability.

- One batch of (38) repeaters failed due to faulty components and required replacement.

REMS

The pilot program included a sub-segment of myPower Connection customers provided with the Itron REMS technology. Since REMS utilized broadband Internet communications to the customer's programmable smart thermostat, only customers having broadband Internet were eligible for this sub-segment. The technology allowed customers to program their thermostat remotely over the Internet once the installation was completed. The REMS technology also allowed the thermostat to respond to price signals from the host system to control thermostat settings based on pre-determined price tiers.

PSE&G gas technicians installed a Honeywell programmable thermostat at the customer's home, as well as a Gateway device that connected to the customer's computer.

Gateways

Gateways provided the RF connection for the Internet, between the meters and the thermostat. A Gateway was installed at each customer home to support the REMS communications.

There were 3 Gateway failures of different types. One occurred because the customer did not have the required Ethernet connection. The other two failures were a result of a device problem.

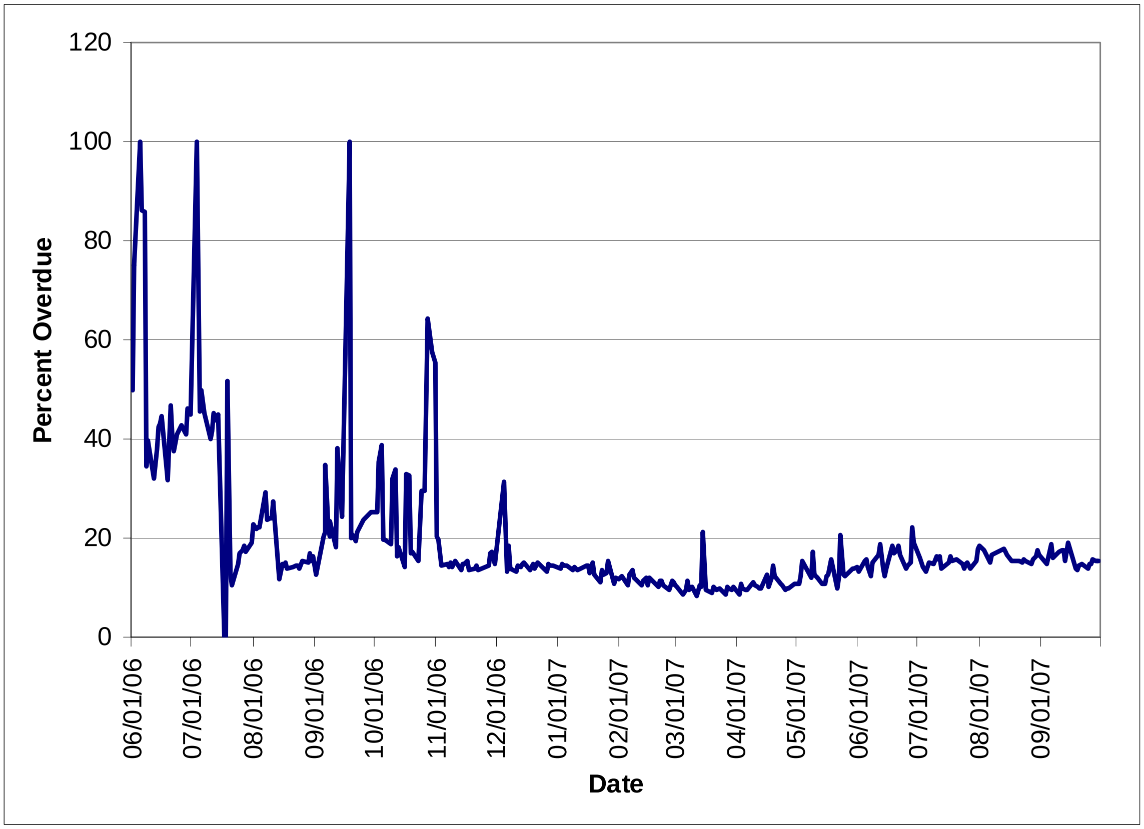
Data Collection

The Itron system collected 15 minute interval meter data. In order to collect the necessary data for the myPower pilot program, Itron adopted the PSE&G required multi speak XML format for data transfer. Data was gathered and analyzed throughout the course of the myPower pilot program. Initial data collection is summarized in Figure 6. There were several instances of late, corrupt, or missing data files. Although these files were later recovered, the notifications of such system problems, and the subsequent delay to billing and other downstream systems were evident. Closer controls of billing grade data are required.

Summary – Project to Date

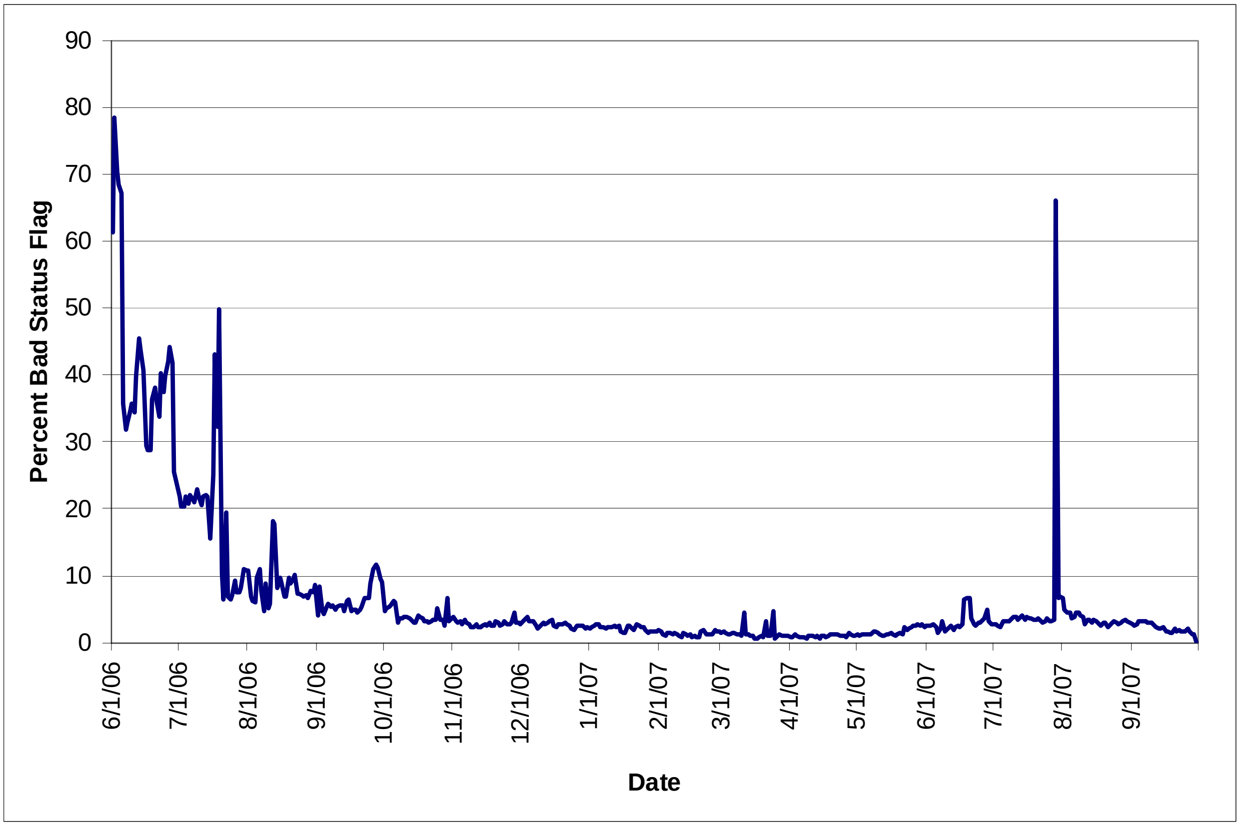
Although the Itron technology was installed according to plan and design, several fixed network communications problems were identified. After the initial program start-up, the fixed network continued to have problems that impeded its function during the first six weeks of program operation. Modifications were made to the network including the re-location of repeaters and CCUs. As a result, the system performance leveled-off near the end of July 2006 and produced better and more consistent results. Figure 6 below illustrates the number of devices overdue (data not communicated when expected) and the rate at which the device overdue rate improved.

Figure 6. Overdue Report – Itron



The other measure used to trend health of the system and the data provided was the number of intervals received with a bad status. Data with a bad status was questionable due to missing or sporadic interval data provided. Figure 7 shows how the number of bad status intervals improved and leveled-off near the end of July 2006.

Figure 7. Bad Status Intervals – Itron



Once the fixed network system was in place and the start-up issues resolved, system performance was effectively tracked and functionality tested throughout the completion of the pilot. As seen in Figure 7 above, the spike on August 12th was caused by a malfunction in the Itron Data collection system. A corrected file was received the next day.

Technology III – Comverge

Comverge was selected to provide their Maingate product which enabled deployment of two-way communication. The Comverge equipment in the pilot utilized a paging system to receive commands, power line carrier (PLC) to communicate with appliances throughout the house, and the customer phone lines to send data back to the host system.

Preliminary Engineering

Comverge requested and was provided with potential participant data to facilitate an upfront study of the townships selected for the pilot program. Comverge personnel spent several days performing ride-bys in both Cherry Hill and Hamilton Township, NJ in preparation for the pilot deployment to ascertain the type, age and condition of dwellings in those municipalities. Comverge also attempted to evaluate radio frequency signal strength to determine how effectively their equipment would operate in those geographic areas.

Equipment Hardware

Gateways

The Comverge Maingates, also known as Gateways, housed the Radio Frequency (RF) paging technology, meter pulse accumulators, and Telco communications boards. PSE&G electric meter technicians installed the Gateways at the time of the customer's electric interval meter installation. The Comverge installers connected the Gateway to the customer's phone line, thermostat, load control relay and other devices installed during the in-home equipment installation. This process required the use of a laptop computer and was called "binding" the equipment. The field technician bound the system components at the time of installation and had to re-bind the equipment in the event of a failure and/or equipment replacement. Approximately 53 Gateways failed during the course of the pilot, from an initial population of 375, which represents a 14% failure rate.

During the installation phase, there were instances of field-site turndowns because the equipment could not be installed due to configurations found at the customer's home. These included customers having stacked or side by side metering, as well as fences and doors that blocked the Gateway installation. Newer technologies in the marketplace now utilize components installed inside of the electric meter negating the need for additional wiring, space and installation time.

The Comverge system is considered a hybrid because various communication technologies are utilized. The technology primarily utilized communications over phone lines, as well as a paging system using RF and PLC. The phone lines were used to send data back to the host network. The paging system to the Maingates enabled them to receive the commands from the host. The PLC transmitted data throughout the customer home to communicate with the in-home devices.

Thermostats

Honeywell manufactured the thermostat utilized by Comverge. The thermostat was programmable and responded to pricing signals to automatically adjust the temperature in the customer's home, according to a pre-determined set-up selected by the customer based on their lifestyle. Pricing information was sent to the smart thermostats the night prior over the phone lines. A full 24 hours of pricing information was provided.

The thermostat could also control electric water heating and in-ground pool pumps by shutting them off according to a pre-determined price response selected by the customer. For example, if the thermostat received a pricing signal for a high or CPP time period, the thermostat could send a signal to the load control device installed on the pool pump or water heater, to shut the equipment off.

Customers had the ability to program their thermostat remotely over the Internet through the Comverge website or through the myPower website linked to the Comverge site. Customers utilized their own Internet provider and logged-in to the Comverge site with a user ID and password.

Field site turn-downs were encountered because the thermostat was not compatible with some of the conditions found in the customer's homes, despite upfront customer screening over the telephone to identify those conditions. Field site turndowns included customers with multi-staged, dual, and multi zoned HVAC systems, heating systems with too few or too many wires to connect to the thermostat, and customers having Voice Over Internet Protocol (VOIP) telephone service rather than the required standard phone line.

Load Control Devices

For customers with electric water heating, or those with in-ground pools, load control devices were available to help manage energy usage. The load control devices were wired directly into the controlling circuits of the water heater or pool pump by Comverge technicians. The load control devices communicated though the PLC with the programmable thermostat and responded to changes in pricing signals according to a predetermined set-up. At the time of equipment installation, the customer determined how they wanted the load control devices to respond to the different pricing tiers. In the myPower pilot, there were eight customers with load control devices installed on their pool pumps as well as one with a device on their electric water heater.

The devices at the pool pumps required Comverge to initiate a remote PLC signal to activate or deactivate the devices prior to, and at the end of the pool season. At the end of the 2006 summer season, Comverge sent a remote signal to customers with load control devices on their pool pumps to disable the devices. The remote deactivation prevented the thermostat from flashing a warning signal “CALL” when the pool pump was shut-off for the season. The signal was reversed prior to summer 2007 to reactivate the load control devices.

Gas Encoder Receiver Transmitters (ERTS)

Although the myPower pilot was an electric based program, it was decided that the customers having PSE&G gas service should have their gas meters upgraded to enable remote gas reads (in addition to the remote electric meter reads) for the duration of the pilot. (At the conclusion of the pilot, the gas ERTs remained in place, however the remote readings were discontinued.) Comverge was contracted to perform the gas meter retrofits by installing a gas ERT unit at the myPower customers’ gas meters. Comverge removed the existing gas meter index, and a new ERT was installed. The exiting meter reading was captured, and the data returned to PSE&G for billing purposes. In cases where a gas meter could not be retrofitted, Comverge notified PSE&G, and PSE&G’s gas division performed a full meter replacement with an ERT equipped meter.

Data Collection

The Comverge system collected 15 minute interval meter data. In order to collect the necessary data for the myPower pilot program, Comverge adopted the PSE&G required multi speak XML format for data transfer. They also performed pre-testing of the systems required to support a CPP event. The CPP system was modified to enhance paging strategies and notification to customer sites. Data collection is summarized below.

- Critical Peak Pricing
  - Not all customer devices were notified. Comverge changed paging strategy to improve notification.
- Data Delivery
  - Failed to deliver morning data on two separate occasions
- Data Quality
  - Acceptable overdue percentage
  - Have had a meter index problem as reported by Comverge

Summary

One of the system performance indicators was the number of gaps in interval data received, per unit, per day. The Comverge system had relatively few gaps and the trend decreased over the course of the first summer. On the other hand, the metering hardware and data collectors (Gateways) had 53 failures as of program's end (14% of the initial number of participants). The devices that did not fail recorded data very well and appeared to be robust in all weather conditions.

The data gaps are portrayed in Figure 8 below in percentage of expected intervals received vs. actual percent of bad intervals received.

Figure 8. Bad Status Intervals – Comverge

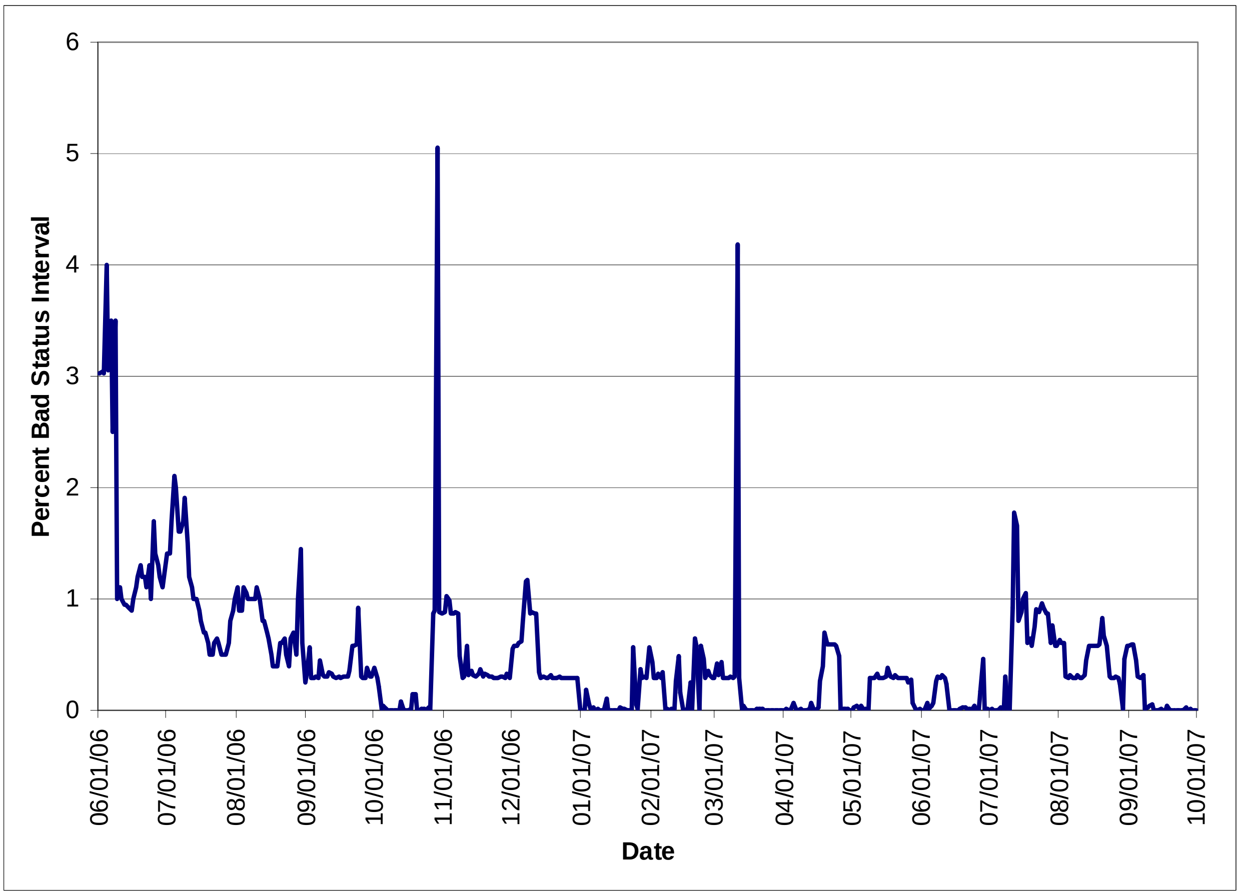
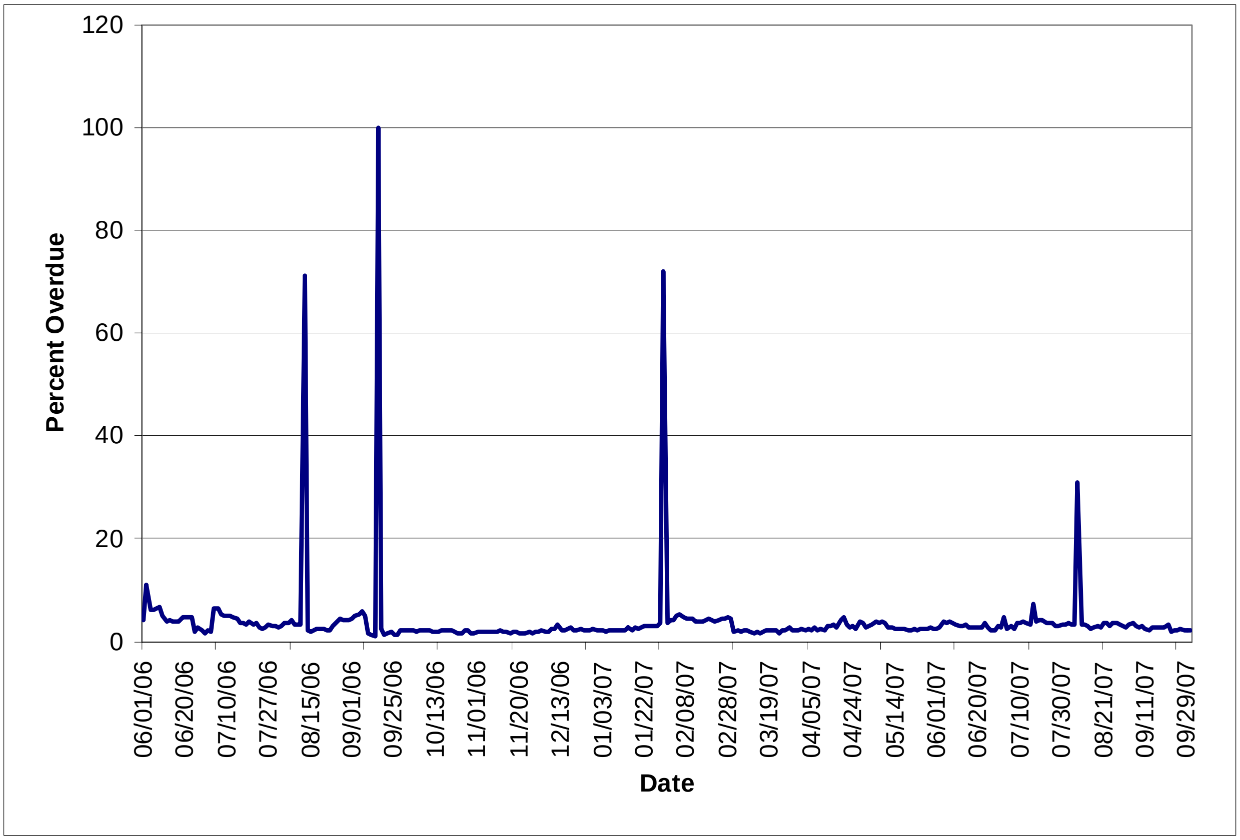


Figure 9 below illustrates the number of devices overdue (data not communicated when expected) and the rate at which the device overdue rate improved.

Figure 9. Overdue Report – Comverge



1.4 PSE&G Systems

Several systems were built by PSE&G's System Integration/Measurement Group to enable data collection, validation, and reporting for myPower customer participants. The systems developed also supported the myPower billing process. All of the systems developed were limited solutions for the myPower pilot program only and are not scalable for a rollout to the general population.

1.4.1 Data Systems

The PSE&G data collection systems use a SQL server database for both the Comverge and Itron systems, and an Oracle database for DCSI. These systems were used to maintain interval data as well as data validation and they provided the necessary data tools for meter synchronization and gap filling.

Several other applications were used for additional functionality and were built in Visual Basic (VB) and Asp.Net.2.0. The interfaces from vendor host systems were built using XML. This allowed for a common database structure for all data. Critical to the myPower pilot program was the ability to transfer files between systems. This was accomplished through a Secure File Transfer Protocol (SFTP), which provided the required data security and connectivity.

1.4.2 Billing Systems

The myPower billing process utilized several integrated systems to provide the required functionality necessary to administer and execute the pilot program billing. The core of the billing system was a SQL server 2005 database, which was used to maintain customer account and billing information, as well as interval data. The myPower billing engine was an application written in VB.Net 2.0 which actually calculated the customer's bill from customer data stored in the database. This was a batch processing operation.

Energy usage data was retrieved from the DB2 tables on the mainframe using QMF queries. Interval data was imported into the myPower database from the SideCar database using a VB.Net program as well as a web service. A web site, written in ASP.Net 2.0, provided the user interfaces for the system. These interfaces collected data for customers, rates, and daily temperature data, which were not available from the mainframe.

Crystal Reports 10 was used to create the report which was used to print the customers' bill, as well as reports used to monitor the status of system functions. Only the bill was actually printed, all other reports were available as pages on the myPower website for customer use (although they could be printed from the site as required). Other reports included:

- Account List
- Adjustments by Billing Month
- Approved Adjustments by Billing Month
- Billing Variance by Customer Account
- Sent Bill Type
- Accounts by Route
- Bills Not Approved
- Program Dropouts

Web applications to support the billing system were also created using ASP.Net 2.0 and helped administer other required functions:

- Bill Approval
- Bill Adjustment
- Bill Reprocess
- Management of Bill Diverts
- Management of Sent Bills
- Management of Customer Accounts

File interfaces were created to export data to the myPower customer website created by Integ, PSE&G's website development vendor. The interfaces contained images of the customers' bills in PDF format, customers' interval data, and the type of rate charged by date (in hourly format). For PSE&G use, ad hoc reports were created and formalized into browser based reports. The overall billing systems were a work in progress and modified as required throughout the myPower pilot to support the myPower billing process.

1.5 System Close-Out

Data:

Although data was collected from all systems throughout the pilot, DVD discs of all system data were delivered by each vendor (Comverge, ITRON) at the close of the pilot. The disks have data in a retrievable format for future use enabling data recovery if the need arises. Data collection systems were turned off as customer's in-home equipment was removed.

Hardware:

- Meters: All meters utilized in the pilot continued to operate as standard meters after the systems were shut-down.

- Data Collectors: Both the ITRON and DCSI data collectors remained in service. Comverge Maingate collectors were removed from service since they could not operate without a time signal from the system host end.

- Repeaters: ITRON repeater system remained in service.

Applications:

- Billing: Billing systems were created by PSE&G to satisfy the temporary tariff required for the pilot. These systems were de-commissioned at the close of the pilot after all final bills were rendered. (November 2007)

- Web Services: All myPower web services were de-commissioned November 30, 2007.

2 RATES AND REGULATORY

2.1 Electric Rates

A specific rate structure was developed for the pricing segments of the myPower pilot program. This section discusses the methodology used in the development of the electric supply and delivery rates for myPower. When myPower was developed, two new BGS electric supply rates were designed to test two different approaches to demand response:

- Critical Peak Pricing or CPP Rate
- Day-Ahead Pricing or DAP Rate

In addition to these new supply rates, some modifications were made to the Rate Schedule RS (the standard residential delivery service rate) for use as the delivery rate for all test customers in this pilot program. This delivery rate was called Rate Schedule RSP (for Residential Service Pilot). The methodologies used for calculating the CPP and RSP rates are discussed herein.

Although ultimately never implemented as part of the myPower pilot program, the DAP rate was originally proposed as an hourly priced rate based on the day ahead PJM market price for each hour. Details on the development of the CPP and DAP rates are included in Appendices A through H.

2.1.1 CPP Rate

The CPP rate (implemented as part of the myPower Sense and myPower Connection portions of the pilot program) was patterned after similar rates which are undergoing trials in other jurisdictions. Essentially, the CPP rate was a standard fixed Time-of-Use (TOU) rate with the addition of a variable adder in certain periods. This variable adder was only applied on days of high energy prices or expected high supply loads. The CPP rate was designed to be revenue neutral, on a seasonal basis, when compared with the otherwise applicable Basic Generation Service (BGS) charges for the average residential customer (on delivery Rate Schedule Residential Service or RS). This revenue neutrality was achieved by linking the CPP charges to the then current BGS charges.

The CPP rate utilized in the pilot program was structured as a four part time-of-day rate. During the summer months (the calendar months of June through September) a Base charge was applied for all kWhs used during the month. During weekday nights, from 10 p.m. to 9 a.m., a Night Discount to the Base charge was applied. During the weekday period from 1 p.m. to 6 p.m., an On-Peak Adder was applied on top of the Base charge. When market prices were very high, the On-Peak Adder was replaced by a much higher Critical Peak Adder. The structure of the rate was the same during the remainder of the year; however, there were variations in the time frames for the various periods.

Due to the linkage to the otherwise applicable BGS rates, the charges on the CPP rate changed over the term of the pilot program. The various CPP rates that were in effect during the pilot are included on the CPP tariff sheets in Appendix I.

The CPP rate actually used in the myPower pilot program (as described above) was slightly different in structure than the proposed rate originally filed by PSE&G with the BPU. These changes and adjustments were the result of discussions with the BPU Staff and the Division of the Ratepayer Advocate (now Rate

Counsel). The final rate design reduced the complexity of the originally filed rate, while still providing accurate pricing signals to customers participating in this pilot.

2.1.2 RSP Rate

The RSP (Residential Service Pilot) rate was the applicable delivery rate for customers participating in myPower. The structure and charges on this new rate were proposed to be nearly identical to the current Rate Schedule RS except that the usage blocks were collapsed and other appropriate changes (to reference the myPower pilot program) were added.

The documentation of the eligibility requirements for program participants was included in this rate schedule. This included a statement that customers, while participating in the myPower pilot program, were not eligible to also participate in:

- The Equal Payment Plan (EPP) also knows as budget billing
- The Auto Pay program (electronic transfer of funds to pay the electric bill)
- Purchase from an electric Third Party Supplier (TPS) (purchase of commodity)

The RSP tariff sheets are included in Appendix J.

2.2 Electric Rate Development

2.2.1 CPP Rate

The Critical Peak Pricing (CPP) rate was originally designed as a standard Time-Of-Use (TOU) rate, based upon three time periods and prices – Low, Medium and High. The prices for each time period were designed to vary across three seasons – summer (June through September), winter (November through March) and shoulder (October, April and May). The primary difference from the typical TOU rate was the addition of a critical peak pricing component. The evening prior to certain days of high energy prices or expected high supply loads, customers were notified that a CPP event would be in effect the following day. On that following day, the normal High Period prices were replaced with a substantially higher Critical Peak Price. This advance notification allowed the customer ample time to alter plans and/or schedules for the following day in order to maximize the dollar savings from reducing electric usage during the CPP event.

The rates and time period definitions for the TOU portion of the CPP rate (those charges other than those in effect during a CPP event) were based upon an analysis of the historic PJM Day-Ahead hourly LMP energy market. The analysis determined the optimized time period definitions and related rates, based on historic market conditions. The additional charges in effect during a CPP event were based upon recovering the costs associated with the highest energy market prices, as well as 50% of the costs of the Generation and Transmission Obligations. The remainder of the obligation costs was spread throughout the summer High Period price.

The detailed calculations of the number and time periods for the CPP rate, as well as the standard time of day periods, are included in Appendix A.

2.2.2 CPP Rate Design Modifications

In response to the concerns raised by BPU Staff and the Rate Counsel regarding the complexity of the myPower rate design as proposed by the Company, PSE&G modified the Company's CPP rate proposal and how it was to be conveyed to the customers, in an effort to enhance customer understanding. The rates were calculated based on the results of the BGS Auction for rates that started June 1st, 2005. The revised rate was designed to make it easier for customers not familiar with rate design, or tariff sheets, to understand the myPower charges and time periods. To accomplish the change, two types of modifications to the proposed CPP rate were made.

The first change involved a shorter summer peak pricing period. PSE&G had originally proposed a summer peak period of 7 hours, from Noon to 7 p.m. BPU Staff suggested a shorter, 5 hour summer peak period, from 1 p.m. to 6 p.m. BPU Staff also suggested eliminating the distinct prices and time periods for the shoulder and winter seasons, effectively combining these two seasons into one, lasting from October to May. As such, during these months, the Low and Medium period prices and time periods were made the same. A High price period still occurred, but was limited to weekdays during the months of November to March. (No major structural changes were made to the summer period.)

The second change made involved the presentations of the CPP rate to potential myPower participants. In the program recruitment materials, customers were informed that the myPower rates would have two seasons, summer and non-summer. It was explained that each season the charges would include a Base price for electricity. Then, during the late night and early morning hours, participants would receive a Night discount, which would reduce the overall cost of electricity used during those hours. Additionally, during the afternoon weekday hours of the summer months, and the early evening hours of November to March, an On-Peak adder went into effect, and was added to the Base price (which in effect increased the price of electricity consumed during those hours). Customers were also informed that, throughout the year, a Critical Peak Adder could be in effect during emergencies or other extremely high priced periods and they would be notified before the adder would be initiated.

Finally, in order to further decrease the complexity of the myPower rates for the customers, the Night discount, On-Peak adder and the Critical Peak Adder were rounded to the nearest cent per kWh, with any over- or under-recovery collected in the Base price charge, which was not rounded. All of these calculations were performed on the charges after the addition of NJ Sales and Use Tax (SUT).

The layout of these charges follows in Table 18 and Table 19 below:

Table 18. CPP Rate – Summer Months (June to September) All charges per kWh

Period	Charge June 1, 2006	Charge July 15, 2006	Charge June 1, 2007	Applicable
Base Price	9.1279¢	9.2032¢	8.6675¢	All Hours
Night Discount	-5¢	-5¢	-5¢	10 p.m. to 9 a.m. Daily
On-Peak Adder	8¢	8¢	15¢	1 p.m. to 6 p.m. Weekdays
Critical Peak Adder	68¢	69¢	$1.37	When called 1 p.m. to 6 p.m. Weekdays. When called is added to the Base Price.

Note: Table 18 (The increase in 2007 in the Critical Peak Adder and the On-Peak Adder was due to a more than 5 fold increase in Generation Obligation costs while lower forward prices resulted in a slight decrease in the Base Price. Also, all charges are shown with NJ Sales and Use Tax (SUT).

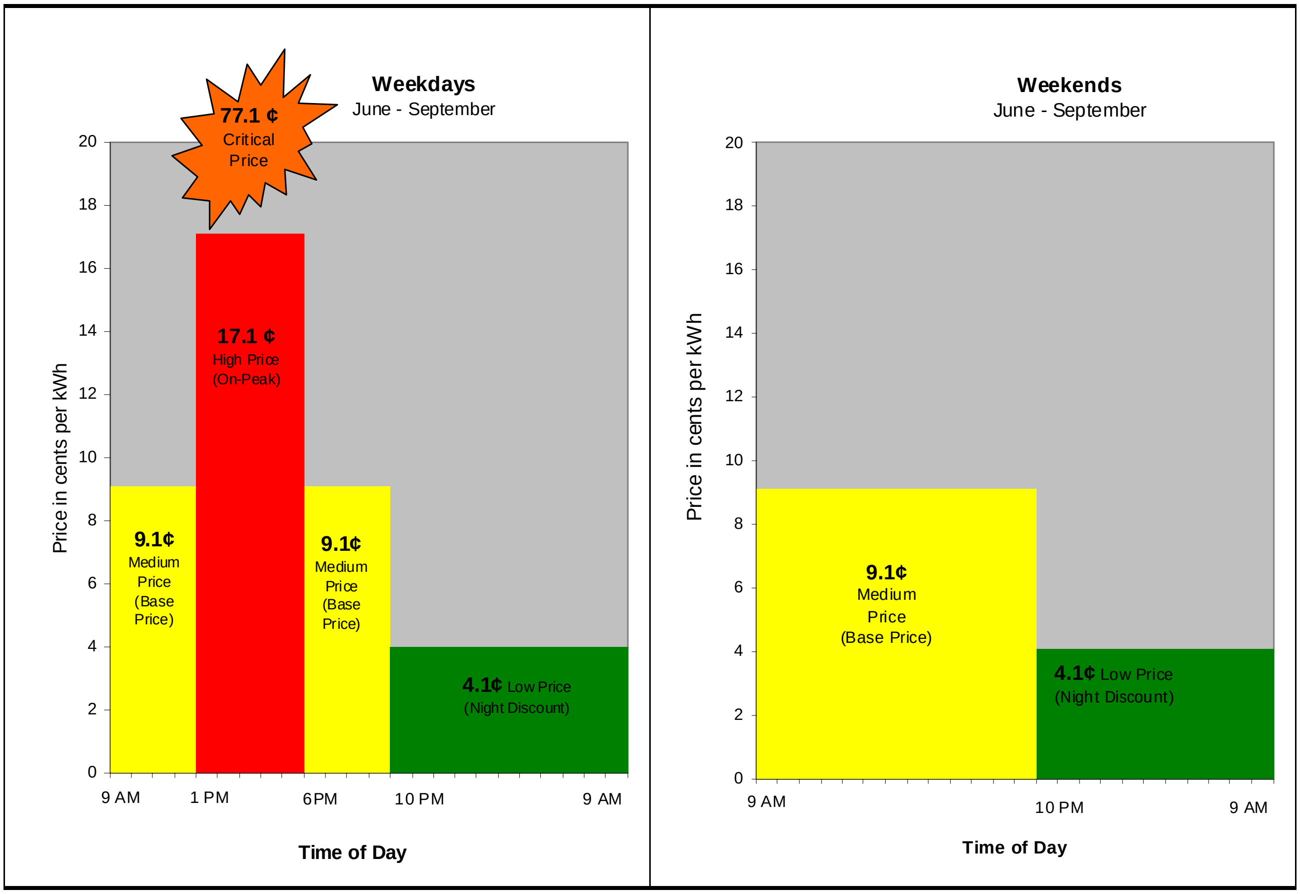
Table 19. CPP Rate – Non-Summer Months (October to May) All charges per kWh

Period	Charge October 1, 2006	Charge January 1, 2007	Applicable
Base Price	8.6670¢	8.6741¢	All Hours
Night Discount	-4¢	-4¢	10 p.m. to 6 a.m. Daily
On-Peak Adder	3¢	3¢	5 p.m. to 9 p.m. Weekdays, November to March
Critical Peak Adder	23¢	23¢	When called 5 p.m. to 9 p.m. Weekdays in November to March; or 1 p.m. to 6 p.m. Weekdays in October, April, and May. When called is added to the Base Price.

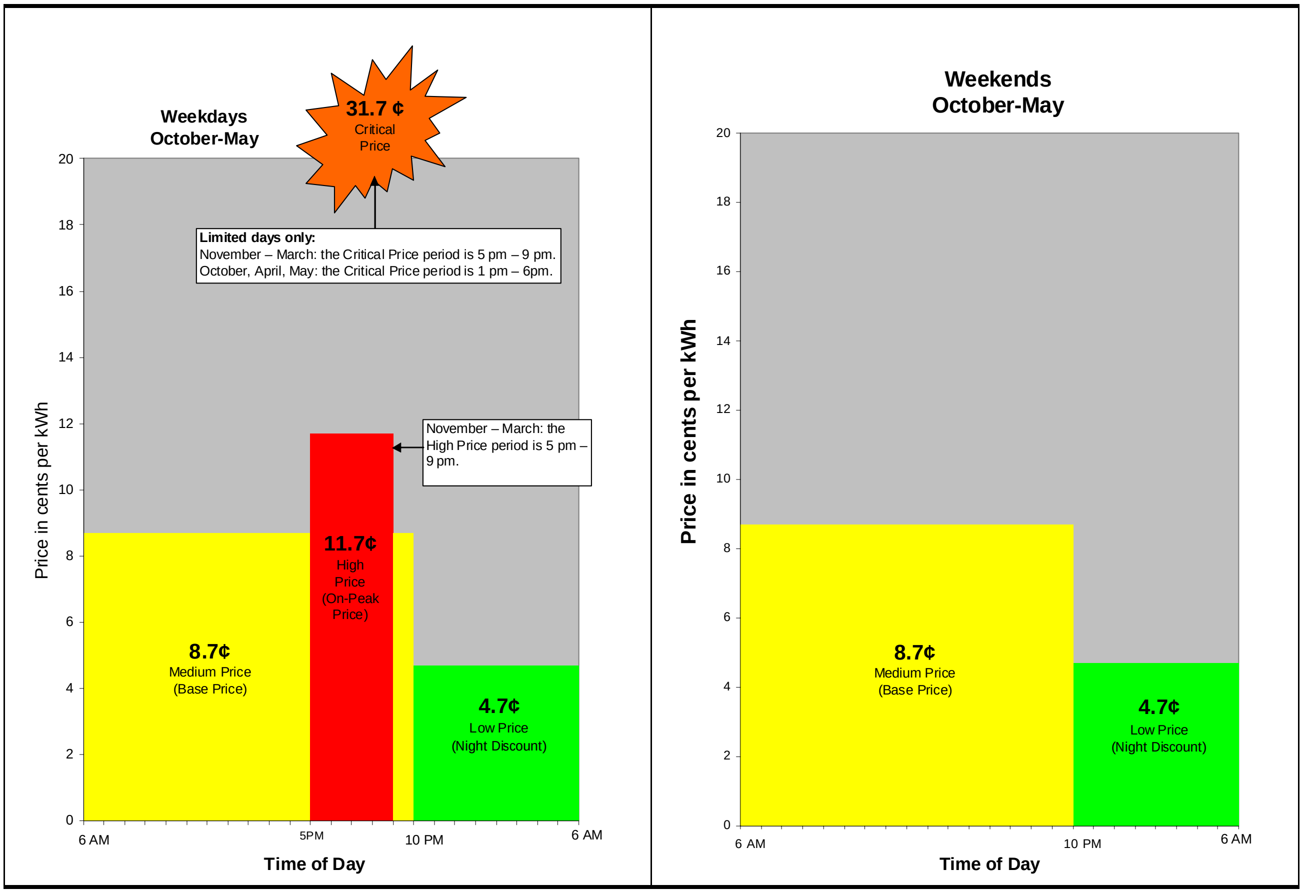
Note: All charges are shown with NJ Sales and Use Tax (SUT)

Figure 10. CPP Rate Examples

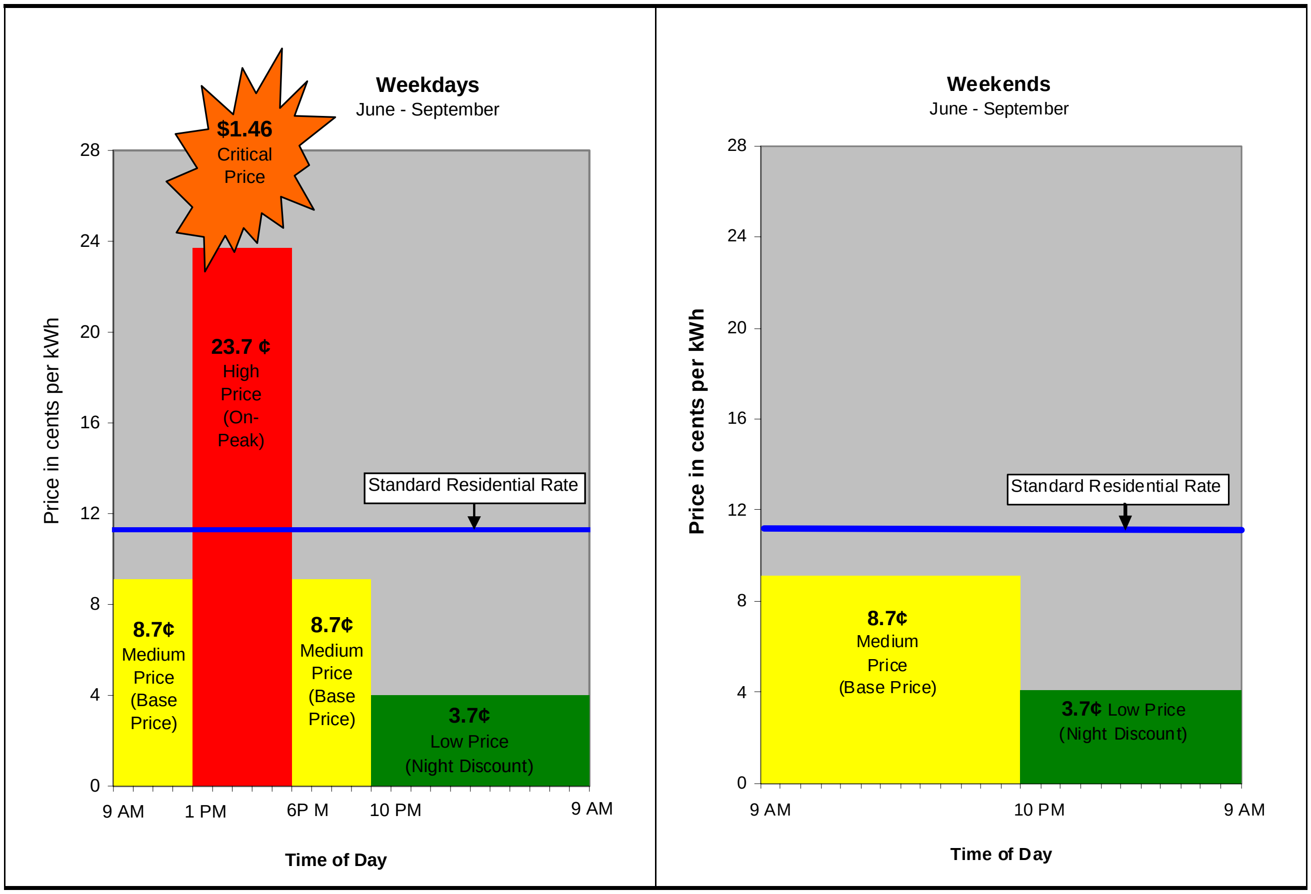
Summer 2006



Non-Summer 2006-2007



Summer 2007



2.2.3 RSP Rate

The standard Delivery Rate, Rate Schedule RS – Residential Service, (the standard residential electric delivery rate), was used as the basis for the applicable delivery rate for customers electing to participate in the myPower pilot program. The new rate, Rate Schedule RSP – Residential Service Pilot, was nearly identical to the current Rate Schedule RS, except for a few minor modifications.

The first modification to the rate made, was the elimination of the blocking in the summer period for monthly usage above and below 600 kWh per month. Since the blocking was only 4 mills per kWh difference, it was eliminated for the pilot to reduce the complexity of the rates and to minimize additional costs of billing. The second modification was the elimination of redundant Special Provisions, and the addition of Special Provisions related to participation in the pilot program. Lastly, the language related to BGS supply and shopping was modified to indicate that customers participating in myPower cannot purchase from a Third Party Supplier (TPS) and had to remain on the new BGS supply rates previously described for the duration of the pilot program. (Note: A customer could have elected to withdraw from the pilot at any time.)

2.2.4 Revenue and Costs

The revenue and costs related to the CPP subset of the BGS rates were treated as if they were part of the standard BGS-FP supply. This was done to simplify the tracking and settlement procedures for the pilot program, since there were a relatively low number of pricing segment pilot participants (less than 1,000) relative to residential customers on standard BGS rates.

For the pilot program, all electric supply revenues from the CPP BGS Rates were treated as BGS-FP revenue. Likewise, for purposes of settlement and payment to the BGS-FP suppliers, usage on this rate was considered part of BGS-FP supply. Any differences between the revenues collected and the costs paid to the BGS-FP suppliers were charged (or credited) to the BGS-FP Reconciliation Charge.

Delivery revenues, including all adjustment clause revenues, from the RSP delivery rate were accounted for in the same manner as standard Rate RS revenues.

2.3 Criteria for Designating Critical Peak Pricing Days

2.3.1 Introduction

The number of critical period events for Critical Peak Pricing (CPP) Basic Generation Service was limited by tariff to a maximum of eight per year. The Company planned to call five events each summer of the pilot (from 1 p.m. to 6 p.m.), one in the shoulder season (from 1 p.m. to 6 p.m.), and two in the winter season (from 5 p.m. to 9 p.m.). This plan for CPP events was based on the design criteria used to establish the CPP pricing and facilitated the testing of customer response to CPP events during different seasons of the year.

Summer 2006

The goal for the summer of 2006 was to designate five (5) Critical Peak days across the months of July, August and September. Critical Peak days were not planned for June of 2006 because customers would not be commencing service on the CPP rate until their June meter reading date. Because of the structure of the meter reading routes, for some customers this meant that their CPP rates were not effective until the end of the month of June.

Selection of the CPP days was based on predetermined price and weather criteria. The pricing criterion references the forecast wholesale price (the day-ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day) and the weather criterion references the expected weather conditions (as measured by the forecast next day 4 p.m. WTHI). The criterion was such that it could have been modified during a summer period to reflect actual conditions that were experienced. For example, if extended above-normal weather conditions were to prevail, the weather criteria would likely be increased to avoid designating too many critical peak days early in the summer. In the summer of 2006, the pricing criteria did not need to be modified.

A review of summer weather data from the 1970-2005 period showed that on average, the highest seven WTHIs each summer exceeded 81.8. (It was necessary to look at seven days in order to select five weekdays.) Using this criterion would, on average, result in the selection of five CPP days per summer. However, since the goal was to designate five days containing a critical period, even if there were fewer days than normal with high WTHIs, it was necessary to initially set the criterion at a lower level. Therefore using a 90/10 weather probability level (instead of the 50/50 level shown above), the criterion was dropped to a WTHI of 80.

Had CPP days been called in early July, the WTHI criteria may have been increased to approximately 82 for the remainder of the summer 2006. (It should be noted that a WTHI of 80 is the same weather criterion used to initiate the PSE&G Cool Customer (residential air conditioning cycling program) events for economic reasons. In a normal summer, it could be expected that there would be approximately 10 weekdays where the WTHI exceeded 80. However, the LMP criterion of $250/MWh for the Cool Customer program limits the number of expected events to approximately five.)

For the summer of 2005, there were seven weekdays when the 4 p.m. day-ahead LMP exceeded $200/MWh although not all of these occurred when the WTHI exceeded 80. Therefore, if 2006 prices had been similar to those experienced in 2005, it would have been reasonable to expect that using a $200/MWh price coupled with the appropriate weather criteria (discussed above) would have produced approximately five CPP days. Further, a review of 2006 PSE&G average prices (LMPs) through May showed a 7% higher level than 2005.

However after May 2006, actual LMPs began to decline. The first day the price and weather criteria were met was July 18. However, all billing and notification systems were not sufficiently in place at that time to call an event. Subsequently, CPP events were called on August 1st and 2nd, 2006 with August 3rd (a potential CPP day) reserved for baseline analysis. As the program progressed through August, there were no more extreme weather days and prices further declined resulting in no additional CPP days that month. Since it was generally agreed that significant data for 2006 was gathered from the August 1st and 2nd events, and the end of the summer season was approaching, the price and weather criteria were not changed and there were no CPP events in September.

Criteria for Designating Summer Period Critical Peak Pricing Days for 2006

WTHI = 80, PSE&G day-ahead LMP @ 4 p.m. = $200/MWh

Winter 2006-2007

The goal for the winter of 2006-2007 was to designate two CPP days across the months of December, January and February. Selection of these days was based on a predetermined price criterion which could be modified as the winter progressed to reflect actual conditions that were experienced. The pricing criterion was the forecast 6 p.m. wholesale price (specifically the day-ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day). The hour of 6 p.m. was selected since it is generally the time of the highest daily winter LMP, and it falls within the 5 p.m. to 9 p.m. CPP period. Weather was not used as a criterion for designating winter CPP days as the relationship between cold weather and high LMP values is not consistent, and the timing of CPP days needed to correspond to days with high prices (i.e., high LMPs).

For the winter of 2005-2006 (December-February), there were three weekdays when the 6 p.m. day-ahead LMP exceeded $190/MWh. Therefore, if 2006/2007 prices were similar to those experienced in 2005/2006, it would be reasonable to expect that using a $190/MWh price would produce the target of two CPP days. However, a review of 6 p.m. PSE&G prices (LMPs) for November 2006 as well as forward PJM prices for the November, December and January period showed a lower price level than the prior year, indicating that using a $190/MWh price would not produce any CPP events. Forward PJM on-peak prices for the upcoming December, January and February 2007 period were approximately $35/MWh below what they were at that time in the prior year. In addition, 6 p.m.

PSE&G day-ahead prices for November had been running $40-50 below November, 2005. Although other factors such as regional generation and transmission conditions could significantly affect prices on any day, then current peak time price levels indicated that the criterion for designating a CPP day should be set significantly lower than prices experienced the prior winter. Therefore, we set a day-ahead PSE&G Locational Marginal Price of $150 at 6 p.m. as the initial criterion. Two winter CPP events were called on January 30th and February 6th, 2007.

Criteria for Designating Winter Period Critical Peak Pricing Days for 2006-2007

PSE&G day-ahead LMP @ 6 p.m. = $150/MWh

Shoulder 2007

The goal for the shoulder period of 2007 was to designate one (1) CPP day during the April and May period. Selection of this day was based on predetermined price and weather criteria which could be modified as the period progressed to reflect actual conditions that were experienced. The pricing criterion was the forecast 5 p.m. wholesale price (specifically the day-ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day). The hour of 5 p.m. was selected since it is generally the time of the highest April and May LMP and it falls within the 1 p.m. to 6 p.m. CPP period. Since the shoulder period CPP day was expected to occur on a hot day with a correspondingly high LMP, weather and day ahead LMP were both used as criteria for designating the CPP day.

For the month of May 2006, there were two weekdays when the 5 p.m. day-ahead LMP exceeded $90/MWh. Forward prices for May 2007 were running about 8% above the prior year. In addition, an expected high WTHI for the April and May period based on the last eight years of data was 77.8 including a 77.5 value in May 2006. Therefore, if then current price levels and normal weather conditions prevailed in the spring, and a price criterion of $100 and a weather criterion of 77 WTHI was established, we were able to reasonably expect one CPP event in the April and May period. A shoulder CPP event was initiated on May 25th, 2007.

Criteria for Designating Shoulder Period Critical Peak Pricing Days for 2007

WTHI=77, PSE&G day-ahead LMP @ 5 p.m. = $100/MWh

Summer 2007

The goal for the summer of 2007 was to designate five (5) CPP days across the months of June, July, August and September. Selection of these days was based on predetermined price and weather criteria which could have been modified as the summer progressed to reflect actual conditions that were experienced. For example, if above normal weather conditions prevailed for an extended period, the weather criteria would likely have been increased to avoid designating too many CPP days early in the summer. The pricing criterion was the forecast wholesale price (the day ahead PSE&G zonal Locational Marginal Price as published by PJM after 4 p.m. each day) and the weather criterion was the expected weather conditions, as measured by the forecast next day 4 p.m. weighted THI (Newark, NJ).

As in 2006, a WTHI of 80 was used as the weather criterion for calling a CPP event in the summer 2007. However, if normal weather conditions prevailed and CPP day(s) were designated in June and early July, the WTHI criteria might have been increased to approximately 82 for the remainder of the summer.

For the summer of 2006 there were five weekdays when the 4 p.m. day-ahead LMP exceeded $190/MWh. Therefore, if 2007 prices were similar to those experienced in 2006, it would have been reasonable to expect that using a $190/MWh price coupled with the appropriate weather criteria (discussed above) would produce approximately five CPP days. A review of the prior PSE&G forward average prices (LMPs) for June, July and August showed a 5-10% higher level than the prior year, indicating that the criteria should be set above $200. However, given the uncertainty of weather and pricing conditions, it was recommended that initially the price criteria be set at $190 and, if necessary, revised later in the summer depending on the number of CPP days designated in June and July.

Recommended initial criteria for a CPP day designation:

WTHI - 80, PSE&G day-ahead 4 p.m. LMP -$190/MWh

For the second summer of the program, the maximum of five CPP days were initiated. CPP events were called on July 9th and 10th, August 2nd, 3rd and 7th, 2007, with additional days (potential CPP days) reserved for baseline analysis. Due to the weather and pricing conditions experienced in the summer of 2007, the weather criteria was not changed, however, the pricing criteria was. LMPs were lower than expected during the summer of 2007. Therefore, the pricing criterion to call a CPP event was changed to $140 or greater.

3 OPERATIONAL ASSESSMENT

3.1 Introduction

The Operational Assessment presents the operational processes that were developed to support the implementation of the myPower pilot program Pricing Segments. These processes required the coordination of various areas within PSE&G and with program contractors and vendors as well. This section discusses the methodologies used for program marketing and recruitment, participant screening, customer education, scheduling, installation, and end-of-program equipment removal. In addition, the assessment addresses program attrition and its causes. This information will be used to measure the impacts on customer participation and retention in the pilot program, critical to the overall program evaluation.

3.2 Operational Processes

3.2.1 Recruitment

Available Market for Pricing Pilot

At the time of program recruitment, PSE&G had 1.8 million residential electric customers and 1.5 million residential gas customers. For the purposes of the Pilot program, towns were ranked based on number of customers with certain rates. Only customers having standard residential rates were eligible for program participation due to the myPower pricing structure. Towns with high numbers of customers on non-standard rates received the lowest rankings, while towns known to have a high penetration of central air conditioning customers, were ranked high. Equal weight was given to each category, and townships were ranked using a composite score. Using these criteria, the top two ranking townships were Cherry Hill and Hamilton Township, NJ.

Based on that information, the total number of residential customer accounts (Rate Schedule RS) available for program recruitment in these two municipalities was 60,000. From this population, certain types of customer accounts were eliminated from recruitment where pilot participation did not make sense from a customer, operational and/or financial perspective, such as accounts who had customers on electrical life sustaining medical equipment, or those accounts that were receiving financial benefits to help offset the cost of a customer's energy bills.

Target Customer

Customers were selected for participation in specific pilot segments and were not offered the opportunity to choose between segments. This was done to help simplify and streamline the marketing offer to customers. Only Basic Generation Service (BGS) customers were eligible to participate in the Program. Universal Service Fund (USF) participants were not eligible to participate. While existing Cool Customer (AC cycling) participants were eligible for participation in the pricing segments, they were informed they would have to suspend their participation in that program for the duration of the myPower pilot, that their existing load control equipment would be remotely disabled, and the monthly Cool Customer bill credits would be discontinued temporarily.

The Pilot utilized a sizeable Control Group in order to obtain baseline data for comparison to other pilot segments to determine changes in energy use patterns and energy savings. Although customers participating in the Control Group were notified by letter that they would be receiving a new meter, which had the capability of two-way communication, they were given no detailed knowledge of the pilot.

Marketing Methodologies

PSE&G utilized direct mail with follow-up telemarketing as the primary marketing channels to solicit customer participation. Customer enrollment was closely monitored and tracked by PSE&G and its third party contractor, Honeywell Utility Solutions (HUS). Customers had the ability to respond to the direct mail campaign via a toll-free telephone number or a business reply card (BRC). Direct mail was supplemented with telemarketing to ensure adequate enrollment.

Direct mail was customized and targeted to customers identified as potential participants in each of the Pilot Pricing segments. The promotional campaign utilized letters supplemented by a brochure insert to convey segment specific program description and benefits, technology to be installed (if any), and applicable rate structure (pricing plan).

Customer recruitment relied heavily on telephone solicitation to augment the direct mail respondents. Telephone scripts were customized to target the specific customers needed to participate in each of the sub-segments. An independent third party telemarketing firm ServiCom, was hired through a competitive RFP to provide the program telemarketing services. PSE&G worked with the telemarketing vendor to develop and deliver appropriate training and Q&A scripts.

Program Incentives

Recruitment incentives were utilized to drive customer participation to meet the program schedule. Incentives were structured to be paid to customers in two phases, at the start of the pilot and at its conclusion. Differences in incentives within each pilot segment were determined by differences in anticipated customer response, driven by the characteristics of each segment (i.e., not all segments received the same incentive amounts).

The upfront incentives, where applicable, were paid to customers once the equipment had been installed and customer education had taken place. Customers were required to complete a pre-implementation telephone survey to discuss their experience with the recruitment and installation processes, reaction to program educational materials, and understanding of rate structures. The amount of the upfront incentive was $25.00 and was paid to the customer in the form of a check.

The second incentive, in the amount of $75.00, was paid to customers at the conclusion of the pilot study (post-implementation) in 2007 after completion of the end-of-program survey. Periodic surveys were conducted throughout the duration of the Pilot to monitor customer reaction and to ask customers about any changes they had made to affect their energy usage as a result of participating in the pilot, but no incentives were paid to customers for any of the other surveys.

The participants in the technology-enabled segment (myPower Connection) also received incentives in the form of a smart thermostat and, where applicable, a load control device to help them manage energy use. The smart thermostat was similar to those having a retail value of approximately $100.

Program incentives were offered to customers in the Pricing Segments of the pilot program based on the sub-segment in which they participated.

- **myPower Sense -** $25 upfront incentive upon completion of the pre-program survey and $75 at the conclusion of the pilot program.

- **myPower Connection** – $75 at the conclusion of the pilot program. (No upfront incentive because customers received in-home technology.)

- **myPower Connection II -** $25 upfront incentive upon completion of the pre-program survey and $75 at the conclusion of the pilot program. (These customers were originally recruited for the myPower Manager segment, with a Day-Ahead Hourly Pricing (DAH) plan. myPower Manager customers had been offered a $100 incentive to ensure adequate enrollment. When the myPower Manager segment was eliminated from the pilot program, these customers were moved over to myPower Connection and they retained the incentive amount originally marketed to them.)

- **myPower Connection REMS -** $25 upfront incentive upon completion of the pre-program survey and $75 at the conclusion of the pilot program. (These customers were originally recruited as myPower Manager REMS participants with a DAH pricing plan. myPower Manager customers had been offered the full $100 incentive to ensure adequate enrollment. When the myPower Manager segment was eliminated from the pilot program, these customers were moved over to myPower Connection and they retained the incentive amount originally marketed to them.)

Recruitment Results

Results from the participant recruitment campaign were analyzed to identify customer response rates, to measure marketing effectiveness, and to provide data to estimate future response and enrollment rates if the program were offered to a larger customer base.

Of the 60,000 residential customers in Cherry Hill and Hamilton Township, NJ, 39,170 were eligible for the pilot and were targeted by the recruitment campaign. 1,527 customers responded to the direct mail campaign, which was equal to a 4% response rate. (This response was well above the average marketplace residential response rate of 1% used as an industry benchmark for similar type mail campaigns.) Of the 1,527 respondents, 50% (or 763 responses) came from business reply cards, and 50% (or 764 responses) from customer call-ins.

An additional 4,844 customers were reached by the follow-up telemarketing campaign with 792 (16%) resulting in campaign leads.

Table 20. Lead Generation Results

Lead Generation Source	#	%
Direct Mail Pieces Mailed	39,170	
# Call-In Leads	764	50%
# Reply Card Leads	763	50%
Total Direct Mail Leads	1,527	
Direct Mail Response Rate		4%
Telemarketing Leads	792	
Telemarketing Response Rate		16%
Total Leads	2,319	

myPower Sense respondents were slightly more likely to use the reply card and myPower Connection respondents were slightly more likely to make a call (see Table 21).

Table 21. Lead Generation Results

Response Method	myPower Sense	myPower Connection	Total
Percent of responses to direct mail campaign - Telephone calls	47%	53%	50%
Percent of responses to direct mail campaign - Reply Card	53%	47%	50%
Direct Mail Response Rate			4%
Telemarketing Response Rate	15%	17%	16%

3.2.2 Customer Intake and Screening

Customer recruitment was followed by scripted customer screening to determine program eligibility. (See Appendices K and L for the myPower Sense and myPower Connection screening scripts.) Potential customers were screened to determine the presence of central air conditioning in the home, electric house heating, broadband Internet access, in-home phone lines, and other measures. For the myPower Sense segment, the screening also captured customer demographic information necessary for program evaluation. (For the myPower Connection segment of the pilot, the customer demographic information was captured at the time of the in-home equipment installation site visit on a work order.)

There were a total of 143 customers interested in the program who were eliminated from program participation during the screening process because they did not meet the program qualifications (Table 22 below).

Table 22. Reasons Interested Customers were Screened-Out on the Phone

Reasons Customers Screened Out on Phone	myPower Sense	myPower Connection
Not Interested	0	1
Summer-Winter Switch (switch that manually changes HVAC system from heating to cooling)	NA	13
Employed by PSEG	1	2
Not going to remain in home for the year	11	7
Doesn't live in home all year	1	4
Commercial Customer	1	
Non-Standard Phone	NA	35
No AC	NA	1
No Central AC	NA	7
AC in Bad Condition	NA	1
More than two condensers	NA	2
T-stats Control Heating	NA	7
Wants to Remain in Cool Customer	17	24
Attic Not Floored (required for safe access)	NA	8
Total	**31**	**112**

HUS conducted the customer screening surveys over the telephone and captured the customer responses in their data base. Customers calling into HUS directly, as a result of program recruitment, were screened during their incoming call. Customers contacted through telemarketing or those returning a BRC were called by HUS for the screening process.

During the screening, customers were asked why they were in interested in participating in the myPower program. While the program was not promoted as a bill savings program, over 90% of myPower participants said their primary reason for participating was to save money on their electric bill. Significantly more myPower Connection participants mentioned conserving energy and helping the environment as a reason for participating. Relatively few thought getting Internet access to their thermostat was a driving reason to participate.

Table 23. Reasons for Participating in myPower

Reason	myPower Sense	myPower Connection
To save money on electric bills	94%	91%
To conserve energy	27	40
Interested in new technology	NA	17
Free thermostat	NA	17
To help the environment	6	13
Incentive payment	7	7
Internet access to thermostat	NA	3
Some other reason	1	0
Don't know/Refused	1	1

Note: Multiple responses were allowed.

During telemarketing, the reasons customers gave when declining to participate were recorded. The most common was simply "not interested" for both segments (see Table 24) with over two thirds of those offered myPower Sense not being interested. The myPower Connection segment was more likely to get past the customer's initial interest screen and had a slightly higher telemarketing response rate.

Table 24. Reasons Given During Telemarketing For Not Participating

Reason Did Not Want to Participate	myPower Sense	myPower Connection
Not interested	64.7%	44.2%
Program too complicated	14.3%	23.2%
Questions validity of program	10.1%	15.8%
No guarantee of savings, therefore not interested	5.9%	10.5%
Returned Reply Card but not interested when called	2.5%	4.2%
Afraid of slamming	2.5%	2.1%
Total	100.0%	100.0%

Note: Eliminated from the table were reasons that could not reasonably be connected to differences between the program offerings, e.g., no central air conditioner, language barrier, deceased, no longer PSE&G customer, etc.

Installation Issues Encountered

Additional customers were unable to participate in myPower due to conditions found at the customer's home at the time of the field installation site visit. Field site turn-downs became inevitable because of conditions found in the home that could not be screened for over the telephone or because a customer answered screening questions incorrectly. The following table illustrates field site turn-downs encountered.

Table 25. Reasons Interested Customers were Screened-Out On-Site

Reason for Elimination	myPower Connection (Comverge)	myPower Connection (Itron REMS)
No access	8	0
Can't detect wire	39	0
On site customer cancellation	20	0
VOIP	16	0
2 Stage HVAC system	44	0
Too many wires	1	0
Not enough wires	9	0
Split System not compatible with technology[6]	9	2
Total	**146**	**2**

Program Participation

The myPower Pricing segment participation goal was to obtain 1,400 participants - 450 Control Group, 550 myPower Sense and 400 myPower Connection. At the conclusion of the program screening, the myPower Connection segment was slightly over populated and the myPower Sense segment slightly under populated as shown in Table 26. As the pilot progressed, the number of customer participants in the pricing segments of the pilot varied throughout the course of the program, with a number of customers removed from the myPower program for a variety of different reasons.

To understand how the number of program participants varied over the life of the pilot, see the comparison in Table 26 below.

Table 26. myPower Pricing Target and Actual Participants

Segment	Segment Size Goal	Beginning Segment Size	Actual Segment Size (11/3/06)	Actual Segment Size (9/30/07)	Percent From Goal Remaining in Program
Control Group	450	450	450	450	100%
myPower Sense – TOU/CPP Educate Only	550	536	459	379	69%
myPower Connection – TOU/CPP Technology Enabled	400	424	377	319	80%
Totals	**1,400**	**1,410**	**1,286**	**1,148**	**82%**

[6] Customers that have split systems were not eligible for program participation because the Comverge technology used in the pilot does not accommodate those systems.

The final 319 myPower Connection customers were further divided into the following sub-segments due to different technologies and the elimination of the former myPower Manager Day-Ahead Hourly segment:

- myPower Connection (original group) – 164 customers
- myPower Connection II (formerly myPower Manager) – 124 customers
- myPower Connection REMS (formerly myPower Manager REMS) – 31 customers

Customer Removals and Program Drop-Outs

Customer Removals. Throughout the course of the pilot, participants were removed from the myPower program for various reasons including incompatible technology due to changes at the customers home, incompatibility with other PSE&G programs, customers who moved, etc. Table 27 below details the customer removals.

Table 27. myPower Pricing Plan Customers Removed

Reasons	myPower Sense	myPower Connection
Technology Issues	22	28
Billing or Incompatible Program	33	18
Customer Moved	42	17
Special Circumstance	1	3
Totals	**98**	**66**

Specific reasons for participant removals included in the main categories in the table above are as follows:

- **Technology Issues include –** Installation related problem, Installing Solar/Net Metering, Installed new 2-stage HVAC, New HVAC System, Changed to VOIP, Technology Incompatible, Communication Issues
- **Billing or Incompatible Program includes –** Signed-Up for USF[7], Stay on Auto Pay[8], Stay on Equal Payment Plan[9], cannot bill un-metered services
- **Customer Moved includes –** Moved, Not Primary Residence
- **Special Circumstance** (Illness, Death in Family)

Customer Drop-Outs. A number of customers dropped-out of the program during the course of the program for various reasons.

[7] Customers receiving Universal Service Fund (USF) benefits could not remain on the program, since the USF program in effect limits the amount of the customer's energy bill. Pilot results would be affected since the customer bill is reduced by USF benefits.

[8] Since this is a pilot program, it was not set-up to enable participation in PSE&G's AutoPay program, which automatically deducts the amount due from the customer's bank account.

[9] Customers in the pilot program were not allowed to participate in PSE&G's Equal Payment Plan (EPP). The EPP could affect pilot results since customers might not notice the bill impacts resulting from program participation.

Table 28. myPower Pricing Plan Customer Drop-Outs

Reasons	myPower Sense	myPower Connection
Technology Issues	NA	24
Billing	23	13
Miscellaneous	21	17
Totals	**44**	**54**

Specific reasons included in the main categories in the table above are as follows:

- **Technology Issues includes –** Did not like T-Stat, Did not like technology
- **Billing includes –** Did Not Like Pricing Plan, Did Not Like Billing, Not Saving
- **Miscellaneous includes -** Changed mind, No reason given, Not happy with program, Unable to shift usage into low cost periods

By the conclusion of the myPower program on September 30, 2007, 8% of the myPower Sense and 13% of the myPower Connection participants had dropped out of the program at their request.

Scheduling and Installation

The in-home myPower equipment varied by segment.

PSE&G's electric division installed two-way interval meters to replace the existing meter at the customer's home. Appointments were not necessary for the meter installations since the work was performed on the exterior of the home. There were a few exceptions for the small number of customers whose meters resided inside the home. PSE&G's electric division performed all substation work and installation of the wireless radio equipment such as the Central Collection Units (CCUs) and Repeaters.

Although the myPower pilot was an electric based program, it was determined that the pricing segment participants with PSE&G gas service would have their gas meters upgraded to enable remote gas reads (in addition to the electric meter reads), for the duration of the pilot. The decision was made to provide consistent services to participating customers and to support a pilot with full remote data collection capability.

The gas meter retrofits (Itron ERTs) for the myPower Connection customers (except those with Itron REMS technology) were performed by Comverge's subcontractors. The work was performed, for the most part, in conjunction with the on-site installation of the Comverge Gateway systems and load control devices. In cases where a gas meter could not be retrofitted, PSE&G's gas division performed gas meter change outs. Appointments were required for the gas meter change outs to gain access to the customer's home in order to relight the customer's gas appliances. PSE&G's gas division handled the scheduling of those appointments.

For myPower Connection customers with the Itron REMS technology, HUS scheduled the customer appointments, PSE&G's gas division installed the thermostat and in-home equipment, and Itron linked the in-home equipment to the customer's computer. PSE&G's gas division also performed full gas meter swaps at the REMS customer homes (as opposed to gas ERT retrofits).

The equipment in the myPower Pricing Segments was installed in a pre-specified order. Table 29 below outlines that process in descending order.

Table 29. Process of Equipment Installation in the myPower Pricing Segments

myPower Pricing Segments	TOU/CPP Education-Only myPower Sense	TOU/CPP Technology-Enabled myPower Connection	TOU/CPP Technology-Enabled myPower Connection REMS
First	PSE&G Electric installed Itron electric Centron ERT Meters	PSE&G Electric installed electric Sentinel meters (Maingates)	PSE&G Electric installed electric Sentinel meters (Maingates)
Second	Comverge subcontractors performed the retrofit of gas meters with ERTs	Comverge subcontractors performed in-home installations of Smart Thermostats and load control and the retrofit of gas meters with ERTs	PSE&G Gas installed the Smart Thermostat and in-home REMS equipment. Itron linked the in-home equipment to the customer's computer
Third	If a gas meter could not be retrofitted with the ERTs, Comverge or Itron passed the customer to PSE&G Gas. PSE&G Gas performed a gas meter change-out to install a gas ERT Meter.		PSE&G Gas performed full gas meter replacement.
Fourth	Itron designed the Fixed Network infrastructure based on locations of the ERT Meter equipment.		
Fifth	PSE&G Electric installed the Itron Repeaters and CCUs.		
Sixth	All installation data was electronically transferred back to Call Handling Vendor for data base collection.		

At the time of the installation site visit, prior to the installation work beginning, the contractors were required to perform a pre-site inspection of the home to ensure that it qualified for program participation. The installer performed a visual inspection of the control wiring, the equipment, and field-qualified the appliance and installation conditions. If a site did not qualify, the reason was explained to the customer.

If the site evaluation proved successful, the myPower equipment was installed. Contractors placed myPower stickers at the installation sites, indicating that the customer was a program participant. The stickers provided a toll-free number for customers (or their service technicians) to call with program questions or service issues.

Permitting Requirements

The myPower pricing segment equipment installations required that municipal permits be obtained and the applicable permitting fees be paid. After discussion with the New Jersey Department of Community Affairs (NJ DCA), it was determined that the myPower pilot qualified for the special permitting process designed specifically by the NJ DCA for utility load management programs. That permitting process allowed for a reduction in the number of required municipal site inspections, as well as a reduced permit fee structure. The NJ DCA permitting process was the same one that PSE&G's legacy residential load control program Cool Customer utilized.

PSE&G handled the permit process for the myPower Connection REMS installations and Comverge for the balance of the myPower Connection customers. Subsequent to filing the permits and applicable fees, the municipalities performed their on-site equipment installation inspections and reported no failures.

Independent Third Party Inspections

Under the NJ DCA Utility Load Control permitting progress, PSE&G was required to perform a minimum of 10% installation inspections through an independent third party contractor to be hired by PSE&G. HUS was contracted for that work and was provided with a random sampling of customers to schedule. Inspections included completed work orders as well as photos. The 10% installation inspections were completed and results submitted to the NJ DCA.

3.2.3 Customer Education and Communication

At the time of the program installation, the installation contractors reviewed the pricing tiers at a high level with the customers while explaining to them the thermostat programming process. The contractors also collected customer HVAC information and the initial thermostat settings at the time of the installation. In addition, the contractors were responsible for asking the customers lifestyle questions that could guide the customers in how to program their thermostat in order to best leverage the thermostat's programmable capabilities to support their lifestyle.

Following program installation and just prior to program start, customers were mailed a package of program educational materials to assist them in their program participation. The educational materials were customized for each segment and technology and included:

- Program welcome letter with program updates
- FAQ informational sheet
- Summer 2006 Pricing Plan information (rates sheet)
- Energy Savers Guide
- Refrigerator magnet with toll-free program phone number

Subsequent to the educational materials mailing, myPower Connection customers were sent a program installation survey with a cover letter asking them to complete the survey and return it in the postage paid envelope provided to them. (The results of the installation surveys are discussed in Chapter 5.)

A myPower website was developed to enable customers to view their energy usage and myPower bills online, to compare myPower bills to what they would have paid on the traditional RS rate structure, and to provide general program information and energy savings tips. Once the website testing had been completed and the site was approved for release, customers received website navigation guides customized for each segment, along with a cover letter providing website log-in instructions, user ID, and initial website password.

As the pilot progressed, participants received program updates and information via postal mail and/or e-mail. Customers were provided with the new myPower pricing plan information (rates sheets) for the non-summer months and for summer 2007, and were reminded of steps they could take to save energy and shift their usage to lower priced time periods. Prior to summer 2007, customers were sent summer reminder letters and asked to verify and/or update their CPP contact information and myPower Connection customers were provided with their thermostat set-points for cooling to enable them to review their settings and program their thermostat to maximize savings during the summer high and CPP periods. This was particularly important for summer 2007, as the cost of electricity increased overall for residential electric customers and those costs affected myPower participants as well, resulting in significantly higher costs during the High and Critical price periods for 2007.

Customer Care

PSE&G contracted with HUS to handle the customer support for the myPower Pricing Segments. Services HUS provided include:

- Participant inquiries, compliments, and complaints

- Equipment trouble calls including scripted, over the phone trouble shooting
- 24 x 7 customer service using a live answering service off-hours, which would direct emergency service calls to the appropriate installation vendor as required
- Customer equipment removal requests
- Customer billing inquiries
- All other calls as required

HUS provided dedicated staff to work with pilot participants on detailed billing inquiries, including explanation of energy usage, myPower rates, and reasons for cost savings (or no savings). They provided customer support to assist with customer education to help participants use their appliances in a way that would provide optimal energy savings. HUS also served as the point of contact for hardware and installation vendors and PSE&G.

3.2.4 Critical Peak Price (CPP) Event Execution

PSE&G was responsible for determining when CPP events would be executed based on PJM/PSE&G supply, demand, operational, weather, and Locational Marginal Price (LMP) conditions. The number of CPP events for CPP Basic Generation Service was limited by tariff to a maximum of eight per year. The Company planned to call five events in the summer (from 1 p.m. - 6 p.m.), one in the shoulder season (from 1 p.m. - 6 p.m.), and two in the winter season (from 5 p.m. - 9 p.m.). This plan for CPP events was based on the design criteria that were used to establish the CPP pricing and would allow the testing of customer response to CPP events in different seasons of the year.

Event Operations

Once it was determined that a CPP event would be initiated, all applicable internal parties were notified the night prior to an event so that they could respond to any customer inquires that might occur. Customers were notified by 6 p.m. the night before an event using the two preferred methods of contact selected by each customer during program enrollment (home/office/cell phone, and/or email). In 2006 customer telephone notifications were delivered through the Davox outbound dialer, housed in PSE&G's Northern Inquiry Center (NIC), utilizing pre-recorded messages. For 2007 an outside, third party firm was hired to perform the outbound dialing campaigns. The myPower e-mail mail box was utilized to notify customers of CPP events using segmented e-mail lists with the appropriate customer message. All outgoing calls to customers were placed prior to 6 p.m. the night before the CPP event. Customers who had selected e-mail as one of their preferred methods of notification were sent an e-mail message prior to 6 p.m. the night before the CPP events.

For the summer of 2006, two CPP events were called, on Tuesday, August 1st and Wednesday August 2nd. In the summer of 2007, five CPP events were initiated: July 9th and 10th and August 2nd, 3rd, and 7th. There were additional CPP events called during non-summer months of the pilot. During the shoulder period an event was initiated on May 25th 2007 and during the winter period events were initiated on January 30th and February 6th, 2007.

The number of customer inquiries during CPP events generally declined over time as customers became more familiar with the program.

Table 30. myPower CPP Events

Date of Event	Wanted explanation of blinking red light	Called for clarification in response to CPP event message	REMS customers did not go into CPP event	Customer wanted explanation of CPP event	Customer inquiry - will CPP event be called following day	Internet access problems, questions	Misc. Questions *	Total Calls Received
08/1/2006	5	89	2					96
08/2/2006				13	1			14
1/30/2006	16	44				1	6	67
2/6/2007		36						36
5/25/2007		25						25
7/9/2007		41				3	3	47
7/10/2007		28						28
8/2/2007		32						32
8/3/2007		4						4
8/7/2007		9				4		13

* Miscellaneous questions – billing inquires, removal request, thermostat set-up question.

3.2.5 Back-Office Operations

Training

PSE&G provided program training to the HUS customer care and program support staff. Training was also provided to the supervisors in PSE&G's Call Center. The customer care and call center training was comprised of a detailed overview of the pilot program, including the various program segments and their attributes. Program installation work flow and data collection were also part of the training process. Prior to the start of the myPower billing and website launch, customer service representatives were trained to utilize the website and billing systems to answer customer inquires.

In addition to the customer care and call center training, in-depth contractor training took place for the installation of the in-home pilot program equipment. That training was broken out into several components.

- Itron installation, troubleshooting, and program training for the PSE&G Appliance Service (AS) technicians was provided by Itron and HUS in cooperation with PSE&G.
- PSE&G provided gas ERT training to Comverge's subcontractor IES.
- Comverge provided troubleshooting and program training to the AS technicians in cooperation with PSE&G.
- Comverge trained their subcontractors (IES and Bullet Communications) to install and troubleshoot their system.

The equipment installation training included both classroom and hands-on training for the contractors and PSE&G staff from the gas delivery group. They provided and created several training manuals and troubleshooting guides for the training efforts:

- Itron REMS manual that was modified for use by PSE&G technicians in the field
- Installation and troubleshooting guide Power Point presentation for Itron technology
- Installation and troubleshooting guide Power Point presentation for Comverge technology
- Presentation for gas ERT retrofit training provided to Comverge by PSE&G gas meter shop

The training sessions were held on-site at PSE&G locations as well as contractor business sites. Upon completion of the training, the initial in-home program installations were overseen by field supervisors for quality control.

3.3 Program Close-Out

The myPower Pilot program concluded on September 30, 2007. In order to close-out the program from a customer and operational perspective, the following steps were taken:

- **Customer Communication**

Letters customized for the myPower Sense and myPower Connection segments were sent to myPower customers reminding them that the program pricing plan ended on 9/30/07 and that they could be contacted for the end-of-program telephone survey prior to payment of the final program incentive of $75.00.

myPower Connection letters explained the equipment removal process and that the customer would be contacted to schedule an appointment for the removal of the in-home equipment. myPower Connection I and II customers were notified that they would receive new programmable thermostats to replace their myPower thermostat, which could no longer operate independent of the myPower (Comverge) head-end system. myPower Connection Itron REMS customers were notified that they would retain their myPower thermostat, as it would operate normally post-program.

- **Equipment Removal Process**

In-home equipment removals were handled by HUS and Comverge depending on the equipment installed in a customers home.

HUS scheduled the removal appointments and performed the in-home equipment removals for the myPower Connection Itron REMS customers. The myPower programmable thermostat remained in place as Itron verified it would function normally. After equipment removal, Itron deactivated the head-end communications.

Comverge, through their subcontractor Bullet, scheduled the myPower Connection I and II appointments and performed those equipment removals. Comverge removed all of the in-home equipment with the exception of the Maingate at the customer's meter. Once the Comverge appointments had been completed, PSE&G's electric division was notified to remove the Maingate on the customers' electric meter. Appointments for that work were not required.

- **Incentive Payments**

After the end-of-program customer surveys had all been completed and the customers' in-home equipment had been removed (applicable to myPower Connection only), customers were mailed a final program thank you letter with their $75.00 incentive check. The letters informed customers that they were now eligible to sign-up and/or return to PSE&G's Auto Pay Program. The letters provided customers with a web link to the site to use for Auto Pay or other PSE&G payment programs.

- **Cool Customer Participants**

myPower participants who were Cool Customer participants had been required to suspend their participation in that program for the duration of the myPower pilot. Their Cool Customer load control devices were remotely deactivated and billing credits suspended. Once myPower concluded, those Cool Customer participants were notified that they would be reinstated to Cool Customer and their load control device would be reactivated before summer 2008.

- **myPower Customer Care**

myPower maintained a toll-free phone center through HUS for the duration of the pilot program to assist customers with program-related inquires. The telephone center was maintained several months after the myPower pilot program concluded to support any final customer inquires, and was shut-down 12/31/07.

- **myPower Billing and Website**

After the final October myPower bills were produced, the customers were returned to the normal billing process. The myPower customer website was shut down on November 30, 2007.

4 BILLING ASSESSMENT

4.1 Introduction

A stand-alone billing system was created specifically for the myPower pilot program. The system enabled PSE&G to bill myPower pilot participants on Time-of-Use (TOU) rates with Critical Peak Pricing (CPP). The billing system provided pilot program participants with a branded myPower billing statement and also supported data inputs required for the myPower customer website.

Because the myPower billing system was developed as an adjunct system to the legacy PSE&G Customer Information System (CIS), it required manual intervention and non-standard billing processes. Customer bills had to be diverted from the CIS billing process and forwarded to dedicated myPower billing staff who in-turn prepared the myPower monthly billing statements. An example bill is shown in Appendix M. As such, the myPower billing system could not be used for a full scale program deployment.

4.2 Billing Processes

4.2.1 Training

PSE&G meter readers and customer service representatives received on-site pilot program overview training. myPower billing staff also planned and executed topic-specific training sessions for Customer Inquiry, Billing, Credit and Collection, Customer Relations and Construction Inquiry. Honeywell Utility Solutions (HUS) was hired to support the myPower billing team for customer inquiries and billing concerns, and they also received billing systems training.

4.2.2 Meter Impacts on Billing

Electric

For the myPower program, electric interval meters were installed at the customer homes to facilitate remote data collection for the pilot. PSE&G meter readers continued to obtain on-site meter readings and entered the data into their handheld meter reading devices for data validation purposes. On-site meter readings were then validated using historic data (hi/low) entries. If an on-site reading could not be obtained, the meter book was left open and an email notification was sent from the meter reader's district to the myPower billing team. The myPower billing team then obtained the necessary electric interval data and sent it to the district to be used to record an actual meter reading.

A number of issues were encountered during the billing process that had a negative impact on the ability to produce a myPower bill. These issues, such as gaps in interval data, required manual review and intervention on a case-by-case basis. There was a direct relationship between the ease of producing a myPower bill and the quality of interval data received from a customer meter. As the interval data collection issues improved, less manual intervention was required.

Gas

Although the myPower program was an electric based pilot, it was decided during the project design phase to include remote meter reading capability for customers with PSE&G gas service. The logic was to provide a program with complete remote meter reading technology and to provide customers with actual gas meter readings as well as electric readings.

The myPower billing process was significantly impacted by the gas meter retrofits, due to a number of unanticipated operational issues such as incorrect recording of new meter numbers and gas indexes when the meters were retrofitted. These issues created exceptions in the billing process and required manual review and intervention on a case-by-case basis.

4.2.3 Billing Conflicts

As the myPower program progressed, it became evident that there were several billing system conflicts that needed to be addressed. Specifically, customers who either participated-in or signed-up for various billing-related programs (in addition to myPower) required individual billing attention.

At the time of the myPower program recruitment, the list of potential customer participants from Cherry Hill and Hamilton Township was filtered to remove customers participating in particular programs such as Universal Service Fund (USF). Customers were further pre-screened over the telephone to remove those participating in billing-related programs to avoid potential billing conflicts with the myPower billing engine.

Unfortunately, throughout the course of the myPower pilot program, customers inadvertently enrolled in billing-related programs which affected the program's ability to create accurate myPower bills. In many cases, this prevented a myPower bill from being generated. Further, the billing issues needed to be resolved on a customer-by-customer basis. Examples of problems encountered included:

- **Auto Pay customers.** The Auto Pay option (electronic bill payment option which automatically deducts the payment from the customer's account) was not compatible with the myPower billing engine and customers were notified that they needed to come off of Auto Pay for the duration of the pilot program. Customers were provided with the option of using the AnyTime Pay (customer authorizes when payment is to be made) or other traditional payment methods.

- **Equal Payment Plan (EPP) customers.** Customers in myPower were not eligible to participate in the EPP because it conflicted with the myPower program objective to understand how customers respond to Time-of-Use (TOU) pricing. Subsequently, customers signing-up for EPP were asked to come off that program for the duration of the pilot program.

- **USF customers.** Customers receiving USF funding were removed from myPower because they would not provide an accurate representation of energy usage vs. energy cost for the pilot program due to the energy cost subsidies (assistance) received.

- **Unknown impacts.** There were unforeseen impacts to customer bills due to existing atypical billing procedures implemented to address extraordinary billing situations. For example, in some cases, customer account numbers were changed to maximize meter reading route efficiency, which then impacted myPower data collection and billing.

4.2.4 Billing Validation

Due to potential billing conflicts identified by the myPower billing team, a Billing Validation Process (BVP) was established. On a daily basis, the myPower billing team identified and documented all database and system conflicts requiring additional investigation in order to ensure accurate billing. Formal validation criteria were established for the BVP, to alert billing staff that further investigation into a customer account was required. The criteria included the review of inactive accounts, possible collection accounts,[10] Equal Payment Plan (EPP) accounts,[11] Third Party Suppliers (TPS) for Electric/Gas Supply, Clean Power accounts, Universal Service Fund (USF) participants, LIHEAP customers, Cool Customers receiving monthly air conditioning credits (ACC), meter product charges (MPC), known myPower pilot program customer dropouts, billing recalculations, and billing estimates.

The close-out of the myPower billing process, resulted in split bills comprised of both RSP and RS rates. The October 2007 myPower bills were produced using interval data collected thru September 30th, and billed on an RSP rate, coupled with usage data from October 1st up to the customer's October meter reading date, billed on the regular RS rates as mandated by the tariff. The split bills were necessary to reflect the end of the myPower pricing plan and the customer's return to the normal RS rates.

4.2.5 Key Findings

In a wide-scale program deployment, a billing system must:

- Be developed and implemented in an efficient process for mass bill production considering time of use rates and multiple data systems;
- Identify all programs that require special billing design, i.e., Auto-Pay, EPP, TPS, etc.;
- In partnership with business leads and the Information Technology department, make certain all billing system requirements support required functionality across the business both internal and external;
- Insure that system design adheres to Sarbanes Oxley requirements and all security protocols, as did the myPower process.

4.3 Customer Website

A myPower website was developed to allow customers to view their monthly energy usage as well as their myPower bills. The website was designed as a tool to provide customers with detailed information so they could understand their individual usage patterns and behaviors. This information allowed myPower participants the ability to manage and take action as needed by shifting usage to times when electricity prices were lowest. Customers could update their profile information on the site with contact

[10] Possible collection accounts including past due and service shut off notices were flagged when a copy of the customer bill was sent to the Credit and Collection group.

[11] PSE&G customer service representatives responding to a customer request would enroll the customer in EPP after the same customer had been removed from EPP in order to participate in the myPower pilot. Customers were also able to sign up for EPP online.

information such as phone numbers or e-mail addresses. myPower Connection customers were also able to select a tab that took them to the MyThermostat page of a linked site where they could remotely change the temperature settings of their programmable thermostat. (Website screen shots appear in Appendix N of this document.)

The myPower website experienced 150-200 hits per month (participants logging–on). Of those, there were between 70-95 unique users each month viewing the site. The majority of website traffic was documented during the summer months where usage varied anywhere from 20 hits during a CPP event up to 30 hits in the days following the event. During this time participants recognized the most savings on their myPower bills with the majority of the savings earned during the CPP events.

In the final month of the myPower pilot, website usage slowed down to 1/2 of what was experienced in the past. The myPower participants continued to have access to the website and past months' electric usage, including PDFs of myPower bills, through November 26, 2007. The myPower customer website was shut down on November 30, 2007.

5 CUSTOMER ASSESSMENT

5.1 Study Introduction and Objectives

This section presents the results of the Customer Assessment Evaluation for the myPower Pricing Segments of the pilot program. The research conducted in 2006 included the Pre-Program, Installation, and Annual Customer Surveys. The research conducted in 2007 included the winter CPP Event, summer CPP Event and End-of-Program Surveys. The Customer Assessment portion of the myPower program evaluation was designed to evaluate the overall effectiveness of the pilot program by measuring changes in participant attitudes and behaviors. The assessment also measured myPower program participants' pre- and post-program attitudes toward energy usage and conservation. In addition, the surveys captured important information on customers' experience with the myPower program equipment, equipment installation, program recruitment, and educational materials. Customers were also questioned about their energy and cost savings as related to their conservation efforts.

5.2 Data Collection–Survey Methods

The Customer Assessment was based on six surveys:

- Pre-Program Survey
- Installation Survey (myPower Connection only)
- 2006 Annual Survey
- 2007 Winter CPP Event Survey
- 2007 Summer CPP Event Survey
- End-of-Program Survey

Given the relatively few (2) Critical Peak Price (CPP) events called in the summer of 2006, questions regarding customers' experience with myPower CPP events were not addressed in a stand-alone CPP survey for the summer of 2006. Rather, events were measured through a series of questions included in the 2006 Annual Survey. The survey methodologies employed varied by study and were as follows:

Pre-Program Survey:	Conducted via telephone as part of the customer screening process.
Installation Survey:	(myPower Connection participants only) Conducted via a paper survey, which was mailed to participants after equipment installation. The participants filled-out the survey and returned it in a postage-paid, pre-addressed envelope directly to PSE&G's Marketing Department.
2006 Annual Survey:	Conducted October 19th through 25th, 2006 via telephone through an independent market research vendor Schulman, Ronca, & Bucuvalas, Inc. (SRBI).
2007 Winter CPP Event Survey:	Conducted January 31st through February 1st, 2007 via telephone through SRBI to measure awareness of and actions taken during the January 30th CPP event.

2007 Summer CPP Event Survey:	Conducted August 4th and 5th, 2007 via telephone through SRBI to measure awareness of and actions taken during the August 2nd and 3rd CPP events. Detailed cost savings questions were added during this survey to get a baseline for the end-of-program survey.
End-of-Program Survey:	Conducted October 8th through 13th, 2007 via telephone through SRBI.

5.3 Data Collection Methods – Completion and Response Rates

The total number of completions for each survey is shown in the following table. Details follow.

Table 31. Survey Completions

Survey	myPower Sense	my Power Connection
Pre-Program	481	397
Installation	NA	301
2006 Annual	100	100
2007 Winter CPP Event	100	100
2007 Summer CPP Event	100	100
End-of-Program	150	150

Pre-Program Survey Response Rate

Interviews were conducted by HUS from November 2005 through February 2006 using a scripted questionnaire. In addition to the five key participant attitude questions, the Pre-Program Survey interview also included a myriad of household characteristics and electricity usage behavior questions.

- myPower Connection[12]: A total of 397 interviews were completed - 358 myPower Connection I and II participants and 59 myPower Connection REMS participants from the 424 eligible residential customers. The overall response rate for this survey was 94%.

- myPower Sense: A total of 481 interviews were completed from the 536 eligible residential customers. The overall response rate for this survey was 90%.

[12] myPower Connection sub-segments:
- myPower Connection I – Comverge technology
- myPower Connection II - Comverge technology (customers were formerly recruited for the myPower Manager segment of the pilot which has since been cancelled)
- myPower Connection REMS – Itron REMS technology (customers were formerly recruited for the myPower Manager REMS segment of the pilot which has since been cancelled)

Installation Survey Response Rate

This survey was conducted via a paper questionnaire mailed to myPower Connection participants. Participants were instructed to fill-out the survey and send it back to PSE&G through the postage-paid envelope provided to them. Of the 450 myPower Connection program participants, a total of 301 completed surveys were returned, for a 67% response rate.

Surveys conducted:

Survey 1: (271 respondents): myPower Connection I and II
Survey 2: (30 respondents): myPower Connection REMS

2006 Annual Survey Response Rate

Interviews were conducted from October 19th through 25th, 2006 for myPower Connection customers and October 23rd through 28th, 2006 for myPower Sense customers, from SRBI's telephone center in West Long Branch, NJ. Interviews with myPower Connection customers averaged 15.2 minutes in length and those for myPower Sense averaged 12.3 minutes.

A total of 100 interviews were completed among myPower Connection program participants and 100 interviews were conducted among myPower Sense program participants. The overall response rates for the surveys were myPower Connection at 59% and myPower Sense at 47%.

2007 Winter CPP Event Survey Response Rate

Interviews were conducted from January 31st through February 1st, 2007 for myPower Connection and myPower Sense customers, by SRBI. Interviews with myPower Connection customers averaged 5.8 minutes in length and those for myPower Sense averaged 5.2 minutes.

A total of 100 interviews were completed among myPower Connection program participants and 100 interviews were conducted among myPower Sense program participants. The overall response rates for the surveys were myPower Connection at 99% and myPower Sense at 94%.

2007 Summer CPP Event Survey Response Rate

Interviews were conducted from August 4th and 5th, 2007 for myPower Connection and myPower Sense customers, by SRBI. Interviews with myPower Connection customers averaged 10.2 minutes in length and those for myPower Sense averaged 9.6 minutes.

A total of 100 interviews were completed among myPower Connection program participants and 100 interviews were conducted among myPower Sense program participants. The overall response rates for the surveys were myPower Connection at 95% and myPower Sense at 92%.

End-of-Program Survey Response Rate

Interviews were conducted from October 8th through 13th, 2007 for myPower Connection and myPower Sense customers, by SRBI. Interviews with myPower Connection customers averaged 18.6 minutes in length and those for myPower Sense averaged 14.8 minutes.

A total of 150 interviews were completed among myPower Connection program participants and 150 interviews were conducted among myPower Sense program participants. The overall response rates for the surveys were myPower Connection at 99% and myPower Sense at 97%.

5.4 Key Findings

The following results are primarily from the 2007 End-of-Program Survey for the myPower Connection and myPower Sense programs, with comparisons (where applicable) to the findings from the Pre-program Survey, the Installation Survey, the 2006 Annual Survey, the January 2007 and the August 2007 CPP Event Surveys.

Program Satisfaction

Satisfaction with the myPower program varied somewhat between the two segments, but remained relatively consistent throughout the pilot whenever measured. Satisfaction with the myPower Connection program overall at the end of the program (7.4 on a 10-point scale where 10 was “extremely satisfied”) was essentially the same as the level achieved in 2006 (7.5), rebounding after a slight decline following both CPP events (7.1 in the January 2007 CPP Survey and 7.0 in the August 2007 CPP Survey).

myPower Sense participants’ satisfaction improved at the end of the program (7.7) compared to 2006 (7.4) and the January CPP Event (7.3), and was similar to the August CPP Event (7.8).

The most frequently mentioned reasons why both myPower Connection and myPower Sense participants were satisfied with the program (customers providing an answer of 8 through 10 on a scale of 1 to 10, 10 being extremely satisfied) were the bill savings, the ease of participation, and the education they received about the best time to use appliances.

Although customers reported saving on the program, the main reason for dissatisfaction (a rating of 1 through 6 on a 10 point scale) with the program was bill savings. myPower Connection participants were also dissatisfied because they had difficulty programming the thermostat (15% reported this issue) and were uncomfortable during the high price and CPP events (15% mentioning this issue). Aligning with these reasons, ‘simplifying the thermostat’ (24%) and ‘improve customer training’ (13%) were cited as the main suggestions for program improvement. Additionally, fewer myPower Connection participants said that their home was comfortable during high price hours outside of critical events (71% vs. 78% in 2006).

Satisfaction with the Equipment Installer

myPower Connection participants were highly satisfied with the knowledge (9.0 on a 10 point scale), professionalism (9.0), and courtesy (8.9) of the myPower equipment installers (Comverge and Itron subcontractors). They were also satisfied that the work was performed neatly (8.5). Participants were less satisfied with the installers regarding their explanation of the myPower Connection Program overall (7.0) and how to program the thermostat (7.3).

Program Understanding and Participation Level

Two-thirds of myPower Connection (65%) and myPower Sense (69%) participants reported that their understanding of the myPower program increased since the pilot programs began in July of 2006. Very few participants reported that their understanding decreased over time (myPower Connection 2%; myPower Sense 3%). More myPower Sense participants reported that their understanding increased at the end of the program than at the end of the 2006 season (69% from 46%). The majority of myPower Connection (80%) and myPower Sense (84%) participants became more knowledgeable about energy consumption reduction as the myPower program progressed (vs. 71% who reported being more knowledgeable in 2006 for both programs).

During the two CPP Event Surveys in January and August of 2007, participants were asked how familiar they were about the myPower program they were participating in. The majority of the myPower Connection (94% in August, 84% in January) and myPower Sense (92% and 89%) participants reported being at least somewhat familiar with their respective myPower program.

Actions Taken to Reduce Consumption

Roughly half of the myPower Connection (48%) and myPower Sense (55%) participants characterized themselves as "very active" participants. Both myPower Connection and myPower Sense participants reported reducing their electric consumption primarily by not using electric appliances, setting the thermostat at a higher temperature, and turning off their air conditioning. Approximately 10% did not change their energy consumption habits. These findings were fairly consistent throughout the program pilot. One third (37%) of myPower Sense participants reported reducing their electric usage all of the time, 55% reported reducing electricity most of the time and 8% reported reducing use sometimes.[13] Most (85%) myPower Connection participants also changed when they did household chores, such as laundry and dishwashing, compared to 69% in 2006.[14]

Program Communications

Generally, participants were satisfied with the myPower communications, and were more satisfied in 2007 than in 2006. Satisfaction with overall communications increased from 7.5 (on a 10 point scale) in 2006 to 8.5 in 2007 for myPower Connection participants and from 7.8 to 8.7 for myPower Sense participants. Satisfaction with the information they received on reducing electricity usage increased from 8.0 in 2006 for both myPower Connection and myPower Sense to 8.2 in 2007 for myPower Connection and 8.6 for myPower Sense. More participants reported having enough information on how to save money in 2007 than in 2006 (myPower Connection increased to 93% in 2007 from 88% in 2006 and myPower Sense increased to 91% from 85%).

myPower Billing

Almost three quarters (71%) of both myPower Connection and myPower Sense participants thought that they saw cost savings on their bill as a result of participating in the myPower program.

Participants were somewhat satisfied with the amount of money saved as a result of program participation (the last section of this report quantifies those savings). myPower Connection participants reported an average satisfaction rating of 6.6 in 2007, on a 10 point scale where 10 is "extremely satisfied", and 6.5 in 2006. myPower Sense participants reported 6.5 in 2007 and 6.4 in 2006.

Although nearly half of myPower Connection (48%) and myPower Sense (52%) participants could not specify how much they expected to save, they expected to have saved more than they did. myPower Connection participants said they saved an average of $188 but said they expected to save an average of $222. In reality, myPower Connection participants saved $102 on average (see details in the last section of this report). myPower Sense participants reported saving $105 on their bill but expected to save $132. In reality they saved $68.[15]

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[13] This question was not asked of Connection participants.

[14] This question was not asked of Sense participants.

[15] Savings based on customers with 12 months of billing data ending September 2007 (See Figures 7.1 and 7.2). "In viewing the bill impacts, it is important to note that they are based on the actual electricity used and billed comparing actual bills under the CPP rate to what would have been billed under the standard rate. In the Impact

Participants were quite satisfied with the structure and content of the bill with satisfaction scores of 8.2 with the ease of understanding the bill for both myPower Connection and myPower Sense, and 8.2 (myPower Sense) and 8.5 (myPower Connection) with the accuracy of the bill.

Thermostat Usage

Over half of the participants (59% for myPower Connection and 61% for myPower Sense) had programmable thermostats prior to the myPower program. Of the 38% of myPower Sense participants who did not have a programmable thermostat in their household, only 41% thought they would have benefited from having one. The primary issue among the 52% who did not believe they would have benefited from a programmable thermostat was that they preferred to have control over the thermostat themselves. More myPower Connection and myPower Sense participants (among those myPower Sense who had one) programmed their thermostat in 2007 than in 2006.

Just under one half (42%) of myPower Connection participants programmed their thermostats to increase by 4 to 5 degrees during a CPP event and one quarter set them to increase by 6 to 10 degrees. Just under half (44%) of the myPower Connection participants pre-cooled their home in preparation for CPP events.

Most myPower Connection participants (87%) reported their thermostat operated up to their expectations during the August CPP event. Three quarters (77%) of myPower Connection participants said the thermostat helped them conserve energy in some way.

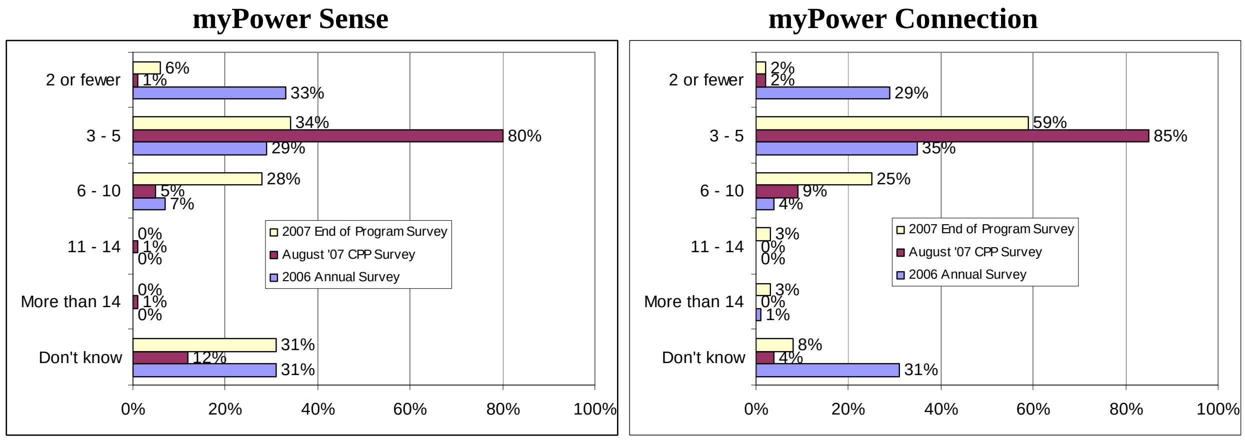
myPower Connection participants were reasonably satisfied with their program thermostat both at the end of the program and in 2006 (providing an average rating of 7.3 on a 10 point scale). The main reason for dissatisfaction with the thermostat (a rating of 1 through 6 on a 10 point scale) was a lack of understanding of thermostat operation.

Critical Peak Price Events

Most participants thought there had been fewer CPP events in 2007 than actually occurred. Only 6% of myPower Connection and 9% of myPower Sense participants accurately reported that PSE&G called eight CPP events in 2007. Over half (59%) of myPower Connection participants believed that between 3 and 5 CPP events were called in 2007 compared to 34% of myPower Sense participants, which may be due to 2 events being called back to back (July 9th and 10th and August 2nd and 3rd). Just 6% of myPower Connection participants and no myPower Sense participants overestimated the number of CPP events in the 2007 End of Program Survey.

Assessment, by comparing consumption patterns across time it was shown that participating customers also reduced their overall energy use, which would also lower their bills. However, the approach to calculating monthly bill savings for the purposes of preparing actual customer bills could not include this type of analysis and so it only shows the savings for the amount of electricity actually consumed. Without any way to quantify the savings in energy use for each customer, the bill comparisons that customers were shown each month tended to understate their actual bill savings."

Figure 11. How Many CPP Events Took Place in 2007?



Satisfaction with the number of CPP events called was generally high in both 2007 and 2006. It declined slightly in 2007 (from 8.0 to 7.0 for myPower Connection participants and from 7.9 to 7.5 for myPower Sense participants), which is not surprising given that there were 8 CPP events in 2007 compared to 2 in 2006.

Comfort during the CPP events varied over the pilot program. myPower Connection participants' comfort varied from 55% in 2007 to 66% in 2006, *where "comfort" is defined as those respondents who answered 'Very Comfortable' and 'Somewhat Comfortable*.' myPower Sense participants' comfort similarly varied from 68% in 2007 to 79% in 2006.

Communication about CPP Events

In 2007, the outbound dialer vendor was changed to improve notification of participants for upcoming CPP events. This may have improved recall of receiving the automated call as the 2007 surveys saw increased recall for both myPower Sense and myPower Connection participants (see the table below). Roughly half of the participants recalled receiving an e-mail notification of CPP events.

Table 32. Percent Recalled Receiving Automated Call Before CPP Events

	myPower Sense				myPower Connection			
	Annual 2006	**Jan, 2007**	**Aug, 2007**	**End of Program 2007**	**Annual 2006**	**Jan 2007**	**Aug 2007**	**End of Program 2007**
Received automated call	67%	89%	92%	94%	55%	78%	78%	90%
Received email	42%	35%	38%	42%	40%	37%	44%	51%

The most effective method of notifying myPower Connection participants about an upcoming CPP event appeared to be the combination of an automated call and an e-mail with program satisfaction of 8.0 for participants who reported receiving this combination of notification methods. Participants recalling other notification combinations[16] generally reported lower levels of satisfaction with the program. Program satisfaction was the same among the myPower Sense participants who received both a call and e-mail versus those who just received a call (7.7).

The majority of program participants were satisfied (Very Satisfied and Somewhat Satisfied) with the communications about CPP events (myPower Connection 94% and myPower Sense 90%). More participants were “very satisfied” with the communications about CPP events in both programs (myPower Connection: 82% from 67% in 2006 and myPower Sense: 78% from 64% in 2006). Most participants (99% in myPower Connection and 98% in myPower Sense) said the notification they received provided the information they needed about the CPP event.

The vast majority of participants said the notification they received had a “great deal of” or “some” impact on their decision to reduce consumption during the event. In August 2007, 88% of myPower Connection participants and 92% of myPower Sense participants said the notification had at least some impact. The notification had a significantly greater impact on changing energy consumption behavior for the August event than for the January event among myPower Sense customers.

myPower Website

By the end of the program, most myPower Connection participants knew they could control their thermostat over the Internet (increasing from 47% in 2006 to 65% in 2007). However, 60% continued to not take advantage of this capability. Among those who did use the Internet to change their thermostat, participants adjusted their thermostats more frequently in 2007 than in 2006 (5.1 times vs. 3.3 times), but on a scale of 1 to 10, fewer rated it easy (8.5 on average rating of Very Easy and Somewhat Easy for 2007 versus 9.1 in 2006).

Also by the end of the program, roughly six in ten myPower Connection (63%) and myPower Sense participants (59%) were aware that they could view their electricity usage on the myPower web site. This was an increase over 2006 results of 51% for myPower Connection and 47% for myPower Sense. About half of the myPower Connection (53%) and one-third (35%) of the myPower Sense participants who were aware of the ability to view daily usage online actually viewed their usage online.

Of those who were aware of this capability, more myPower Connection and myPower Sense participants reported actually viewing their electric use online than those surveyed previously: myPower Connection 53% in 2007 vs. 38% in August, 43% in January and 35% in 2006 and myPower Sense 35% in 2007 versus 27% in August, 17% in January and 32% in 2006. The main reasons respondents cited for not viewing their usage on the website were a lack of interest and a lack of internet access.

Nearly all myPower Connection (86%) and myPower Sense (93%) participants who accessed their electricity usage information online rated it Very Easy or Somewhat Easy to do. Sense participants were more likely to say it was “very easy” to view their usage (72%) at the end of the program than in 2006 (57%) and were also more likely than myPower Connection (58%) participants.

The Future of myPower

The majority of participants agreed that PSE&G should offer more programs like myPower in the future (91% of myPower Connection participants and 85% of myPower Sense participants). Over three quarters

[16] Other reported CPP event notification combinations included: Call, e-mail and thermostat message, Call & thermostat message, E-mail & thermostat message, Call & e-mail, Call Only, and E-mail Only.

would recommend the program to others (77% for myPower Connection and 81% for myPower Sense). More than three quarters also believe that the program benefits the environment (84% for myPower Connection and 83% for myPower Sense). Although almost all in both programs believe that participation in the program should be voluntary (91% for myPower Connection and 85% for myPower Sense), 13% of participants in both programs responded “expand the program” when asked what PSE&G should do to improve the program.

Demographics of myPower Sense and myPower Connection participants

Although myPower Connection participants had somewhat larger families, somewhat more education, and somewhat more income than myPower Sense participants, the characteristics of the myPower Sense and myPower Connection participants were relatively similar.

Table 33. Characteristics of Residential Participants

		myPower Sense	myPower Connection
Number of People in the Household	Five or more	7%	13%
	Four	11%	16%
	Three	11%	17%
	Two	47%	39%
	One	23%	15%
Respondent Age	65 or over	38%	39%
	55 – 64	25%	23%
	45 – 54	17%	17%
	35 – 44	12%	15%
	25 – 34	7%	5%
	18 – 24	0%	0%
Respondent Ethnicity/Race	Hispanic	2%	2%
	Other	11%	9%
	Caucasian	87%	89%
Education	Postgraduate work or degree	15%	26%
	College graduate	36%	35%
	Some college	19%	17%
	Technical or trade school graduate	3%	1%
	Some technical or trade school	3%	1%
	High school graduate	19%	15%
	Some high school or less	4%	2%
Income	$100,000 or more	19%	25%
	$75,000 up to $100,000	15%	19%
	$50,000 up to $75,000	24%	19%
	$25,000 up to $50,000	15%	10%
	Up to $25,000	10%	5%

6 IMPACT ASSESSMENT

This chapter presents the results of the Impact Evaluation for the myPower pilot. This evaluation addresses both the Time-Of-Use (TOU) and Critical Peak Pricing (CPP) aspects of the myPower pilot while it was active from July 15, 2006 through September 30, 2007. Two summer periods, one winter period and three shoulder months were covered during this timeframe. Each season had a different pricing structure so impacts were estimated separately for each season.

The TOU part of the pilot provided participants with different prices for electricity depending upon the time-of-day they used electricity (essentially a base rate with a night discount and an on-peak adder). During weekends and the shoulder months of October, April and May there were no on-peak price periods. Since both the base price and the night discount were below the regular RS rate, weekends and shoulder months were times of guaranteed bill savings for customers.

The CPP aspect of the program involved a significant adder to the kWh rate during called CPP event periods. The called CPP event period was from 1 p.m. to 6 p.m. during the months of April through October, and from 5 p.m. to 9 p.m. during the months of November through March. These time periods matched the periods of highest system peak load during those seasons. CPP events were determined on a day-ahead basis and communicated to customers the evening before the event. There were seven CPP events called during the two summers, two events called during the winter, and one event during the shoulder months.

The following sections of this chapter describe the methods that were used to estimate the impacts of the myPower program, and the results that were found. Several different areas of impacts were analyzed:

- Summer Peak Day Hourly kW Impacts
- Summer Season kWh Shifts
- Summer Energy Conservation
- Summer Elasticities of Substitution
- Winter and Shoulder Month Impacts

The major findings from these studies are summarized here:

- myPower participants consistently lowered their on-peak demand in response to price signals across two summers.

- During the summer there were daily reductions in demand from 1:00 p.m. to 6:00 p.m. on weekdays due to the on-peak prices in the TOU rate.

- When CPP days were called, customers reacted to the CPP rates and created even more demand reduction during the 1:00 p.m. to 6:00 p.m. period.

- Customers who received enabling technology as part of the program (myPower Connection customers received programmable, communicating thermostats) showed greater reductions in demand, both in response to the TOU rates and the CPP events.

    - On the hottest summer days, myPower Connection customers reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 21% (0.59 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 26% (0.74 kW) if a CPP event was called. This is a total reduction of 47% (1.33 kW).

  - On the hottest summer days, myPower Sense customers with central air conditioning reduced their average hourly demand during the 1:00 p.m. to 6:00 p.m. period by 3% (0.07 kW) in response to the TOU on-peak rate, and they reduced their demand by an additional 14% (0.36 kW) if a CPP event was called. This was a total reduction of 17% (0.43 kW).

- Many customers used less air conditioning during the high price periods. This created snapback demand after 6:00 p.m. when prices returned to base levels and air conditioners started running at full capacity to bring down indoor air temperatures.

  - Snapback occurred on all hot weekdays due to the on-peak TOU rate. The snapback effect was highest from 6:00 p.m. to 7:00 p.m. and diminished over the next few hours.

  - On CPP event days, there was additional snapback adding to what normally occurred on regular TOU days. There was a limiting factor on the amount of snapback that occurred in the first hour after the end of the control period, suggesting that many air conditioners were running at 100% of their capacity.

- myPower customers were able to reduce their total summer energy use by 3-4% compared to Control Group customers.

- The elasticity of substitution ranged from –13.7% to -8.8% for myPower Connection customers over the two summers of the study, and from –8.5% to –6.1% for myPower Sense customers. The on-peak to off-peak rate differential changed from 4.1 to 6.5 over this same period.

- Customers also responded to price signals on winter peak days, but winter kW demand reductions were smaller than summer kW demand reductions. For example, myPower Connection customers had average on-peak winter impacts of –0.41 kW compared to –1.33 kW during summer.

- myPower Connection customers did not show any reduction in their total winter energy use. However, myPower Sense customers showed a 1.65% decrease in energy use during winter months which was statistically significant at the 90% confidence level. It appears that their conscious attention to energy demands and load shifting during the summer may have become habit and carried over into the winter months.

6.1 Summer Peak Day Impacts

One of the primary goals of the TOU and CPP rates was to induce customers to reduce their electricity consumption on summer peak days by exposing them to the higher costs of energy production on those days. Demand reductions that customers could make on peak days not only benefited them individually, but also benefited all customers on the system by reducing the need for peak capacity.

myPower participants were exposed to two types of higher prices on summer peak days; on-peak prices every summer weekday and critical peak prices on a small number of days. The on-peak prices encouraged participants to reduce demand every week day during the summer. When CPP events were called, participants faced even higher peak rates and were encouraged to reduce demand even more.

In the summer of 2006, the base rate was 9.2032 cents/kWh and the on-peak adder was 8 cents/kWh. The critical peak adder was 69 cents/kWh. In the summer of 2007, the base rate dropped slightly to 8.6675 cents/kWh while the on-peak adder increased to 15 cents/kWh and the critical peak adder increased to $1.37/kWh. This meant that customers were paying 78.2032 cents/kWh during the critical peak period in 2006, and $1.456675/kWh in 2007. The high prices during CPP events strongly encouraged customers to reduce demand during the CPP periods. Table 34 shows the summer season rates for the two years of the pilot.

Table 34. myPower Pilot Time-of-Use Rates for Summer Months (June through September)

Period	2006 Charge	2007 Charge	Applicable
Base Price	9.2032¢ per kWh	8.6675¢ per kWh	All Hours
Night Discount	-5¢ per kWh	-5¢ per kWh	10 p.m. to 9 a.m. Daily
On-peak Adder	8¢ per kWh	15¢ per kWh	1 p.m. to 6 p.m. Weekdays
Effective Off-peak Rate	4.2032¢ per kWh	3.6675¢ per kWh	
Effective On-peak Rate	17.2032¢ per kWh	23.6675¢ per kWh	
On-peak/Off-peak Ratio	4.1	6.5	

TOU and CPP impacts on summer peak days were estimated separately so the individual effects of the two rate levels could be understood clearly. Analysis of each rate required a different method. Those methods will be described in the next sections.

In addition to analyzing TOU and CPP effects separately, the myPower customers were separated into three groups for analysis. First, myPower Connection customers were analyzed separately from myPower Sense customers. This was done because it was expected that customers who received the programmable, communicating thermostats (myPower Connection customers) could achieve greater demand reductions than myPower Sense customers who did not receive any enabling technology. Second, when working with the myPower Sense customer data and the Control Group data, it became apparent that there were distinct differences in the size of the loads and the ability to reduce demand on summer peak days related to whether or not the customer had central air conditioning. Customers with central air conditioning had higher load curves and greater ability to reduce demand during summer peak hours. For this reason, myPower Sense customers with central air conditioning were analyzed separately from myPower Sense customers without central air conditioning. All myPower Connection customers had central air conditioning, so there was no need to split them into two groups for analysis.

6.1.1 Data and Methods

The analysis of demand impacts from the TOU rate alone (minus the impact of the CPP) was based on a comparison of participant group to Control Group kWh usage on the hottest summer days of 2006 and 2007 that did not have CPP events. Care was taken to create a Control Group of customers that closely matched the participant group in each participant segment and size strata.

The hottest summer days were identified by calculating the average hourly THI[17] from hour ending 1200 to hour ending 2000 each day of the summer. If the average was greater than 14 THI, it was selected as one of the hottest days. This range of temperatures is equivalent to the temperatures that occurred during control event days in 2006 and 2007. This method produced the following list of hot days without CPP events:

July 17, 2006	July 18, 2006	July 31, 2006	August 3, 2006
June 26, 2007	June 27, 2007	August 8, 2007	

Between 11:00 a.m. and 8:00 p.m. on those days, the average temperature exceeded 85^{o} F.

Even with close matching of the Control Group to the participant group for each program segment and size strata, there remained a difference in total daily usage between the Control Group and the participant group in each comparison. In order to properly estimate the hourly impacts of the TOU rate as distinct from the energy savings impacts[18], this analysis assumed no overall energy savings from switching to the TOU rate and adjusted the data accordingly. To properly estimate the hourly kWh impacts, usage for each participant group and the Control Group was indexed across all hours of the day. With indexing, the percent of use in each hour was calculated for the participant group and compared to the Control Group to estimate percent shifting of demand. The percent shifts were translated to actual kWh shifts by applying them to the weighted average daily use for all of the sample customers in that group, both participants and Control Group.

The CPP analysis is based on a fixed effects regression model[19] which compares expected kWh usage on the hottest summer days of 2006 and 2007 to the actual impacts on days with CPP events. The Control Group is not needed as part of this analysis since the load curves on CPP event days can be compared to the load curves for other hot days for the same customers. By eliminating the Control Group, the CPP analysis estimates demand reductions on CPP event days that are incremental to the normal 1:00 p.m. to 6:00 p.m. peak period demand for the same customers.

All CPP event days are considered to be summer peak conditions. All except one CPP event day in 2006 and 2007 occurred when the average THI between the hours ending 1200 to 2000 was greater than 14. Appendix O presents graphs of the average daily load curve for each customer group on each individual CPP event day, along with the hourly THI for each day. Separate graphs are shown for customers with and without central air conditioning. Review of these graphs gives a good sense of how customers responded to individual CPP events.

The fixed effects regression model uses pooled time-series and cross-sectional data (panel data). That is, all hourly observations over the summer for all households in the same customer segment are combined into one model. In order to capture differences across households, the model includes a constant term that is specific to each household. This constant term (the fixed effect) captures the influence on hourly AC demand of all the variables that do not change over time. Thus, this model indirectly controls for such things as the orientation of the house, the size of the house, and the characteristics of the AC.

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[17] THI combines temperature and humidity into one number. The formula is presented later in this chapter.

[18] Energy savings impacts will be discussed later.

[19] The time-series cross-sectional regression procedure (Proc TSCSREG) in SAS (Statistical Analysis System) was used for the modeling work.

Algebraically, the fixed-effect panel data model is described as follows:

$$y_{it} = \alpha_i + \beta x_{it} + \phi\, c_t + \varepsilon_{it},$$

where:

y_{it} = energy consumption for customer *i* during hour *t*

α_i = constant term for customer *i*

ß = vector of coefficients

x_{it} = vector of variables that represent factors causing changes in energy consumption for customer *i* during hour *t* (i.e., weather, hour of the day)

Φ = vector of estimated impacts during and after critical peak events

c_t = vector of variables that represent presence of control or snapback for hour *t*

ε_{it} = error term for customer *i* during hour *t.*

The Temperature Humidity Index (THI) was used as the weather measurement in this model. THI is designed to be equal to zero for all weather conditions where there is no expectation of any air conditioning demand. In other words, air conditioning demand begins to appear when the THI is greater than zero, and it grows as THI grows. The exact definition of THI used for this study follows the PSE&G standard equation shown here:

THI = (0.55 x Temperature) + (0.2 x Dewpoint) – 48.5

For the range of temperatures of interest, dewpoint is estimated using the following standard formula:

Dewpoint = Temperature – ((100 – Relative Humidity)/3.333)

Hour-of-the-day dummy variables were used in the fixed effects model since whole house data was the source of the kWh measurement. Whole house residential loads have a definite shape throughout the day based on household occupancy and energy use patterns that are related to the time of the day and not the weather. This non-air conditioning base use needs to be identified by the model in addition to the weather impacts so hourly differences due to control and snapback can be accurately identified.

Each individual hour during CPP events was modeled separately since graphs of the data indicated substantial differences by hour in a regular pattern. Impacts started high at the beginning of the control period and de-graded over time. This is an expected pattern for a control strategy that raises temperature set points.

Snapback hours were also modeled individually to capture changing impacts over time. Again, examination of the daily load curves indicates that snapback starts high and degrades over time as more and more air conditioners catch-up to the indoor set point temperatures.

6.1.2 Results

TOU rates created a reduction in demand during the on-peak period of 1:00 p.m. to 6:00 p.m. throughout the summer for all participant groups. The technology-enabled segment (myPower Connection customers) performed significantly better than those who received education only (myPower Sense customers). Table 35 shows that myPower Connection customers regularly reduced their on-peak demand on summer peak days by 21%, while myPower Sense customers reduced their demand by 3 to 6%. It appears likely that myPower Connection customers were using the programmable feature of their new thermostat to regularly and automatically reduce their air conditioning demand from 1:00 p.m. to 6:00 p.m. each summer weekday, and on hot summer peak days these reductions were substantial.

Table 35. myPower TOU and CPP Demand Reduction on Summer Peak Days

Segment	Baseline Avg On Peak kW	TOU Only		CPP		Total	
		kW	%	kW	%	kW	%
myPower Connection	2.85	-0.59	-21%	-0.74	-26%	-1.33	-47%
myPower Sense with Central AC	2.6	-0.07	-3%	-0.36	-14%	-0.43	-17%
myPower Sense without Central AC	1.61	-0.09	-6%	-0.23	-14%	-0.32	-20%

Source: Summit Blue analysis of PSEG myPower data

Among myPower Sense customers, those without central air conditioning were able to achieve a higher percentage of savings than those with central air conditioning. This shows that customers were taking voluntary actions to reduce peak demand based on the education they had received, and they were able to find loads to shift even if they did not have central air conditioning.

Table 35 also shows that CPP events created additional demand reductions. myPower Connection customers reduced their demand by an additional 26%, creating a total demand reduction of 47%. This is equivalent to an average reduction of 1.33 kW over the on-peak period. While myPower Connection customers more than doubled their demand reductions when CPP events were called, myPower Sense customers responded more dramatically to CPP events and created demand reductions that were two to four times greater than the demand reductions they showed under the TOU rate alone. myPower Sense customers with central air conditioning moved from 3% demand reduction under TOU to 17% demand reduction when CPP events were called. myPower Sense customers without air conditioning moved from 6% to 20%. This shows that all customers were able to find significant loads to move out of the on-peak period if they were only called on to do so occasionally. These results come from two CPP events in the summer of 2006 and five CPP events in the summer of 2007.

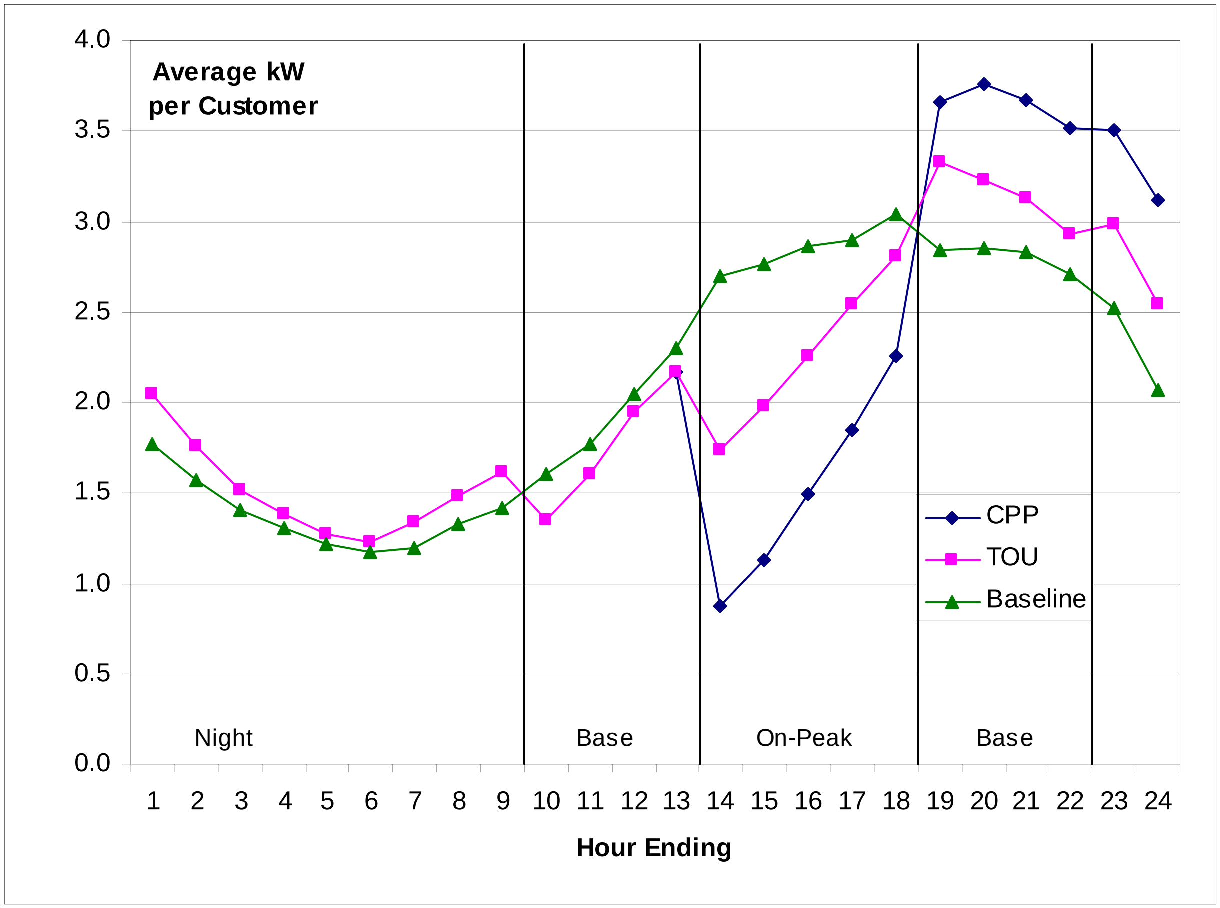
By way of comparison, in the California Statewide Pricing Pilot, peak demand reduction during CPP events was 4% for customers who were only on TOU rates, 12.5% for customers on the Fixed Critical Peak rates without any automated control and 34.5% for customers on Variable Critical Peak rates with automated control.[20]

Table 35 reports average demand reductions over the five hour on-peak period from 1:00 p.m. to 6:00 p.m. These demand reductions were not constant over the five hour period. Figures 12, 13, and 14 show how these load impacts varied by hour, both during and after the on-peak period, for each of the customer

[20] Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission Staff Report, Docket Number AD-06-2-000, August 2006, p. 58.

groups. These Figures are based on modeled loads and they are the best representation of the impacts of the TOU and CPP rates on summer peak days. The TOU impacts are based on a comparison of indexed loads to the matched Control Group. The CPP impacts are based on a comparison of CPP days to other hot summer days that did not have CPP events. This comparison is done for the program participants using a fixed effects regression model. (Details on both of these impact estimation methods can be found in the preceding section.) The baseline represents the best estimate of what the participants' average load curve would have been without TOU or CPP rates in effect.

Figure 12. TOU and CPP Impacts for myPower Connection Customers on Summer Peak Days



Source: Summit Blue analysis of PSEG myPower data

Figure 12 shows the TOU and CPP hourly impacts for myPower Connection customers. It clearly shows that demand reductions are at their maximum when they are first called, and they reduce in magnitude over time. This is as expected for a control strategy that raises the indoor temperature set point once at the beginning of the period. As homes see their indoor temperatures rise, they will slowly start using air conditioning again to maintain their new set point.

Figure 12 also shows that TOU rates create a snapback effect after the end of the on-peak period, and CPP events create additional snapback. The regular snapback seen in response to TOU demand reductions during the on-peak period starts high and decreases as the evening progresses. When more substantial on-peak demand reductions have been made on CPP days, the snapback load is considerably higher. This reflects the fact that more houses reached higher indoor temperatures and air conditioners have to run longer to bring them back to their set point. Snapback load stays almost constant across the evening hours on CPP event days. This implies that many air conditioners are running at 100% of their capacity for several hours after the end of the control event. Recall that the average daytime temperatures on the days used in this analysis was greater than 85° F – they were very hot days.

Estimated snapback for hours ending 2300 and 2400 actually increased a bit on days without CPP events. This is because the night period begins during those hours for the TOU rate and some customers were probably reducing their temperature set-point and calling for more cooling capacity. This additional load is really a result of the decreased price of energy in the night period and is not a reaction to what happened during the control period.

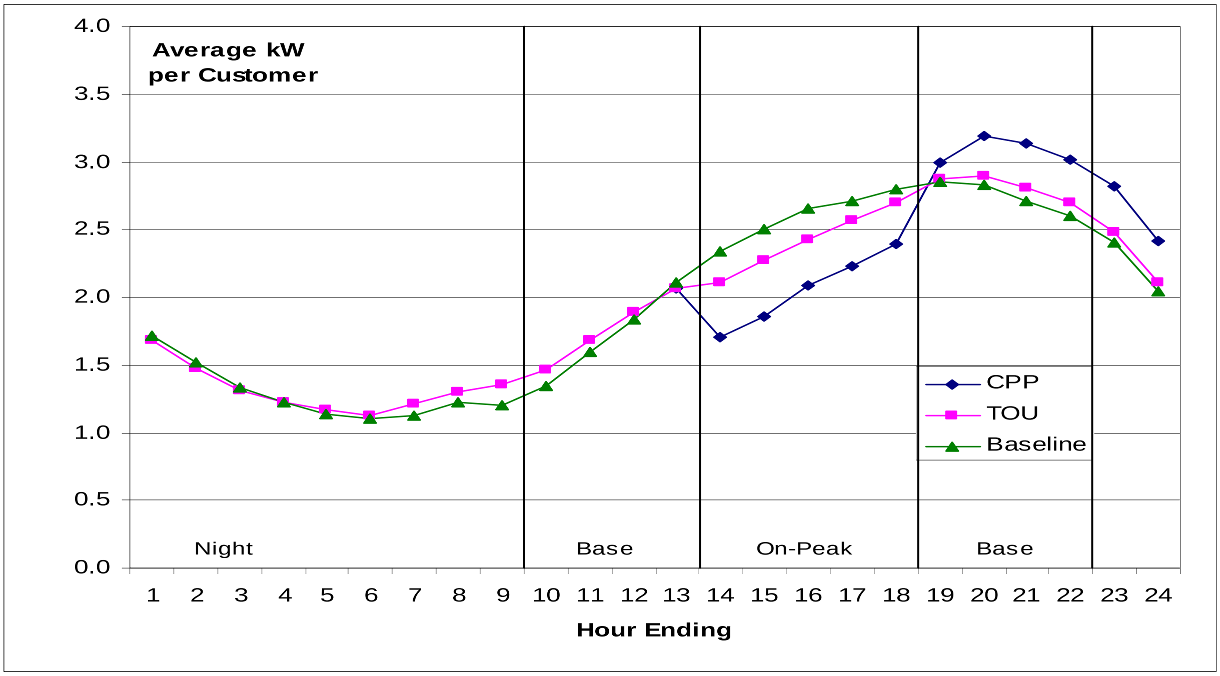
Another point of interest on this Figure is the response of myPower Connection customers to each changing TOU rate period throughout the day. The beginning of each rate period shows customer response. Demand drops at 9:00 a.m. as the night rates increase to base rates. This indicates that customers are making load shifts to take advantage of night discounts. Demand drops again at 1:00 p.m. when base rates change to on-peak rates. Customers are avoiding energy use during the on-peak period. Conversely, demand increases at 6:00 p.m. when the on-peak rates drop to base rates, and it increases again at 10:00 p.m. when base rates drop to night rates. Customer response to changing prices is clear.

Figure 13 shows similar information for myPower Sense customers with central air conditioning. The Figure illustrates this group's moderate response to on-peak TOU rates on summer peak days. It is unknown how much of the response that does occur is due to reduced air conditioning, or if it is shifting of other loads. Most likely it is a combination of both.

The TOU reduction tapers off across the five hours which would be the signature effect of a lowered indoor temperature set point, indicating that the reductions were coming from reduced air conditioning load. However, 4:00 p.m. to 6:00 p.m. also represent hours of increasing household occupancy and activity, such as dinner time, which may be responsible for the smaller load reduction during those hours. There is also very little TOU snapback load, which would imply that only part of the reductions are coming from air conditioning.

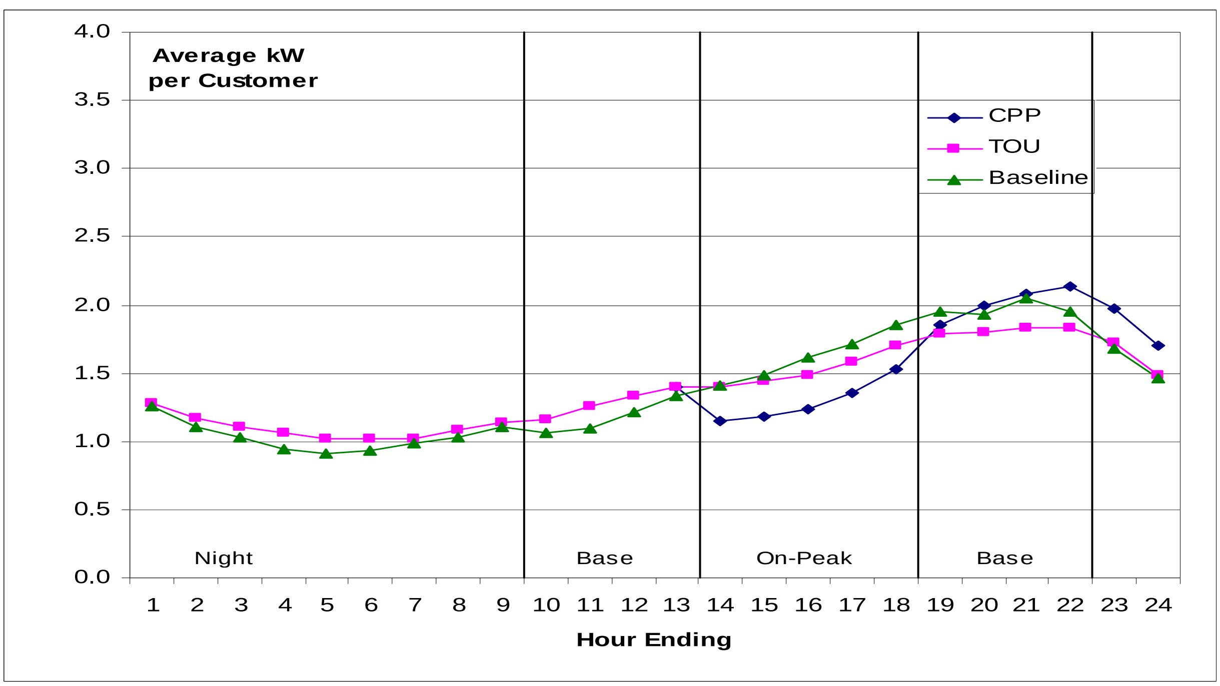
In comparison, demand reductions on CPP days are larger and there is definite snapback load. This indicates there may be more reduction coming from air conditioning on CPP days. Interestingly, the snapback starts slowly in the first hour after the end of the control event. This may represent the manual interaction with the thermostat for this group. myPower Sense customers do not all turn their air conditioning back on at exactly 6:00 p.m., so the snapback effect is not immediate like what is seen for the myPower Connection customers.

Figure 13. TOU and CPP Impacts for myPower Sense Customers with Central Air Conditioning on Summer Peak Days



Source: Summit Blue analysis of PSEG myPower data

Figure 14. TOU and CPP Impacts for myPower Sense Customers without Central Air Conditioning on Summer Peak Days



Source: Summit Blue analysis of PSEG myPower data

Figure 14 presents the hourly TOU and CPP impacts for myPower Sense customers without air conditioning. The most obvious difference from the preceding customer groups is their lower level of overall energy use on summer peak days. This would be expected for customers without central air conditioning. They exhibit some shifting of use out of the on-peak and evening base periods into the night and morning base periods. While this TOU shifting is not as large in magnitude, it is a slightly higher percentage of load shifting out of the on-peak hours than the myPower Sense customers with central air conditioning show. This group also exhibits the ability to find substantial amounts of load to shift out of the on-peak periods during the occasional CPP event days. Of note in this group is the very small snapback and its slow appearance on CPP days. Some customers may shift loads to other days rather than to later in the evening on the same day. Those that do shift loads to later in the same day do it at staggered times throughout the evening, rather than all at exactly 6:00 p.m. when the control event is over. These characteristics are consistent with shifting of loads that are not central air conditioning. The detailed hourly data behind these three graphs can be found in Appendix P.

6.2 Summer KWh Shifts

The previous section looked at the TOU and CPP impacts that occurred on summer peak days. Peak day reductions are primarily related to lowering the need for system capacity. The benefits related to these reductions come from avoided capacity costs. However, participants face TOU prices every day and so TOU rates inspire load impacts that stretch across the entire summer season. This section will look at how much load shifted from one price period to another over the whole summer. This information is important for understanding how the TOU rate will affect the average daily load curve, and how much load will be shifted from hours of high wholesale energy prices to hours of lower wholesale energy prices. This shifting could potentially have an impact on average system energy costs.

Summer kWh shift impacts were estimated separately for three groups of customers – myPower Connection, myPower Sense with central air conditioning, and myPower Sense without central air conditioning. Within each of these three groups, summer kWh shifts are reported for four size strata – Very Small, Small, Medium, and Large.

6.2.1 Data and Methods

This analysis is based on a comparison of participant group to Control Group kWh usage during summer days without CPP events. Care was taken to create a Control Group of customers that closely matched the participant group in each participant segment and size strata.

Summer data for 2006 covered July 15th, when the TOU rate became effective, until September 30th, the end of the summer season. Summer data for 2007 covered June 1st through September 30th, the date when the myPower pilot ended.

Average kWh usage per customer for each hour of the study period for each study group was estimated. Using average kWh usage per customer, per hour, minimized the problem of missing data. If a kWh reading was missing for a particular customer during a particular hour, the impact on the calculated average for that hour was small.

The average kWh usage for each hour was then assigned to the proper rate period: Night, Base or On-Peak. The result was the average kWh per customer used during each rate period during the summer study period. The summer study period covered 199 days. A summer of normal length is 122 days (30+31+31+30). The average kWh use for each period was then adjusted by 122/199, or 61.3%, to reflect the kWh use expected during a summer of normal length.

Even with close matching of the Control Group to the participant group for each program segment and size strata, there remained a difference in average total usage per customer between the Control Group and the participant group in each comparison. In order to properly estimate the hourly impacts of the TOU rate as distinct from the energy savings impacts, this analysis assumed no overall energy savings from switching to the TOU rate and adjusted the data accordingly. To properly estimate the kWh switched, usage for each participant group and Control Group was indexed across the rate periods. With indexing, the percent of use in each rate period was calculated for the participant group and compared to the Control Group to estimate percent shifting of load. The percent shifts were translated to actual kWh shifts by applying them to the weighted average normalized summer use for all of the sample customers in that group, both participants and Control Group.

While these estimates of kWh shift due to TOU rates have been normalized to reflect the length of a normal summer season (122 days), they have not been normalized for weather. This analysis of kWh shifting assumes that the weather seen over the study period is the same mix of summer weather that could be expected in a normal weather summer. During this study period, the average hourly THI was 3.02 for Night hours, 5.90 for Base hours, and 7.13 for On-peak hours.

6.2.2 Results

Summer kWh shift impacts for each participant group are summarized in Table 36.

Table 36. TOU Summer KWh Shift Impacts by Size of Participant

Participant Group	Rate Period	Very Small	Small	Medium	Large	All Partici-pants	Pct of Summer kWh
myPower Connection	On-peak	-3	-52	-138	-219	-134	-3.2%
	Base	32	6	-10	1	0	0.0%
	Night	-29	46	148	218	135	1.6%
myPower Sense with Central AC	On-peak	-13	-22	-35	-83	-44	-1.2%
	Base	41	-3	-17	-31	-11	-0.1%
	Night	-28	25	52	114	55	0.8%
myPower Sense without Central AC	On-peak	-64	-15	-24	-33	-32	-1.2%
	Base	-2	11	-46	-105	-41	-0.6%
	Night	66	4	70	138	73	1.1%

These impacts show the expected kWh change during a summer season (June through September) for a single residential customer that switches from a regular rate to the myPower TOU rate. Percent changes are based on Control Group average summer kWh for the given rate period.
Source: Summit Blue analysis of PSEG myPower data

In general, myPower Connection customers showed the greatest shifting. myPower Sense customers also showed shifting, but the volume of shifting was about half of that achieved in the myPower Connection group. There was little difference in the volume of shifting between myPower Sense customers with central air conditioning and myPower Sense customers without central air conditioning.

myPower Connection customers generally moved load out of the on-peak period and into the night period. There was little change to overall base period load, but previous information on the summer peak day shifts for this group showed that they lowered their morning base period use while their evening base period use increased because of snapback. These two offsetting factors during the split base period probably explain the lack of any overall shift.

myPower Sense customers without central air conditioning show a very different shift pattern. For these customers, most shifted load came out of the base period and moved to the night period. There is probably little load shifted out of the on-peak period because load shifts in this group are generally behavior based and customers need to be home to implement them. The on-peak period is during a time of day that homes are most likely to be unoccupied, leaving little opportunity for load shifting. The morning and evening base hours are when customers are home and can take action. Also, since there is no central air conditioning load there is no snapback load during the base period to offset other savings.

Additional details on the TOU summer shifts, including sample size information, can be found in Appendix Q. In all program groups, the Very Small size strata had low sample sizes and results for that group may be unreliable.

6.3 Summer Energy Conservation

The kWh shift analysis looks at how energy use is shifted from one rate period to another based on the assumption that the overall energy use is fixed. It is possible that overall energy use changes when customers participate in a TOU rate. Their greater attention to when energy is used may also help them reduce their total energy use.

Reducing the use of some loads, like lighting, during the on-peak period will automatically create energy reductions because the foregone lighting cannot be replaced by using more lighting in a different time period. Likewise, if customers are raising their indoor temperature set point during the on-peak period every weekday of the summer, that increase in average indoor temperature could translate into an overall energy savings. Bringing the house back down to a lower temperature setting each evening does take extra energy, but it may not be so much that it offsets all of the savings achieved during the day.

6.3.1 Data and Methods

The TOU summer energy savings analysis is based on a difference of differences approach since each participant group has a matched Control Group.

Four years of monthly billing data were collected for each customer. The data covered the billing months of June, July, August and September for years 2004, 2005, 2006 and 2007. Billing route information was associated with each bill so the beginning date and ending date of each billing period was known and the appropriate temperature-humidity index (THI) and the number of billing days could be calculated for each bill.

The billing data was cleaned to remove outliers. A review of the data indicated that the 1% tails on the high and low end of monthly bills should be removed because they were unreasonable levels of kWh for a single month. The billing process sometimes accumulates missed kWh or makes downward corrections that create monthly billing units that are not appropriate for analysis.

Each monthly bill was marked as being before the program or during the program so differences in kWh usage between the two periods could be estimated. The myPower TOU rates became effective on July 15, 2006. If a billing month covered the July 15 start date, it was removed from the analysis. This is because the effect of the TOU rate would only be partial during this month and it would not give a clean measurement of the TOU effect over a whole month. In general, this left each customer with fifteen months of good data.

The number of months of billing data for each customer was then examined. Customers with twelve or fewer months of summer data (out of 15) were removed. This reduced the number of customers in the sample by 12%, but it was done to ensure that averages before the program and averages after the program were not biased by the inclusion of different customers within each group.

Simple averages of monthly use before and after the program were initially calculated for each program group, including separate estimates for the matched Control Groups. Looking at the difference before and after the start of the program for each group created an estimate of the impact of the program on monthly energy use during summer months. The difference for the program groups could then be compared to the difference for the Control Groups to estimate the effect of the program on energy use compared to what it would have been without the program.

Since the data for both groups, the participants and the Control Group, covered the same time periods and the same weather, this comparison gives an accurate estimate of the savings that actually occurred. However, the weather during the four years of the study may not have been normal. Also, there is no way to use these averages to estimate what the TOU energy savings would be if weather was different than what had occurred. To overcome these shortcomings, a regression model was used to create normalized savings estimates and a model for how savings would change at different weather levels.

A fixed effects regression method was used to create models for two separate customer groups.[21] One group was for customers with central air conditioning. The other group was customers without central air conditioning. Review of the data from the comparison of means showed that ownership of air conditioning had an effect on the energy savings from TOU and these two groups should be modeled separately.

A log transformation of the monthly kWh variable was used to focus on the percent change in use instead of the absolute change in use. The energy savings models had the following specification:

Ln(Monthly kWh) = f (Monthly THI,
Billing Days,
myPower Connection Customer after program began,
myPower Sense Customer after program began,
Control Group Customer after program began)

Once the models were derived from the data, they were used with normal monthly THI and billing days to estimate a normalized monthly kWh use for each program group before and after the start of the program. Again, difference of differences approach with matching Control Groups was used to estimate normalized energy savings from the program. The same models could be used with different monthly THI values to estimate savings for different weather levels.

Initial results from these models indicated that customers with very large changes in either the positive or negative direction had high influence over the estimated means for these groups. Work was done to address how these outliers should be handled. The three typical causes of outliers[22] were examined:

1. The measurement is observed, recorded, or entered incorrectly.
2. The measurement comes from a different population.
3. The measurement is correct, but represents a rare (chance) event.

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[21] The time-series cross-sectional regression procedure (Proc TSCSREG) in SAS (Statistical Analysis System) was used for the modeling work.

[22] Business Statistics by Example, Fifth Edition, Terry Sincich, Prentice Hall, 1996, p. 122.

Observation of the frequency distributions indicated that the cause of the outlier problem in this case was # 2), the measurement comes from a different population. The energy savings from TOU rates is expected to be small. Each participant group showed more customers with small reductions in energy use than the Control Group had. However, other large changes to energy use were occurring in a few homes and overshadowing the measurement of the TOU effect for the group. These changes were so large they probably represented non-TOU factors, such as the addition or loss of a family member, a change in work or school arrangements, the purchase of a new appliance or other factors that can cause large changes in energy use. Customers with very large changes in either positive or negative directions represent a population of customers that have changing loads due to influences other than TOU and they should be excluded from the analysis to allow identification of the small changes that are related to TOU.

The result of the outlier analysis was a recommendation to use only the 80% of customers within the mid-range of the change in use distribution for the estimation of the means. The basic energy savings models were re-run using only customers who were within the 80% mid-range. Appendix R provides more detail on the 80% mid-range analysis of outliers that was used.

Alternative methods for identifying outliers were also tried. This included a comparison of medians, and the exclusion of both mild and extreme outliers based on an interquartile range analysis. Results from these alternative methods created larger energy savings estimates (5% to 10%) for central air conditioning customers, and a large estimated increase in energy use that did not appear reasonable for the non-central air conditioning group. The 80% mid-range analysis was adopted for the final energy savings estimates because it was a more conservative approach than the alternative outlier methods.

6.3.2 Results

Results from the two models are shown in Table 37 where the coefficient is the percent change in energy use (thus 0.018578 is 1.9%). For each participant group, energy use increases after the beginning of the TOU program by 1-2%. For the central air conditioning group, myPower Connection customers show a 1.9% average increase in use while myPower Sense customers show a 1.5% average increase. myPower Sense customers without central air conditioning show an average 2.1% increase. Both myPower Sense group estimates are statistically significant at the 80% confidence level. The myPower Connection group estimate is statistically significant at the 95% confidence level.

This increased usage does not mean that the TOU rate causes increased energy use. Control Group customers showed much larger increases, indicating that the TOU rate has an energy saving effect on customer usage.

Table 37 shows that Control Group customers with central air conditioning increased their usage by 5.2% on average after the beginning of the TOU rate, and Control Group customers without central air conditioning increased their usage by 6.4%. This increase is a reflection of normal growth in usage. It has no relation to the TOU rate, but it indicates what the normal change in usage would be between the pre- and post- TOU periods. The difference between the Control Group increases and the lower increases for the TOU participant groups is the appropriate estimate of energy savings due to the TOU rate.

Table 37. TOU Summer Energy Savings Models

Variable	Central AC Group Coefficient *(t-value)*	No Central AC Group Coefficient *(t-value)*
Month is during program and the customer is in myPower Connection	**0.018578** ***(2.1)***	
Month is during program and the customer is in myPower Sense	**0.014518** ***(1.3)***	**0.021052** ***(1.6)***
Month is during program and the customer is a Control Group Customer	**0.052206** ***(5.8)***	**0.064252** ***(4.2)***
Monthly THI	0.00012 *(58.4)*	0.00011 *(27.5)*
Billing Days	0.01744 *(7.3)*	0.02614 *(5.9)*
Sample Size Customers	8,893 672	2,256 174

Source: Summit Blue analysis of PSEG myPower data

Comparing the differences between the participant groups and the Control Groups, the best estimates of summer energy savings from the myPower Pricing program is 3.3% for myPower Connection customers, 3.7% for myPower Sense customers with central air conditioning, and 4.3% for myPower Sense customers without central air conditioning. These savings, shown in Table 38, are in comparison to what the participants would have used if they had not been on the TOU rate.

Table 38. myPower Pricing TOU Summer Energy Savings Estimates

Variable	Control Group Change in Use		Participant Group Change in Use		Summer Energy Savings from TOU (Percent)		Total Summer Energy Savings from TOU (kWh per Cust)
myPower Connection	**5.2%**	**-**	**1.9%**	=	**3.3%**		**139**
myPower Sense with Central AC	**5.2%**	**-**	**1.5%**	=	**3.7%**		**144**
myPower Sense without Central AC	**6.4%**	**-**	**2.1%**	=	**4.3%**		**127**

Source: Summit Blue analysis of PSEG myPower data

In comparative studies, Arizona Public Service (APS) residential TOU customers who used more than 1000 kWh/month saved 8% on their bills,[23] Puget Sound residential TOU pilot customers achieved 5%

[23] Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission Staff Report, Docket Number AD-06-2-000, August 2006, p. 55

energy savings during winter months with high electric space-heating saturation,[24] and Chicago Community Energy Cooperative real-time-pricing customers showed summer energy savings of 3-4%.[25]

The ASP and Puget Sound estimates of TOU energy savings are not apples-to-apples comparisons for the results of the myPower program reported here. The APS results are bill savings, not energy savings and the Puget Sound estimates are for winter, not summer. The best comparison is the Chicago study, and the reported savings in Chicago are the same as the myPower estimates.

In general, it is difficult to find estimates of energy savings for TOU programs since a large, matched control group is needed to answer the question of what customers would have done if they had not been on the TOU rate. Large control groups are necessary to get a sufficient sample size to measure the small energy savings reliably. Since it can be a costly undertaking to collect hourly data for large control groups, it is rarely done. The myPower pilot undertook the effort of collecting hourly data for a large control group and is one of only a few studies that can present reliable energy savings estimates for TOU rates.

6.4 Summer Elasticities

The analysis presented to this point discusses shifts in kWh and changes in demand induced by the TOU rate. These analyses showed how customers responded to the actual prices they faced in the myPower TOU rate and expressed those results in kW, kWh, and percent change. In order to predict customers' demand response to different TOU rates, we need a different metric. The elasticity of substitution provides that metric. It provides a scalable measure of participants' response to changes in prices. This section describes the method taken to calculate the elasticity of substitution and the results obtained.

6.4.1 Data and Methods

The constant elasticity of substitution (CES) demand model is an econometric model that has been used extensively by other evaluations of TOU rates, going back to the early TOU experiments in the 1980s.

The CES demand model is a convenient method to capture how relative price changes between two time periods change the relative amount of electricity consumed in each of the periods. In this model, the ratio of peak electricity use to off-peak electricity use is related to the ratio of peak to off-peak prices. A log specification is used to capture relative rather than absolute size changes. The coefficient on the ratio of peak to off-peak prices is termed the substitution elasticity. This elasticity measure indicates how much electricity will be shifted from the peak period to the off-peak period as their relative prices change.

Implicit in the CES model approach used in most all statistical analyses of TOU rates is the assumption that there is no load reduction; all changes are substitutions between peak and off-peak electricity use. If the TOU rate was designed to be revenue neutral (as PSE&G's was), then, in theory, there is little economic incentive for the customer to substitute other goods (such as cooling) for electricity, and thus the only behavioral response would be when the electricity is consumed and not how much is consumed relative to other goods. This is only theoretical, and may not be the actual response of customers. The use of the CES approach allows for comparisons to be made between this effort and other studies.

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[24] Assessment of Demand Response and Advanced Metering, Federal Energy Regulatory Commission Staff Report, Docket Number AD-06-2-000, August 2006, p. 69.

[25] Chicago Community Energy Cooperative Real-Time-Pricing Impact Analysis Final Report, Summit Blue Consulting, August 1, 2006.

Algebraically, the CES model is described as follows:

$$\ln\left(\frac{kWh_{peak_i}}{kWh_{offpeak_i}}\right) = \alpha + \beta x_{it} + \eta \ln\left(\frac{\Pr ice_{Peak}}{\Pr ice_{offpeak}}\right) + \varepsilon_{it} \text{ ,}$$

where:

kWh_{it}	=	the energy consumption for home *i* during the peak and off-peak periods
α_i	=	constant term
β	=	vector of estimated coefficients
x_{it}	=	vector of variables that represent weather factors (temperature and humidity) causing changes in household energy
η	=	the substitution elasticity of electricity between the peak and off-peak periods
Price	=	the price of electricity during the peak and off-peak periods
ε_{it}	=	error term for home *i* during hour *t*.

In this model, the dependent variable is the natural log of the ratio of the peak to the off-peak usage for each customer (participant and non-participant), spanning the entire summers of 2006 and 2007. Note that the rates do not change for each customer, so it is not possible to develop a fixed-effect model for this specification. Therefore, the model is a purely cross-sectional, and the R-squared is expected to be quite low.

6.4.2 Results

Table 39 compares the model results from the 2007 data with the results for 2006 that were published in the myPower Interim Report. As expected, the 2007 elasticity estimates are lower than the 2006 elasticities. The substitution elasticity dropped from 13.7% to 7.1% for myPower Connection customers, and from 8.5% to 6.3% for myPower Sense customers. This is to be expected since the on-peak to off-peak price ratio increased by over 50% in 2007 and there was little change in the on-peak to off-peak kWh ratio.

Table 39. Comparison of Substitution Elasticities for Summer 2006 and 2007

Variable	2006 DATA Coefficient (t-value)	2007 DATA Coefficient (t-value)
Substitution Elasticity – myPower Connection participants	**-0.137** **(-40.8)**	**-0.071** **(-23.5)**
Substitution Elasticity – myPower Sense participants	**-0.085** **(-26.3)**	**-0.063** **(-21.7)**
Humidity	0.003 (11.69)	
Temperature	0.018 (29.5)	
THI (Temperature Humidity Index)		0.006 (40.6)
Sample Size Households	128,921 1,190	88,078 1,178
R-Squared	0.02	0.04

Source: Summit Blue analysis of PSEG myPower data

There is a difference in the sample sizes used for each year, although both sample sizes are very large. There is a slight decline in the number of households included in 2007 due to customer drop-outs. There is also a difference in the number of days included in the analysis for each household. There were five critical peak event days excluded from the 2007 analysis and there were only two critical peak event days excluded in 2006.

The 2007 elasticity estimates are lower than the 2006 estimates, and this makes sense. The on-peak/off-peak price ratio changed from 4.1 in 2006 to 6.5 in 2007 while the observed kW responses in the average load shapes had little change. This implies a reduction in the elasticity, at least in the short run. It is possible that long-run elasticities would increase as participants developed more energy-shifting habits and adopted technology to help them shift energy use.

Having two years of program data available offers the opportunity to create a single elasticity model which covers both years and the changing prices in those years. These combined year models give a good summary of the elasticity of substitution for the myPower program. Table 40 presents the results of these combined year models for each customer segment of interest.

Table 40. Comparison of Summer Substitution Elasticities for myPower Customer Segments

Variable	myPower Connection Coefficient (t-value)	myPower Sense with Central AC Coefficient (t-value)	myPower Sense without Central AC Coefficient (t-value)
Substitution Elasticity	**-0.125** **(-44.9)**	**-0.069** **(-21.9)**	**-0.063** **(-14.6)**
THI (Temperature Humidity Index)	0.005 (44.85)	0.007 (61.2)	0.003 (17.86)
Sample Size Households	81,369 692	66,919 603	29,188 257
R-Squared	0.04	0.06	0.02

Source: Summit Blue analysis of PSEG myPower data

Review of this table shows that myPower Connection customers had a much higher elasticity of substitution than either of the myPower Sense customer groups, and elasticities for the two myPower Sense groups are very similar.

These elasticity estimates are not the same as a simple average of the two years shown in Table 39 for each group. The model results in Table 39 come from a generalized model that estimates a single weather-normalization coefficient for all customers and compares all participants to everyone in the Control Group. Results in Table 40 are based on individual models for each customer group which allow for different weather-normalization coefficients and matched Control Groups.

An additional question of interest is whether or not the differences between the three groups are statistically significant. Table 41 shows that the difference between myPower Connection customers and myPower Sense customers is both large and statistically significant. However, there is no significant difference between the two myPower Sense customer groups.

Table 41. 95% Confidence Interval About Elasticity Estimates

	Lower Bound	Substitution Elasticity	Upper Bound
myPower Connection	-12.0%	-12.5%	-13.1%
myPower Sense with Central AC	-6.3%	-6.9%	-7.5%
myPower Sense without Central AC	-5.5%	-6.3%	-7.2%

Source: Summit Blue analysis of PSEG myPower data

In comparative studies, pooled data from five residential TOU pilots implemented in the U.S. in the last half of the 1970s showed the elasticity of substitution averaged –14%, with a range from 7% to 21%,[26] and the California Statewide Pricing Project reported a statewide average elasticity of substitution of 9% on critical peak days during summer.[27] The myPower results fall within the range of these other studies.

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[26] Caves, Douglas W., Laurits R. Christensen and Joseph A. Herriges, 1984, “Consistency of Residential Customer Response in Time of Use Pricing Experiments” *Journal of Econometrics* 26: 179-203.

[27] Faruqui, Ahmad and Stephen George, 2005, “Quantifying Customer Response to Dynamic Pricing” *The Electricity Journal* 18(4):53-63.

6.5 Winter and Shoulder Month Impacts

Summer is the season of greatest potential shifting and savings due to high air conditioning loads in residential homes and the availability of programmable, communicating thermostats to control those loads. But customers still have the opportunity to change their energy use patterns during the other seasons of the year to benefit from the TOU and CPP rate structures. This section presents the impacts achieved during the winter season (November, December, January, February, March) and the shoulder season (October, April, and May).

In the summer impact results presented above, both myPower Sense participants and the Control Group were separated into two groups for analysis: those with central air conditioning and those without central air conditioning. This was done because the presence of central air conditioning has such a large effect on the summer energy use of residential customers and their opportunities for shifting and saving.

Although it is true that central air conditioning does not have a large effect on energy use during the winter season and may not have a large effect during the shoulder season, ownership of central air conditioning may be related to other household energy use characteristics that would make it worthwhile to continue looking at possible impact differences between these two groups. Also, when looking at size strata within the two groups, the size strata definitions are distinct for each of these groups. Each group was split into three size strata to create an equal number of customers in each stratum. The size definitions are different for each stratum within each group. It makes sense to continue with the summer size strata definitions for the winter and shoulder seasons so customers do not have to be re-assigned depending on the season. Maintaining groups and strata definitions will make population projections easier. For these reasons, it was decided to continue looking at the central air conditioning groupings for the winter and shoulder analyses.

It could also be argued that there would be little difference in impacts between myPower Connection and myPower Sense customers during the winter and shoulder months since a programmable or communicating thermostat might have little effect on electricity usage during those months. These two groups, myPower Connection and myPower Sense, will still be studied separately to see if there is a difference between customers who had communicating thermostats to help them automatically shift their energy usage during summer, and customers who had to take personal actions on a daily basis to benefit from the new rates. During the shoulder and winter seasons, assuming no AC load, both groups would need to take personal actions on a daily basis to benefit from the rates. Having previous experience doing this during the summer may make a difference.

6.5.1 Data and Methods

Appendix S presents the details of the data and methods used to estimate impacts for the winter and shoulder months. In general, the methods duplicate the methods used for the summer month studies.

6.5.2 Results

Customers did respond to price signals on winter peak days and shift usage out of the on-peak period. However, as expected, winter kW impacts were lower than summer kW impacts. For example, myPower Connection customers had average on-peak winter impacts of –0.41 kW compared to –1.33 kW during summer. This is largely because there is less electric load being used in residential households during winter. However, if the achieved impacts are considered as a percent of load, the summer and winter impacts are very comparable.

The one case with the largest difference between summer and winter impacts, both on a kW basis and a percent basis, is the TOU impact for myPower Connection customers. Without automatic control of air conditioning load, the on-peak TOU impacts drop from a 21% reduction in summer to a 3% reduction in winter.

Snapback load does occur in winter after the end of the CPP control events. However, the snapback load does not exceed the normal baseline for winter peak days. Compared to a baseline day, the demand reduction impacts of a CPP event linger into the evening creating an overall energy savings for the day.

There was only one CPP event during the shoulder months, on Friday, May 25th, 2007, the Friday before Memorial Day. Selection of this day was based on predetermined price and weather criteria. myPower Connection customers showed a -0.27 average kW demand reduction in response to the shoulder month's CPP event. This event was on a very hot day and there was air conditioning load which responded to the control signal. Neither of the myPower Sense customer groups demonstrated a change in usage in response to this event. This is not surprising given that it occurred on the Friday before a holiday weekend. Customer attention was probably not focused on energy use during that single event.

Moving beyond peak day analyses and looking at entire seasons, there was little overall kWh shifting for any of the customer groups during winter months and even less during the shoulder months. The observed kWh shifts in the winter and shoulder months are much lower than the summer shifts and are not large enough to create sizable changes in the load curve.

In addition to analyzing hourly data for kWh shifts which change the shape of the load curve, billing analysis was done to look for changes in total energy use after the start of the myPower pilot in both the winter and the shoulder months. There were estimated reductions in energy use for several groups, but all of the reductions were very small and most were not statistically significant at the 90% confidence level. There is a high likelihood that these impacts are actually zero and there was no real change in shoulder or winter energy use after the start of the program.

The one exception is the myPower Sense with central air conditioning group. They showed a 1.65% decrease in energy use during winter months which was statistically significant at the 90% confidence level. It appears that their conscious attention to energy demand and load shifting during the summer may have become habit and carried over into the winter months.

Appendix S presents the detailed results for winter and shoulder month impacts.

7 BILL IMPACT ASSESSMENT

An analysis was also performed to understand the bill impacts experienced by customers participating in the Pricing Segments of the pilot. On each monthly bill, customers were shown a comparison of their actual bill under the myPower program and what their bill would have been had they used the same amount of electricity under the otherwise applicable Residential Service (RS) rate schedule. The bill also provided a similar comparison of program-to-date impacts.

The CPP rate was designed to be revenue neutral for the average residential customer. An average hourly load shape was constructed for the RS rate class and the critical peak prices were established such that over each summer period and, separately, over the non-summer period, a customer using electricity according to this average load shape would have experienced a zero bill impact if billed on the CPP rate and the customer took no action to modify his energy use pattern.

Needless to say, it is highly likely that no customer, including the customers participating in the pilot, used electricity exactly according to the average load shape. If all of the participating customers had done nothing to change their energy use, one would expect about half of the participants to experience a bill increase and about half to experience a bill decrease. Even this conclusion assumes that the electricity usage of participating customers was reflective of the average RS customer, a conclusion that is likely not true. Participating customers in general used more electricity than average use customers, especially the myPower Connection customers who all had central air conditioners.

A summary of the bill impacts is provided in Table 42 below. This summary provides several different views of the bill impacts. These views are considered logical slices of time of the myPower program during 2006 and 2007. The table shows the percentage of customers in both the myPower Sense and myPower Connection segments that saved and/or lost money because of the CPP rate, the average savings or loss for customers in each segment, and the maximum and minimum savings or loss.

Table 42. Bill Impacts

	Higher Bills				Lower Bills			
Participant Group	**%**	**Average**	**Max**	**Min**	**%**	**Average**	**Max**	**Min**
myPower Connection – 12 Months Ending September 2007	13%	$35.77	$136.92	$0.22	87%	($101.68)	($421.67)	($0.60)
myPower Sense - 12 Months Ending September 2007	32%	$34.78	$196.12	$0.53	68%	($68.14)	($501.12)	($0.62)
myPower Connection - Entire Program	14%	$44.41	$201.82	$0.67	86%	($156.91)	($639.20)	($2.17)
myPower Sense - Entire Program	29%	$44.36	$238.25	$0.53	71%	($95.88)	($601.82)	($0.62)
myPower Connection - Summer 2007	16%	$33.91	$113.85	$1.56	84%	($88.93)	($347.89)	($1.61)
myPower Sense - Summer 2007	33%	$36.98	$126.15	$0.05	67%	($57.33)	($483.82)	($0.12)
myPower Connection - Non Summer October 2006 through May 2007	23%	$6.67	$26.68	$0.27	77%	($20.05)	($187.32)	($0.03)
myPower Sense - Non Summer October 2006 through May 2007	26%	$6.25	$69.97	$0.08	74%	($13.41)	($61.15)	($0.01)

The percent of customers with higher bills vs. lower bills appears to be fairly consistent across each of the different time periods analyzed with higher savings consistently experienced by the myPower Connection customers. The percent of customers that did not save in the pilot also remained consistent across all views. It is also noteworthy that by far, most of the savings occurred during the summer periods.

In viewing the bill impacts, it is important to note that they are based on the actual electricity used and billed comparing actual bills under the CPP rate to what would have been billed under the standard rate. In the Impact Assessment, by comparing consumption patterns across time it was shown that participating customers also reduced their overall energy use, which would also lower their bills. However, the approach to calculating monthly bill savings for the purposes of preparing actual customer bills could not include this type of analysis and so it only shows the savings for the amount of electricity actually consumed. Without any way to quantify the savings in energy use for each customer, the bill comparisons that customers were shown each month tended to understate their actual bill savings.

The graphs below, Figure 15 and Figure 16 are histograms that show the range and frequency of the bill impacts by myPower Connection and myPower Sense customers for 12 months ending September 2007. Figure 15 and Figure 16 show that for myPower Connection customers, based on the electricity that they actually used, 87% of customers saved money, averaging about $102 per year. For myPower Sense, 68% of the customers showed lower bills, and these customers saved on average $68 per year.

Figure 15. myPower Connection Customers – 12 Months Ending September 2007

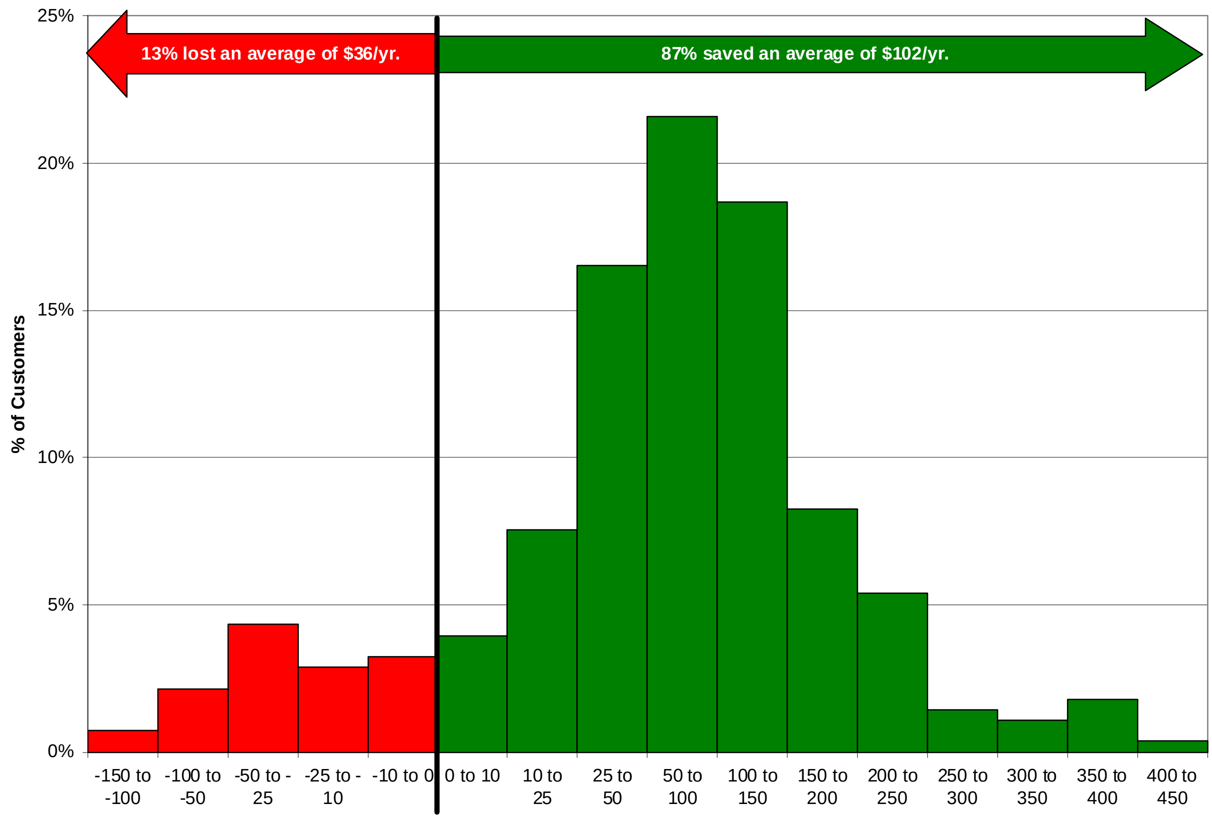
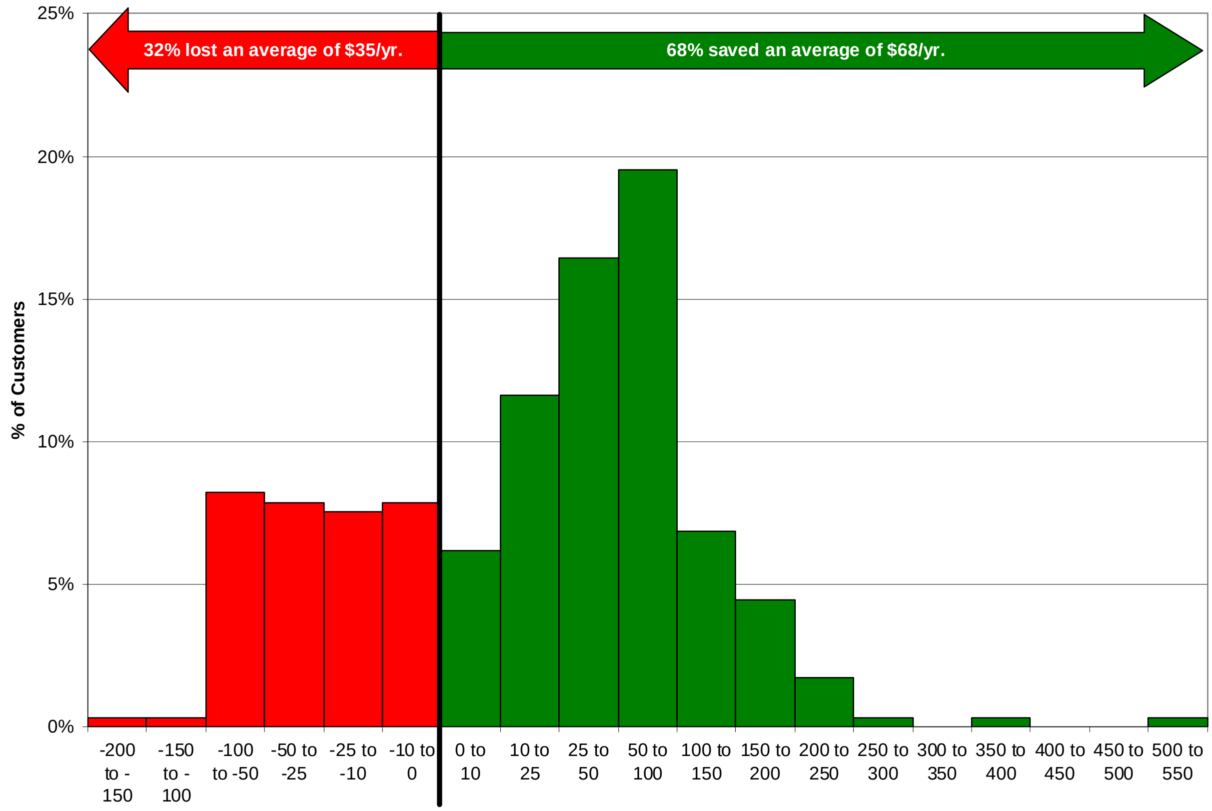


Figure 16. myPower Sense Customers – 12 Months Ending September 2007



The impact analysis component focusing on the summer kWh shifts due to the TOU rate provides data for another view of the bill savings the participants achieved. This analysis calculated the amount of electricity shifted during the summer, primarily from On-Peak hours to Base and Night hours by groupings of Very Small, Small, Medium and Large customers (based on total electricity use) as well as all the participants in the group combined. For this analysis, the myPower Sense customers were separated into those with and without central air conditioning. These electricity savings results are shown in Table 36 of the Impact Assessment section of this report. Table 43 shows the value of the electricity savings priced-out at the summer 2007 TOU rates.

Table 43. Summer Electricity Shifting Expressed in Dollars (per Participant)

Participant Group	Rate Period	Very Small	Small	Medium	Large	All Participants
myPower Connection	On-Peak	($0.71)	($12.31)	($32.66)	($51.83)	($31.71)
	Base	$2.77	$0.52	($0.87)	$0.09	$0.00
	Night	($1.06)	$1.69	$5.43	$8.00	$4.95
myPower Sense with Central AC	On-Peak	($3.08)	($5.21)	($8.28)	($19.64)	($10.41)
	Base	$3.55	($0.26)	($1.47)	($2.69)	($0.95)
	Night	($1.03)	$0.92	$1.91	$4.18	$2.02
myPower Sense without Central AC	On-Peak	($15.15)	($3.55)	($5.68)	($7.81)	($7.57)
	Base	($0.17)	$0.95	($3.99)	($9.10)	($3.55)
	Night	$2.42	$0.15	$2.57	$5.06	$2.68

In addition to savings achieved by shifting energy usage from On-Peak to Base and Night hours, the participants in the pilot also achieved some energy savings during the summer months as shown in Table 38 of the Impact Assessment section of this report. Table 44 shows the value of the savings in terms of energy and delivery bill reductions at the current residential RS Rate.

Table 44. Summer Energy Savings (kWh and dollars per Participant)

Participant Group	Percent Saved	kWh Saved	Energy Bill Savings	Delivery Bill Savings	Total Savings
myPower Connection	3.3%	139	$15.84	$7.30	$23.14
myPower Sense with Central AC	3.7%	144	$16.41	$7.56	$23.97
myPower Sense without Central AC	4.3%	127	$14.48	$6.67	$21.15

Appendix A

Details of the Development of the CPP Rate

Determination of number and time periods for CPP events

The energy charges for the CPP rate were based upon the relationships between hourly costs over various times and seasons of the year in the PJM Day-Ahead LMP energy market. The Day-Ahead LMPs were used in lieu of the Real Time LMPs since the latter do not allow for advance notice to participants, a key requirement for the CPP rate being tested in this pilot program. The data points used were the historic PJM Day-Ahead load weighted zonal LMPs for the PSE&G zone for the four year calendar period of 2000 to 2003. For the first few months in 2000 prior to the establishment of the Day-Ahead market, the Real-Time LMPs were used as a proxy for the Day-Ahead LMPs.

The first step in the analysis was to convert the actual historic Day-Ahead LMPs (expressed as $/MWh) to a percent of the seasonal (summer and non-summer) average Day-Ahead prices. This normalization adjustment tended to reduce any excessive weighting of the hourly data from general fuel price increases (which are reflected directly in the LMPs) over the study period, while keeping the relative relationship between costs during different hours of the day intact.

This data was then analyzed to determine the number of times the hourly price "significantly exceeded" the annual average price. The hypothesis was to define a Critical Peak Period (CPP) event as those periods when the market price exceeds a pre-defined price threshold. The normal time-of-use rates would recover revenue related to costs at or below such a threshold, while the additional charges imposed during a CPP event would recover the costs related to the load and prices above the threshold.

Varying cut-off points from 300% to 900% of the average seasonal (summer and non-summer periods) LMPs were tested as potential definitions of this use of the term "significantly exceeded". This analysis was conducted for each of the four study years individually and for the four year period in total. The results are indicated in Appendix B which show the number of hours, unique number of days, summer and non-summer factors per kWh (which will be explained later in this document) and average kWh per RS customer, by varying levels of cut-off points, that occur during each potential CPP event definition for the summer and non-summer periods.

Although the selection of any one of these various cut-off points would result in a CPP event definition, the selection of the final criteria used for the rate design needed to balance several items. Selecting a cut-off level too low would have exposed customers to many CPP events and, since the CPP price would be lower, the possibility would exist that customers would tire of the constant CPP notification and reduce their response to each event. Selecting a cut-off level too high would expose the customer to only a few events a year, where they might forget what to do and how to respond to a CPP notification. Although the prices are high during these events, customer might perceive that demand response during the limited duration might not be "worth" it, since there would be relatively small total dollars at risk for so few events.

The cut-off points of 300% for the summer months and 400% for the winter and shoulder months were selected as reasonable levels that balance supplying a reasonable pricing signal with customer ability to respond to the signal. For the purposes of this pilot program, the rate design was based upon 5 CPP events in the summer, 2 in the winter, and 1 in the shoulder months. The number of expected CPP events was selected based upon the four year average number of CPP events of 5.75 days/yr in the summer (5.75 days/yr = 23 days / 4 years) and 2.75 days/yr for the non-summer period (2.75 days/yr = 11 days / 4 years), as indicated in Appendix B.

Development of Time-of-Day Time Periods and Hours

Once the definition of a CPP event was completed, all hourly Day-Ahead LMPs in the four year study period were limited to the cut-off point selected. The concept, as previously mentioned, is that normal rates would recover revenue related to costs at or below the cut-off point, while the additional charges imposed during a CPP event would recover the costs related to load and prices above the cut-off point.

The goal was to develop time-of-use rates that best reflect market conditions. To do so, two types of variables were calculated: 1) the rates charged, and 2) the time periods during which each rate is applicable. Rates could be developed that recover the correct revenue for any specific definition of a time period by simply dividing the total revenue that needed to be recovered during this time period by the total kWhs in the time period. The resulting rate would recover the proper revenue, but might not provide the proper pricing signal to the customer.

In order to meet both the development of correct rates and proper pricing signals criterion, the rate in any hour should be as close as reasonably possible to the actual market rate that is trying to be mimicked. Conceptually, a time period must first be defined. A rate for each time period was then calculated (as total revenue that needed to be recovered divided by the total kWhs in the time period). The last step was to compare, hour by hour, the difference between the calculated rate and the actual market prices which the analysis is to reflect; in this case, the Day-Ahead LMPs. The process was then repeated for alternate time periods, and the overall differences were compared. The time period definition having the smallest difference is the one that best reflects the market.

Although the "best fit" might be done with 24 time periods per day, and a different set of rates every month, there are some practical limits set by certain factors in the myPower pilot program such as: the technology used, the costs to implement the program, the cost to bill the customer, and customer understanding of the myPower rates. All factors must be balanced taking into account the diminishing returns on increasing the complexity of the rate structure itself. In order to limit the complexity of the rates for this pilot program, a number of guidelines were established:

- Utilize a maximum of three time periods (along with associated prices) designated as the Low, Medium and High periods. Based on the experience of other utilities across the country, the use of three time periods has been accepted by customers on similarly structured CPP rates.
- Utilize a maximum of three seasons. For simplicity and consistency with other PSE&G electric and gas supply rates, the summer period was defined as the months of June through September and the winter period as the months of November through March. The shoulder period has been defined as the remaining months of October, April and May.
- When a CPP event is called, the entire High period price for that day will change to that of the CPP price. This limitation is intended to reduce customer confusion regarding when the CPP event prices are in effect.

Graphs of the average hourly prices over the four year period (expressed as % of the seasonal average Day-Ahead prices) were examined for each of the three seasons defined above in order to determine a reasonable starting point for the calculations. These graphs are included as Appendix C.

During the rate design it was critical to balancing the additional costs required for specialized myPower billing and the overall operation of the pilot program, with the desire to minimize the overall complexity of the program. In order to ensure that customers would both understand and accept the new rates, it was determined that implementing the following additional limitations were reasonable and should be implemented:

1. Summer Months
    a. The summer weekday rates best fit a profile of Low, Medium, High, Medium, and then returning to Low prices.
    b. The summer Saturday and Sunday prices were combined into a Weekend set of rates.
    c. The Weekend rates are identical to the weekday rates for values and time periods with the exception that on the weekend, there is no High period price. During this period, the Medium price will continue.
2. Winter Months
    a. The winter weekday rates best fit a profile of Low, Medium, High, Medium, High, Medium, and then returning to Low prices. However, the morning high period is very short and substantially lower than the evening's high prices.
    b. Consequently, the rate profile of Low, Medium, High, Medium, and then returning to Low prices was selected.
    c. The winter Saturday and Sunday prices were combined into a Weekend set of rates.
    d. The Weekend rates are identical to the weekday rates for values and time periods with the exception that on the weekend, there is no High period price. During this period, the Medium price will continue.
3. Shoulder Months
    a. The Shoulder weekday rates best fit a profile with only two time periods of Low, High, and then returning to Low prices.
    b. The Shoulder Saturday and Sunday prices are combined into a Weekend set of rates.
    c. The Weekend rates are identical to the weekday rates for values and time periods.

The measure selected to determine the quality of fit between the resulting time-of-use rates and the actual market prices was the sum of the squares of the hourly differences. For example, for each set of possible time periods for the summer period, the difference between the appropriate rate (the calculated Low, Medium or High period rate, as applicable) and each Day-Ahead LMP was determined for each of the summer hours. These individual differences for all hours in the study period were then squared, and then the sum of these squares made available for comparison with those resulting from alternate definitions of time periods.

Since the evaluation of all possible time period definitions would be a huge task due to the extremely large number of possible different time period definitions, reasonable limits were developed based upon inspection of the hourly curves shown in Appendix C.

The information contained in Table A below – Listing of Range of Time Periods Analyzed lists the various periods, by season, and the hours at which the periods could reasonably start. Hour 1 begins at midnight and ends at 1 AM. Hour 5 begins at 4 AM and ends at 5 AM. Hour 24 begins at 11 PM and ends at midnight. For example, for the Summer graph, it was determined by inspection that the first Medium time period could reasonably start anytime from hour numbers 5 to 11 (5 AM to 11 AM, inclusive). The High period could reasonably start sometime from hour number 11 to 16 (11 AM to 4 PM). All of the other potential starting times are listed for the options analyzed. The listing of an hour 25 (usually associated with the 2nd Low period of a day) indicates that that period does not end that day. For example, the hour 25 listed for the 2nd Low starting period for the Summer listing indicates that there is no 2nd Low period, and thus the day ends on a Medium period.

Table 1 – Range of Time Periods Analyzed

	Summer	Winter – One High	Winter – Two Highs	Shoulder – Three Period	Shoulder – Two period
1st Low start	1	1	1	1	1
1st Medium start	5 to 11	5 to 8	5 to 8	6 to 10	6 to 10
1st High start	11 to 16	7 to 20	6 to 8	6 to 21	--
2nd Medium start	18 to 23	17 to 25	8 to 16	20 to 24	--
2nd High start	--	--	15 to 20	--	--
3rd Medium start	--	--	20 to 23	--	--
2nd Low start	21 to 25	22 to 25	21 to 25	21 to 25	21 to 25
Total # of combinations analyzed	1,260	2,016	12,960	2,000	25

Many of the above combinations analyzed were not possible, and thus were eliminated during the analysis of the results. An example of such a combination not tested is the summer time period having a 2nd Medium period start of hour 23, with a 2nd Low period start of hour 21, where the final Low period would start before the prior Medium time period.

A spreadsheet was constructed with macros that performed the analysis on all of the possible combinations of time period definitions listed above. For each combination, a rate was calculated for each time period (Low, Medium or High) equal to the total revenue needed to be recovered divided by the total kWhs in the time period. The difference between the calculated rate and each hourly Day-Ahead LMP was determined for each hour in the 4 year study period. Each of these differences was then squared, and the squares summed for the entire study period. This process was repeated for each of the possible time period combinations listed above. The results were then sorted based upon the sum of the squares of the differences, with the time period definition having the smallest difference selected as one that best reflects the market.

This analysis resulted in the selection of the best definition of time periods, given the limitation listed above, for the Summer, Winter and Shoulder seasons as indicated in the following table:

Table 2 – Resulting Best Definition of Time Periods

Time Period	Season					
	Summer		Winter		Shoulder	
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
Low	11 PM to 9 AM	11 PM to 9 AM	10 PM to 6 AM	10 PM to 6 AM	10 PM to 6 AM	10 PM to 6 AM
Medium	9 AM to Noon & 7 PM to 11 PM	9 AM to 11 PM	6 AM to 5 PM & 9 PM to 10 PM	6 AM to 10 PM	none	none
High	Noon to 7 PM	none	5 PM to 9 PM	none	6 AM to 10 PM	6 AM to 10 PM

The above calculation of the definition of time periods also provided an indication of the ratio of the preliminary energy charges for each time period, expressed as a % of the seasonal average Day-Ahead LMP as shown in the table below:

Table 3 – Resulting % of the Seasonal Average Day-Ahead LMP

Time Period	Season		
	Summer	**Winter**	**Shoulder**
Low	0.468250	0.638740	0.547420
Medium	0.998190	1.042660	0.000000
High	1.522280	1.514340	1.132380

Development of Energy Related Components for the Time-of-Day Prices

Once the above analysis was completed, the resulting time period rates (still expressed as a % of the seasonal average Day-Ahead LMPs) were multiplied by the current seasonal estimated energy only BGS costs applicable to Rate RS. These energy only BGS costs are shown in Appendix D, which is Table #9 of the PSE&G BGS Bid Factor Spreadsheet for 2005-6 used in the design of BGS rates following the BGS annual auction.

Development of Energy Related Component for Prices During a CPP Event

The energy related components for prices during a CPP event were designed to recover Day-Ahead LMP costs greater than the cut-off point. Appendix B, which was previously used in the determination of the time periods for a CPP event, includes two values that require further definition. The values labeled “Summer factor/kWh” and “Non-Summer factor/kWh” are the average supply prices above the respective cut-off point for the kWhs related to the potential CPP event and are expressed as a multiplier of the seasonal average energy supply costs. These values, when multiplied by the CPP event kWhs, result in the total energy supply revenue that must be obtained <u>in addition to</u> the energy supply revenue from all usage related to energy prices below the cut-off point. Although there is not a exact correlation between the CPP event hours used in the rate design and the average historic number of hours where the Day-Ahead market is above the cut-off point, the average energy costs during these latter periods are be used as the basis for the energy commodity charge adder during a CPP event.

The same CPP incremental adder of 2.5 times was selected for both the summer and non-summer periods, rounded from the 2.47 summer and 2.61 non-summer factors indicated in the Appendix B. The final energy supply portion of the CPP rate will be an adder equal to 2.5 times the summer or non-summer average energy only BGS cost. As shown in Appendix D, Table #9 of the PSE&G BGS Bid Factor Spreadsheet for 2005-6, the summer period (June to September) average energy only BGS cost applicable to Rate RS is 5.688 cents/kWh (w/o SUT) while the winter period (November to March) value is 4.661 cents/kWh (w/o SUT). This resulted in the energy increment to the summer High period price of 14.22 cents/kWh (w/o SUT), while the energy increment to the winter and shoulder months High Period price is 11.65 cents/kWh (w/o SUT).

Development of Obligation Related Component for Prices During a CPP Event

The design of the CPP rate is based on charging customers a high price when energy prices are extremely high. Although related, high prices are not necessarily correlated with high loads. If they were, CPP events (based on the Day-Ahead LMPs) would include all peak days used to determine customers’ Generation Obligation and Transmission Obligations. If that were the case, it would be appropriate to recover all the costs of the obligations in the CPP event charges, in addition to the energy costs.

An analysis of the specific summer dates in which the market energy price exceeded the 300% cutoff indicates that, on average, it does not capture 3 of the average of 6.25 different days per year used to determine the obligation. These results are summarized in Appendix E.

Since this analysis indicated that there is approximately a 50% coincidence between high LMPs and peak loads, 50% of the Generation and Transmission Obligation related cost were designed to be recovered from the additional charges in effect during a CPP event. The remaining Generation and Transmission Obligation related costs were included (as will be discussed later) in the kilowatthour charge in effect for the summer High Period.

The average per customer Generation Obligation and Transmission Obligation costs used in these calculations were based upon data included in Table #10 of the PSE&G BGS Bid Factor Spreadsheet for 2005-6, which itself is included as Appendix F. This data indicated that the total obligation costs for an average customer is $54.18 per year as shown in Appendix F.

To determine a per kWh unit charge for recovery during the CPP events, the total number of kWhs expected during the summer CPP events over an average year were needed. This required three values:

1. The average customer load (in kW) during a summer CPP event,

2. The average number of summer CPP events, and

3. The duration (in hours) of each summer CPP event.

The first of these values, the average customer load during a CPP event is based on the data for a 300% cut-off point for the entire four year period included in Appendix B, and whose calculation as follows:

$$\frac{211.27\ \text{kWh/customer}}{106\ \text{hours}} \approx 2\,\text{kWh/customer}$$

The second of the required values, the average number of summer CPP events, is equal to the expected number of CPP events, by season. As previously determined, there were 5 expected in the Summer months.

The third item, the duration of each summer CPP event, is equal to the duration of the applicable seasonal High price period, as previously determined from the time-of-use optimization analysis. This analysis indicated a High period of 7 hours in the Summer.

The results were that 70 kWh are expected from the average customer during the expected annual CPP events during the summer months, with each kWh recovering $.38707 of obligation related charges. Details of these calculations are shown in the Proof of Revenue, included as Appendix G.

Development of Obligation Related Components for the Time-of-Day Prices

In a prior step, the energy related price components were developed for each of the time periods in each of the three seasons. The final step was to add the remaining 50% of the Generation and Transmission Obligation related costs (those not otherwise recovered during the CPP event) to the revenue requirements of the summer High time period, which resulting in a total summer High period price. The detailed calculations of the Obligation related costs included in the CPP event are shown in the Proof of Revenue, included as Appendix G.

Assuring Revenue Neutrality

In the development of the myPower rates structure, it was important to assure revenue neutrality for the CPP rate for both the summer and non-summer periods compared to the standard rates. To the extent that the total revenue for the class average customer on the above calculated preliminary CPP rate differed from the revenue that would have been received for the customer on standard BGS rates, for the summer and non-summer periods, an adjustment was applied to the preliminary CPP charges by season. This was accomplished by multiplying the Low, Medium and High period charges by a common seasonal factor. For purposes of this final calculation, it was assumed that a CPP event would be called five times during the summer, two times during the winter, and one time during the shoulder months. The details of these calculations are included in the Proof of Revenue, included as Appendix G. These revenue neutrality calculations are based upon the BGS-FP prices in effect at that time. Once future BGS Auctions are completed and the BGS rates are finalized, the new values of the all-in Rate RS applicable BGS rates will be utilized to calculate revised CPP Rates effective for this same period.

Appendix B

Analysis for Data
From 1/1/2000 to 12/31/2003

Analysis for data from 1/1/2000 to 12/31/2003 (4 years)

Cut-off	Summer hrs	Summer unique # of days	Summer factor/kWh	Summer kWh/cust	Non-summer hrs	Non-Summer unique # of days	Non-Summer factor/kWh	Non-summer kWh/cust
300%	106	23	2.47	211.27	138	37	1.38	152.33
400%	50	9	3.64	103.34	32	11	2.61	44.23
500%	35	8	3.85	73.30	14	4	3.97	21.28
600%	27	5	3.79	57.66	9	2	4.78	14.21
700%	25	5	3.11	52.68	8	1	4.32	12.67
800%	19	5	2.88	40.16	6	1	4.78	8.92
900%	16	5	2.33	33.63	5	1	4.47	7.58

Analysis for data from Year 2000 Only

Cut-off	Summer hrs	Summer unique # of days	Summer factor/kWh	Summer kWh/cust	Non-summer hrs	Non-Summer unique # of days	Non-Summer factor/kWh	Non-summer kWh/cust
300%	12	3	0.70	20.79	91	24	1.73	102.04
400%	3	1	0.06	5.61	26	9	3.11	34.69
500%	0	0	#DIV/0!	0.00	12	3	4.58	18.18
600%	0	0	#DIV/0!	0.00	9	2	4.78	14.21
700%	0	0	#DIV/0!	0.00	8	1	4.32	12.67
800%	0	0	#DIV/0!	0.00	6	1	4.78	8.92
900%	0	0	#DIV/0!	0.00	5	1	4.47	7.58

Analysis for data from Year 2001 Only

Cut-off	Summer hrs	Summer unique # of days	Summer factor/kWh	Summer kWh/cust	Non-summer hrs	Non-Summer unique # of days	Non-Summer factor/kWh	Non-summer kWh/cust
300%	47	5	4.42	97.35	11	6	0.29	11.90
400%	36	4	4.56	75.61	0	0	#DIV/0!	0.00
500%	30	4	4.28	63.34	0	0	#DIV/0!	0.00
600%	26	4	3.80	55.43	0	0	#DIV/0!	0.00
700%	24	4	3.14	50.45	0	0	#DIV/0!	0.00
800%	18	4	2.96	37.93	0	0	#DIV/0!	0.00
900%	15	4	2.46	31.40	0	0	#DIV/0!	0.00

Analysis for data from Year 2002 Only

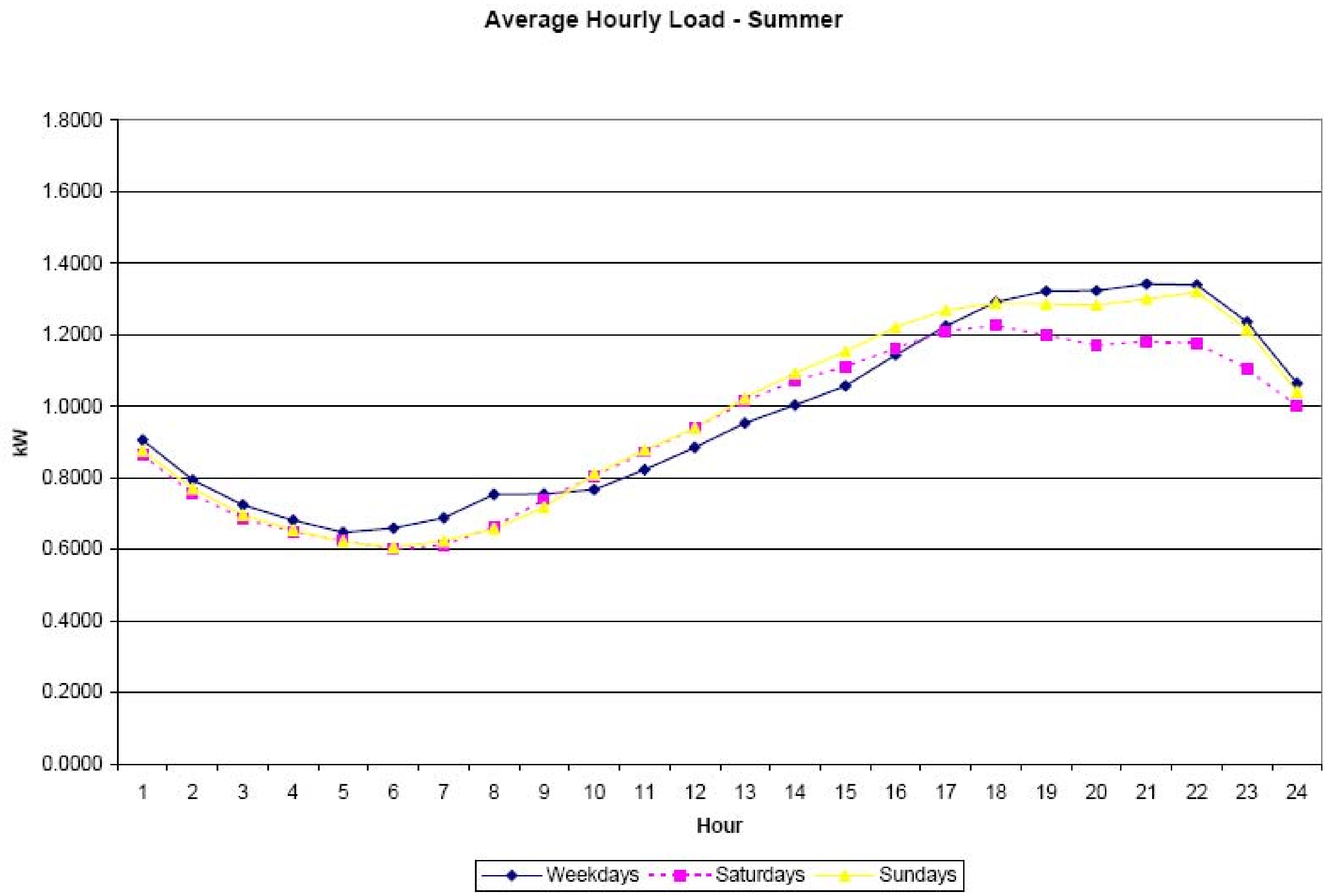
Cut-off	Summer hrs	Summer unique # of days	Summer factor/kWh	Summer kWh/cust	Non-summer hrs	Non-Summer unique # of days	Non-Summer factor/kWh	Non-summer kWh/cust
300%	45	13	0.86	89.15	16	3	1.16	21.51
400%	11	4	1.37	22.12	6	2	0.79	9.54
500%	5	4	1.16	9.96	2	1	0.36	3.10
600%	1	1	3.52	2.23	0	0	#DIV/0!	0.00
700%	1	1	2.52	2.23	0	0	#DIV/0!	0.00
800%	1	1	1.52	2.23	0	0	#DIV/0!	0.00
900%	1	1	0.52	2.23	0	0	#DIV/0!	0.00

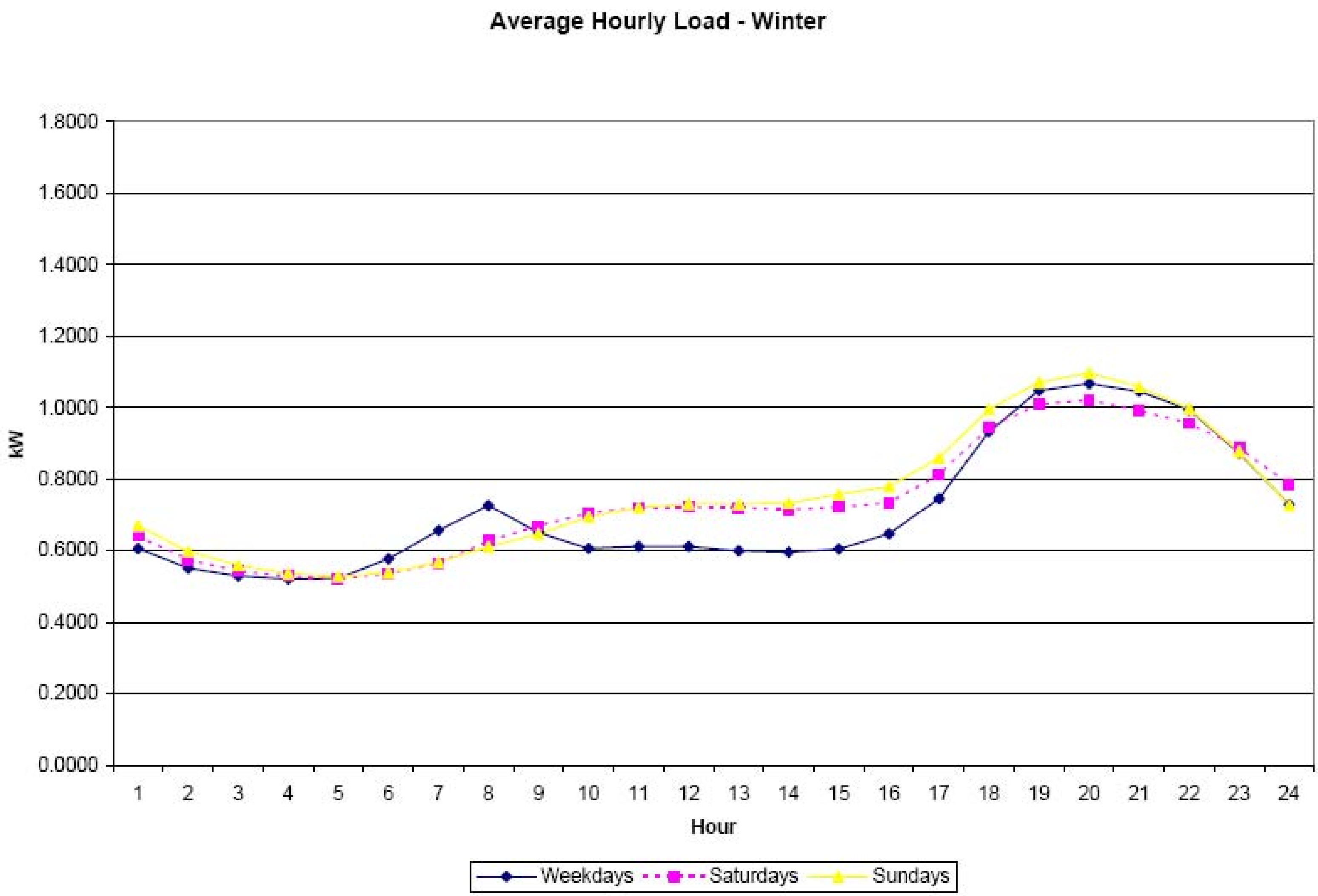
Analysis for data from Year 2003 Only

Cut-off	Summer hrs	Summer unique # of days	Summer factor/kWh	Summer kWh/cust	Non-summer hrs	Non-Summer unique # of days	Non-Summer factor/kWh	Non-summer kWh/cust
300%	2	2	0.12	3.98	20	4	0.34	16.88
400%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	0.00
500%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	1.00
600%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	2.00
700%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	3.00
800%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	4.00
900%	0	0	#DIV/0!	0.00	0	0	#DIV/0!	5.00

Appendix C

Average Hourly Loads


Average Hourly Load - Summer
1.8000
1.6000
1.4000
1.2000
1.0000
0.8000
0.6000
0.4000
0.2000
0.0000
kW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Weekdays
Saturdays
Sundays


Average Hourly Load - Winter
1.8000
1.6000
1.4000
1.2000
1.0000
0.8000
0.6000
0.4000
0.2000
0.0000
kW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Weekdays
Saturdays
Sundays

Appendix D

Summary of Average BGS Energy Only Unit Costs @ Customer – PSE&G Time Periods

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #9 **Summary of Average BGS Energy Only Unit Costs @ customer - PSE&G Time Periods**
based on Forwards prices corrected for congestion & all losses - PSE&G billing time periods
in $/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 56.88	$ 57.29	$ 57.04	$ 51.17	$ 47.75	$ 61.61	$ 41.82	$ 41.53	$ 60.71	$ 58.04
	PSE&G On pk			$ 81.47							$ 79.51
	PSE&G Off pk			$ 35.65							$ 35.09
Winter - all hrs		$ 46.61	$ 47.17	$ 46.67	$ 44.99	$ 44.06	$ 47.72	$ 41.44	$ 41.57	$ 48.60	$ 47.61
	PSE&G On pk			$ 59.71							$ 58.77
	PSE&G Off pk			$ 36.58							$ 36.27
Annual Average		$ 50.85	$ 49.39	$ 51.13	$ 46.71	$ 45.10	$ 49.98	$ 41.55	$ 41.56	$ 53.02	$ 51.40
System Average		$ 51.45									

Appendix E

Dates and Hours Used to Set Generation and Transmission Obligation

Dates and Hours used to set Generation & Transmisssion Obligation

Capacity Date	Capacity Hour	Transmission Date	Transmission Hour	# of Unique Days	# of additional days to capture >300% DA LMP
6/26/2000	1600	6/26/2000	1600		
7/10/2000	1700	6/27/2000	1500		
8/7/2000	1600	8/7/2000	1600	6	0
8/8/2000	1700	8/8/2000	1600		
8/9/2000	1700	8/9/2000	1600		
7/25/2001	1600	7/25/2001	1500		
8/6/2001	1700	8/7/2001	1700		
8/7/2001	1700	8/8/2001	1700	6	1
8/8/2001	1700	8/9/2001	1600		
8/9/2001	1600	8/10/2001	1400		
7/3/2002	1700	7/3/2002	1700		
7/29/2002	1700	7/23/2002	1600		
8/2/2002	1600	7/29/2002	1700	6	9
8/13/2002	1700	8/13/2002	1700		
8/14/2002	1600	8/14/2002	1600		
6/26/2003	1700	6/26/2003	1700		
7/8/2003	1800	6/27/2003	1600		
8/14/2003	1600	7/7/2003	1600	7	0
8/21/2003	1700	7/8/2003	1700		
8/22/2003	1600	8/22/2003	1600		
			Average/year >>>	6.25	2.5
				Total =	8.75

Appendix F

Generation and Transmission Obligations and Costs

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #10 **Generation & Transmission Obligations and Costs and Other Adjustments**
obligations - values effective June 2004; costs are market estimates

in MW	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 1500 kW LPL-S
Gen Obl - MW	4,297.7	60.1	103.7	1.1	0.0	6.6	0.0	0.0	2,605.2	2,289.2
Trans Obl - MW	3,681.0	49.0	85.0	1.0	0.0	6.0	0.0	0.0	2,368.0	1,999.9

# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	243	# of winter months =	8
		total # months =	12

Transmission Cost	year round = $	17,631	per MW-yr
Generation Capacity cost	summer = $	44.00	$/MW/day
	winter = $	7.00	$/MW/day

	RS	RHS		
% usage in Summer Blocks				
Block 1 (0-600 kWh/m)	60.8%	47.2%		*(based on W/N actuals for 2002, rounded to .1%)*
Block 2 (>600 kWh/m)	39.2%	52.8%		
Required summer inversion =	0.8652	1.1569	¢/kWh	*(same as 2003/2004 BGS blocking inversion)*

Generation & Transmission Obligation Costs - for CPP Rate

	Input Assumptions			Notes
1	Generation Obligation	4,297.7	MW	from Attachment 6
2	Transmission Obligation	3,681.0	MW	from Attachment 6
3	# of customers	1,758,515	customers	RS total billed in 8/04
	Avg cust load during CPP event			
	Generation Obligation costs			
4	Summer	$ 44.00	/MW/day	from Attachment 6
5	Non-Summer	$ 7.00	/MW/day	from Attachment 6
6	Transmission	$ 17,631	/MW/yr	from Attachment 6
7	# summer days	122	days	from Attachment 6
8	# non-summer days	243	days	from Attachment 6
	Total Generation Obligation costs			
9	summer	$ 13.12	/customer	= (1)/(3) * (4) * (7)
10	non-summer	$ 4.16	/customer	= (1)/(3) * (5) * (8)
11	Total	$ 17.28	/customer	= (9) + (10)
12	Total Transmission Obligation costs	$ 36.91	/customer	= (2)/(3) * (6)
13	Total Gen + Trans Obligation costs	$ 54.18	/customer	= (11) + (12)

Appendix G

Critical Peak Pricing

Proof of Revenue Neutrality

RSP Proof of Revenue
Explanation of Format and Calculations

Critical Peak Pricing Proof of Revenue Neutrality

This page shows the revenue neutrality of the RSP and BGS-CPP rate design. Column 1 units are the class average Annualized Weather Normalized billing determinants from the Company's recent Electric Base Rate Case. Column 2 Delivery and Supply rates are the RS and BGS-FP rates in effect July 1, 2004 excluding SUT. Column 3 is the resulting revenue. Column 4 Delivery units are the same as Column 1. The calculations developing the Supply Critical Peak Period units are provided on the succeeding page. The work papers to develop the Distribution Summer rates and the Supply rates in Column 5 are provided on a succeeding page. Column 6 provides the resulting revenue. Columns 7 and 8 provide the revenue difference and the percent difference, respectively. Column 9 provides the tariff charges including SUT.

Critical Peak Pricing Proof of Revenue Neutrality Work papers

Unblock Distribution Rate

Lines 41-45 show the development of the average summer distribution rate and its revenue neutrality.

Critical kWhr Calculation

Lines 55-58 calculate the Critical kWhrs based upon the seasonal assumptions of:

1. kWhr/hr,
2. Hours per occurrence, and
3. Number of occurrences.

BGS Charge Calculations

Energy Rates

Calculates the time period and seasonal BGS rates using the seasonal All Hours RS Average BGS Energy Only Unit Costs (line 59) from the Company Specific Addendum of the Company's July 1, 2004 BGS filing (See Attachment 8), the percent of seasonal average Day Ahead LMP's (Low, Medium and High) from the analysis (lines 62-64), and the CPP Incremental Adder (line 66). Application of these factors derives BGS Energy rates (lines 62-64, columns 7-9).

Obligation Adder

Obligation costs per customer are then derived (lines 72-77) using values from the 2005/2006 BGS filing (See Attachment 6), allocated between Summer High and Summer Critical (lines 83-84) and then obligation adders per kWhr are calculated. Combing these with the BGS Energy rates produces Energy Rates+ Obligation adder (lines 88-91, columns 7-9) before application of a Seasonal Equality Factor.

Seasonal Equality Factors

Seasonal Equality Factors are then developed through Backsolve (lines 97-99) and applied to the "Energy Rates plus Obligation adder" to insure seasonal revenue neutrality. The final BGS Supply rates including Seasonal Equality

Factor (lines 102-105, columns 7-9) are then used in the CPP Proof of Revenue Neutrality, Column 5, starting at line 22.

Day Ahead Pricing Adder Work paper

Ancillary Services Adder shows the derivation of the tariff adder based upon present rates.

Obligation Adders are derived based upon the CPP calculations found in the CPP work papers at lines 72-77. The cost per customer is then divided by the Summer High plus Summer Critical kWhrs to derive the tariff adders.

Critical Peak Pricing
Proof of Revenue Neutrality

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
Critical Peak Pricing (CPP)
Class Average Customer

Schedule XX
Page x of x

		Annualized Weather Normalized			Proposed			Difference		Tariff Charges
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent	Incl. SUT
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)	(9=5*1.06)
2	Service Charge	12.000	2.27	27.24	12.000	2.27	27.24	0.00	0.0	2.41
3	Distribution 0-600 Sum	1,754	0.028590	50.15	1,754	0.030090	52.78	2.63	5.2	0.031895
4	Distribution 0-600 Win	3,145	0.036234	113.96	3,145	0.036234	113.96	0.00	0.0	0.038408
5	Distribution over 600 Sum	1,132	0.032411	36.69	1,132	0.030090	34.06	(2.63)	(7.2)	0.031895
6	Distribution over 600 Win	929	0.036234	33.66	929	0.036234	33.66	0.00	0.0	0.038408
7	SBC	6,960	0.003120	21.72	6,960	0.003120	21.72	0.00	0.0	0.003307
8	NTC	6,960	0.003922	27.30	6,960	0.003922	27.30	0.00	0.0	0.004157
9	STC-TBC	6,960	0.006862	47.76	6,960	0.006862	47.76	0.00	0.0	0.007274
10	STC-MTC-Tax	6,960	0.002087	14.53	6,960	0.002087	14.53	0.00	0.0	0.002212
11	Amort. Excess Deprec. Resv.	6,960	(0.001565)	(10.89)	6,960	(0.001565)	(10.89)	0.00	0.0	(0.001659)
12	System Control Charge	6,960	0.000115	0.80	6,960	0.000115	0.80	0.00	0.0	0.000122
13	Delivery Subtotal			362.92			362.92	0.00	0.0	
14										
15	**Supply-BGS**									
16	BGS 0-600 Sum	1,754	0.068195	119.61				(119.61)	(100.0)	
17	BGS 0-600 Win	3,145	0.055209	173.63				(173.63)	(100.0)	
18	BGS over 600 Sum	1,132	0.076847	86.99				(86.99)	(100.0)	
19	BGS over 600 Win	929	0.055209	51.29				(51.29)	(100.0)	
20	**Critical Peak Pricing (CPP)**									
21	**June-Sept**									
22	Low Hours				914	0.024372	22.28	22.28	0.0	0.025834
23	Medium Hours				1,215	0.051956	63.13	63.13	0.0	0.055073
24	High Hours				687	0.115319	79.22	79.22	0.0	0.122238
25	Critical Hours				70	0.599584	41.97	41.97	0.0	0.635559
26	**Nov-Mar**									
27	Low Hours				762	0.034737	26.47	26.47	0.0	0.036821
28	Medium Hours				1,454	0.056703	82.45	82.45	0.0	0.060105
29	High Hours				448	0.082354	36.89	36.89	0.0	0.087295
30	Critical Hours				11	0.218313	2.40	2.40	0.0	0.231412
31	**April, May & Oct.**									
32	Low Hours				391	0.029770	11.64	11.64	0.0	0.031556
33	Medium Hours				0	0.000000	0.00	0.00	0.0	0.000000
34	High Hours				986	0.061582	60.72	60.72	0.0	0.065277
35	Critical Hours				22	0.197541	4.35	4.35	0.0	0.209393
36	BGS Reconciliation	6,960	0.000000	0.00	6,960	0.000000	0.00	0.00	0.0	
37	Supply Subtotal			431.52			431.52	0.00	0.0	
38										
39										
40	Total Delivery + Supply	6,960		794.44	6,960		794.44	0.00	0.0	

Notes: Annualized Weather Normalized rates are Tariff rates effective July 1, 2004, excluding SUT.
Does not reflect monthly changing Reconciliation Charges.

Critical Peak Pricing
Proof of Revenue Neutrality
Workpapers

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
Critical Peak Pricing (CPP)
Class Average Customer

	Unblock Distribution Rate	Annualized Weather Normalized Units	Rate	Revenue	Proposed Units	Rate	Revenue	Difference Revenue
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)
41	Distribution 0-600 Sum	1,754	0.028590	50.15	1,754	0.030090	52.78	2.63
43	Distribution over 600 Sum	1,132	0.032411	36.69	1,132	0.030090	34.06	(2.63)
45	Totals	2,886	0.030090	86.84			86.84	0.00

50 kWhrs Calculation

		@ 300% CPP Summer	@ 400% CPP Winter	@ 400% CPP Shldr
54	Critical kWhr Calculation			
55	kWhr/hr	2.0	1.4	1.4
56	Hours/occurence	7.0	4.0	16.0
57	occurrences	5.0	2.0	1.0
58	Critical kWhrs	70.0	11.0	22.0

Critical Peak Pricing
Proof of Revenue Neutrality
Workpapers

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
Critical Peak Pricing (CPP)
Class Average Customer

Schedule XX
Page x of x

BGS CHARGE CALCULATIONS	Summer	Winter	Shldr					Summer	Winter	Shldr
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)
All Hrs RS BGS Energy Rates	0.056880	0.046610	0.046610							
% of Seasonal average Day Ahead LMP's								Energy Rates		
Low Energy	0.468250	0.638740	0.547420					0.026634	0.029772	0.025515
Med Energy	0.998190	1.042660	0.000000					0.056777	0.048598	0.000000
High Energy	1.522280	1.514340	1.132380					0.086587	0.070583	0.052780
CPP Incremental Adder	2.50	2.50	2.50							
All Hrs RS BGS Energy Rates	0.056880	0.046610	0.046610							
Critical Adder	0.142200	0.116525	0.116525					0.228787	0.187108	0.169305
Critical $	9.95	1.28	2.56							
Obligation Cost per Customer	Gen Sum	Gen Non Sum	Trans							
Obligation	4,297.7	4,297.7	3,681.0							
# Custs	1,758,515	1,758,515.0	1,758,515							
Per Cust	0.002444	0.002444	0.002093							
Obl. Costs(gen/day/trans/year)	44.00	7.00	17,631.00							
# days/year	122	243	1							
Cost/Cust	13.12	4.16	36.90							
Total Cost/Cust			54.18							
Obligation Adder	Multiplier				kWhrs	Obl Adder		Energy Rates + Obligation adder		
	(1)	(2)	(3=1*2)		(4)	(5=3/4)				
1/2 Summer High	0.50	54.18	27.09		687.0	0.039432				
1/2 Summer Critical	0.50	54.18	27.09		70.0	0.387000				
Energy + Obligation										
Low								0.026634	0.029772	0.025515
Med								0.056777	0.048598	0.000000
High								0.126019	0.070583	0.052780
Critical								0.655219	0.187108	0.169305
Backsolve for Seasonal Revenue Neutrality					Seasonal					
					Equality					
Season BGS Total	WN	Proposed	Diff		Factor	Set Cell = 0	Change cell			
Summer	206.60	206.60	0.00	>>	0.915089	f139	h139			
Non-Summer	224.92	224.92	0.00	>>	1.166775	f140	h140			
Total	431.52	431.52	0.00							
								Rates incl. Seasonal Equality Factor		
Low								0.024372	0.034737	0.029770
Med								0.051956	0.056703	0.000000
High								0.115319	0.082354	0.061582
Critical								0.599584	0.218313	0.197541

DAY AHEAD PRICING ADDER WORKPAPERS

	$/MWh @ Bulk	Losses	$/MWh @ Customer	kWhr/MWh Factor	$/kWhr	with SUT 1.06
Anciliary Services Adder	2.00	0.075377	2.1630	1,000	0.002163	0.002293

Obligation Adders	Cost/Cust	Summer High + Critical kWhrs	$/kWhr	with SUT 1.06
Generation	17.28	757.0	0.022827	0.024197
Transmission	36.90	757.0	0.048745	0.051670
	54.18			

Appendix H
Detailed Calculation Of The
Day-Ahead Pricing (DAP) Rate

Although the DAP rates were never implemented, the following section provides a detail on the development of the hourly priced supply rate which had been developed for the myPower pilot program.

Overview

The DAP rate was designed to be hourly priced, with the hourly price based on the day ahead PJM market price for each hour. Although similar in concept to the current BGS-CIEP default service rate, the DAP rate was based on the day-ahead LMPs instead of the real time LMPs. It was also designed to recover all costs related to the Generation and Transmission Obligations through the summer kWh energy charges, in lieu of through separate kW based charges. Program participants to be placed on this rate were to have been notified each evening of the pilot program, what the 24 hourly prices would be for the following day. This day ahead notification would allow customer to plan their energy usage for the next day. These prices would be based upon the hourly clearing prices for the following day as settled in the PJM Day-Ahead energy market. Unlike the CPP rate, no adjustments to maintain revenue neutrality were proposed in the original rate design.

Original Development of the DAP rate

Although the hourly DAP rate was based upon the current BGS-CIEP rate structure, there are a number of significant differences as discussed below.

One difference between BGS-CIEP and the DAP rates is that in lieu of using the real-time LMPs, the hourly Day-Ahead LMPs were used. Similar to the prior day notification of a CPP event described above, the proposed advanced notice of hourly prices would give customers on the DAP rate adequate time to take action to plan their energy usage for the next day and take action to use electricity at times the prices would be lowest.

A second difference between the BGS-CIEP and the DAP rates is in the way charges are structured for the costs related to the customer specific Generation and Transmission Obligations. In the hourly DAP rate, these obligation costs are combined in the energy charge and not charged as a separate billing determinant, as currently done for most non-residential customers. These costs are recovered, on a per kilowatthour basis, over the kilowatthours in the same summer daytime hours designated as Summer High Period hours for the CPP rate. Identical to what was done for the CPP rate, the average per customer Generation Obligation and Transmission Obligation costs used in these calculations was based upon data included in Table #10 of the PSE&G BGS Bid Factor Spreadsheet for 2005-6, (Appendix F). This data indicated that the total obligation costs for an average customer is $54.18 per year as shown in Appendix F.

Since Day-Ahead LMPs are unknown until the day ahead, there is no practical way to assure revenue neutrality for this DAP rate, thus these calculations were not performed. Therefore, the total charges to a customer participating on the DAP Rate, even if the customer does not change usage and usage patterns, may be higher or lower than they would have been if they had purchased BGS supply through the standard BGS-FP related charges applicable to Rate RS.

In order to provide some protection to customers, a total BGS Energy Charge per kilowatthour ceiling of $0.99 was agreed upon. Although not cost based, this upper limit was proposed to give some assurance to participants that the price would have an upper limit.

The DAP rate, similar to the CPP rate, was to be updated once the results of the BGS-CIEP Auction for the following summer was finalized so that the then current values for the Generation and Transmission Obligations could be utilized in the DAP rate. Appendix I includes the BGS tariff sheet that were in effect at the time of the development of the DAP rate.

Proposed Modifications To The Day Ahead Pricing (DAP) Rates

Overview

During autumn of 2005, two issues arose concerning the structure of the DAP rate as originally filed with the NJ BPU. The first was related to the lack of revenue neutrality between the DAP rate and the otherwise applicable BGS rate that became especially prominent following a rapid rise in PJM LMPs in the summer of 2005. The second issue was the result of comments provided by Summit Blue Consulting, the third party evaluation contractor that the Company hired to perform the impact analysis on the myPower pilot program.

In order to resolve these issues, on February 6, 2006 PSE&G filed with the NJ BPU and RPA two proposed modifications to the previously approved tariff sheets. The first proposed modification was to include an adjustment factor in the calculation of the hourly charges such that the average DAP prices, over time, more closely align with the standard and otherwise applicable BGS-FP Rate. The second modification proposed was a change in the way in which the Generation and Transmission Obligation costs are recovered in the DAP Rate, to more closely align with cost causation, and provide an improved market price signal to customers. These two proposed modifications are discussed in detail below.

Modification #1 – DAP Adjustment Factor

Introduction

The Company filed its original proposal for the DAP Rate in November 2004. Since that time, a substantial increase in the market price of electricity occurred, especially during the summer and through the fall of 2005, as measured by the PJM Locational Marginal Prices (LMP). The majority of the charge to customers to have been billed on the DAP Rate, is based on this LMP. Had the rate been in effect during this time period, an average customer's bill on the DAP Rate would have been substantially higher than the otherwise applicable BGS-FP rate.

Customers billed on the standard BGS-FP rates are insulated from such short term impacts in market prices due to the structure of the BGS-FP procurement methodology, which essentially hedges each third of the entire BGS-FP supply over a separate three-year contract term. Likewise, if there are long term increases (or decreases) in the market price of electricity, these cost changes, while reflected immediately in DAP rates, would take several years to be fully reflected in BGS-FP rates.

Customers who would have been participating in the DAP pricing segment would have had the option to switch back to BGS-FP at any time. Assuming market prices remained high during the period of the pilot; participating customers would have likely experienced significant bill increases compared to BGS-FP, even if they made substantial reductions in their use of electricity. Therefore, if no adjustments to the DAP rate were made, it was likely that many of the customers would have opted out of this pilot program in order to be billed on the much lower standard residential BGS-FP rate.

Discussion of Issues

There was a possibility that the current high market prices would persist into the future, which would have continued the disparity between residential bills utilizing the DAP Rate verses the standard BGS rates. In order to minimize the potential impacts resulting from significant numbers of customers potentially requesting to be removed from the pilot program due to high bills, the Company proposed to implement a modification to the way in which the hourly DAP charge was calculated to address the problem. The change proposed was that for each month, an adjustment factor would be applied to the market energy prices (the LMPs) used to determine the hourly charges on the DAP Rate. This would ensure that the total average RS customer's bill would move closer to what it would have been on the otherwise applicable standard BGS-FP charges, yet participating myPower customers would have experienced hourly changing prices based on the hourly PJM energy market.

In reviewing the proposed modifications, several questions arose:

> **Question #1 -** If the hourly prices are modified, then customers will not be exposed to real market prices and, therefore, won't the purpose of this segment of the pilot be compromised?
>
> **Answer -** The purpose of this pilot program is not to determine a residential customer's response to a particular set of actual market prices, but rather, to determine a residential customer's response to hourly changing prices. The proposed modifications would still generate hourly changing prices tied to actual hourly market prices. Application of this correction factor will cause no confusion or additional work on the part of participating customers in this pilot. Participants will still be provided 24 prices each night, representing the total hourly price of electricity for each hour in the following day. This proposed correction factor would already be included in each of these hourly prices, thus the inclusion of this additional calculation would be transparent to all of the participating customers.
>
> **Question #2 -** If the hourly prices are modified, then won't the result be that the pilot will not demonstrate the response of customers to actual market prices and provide the information necessary to properly evaluate whether this type of pricing is a viable option for the residential market in the future?
>
> **Answer -** This type of adjustment factor will likely be a critical feature of a potential full scale offering of hourly pricing to residential customers where the customers would have the option of a fixed price alternative. It appears unlikely at this time that the Board will mandate that residential customers be offered hourly LMP based pricing as the only default option. Anytime there are two different prices for the same product available, customers will naturally seek the least expensive option. This is the case between pricing on the DAP Rate for this pilot program and the otherwise applicable standard BGS-FP rates.
>
> If the prices are not corrected, then there are two possible outcomes that would render the pilot essentially useless. In one scenario, market prices stay very high and customers drop out immediately. They would describe the program as a terrible idea and one that should not be rolled out on a permanent basis. Further, with the customers immediately dropping out, there will be very little price response data generated. If on the other hand, market prices fall dramatically below BGS-FP, customers will stay on the program, will likely

experience substantially lower bills even if they do nothing to change their usage, and will describe the program very positively, even though their savings were simply a quirk of the market.

Question #3 - If customers' bills are adjusted such that they are essentially neutral with respect to BGS-FP, then won't this remove any incentive to respond to the hourly prices?

Answer - The proposed pricing adjustment will move the hourly prices such that the class average RS customer being billed on BGS-FP would experience similar bills, over time, had the customer been billed on the adjusted hourly prices. Individual customers participating in the pilot will likely have usage profiles that differ from the RS class average and will therefore experience different impacts, either higher or lower, than the class average. Further, as the participating customers adjust their usage in response to the pricing, their bills will change accordingly.

Question #4 - Aren't PSE&G's large customers presently being charged hourly prices without such adjustments?

Answer - Such an adjustment in pricing would not be required in those cases where such short term market based pricing is mandatory for an entire rate class or subgroup of customers. Such is the case with current customers whose only option for default service is at the hourly market based BGS-CIEP. Since there is no choice to a customer among different default prices, no adjustment is necessary.

Question #5 - If this pricing adjustment is so critical, why didn't the Company propose the adjustment when it first proposed the DAP pilot in November 2004?

Answer - At the time of the original filing, a review of the historical BGS-FP and potential DAP charges over several years did not reveal any substantial differences between the two pricing approaches. As a result, this potential problem was not recognized or addressed in the proposal. With the experience of this past year, it has become clear that an adjustment of this type will be critical not only for the pilot, but for any future full scale offering, and should have been included in the original proposal.

Detailed Proposal

The Company proposed the establishment of a monthly changing adjustment factor applicable in the calculation of the DAP charges. This factor, called the BGS Alignment Factor or BGSAF, would have been set such that for a class average RS customer, it would have targeted recovery of most of the difference between the prior month's bill on the DAP rate verses the prior month's bill on the BGS-FP rate, plus any shortfall (or excess) in recovery from the application of last month's factor in the prior month. In that way, the bill for a class average RS customer participating in the pilot program would have moved closer, over time, to what it would have been on the otherwise applicable standard BGS-FP charges.

The adjustment factor would have been applied as a multiplier to the PJM LMPs used in the calculation of the DAP pricing. Only one factor would have been calculated for each month, and applied to all hours in that month for all customers on the DAP rate, based on the impacts to the average RS customer as determined by the load research sample profile used for retail load settlement purposes.

The Company also proposed that this adjustment factor be limited to a minimum value of 0.7 and a maximum value of 1.3. If this adjustment factor has been applied without any limits, the actual factor could have varied significantly each month, especially in any month where the PJM LMPs were considerably different, either much higher or much lower, that those in a prior month. Establishing limits would have allowed customers to experience most of the normal seasonal pattern of change in the market price of energy.

The specific values selected for these limits were set as a balance between the impact on DAP prices caused by having narrow limits verses having wider limits. Wide limits would have resulted in large month-to-month variations in customer charges that could have moved the rates charged far away from the actual market costs. On the other hand, narrow limits, having the adjustment factor closer to a value of 1.0, would have limited the effectiveness of the adjustment factor and most likely prevented an average customer's bill on DAP pricing from being, over time, similar to the average customer on BGS-FP.

In addition to limits on the resulting adjustment factor, the total amount of any over or under recovery that would have been attempted to be recovered in a subsequent month was also proposed to be limited by a dampening factor. The proposed value of the dampening factor was 0.8, meaning that 80% of the total shortfall (or excess) at any point in time would be targeted for recovery in the following month. This dampening factor was also developed to reduce month to month variations in the total adjustment to the market prices.

There are no mathematical formulas that could have been used to determine the ideal limits of the adjustment factor or the dampening factor. The values proposed were selected to balance the overall purposes of the factor which were to provide, over time, significant alignment of the DAP prices with the BGS-FP prices and to avoid wide month to month variations in the price adjustment.

Specifically, the factor for month x was to have been calculated as follows:

1. The actual usage for the RS profile customer for month x-1 was to be first billed on both the DAP rate (as corrected in that month) and on BGS-FP. Any difference in costs would be added to the over/under recovery balance.
2. The outstanding recovery balance at the end of month x-1 would then be multiplied by the dampening factor to determine the total desired for recovery in month x.
3. This desired amount of recovery would then divided by the product of the forecasted weather normalized usage for the profile customer expected in month x and the actual average DA LMP for month x-1. This result would then be added to 1.0 to convert it to a factor.
4. The resulting factor would then be checked against the pre-established upper and lower limits. If the factor from the above calculation is greater than the upper limit, the final correction factor would be set equal to the upper limit. If the factor would have been less than the lower limit, the final correction factor would then be equal to the lower limit.

Any amounts of monthly over- or under-recovery would automatically flow to the BGS-FP Reconciliation Charge; therefore there was no need to request from the Board any special accounting treatment of the adjustment charge balance.

Modification #2 – Obligation Cost Recovery

Introduction

The then approved DAP Rate included the recovery of Generation and Transmission Obligation related costs equally across all Summer weekday afternoon hours between 1 PM and 6 PM. That method of cost recovery, which totaled approximately $63 per year for the average residential customer, resulted in an adder of approximately 10 cents per kWh for all kWhs used during that period.

Discussion of Issues

The Company's evaluation contractor, Dr. Daniel Violette from Summit Blue Consulting, noted that on cooler days when the load (and market prices) is most likely low, the identical obligation cost recovery adder would still be charged to customers as on a hot day, when the system load is high. Although the customers would have still seen hourly changes in price due to the variations in the PJM market price of energy, these obligation related charges to the customers were basically fixed during the summer weekday afternoons. Dr. Violette recommended that the original rate design related to the cost recovery be changed in order to better match the recovery of the obligation costs with the peak hours that caused the costs to be incurred by load in the PSE&G zone.

After various options were discussed with Summit Blue Consulting, Dr. Violette agreed that a modification to the DAP rate design to change the recovery of Generation and Transmission Obligation costs to one based on forecasted weather conditions was an appropriate way in which to address this issue. Since it was the occurrence of the peak system loads that actually caused Generation and Transmission Obligation related costs, and such loads were highly correlated with temperature, basing recovery on hourly temperature would have allowed recovery of costs closer to a cost causation basis.

Detailed Proposal

The Company proposed to modify the design of the DAP Rate originally filed and approved by the Board with respect to the way in which Generation and Transmission Obligation related costs were to have been recovered. In lieu of recovering these costs on a fixed basis during predetermined times, the Company proposed to recover these costs based upon the temperature expected for each hour during a period which is nominally summer weekday afternoons.

Although there are many ways in which to base this type of cost recovery, the specific proposal was selected to:

1) Vary the adder in response to temperature;
2) Recover the costs during a period that is close to the summer weekday on-peak period;
3) Expect to recover approximately $63 per year on average per customer based on the six years of available data and the hourly load profile an average RS customer;
4) Minimize the year to year variance in the amount recovered; and
5) Avoid extremely high charges in only a limited number of hours.

While there was not a unique solution that addressed all of these criteria, the proposal below was selected since it provided a good balance among the criteria. Specifically, these Generation and Transmission Obligation costs were proposed to be recovered via a charge added to the hourly energy costs any time the hourly temperature was in excess of 80 degrees. This adder would only have been in effect during weekdays of the summer months (June through September) during the period of 11 AM to 8 PM. In addition, the value of the adder would have increased as the temperature increased, according to the following table.

Temperature (in degrees Fahrenheit)	**Obligation Adder (w/o NJ SUT and shown in cents/kWh)**
80 and lower	0 ¢
81	2 ¢
82	4 ¢
83	6 ¢
84	8 ¢
85	10 ¢
86	12 ¢
87	14 ¢
88	16 ¢
89	18 ¢
90	20 ¢
91	22 ¢
92 and higher	24 ¢

Since the total hourly supply prices needed to be communicated to the potential customer participants the evening prior to being in effect, the day ahead forecast of the hourly dry bulb temperatures for the Newark area performed by Accuweather, (a commercial weather forecasting service), would have been used as the weather parameter in the calculation of the adder.

The actual amount of this adder would have been included in the total hourly price communicated to the participating customers each evening, to have become effective the following day. As with the other modification being proposed in the filing, charging of these costs in this way would have caused no confusion or additional work on the part of participating customers in the pilot program. Participants would have still been provided 24 prices each night, representing the total hourly price of electricity for each hour in the following day. The value of this adder would have already been included in the determination of those hourly prices, thus the inclusion of the additional calculation would have been transparent to the participating customers.

The Company also proposed to modify each of the above indicated temperature-based obligation charges as the Generation or Transmission Obligation costs for the average RS customer would have changed over time. Such changes could have been those as a result of changes in the RMR or SECA charge, revisions in the Generation and Transmission Obligation unit costs used in the development of new BGS-FP rates effective each June 1st, or changes in the average kW obligations for the class average RS customer. The modifications to the above temperature-based obligation charges would have been done in the same proportion as the difference in the total obligation cost for the class average RS customer is from $63.64 (without NJ SUT). This $63.64 is the annual average recovery expected over time of using the above temperature-based charges.

An example of the calculations of the proposed modification is as follows. Assume changes in the RMR costs resulted in a new total Generation and Transmission Obligation cost for the class average RS customer of $66.82. Since this $3.18 increase ($3.18 = $66.82 - $63.64) is a 5% increase over the $63.64, each of the temperature-based obligation charges would have been increased by 5%.

Final Resolution

Meetings were held with both the NJ BPU Staff and RPA to review the proposed modifications to the originally proposed DAP rates. The primary issues discussed were that any modifications to the actual market price would “taint” the results of the testing of a true market price and would not produce valid results. The second concern was the complexity of the calculations that were required to determine the final DAP price in any hour.

After several meetings, consensus on the proposed changes could not be reached. On April 27, 2006 the BPU issued an Order requiring PSE&G to cancel the implementation of the DAP pilot rate.

Appendix I

PSE&G Basic Generation Service – Fixed Pricing (BGS-FP) Electric Supply Charges

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 14 ELECTRIC

Seventh Revised Sheet No. 67B
Superseding
Sixth Revised Sheet No. 67B

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS ENERGY CHARGES:

Applicable to Rate Schedule RSP customers receiving Critical Peak Pricing (CPP) Basic Generation Service

Charges per kilowatthour:

TIME OF USE	Applicable	Charges	Charges Including SUT
Summer Months: June through September			
Base Price	All Hours	8.1005 ¢	8.6675 ¢
Night Discount	10 P.M. to 9 A.M. Daily	(4.6729) ¢	(5.0000) ¢
On-Peak Adder	1 P.M. to 6 P.M. Weekdays	14.0187 ¢	15.0000 ¢
Critical Peak Adder	1 P.M. to 6 P.M. When called, replaces On-Peak Adder	128.0374 ¢	137.0000 ¢
Non-Summer Months: October through May			
Base Price	All Hours	9.4347 ¢	10.0951 ¢
Night Discount	10 P.M. to 6 A.M. Daily	(3.7383) ¢	(4.0000) ¢
On-Peak Adder	5 P.M. to 9 P.M. Weekdays, November through March	3.7383 ¢	4.0000 ¢
Critical Peak Adder	5 P.M. to 9 P.M. When called, replaces On-Peak adder, November through March 1 P.M. to 6 P.M. When called, October, April and May	26.1682 ¢	28.0000 ¢

The Critical Periods shall be invoked at the sole discretion of Public Service. Critical Periods will be activated for one or more of the following:

- PJM Day Ahead Price,
- Public Service discretionary events including but not limited to test purposes, program evaluation or system contingencies.

Public Service may invoke a maximum of five Critical Periods during the period of June through September, a maximum of two Critical Periods during the period of November through March and a maximum of one Critical Period in either October, April or May. Each customer will be notified by 6:00 P.M. the evening before a day with a Critical Period. Notification will be provided by either email or telephone as elected by the customer at the time of their enrollment in the pilot program.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Date of Issue: June 5, 2007 Effective: June 1, 2007
Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 9, 2007
in Docket No. EO06020119

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS ENERGY CHARGES:

Applicable to Rate Schedule RSP customers receiving Critical Peak Pricing (CPP) Basic Generation Service

Charges per kilowatthour:

TIME OF USE	Applicable	Charges	Charges Including SUT
Summer Months: June through September			
Base Price	All Hours	8.6073 ¢	9.2098 ¢
Night Discount	10 P.M. to 9 A.M. Daily	(4.6729) ¢	(5.0000) ¢
On-Peak Adder	1 P.M. to 6 P.M. Weekdays	7.4766 ¢	8.0000 ¢
Critical Peak Adder	1 P.M. to 6 P.M. When called, replaces On-Peak Adder	64.4860 ¢	69.0000 ¢
Non-Summer Months: October through May			
Base Price	All Hours	8.1066 ¢	8.6741 ¢
Night Discount	10 P.M. to 6 A.M. Daily	(3.7383) ¢	(4.0000) ¢
On-Peak Adder	5 P.M. to 9 P.M. Weekdays, November through March	2.8037 ¢	3.0000 ¢
Critical Peak Adder	5 P.M. to 9 P.M. When called, replaces On-Peak adder, November through March 1 P.M. to 6 P.M. When called, October, April and May	21.4953 ¢	23.0000 ¢

The Critical Periods shall be invoked at the sole discretion of Public Service. Critical Periods will be activated for one or more of the following:

- PJM Day Ahead Price,
- Public Service discretionary events including but not limited to test purposes, program evaluation or system contingencies.

Public Service may invoke a maximum of 8 Critical Periods per year. Each customer will be notified by 6:00 P.M. the evening before a day with a Critical Period. Notification will be provided by either e-mail or telephone as elected by the customer at the time of their enrollment in the pilot program.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Date of Issue: December 28, 2006 Effective: January 1, 2007
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated June 22, 2005
in Docket Nos. ER05040368 and EO04040288

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS ENERGY CHARGES:

Applicable to Rate Schedule RSP customers receiving Critical Peak Pricing (CPP) Basic Generation Service

Charges per kilowatthour:

TIME OF USE	Applicable	Charges	Charges Including SUT
Summer Months:			
June through September			
Base Price	All Hours	8.6011 ¢	9.2032 ¢
Night Discount	10 P.M. to 9 A.M. Daily	(4.6729) ¢	(5.0000) ¢
On-Peak Adder	1 P.M. to 6 P.M. Weekdays	7.4766 ¢	8.0000 ¢
Critical Peak Adder	1 P.M. to 6 P.M. When called, replaces On-Peak Adder	64.4860 ¢	69.0000 ¢
Non-Summer Months:			
October through May			
Base Price	All Hours	8.1000 ¢	8.6670 ¢
Night Discount	10 P.M. to 6 A.M. Daily	(3.7383) ¢	(4.0000) ¢
On-Peak Adder	5 P.M. to 9 P.M. Weekdays, November through March	2.8037 ¢	3.0000 ¢
Critical Peak Adder	5 P.M. to 9 P.M. When called, replaces On-Peak adder, November through March 1 P.M. to 6 P.M. When called, October, April and May	21.4953 ¢	23.0000 ¢

The Critical Periods shall be invoked at the sole discretion of Public Service. Critical Periods will be activated for one or more of the following:

- PJM Day Ahead Price,
- Public Service discretionary events including but not limited to test purposes, program evaluation or system contingencies.

Public Service may invoke a maximum of 8 Critical Periods per year. Each customer will be notified by 6:00 P.M. the evening before a day with a Critical Period. Notification will be provided by either e-mail or telephone as elected by the customer at the time of their enrollment in the pilot program.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Date of Issue: July 14, 2006 Effective: July 15, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 23, 2006
in Docket No. EO05040317 and also Docket No. AT06070502

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS ENERGY CHARGES:

Applicable to Rate Schedule RSP customers receiving Critical Peak Pricing (CPP) Basic Generation Service

Charges per kilowatthour:

TIME OF USE	Applicable	Charges	Charges Including SUT
Summer Months: June through September			
Base Price	All Hours	8.6112 ¢	9.1279 ¢
Night Discount	10 P.M. to 9 A.M. Daily	(4.7170) ¢	(5.0000) ¢
On-Peak Adder	1 P.M. to 6 P.M. Weekdays	7.5472 ¢	8.0000 ¢
Critical Peak Adder	1 P.M. to 6 P.M. When called, replaces On-Peak Adder	64.1509 ¢	68.0000 ¢
Non-Summer Months: October through May			
Base Price	All Hours	8.1063 ¢	8.5927 ¢
Night Discount	10 P.M. to 6 A.M. Daily	(3.7736) ¢	(4.0000) ¢
On-Peak Adder	5 P.M. to 9 P.M. Weekdays, November through March	2.8302 ¢	3.0000 ¢
Critical Peak Adder	**5 P.M. to 9 P.M. When called, replaces On-Peak adder,** November through March 1 P.M. to 6 P.M. When called, October, April and May	21.6981 ¢	23.0000 ¢

The Critical Periods shall be invoked at the sole discretion of Public Service. Critical Periods will be activated for one or more of the following:

- PJM Day Ahead Price,
- Public Service discretionary events including but not limited to test purposes, program evaluation or system contingencies.

Public Service may invoke a maximum of 8 Critical Periods per year. Each customer will be notified by 6:00 P.M. the evening before a day with a Critical Period. Notification will be provided by either e-mail or telephone as elected by the customer at the time of their enrollment in the pilot program.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Date of Issue: May 30, 2006 Effective: June 1, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 23, 2006
in Docket No. EO05040317

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,000 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

Rate Schedule	For usage in each of the months of October through May: Charges	Charges Including SUT	For usage in each of the months of June through September: Charges	Charges Including SUT
RS – first 600 kWh	8.9005 ¢	9.5235 ¢	10.6522 ¢	11.3979 ¢
RS – in excess of 600 kWh	8.9005 ¢	9.5235 ¢	11.5193 ¢	12.3257 ¢
RHS – first 600 kWh	8.7263 ¢	9.3371 ¢	10.8402 ¢	11.5990 ¢
RHS – in excess of 600 kWh	8.7263 ¢	9.3371 ¢	11.9996 ¢	12.8396 ¢
RLM On-Peak	11.1019 ¢	11.8790 ¢	15.4023 ¢	16.4805 ¢
RLM Off-Peak	7.1913 ¢	7.6947 ¢	7.0404 ¢	7.5332 ¢
WH	7.8392 ¢	8.3879 ¢	8.2188 ¢	8.7941 ¢
WHS	7.7144 ¢	8.2544 ¢	7.7806 ¢	8.3252 ¢
HS	8.7591 ¢	9.3722 ¢	12.3707 ¢	13.2366 ¢
BPL	7.2958 ¢	7.8065 ¢	7.0741 ¢	7.5693 ¢
BPL-POF	7.2958 ¢	7.8065 ¢	7.0741 ¢	7.5693 ¢
PSAL	7.2958 ¢	7.8065 ¢	7.0741 ¢	7.5693 ¢

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed fom time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 14 ELECTRIC

Eighteenth Revised Sheet No. 67
Superseding
Seventeenth Revised Sheet No. 67

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,250 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	7.4490 ¢	7.9704 ¢	8.9333 ¢	9.5586 ¢
RS – in excess of 600 kWh	7.4490 ¢	7.9704 ¢	9.8074 ¢	10.4939 ¢
RHS – first 600 kWh	7.4856 ¢	8.0096 ¢	8.6816 ¢	9.2893 ¢
RHS – in excess of 600 kWh	7.4856 ¢	8.0096 ¢	9.8504 ¢	10.5399 ¢
RLM On-Peak	8.8125 ¢	9.4294 ¢	11.8603 ¢	12.6905 ¢
RLM Off-Peak	6.3662 ¢	6.8118 ¢	6.8813 ¢	7.3630 ¢
WH	6.8747 ¢	7.3559 ¢	8.2731 ¢	8.8522 ¢
WHS	6.7348 ¢	7.2062 ¢	7.6611 ¢	8.1974 ¢
HS	7.6196 ¢	8.1530 ¢	10.0329 ¢	10.7352 ¢
BPL	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢
BPL-POF	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢
PSAL	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: December 28, 2006 Effective: January 1, 2007
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated June 22, 2005
in Docket Nos. ER05040368 and EO04040288

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Seventeenth Revised Sheet No. 67
Superseding
Sixteenth Revised Sheet No. 67

B.P.U.N.J. No. 14 ELECTRIC

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,250 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	7.4424 ¢	7.9634 ¢	8.9267 ¢	9.5516 ¢
RS – in excess of 600 kWh	7.4424 ¢	7.9634 ¢	9.8008 ¢	10.4869 ¢
RHS – first 600 kWh	7.4807 ¢	8.0043 ¢	8.6767 ¢	9.2841 ¢
RHS – in excess of 600 kWh	7.4807 ¢	8.0043 ¢	9.8455 ¢	10.5347 ¢
RLM On-Peak	8.8058 ¢	9.4222 ¢	11.8536 ¢	12.6834 ¢
RLM Off-Peak	6.3595 ¢	6.8047 ¢	6.8746 ¢	7.3558 ¢
WH	6.8747 ¢	7.3559 ¢	8.2731 ¢	8.8522 ¢
WHS	6.7348 ¢	7.2062 ¢	7.6611 ¢	8.1974 ¢
HS	7.6145 ¢	8.1475 ¢	10.0278 ¢	10.7297 ¢
BPL	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢
BPL-POF	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢
PSAL	6.4916 ¢	6.9460 ¢	7.0945 ¢	7.5911 ¢

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: July 14, 2006 Effective: July 15, 2006

Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 23, 2006
in Docket No. EO05040317 and also Docket No. AT06070502

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,250 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	7.4424 ¢	7.8889 ¢	8.9267 ¢	9.4623 ¢
RS – in excess of 600 kWh	7.4424 ¢	7.8889 ¢	9.8008 ¢	10.3888 ¢
RHS – first 600 kWh	7.4807 ¢	7.9295 ¢	8.6767 ¢	9.1973 ¢
RHS – in excess of 600 kWh	7.4807 ¢	7.9295 ¢	9.8455 ¢	10.4362 ¢
RLM On-Peak	8.8058 ¢	9.3341 ¢	11.8536 ¢	12.5648 ¢
RLM Off-Peak	6.3595 ¢	6.7411 ¢	6.8746 ¢	7.2871 ¢
WH	6.8747 ¢	7.2872 ¢	8.2731 ¢	8.7695 ¢
WHS	6.7348 ¢	7.1389 ¢	7.6611 ¢	8.1208 ¢
HS	7.6145 ¢	8.0714 ¢	10.0278 ¢	10.6295 ¢
BPL	6.4916 ¢	6.8811 ¢	7.0945 ¢	7.5202 ¢
BPL-POF	6.4916 ¢	6.8811 ¢	7.0945 ¢	7.5202 ¢
PSAL	6.4916 ¢	6.8811 ¢	7.0945 ¢	7.5202 ¢

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges and the PJM Reliability Must Run Charge, may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: May 30, 2006 Effective: June 1, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated February 23, 2006
in Docket No. EO05040317

Appendix J

PSE&G Rate Schedule RSP Residential Service Pilot

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential pilot purposes. Customers must purchase electric supply from Public Service's Basic Generation Service default service as detailed in this rate schedule.

Eligible customers will be selected by Public Service to participate in this pilot. Selected customers who agree to participate in this pilot will take service under this Rate Schedule. Eligibility for service under this pilot rate schedule is limited to selected residential customers taking service under Rate Schedule RS as of January 1, 2005 within the municipal boundaries of Hamilton Township, Cherry Hill or other municipalities as selected by Public Service to attain the target number of residential customer participants. This Rate Schedule expires October 1, 2007.

DELIVERY CHARGES:

Service Charge:

$2.27 in each month [$2.41 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatthour:

In each of the months of October through May		In each of the months of June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
3.6234¢	3.8408¢	3.0090¢	3.1895¢

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-Utility Generation Transition Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-Utility Generation Transition Charge sheet of this Tariff for the current charge.

Securitization Transition Charges:

These charges include the Transition Bond Charge and the MTC-Tax charge and shall recover costs and associated taxes for transition bonds collected by PSE&G as servicer on behalf of PSE&G Transition Funding LLC. Refer to the Securitization Transition Charges sheet of this Tariff for the current charges.

System Control Charge

This charge is designed to provide recovery of costs associated with the operation of certain programs as approved by the BPU. Refer to the System Control Charge sheet of this Tariff for the current charge.

Date of Issue: September 28, 2005 Effective: April 19, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated September 19, 2005
in Docket No. EO04060395

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
(Continued)

Amortization of Excess Depreciation Reserve

This charge shall amortize an excess depreciation reserve that shall be amortized over 29 months beginning August 1, 2003 and is intended to expire December 31, 2005. Refer to the Amortization of Excess Depreciation Reserve sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-Utility Generation Transition Charge, Securitization Transition Charges, System Control Charge, and the Amortization of Excess Depreciation Reserve Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer must receive electric supply from Public Service through its Basic Generation Service – Fixed Pricing (BGS – FP) default service.

Basic Generation Service:

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatthours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RSP. Customers selected to participate in the pilot will be provided BGS-FP service at Critical Peak Pricing (CPP).

While participating in this pilot program, the customer is precluded from using on-site generation equipment except when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service.

Date of Issue: May 5, 2006 Effective: April 27, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated April 27, 2006
in Docket No. EO04060395

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
(Continued)

TERMS OF PAYMENT:

Bills are due on presentation.

TERM:

Customer may discontinue delivery service upon notice. Public Service may terminate the availability of this Rate Schedule at its discretion and upon proper notice to the customer.

SPECIAL PROVISIONS:

(a) **Installation and Removal:** Metering and Energy Management Equipment will be owned, installed and maintained by Public Service at the customer's residence upon customer's initial acceptance of service under Rate Schedule RSP at no charge to the customer. The customer shall provide a suitable location approved by Public Service for such facilities. Energy Management Equipment may be removed by Public Service at the conclusion of the pilot or at any time that the customer decides to withdraw from the pilot. Customers completing the pilot may keep the pilot thermostat at no cost.

(b) **Voluntary Withdrawal:** Customers who voluntarily withdraw from this pilot program can return to Rate Schedule RS. If customer notification is received at least three days prior to the end of the customer's billing month the customer will be billed for the full billing month at Rate Schedule RS (the billing month normally ends with the customer's scheduled meter reading date). Customers voluntarily withdrawing from this pilot program are not eligible to reenter the pilot program.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Budget Plan (Equal Payment Plan):** Participation in the Budget Plan (Equal Payment Plan) will be suspended for the duration of customer participation in this pilot program.

(e) **A/C Cycling Program:** Participation in Public Service's A/C Cycling (Cool Customer) Program will be suspended and the installed load control device will be deactivated during customer participation in this pilot program.

(f) **Billing Information:** Upon customer request, historical pilot program billing information will be provided to the customer at no charge.

STATE OF NEW JERSEY AUTHORIZED TAXES:

The Transitional Energy Facility Assessment and the New Jersey Sales and Use Tax are applied in accordance with P.L. 1997, c. 162 and are included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

Date of Issue September 28, 2005 Effective: April 19, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated September 19, 2005
in Docket No. EO04060395

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential pilot purposes. Customers must purchase electric supply from Public Service's Basic Generation Service default service as detailed in this rate schedule.

Eligible customers will be selected by Public Service to participate in this pilot. Selected customers who agree to participate in this pilot will take service under this Rate Schedule. Eligibility for service under this pilot rate schedule is limited to selected residential customers taking service under Rate Schedule RS as of January 1, 2005 within the municipal boundaries of Hamilton Township, Cherry Hill or other municipalities as selected by Public Service to attain the target number of residential customer participants. This Rate Schedule expires October 1, 2007.

DELIVERY CHARGES:

Service Charge:

$2.27 in each month [$2.43 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatthour:

In each of the months of October through May		In each of the months of June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
3.6234¢	3.8770¢	3.0090¢	3.2196¢

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-Utility Generation Transition Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-Utility Generation Transition Charge sheet of this Tariff for the current charge.

Securitization Transition Charges:

These charges include the Transition Bond Charge and the MTC-Tax charge and shall recover costs and associated taxes for transition bonds collected by PSE&G as servicer on behalf of PSE&G Transition Funding LLC. Refer to the Securitization Transition Charges sheet of this Tariff for the current charges.

System Control Charge

This charge is designed to provide recovery of costs associated with the operation of certain programs as approved by the BPU. Refer to the System Control Charge sheet of this Tariff for the current charge.

Date of Issue: July 14, 2006 Effective: July 15, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated September 19, 2005
in Docket No. EO04060395 and also Docket No. AT06070502

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
(Continued)

Amortization of Excess Depreciation Reserve

This charge shall amortize an excess depreciation reserve that shall be amortized over 29 months beginning August 1, 2003 and is intended to expire December 31, 2005. Refer to the Amortization of Excess Depreciation Reserve sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-Utility Generation Transition Charge, Securitization Transition Charges, System Control Charge, and the Amortization of Excess Depreciation Reserve Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer must receive electric supply from Public Service through its Basic Generation Service – Fixed Pricing (BGS – FP) default service.

Basic Generation Service:

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatthours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RSP. Customers selected to participate in the pilot will be provided BGS-FP service at Critical Peak Pricing (CPP).

While participating in this pilot program, the customer is precluded from using on-site generation equipment except when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service.

Date of Issue: May 5, 2006 Effective: April 27, 2006
Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated April 27, 2006
in Docket No. EO04060395

RATE SCHEDULE RSP
RESIDENTIAL SERVICE PILOT
(Continued)

TERMS OF PAYMENT:

Bills are due on presentation.

TERM:

Customer may discontinue delivery service upon notice. Public Service may terminate the availability of this Rate Schedule at its discretion and upon proper notice to the customer.

SPECIAL PROVISIONS:

(a) **Installation and Removal:** Metering and Energy Management Equipment will be owned, installed and maintained by Public Service at the customer's residence upon customer's initial acceptance of service under Rate Schedule RSP at no charge to the customer. The customer shall provide a suitable location approved by Public Service for such facilities. Energy Management Equipment may be removed by Public Service at the conclusion of the pilot or at any time that the customer decides to withdraw from the pilot. Customers completing the pilot may keep the pilot thermostat at no cost.

(b) **Voluntary Withdrawal:** Customers who voluntarily withdraw from this pilot program can return to Rate Schedule RS. If customer notification is received at least three days prior to the end of the customer's billing month the customer will be billed for the full billing month at Rate Schedule RS (the billing month normally ends with the customer's scheduled meter reading date). Customers voluntarily withdrawing from this pilot program are not eligible to reenter the pilot program.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Budget Plan (Equal Payment Plan):** Participation in the Budget Plan (Equal Payment Plan) will be suspended for the duration of customer participation in this pilot program.

(e) **A/C Cycling Program:** Participation in Public Service's A/C Cycling (Cool Customer) Program will be suspended and the installed load control device will be deactivated during customer participation in this pilot program.

(f) **Billing Information:** Upon customer request, historical pilot program billing information will be provided to the customer at no charge.

STATE OF NEW JERSEY AUTHORIZED TAXES:

The Transitional Energy Facility Assessment and the New Jersey Sales and Use Tax are applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44. and are included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

Date of Issue: July 14, 2006 Effective: July 15, 2006
Issued by FRANCIS E. DELANY, Jr.. Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated September 19, 2005
in Docket No. EO04060395 and also Docket No. AT06070502

Appendix K

PSE&G myPower Sense Pricing Segment – Customer Phone Screening Questions

PSE&G myPower Pricing Segments – Customer Phone Screening Questions
Revised FINAL November 10, 2005
myPower Sense
Segment – B TOU/CPP Education Only - 550 customers needed

Confirm Customer Name, Address, home phone, work phone, and e-mail address.

CUSTNME **Customer Name: ____**

CUSTADD **Address: ____**

CUSTTWN ☐ Cherry Hill OR ☐ Hamilton Township

CUSTZIP **Zip _________________**

ACCOUNT **PSE&G account number: ___________________________________**

HOMETEL **Home Telephone number: ___________________________________**

OFFICETEL **Office Telephone number: ___________________________________**

PSE&G1 **Do you or anyone in your household work for PSE&G?**
☐ Yes THANK & TERMINATE
☐ No CONTINUE

HOME1 **Do you expect to remain at this address for at least one year?**
☐ Yes CONTINUE
☐ No THANK & TERMINATE

CUSTYPE **Is this a home or business?**
☐ Home CONTINUE
☐ Business THANK & TERMINATE

COND1. **Do you have air-conditioning?**
☐ Yes CONTINUE
☐ No CONTINUE

COND2 Is it through central air conditioning or room units?
☐ Central AC
☐ Electric Heat Pump
☐ Room, window or wall units

IF CUSTOMER HAS ROOM, WINDOW OR WALL UNITS, ASK:

COND3 How many room units do you have? _____________

IF CUSTOMER HAS ROOM, WINDOW OR WALL UNITS, ASK:

COND4 **During the summer, do you normally turn your room units on only when someone is home or do you normally have at least one of your room units running while no one is home so that when someone comes home the room or rooms will be cool?**

- ☐ Room units running only when someone is home
- ☐ Room unit or units running when no one is home
- ☐ Other operation of room units – Specify ________________
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

IF CUSTOMER HAS CENTRAL AIR CONDITIONER OR AN ELECTRIC HEAT PUMP, ASK:

COND5 **How many condensers (which are the outside units) do you have? _____________**

IF CUSTOMER HAS CENTRAL AIR CONDITIONER OR AN ELECTRIC HEAT PUMP, ASK:

COND6 **Which of the following statements best describes how you usually operate your central air conditioning system?**

- ☐ You keep the temperature setting the same no matter what time it is or if you are home or not
- ☐ You raise the temperature when no one is home and lower it when you get home
- ☐ You program your thermostat to raise the temperature during the hours you expect to be away from home and lower the temperature during the hours you are normally home.
- ☐ You manually turn your air conditioner on and off
- ☐ You rarely use the central air conditioning system

ASK ALL:

COND7 **During the summer months, would you say that you never, rarely, sometimes or often turn on your air conditioners during the following time periods…?** ASK FOR EACH TIME PERIOD

Weekday Afternoons from 2pm to 5pm # __________

Weekday Evenings from 5pm to 7pm ___#___________

All other times______________________#___________

1. Never

2. Rarely (1 day per week)

3. Sometimes (2-3 days a week)

4. Often (4 or more days per week)

THERM1 **What kind of thermostat do you have?**

- ☐ Round dial
- ☐ Rectangular box
- ☐ Digital display
- ☐ Something Else, Please Specify: ______________________
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

IF CUSTOMER HAS A DIGITAL DISPLAY THERMOSTAT, ASK:

THERM2 **Is your digital display thermostat a programmable thermostat, meaning that you can program it?**

- Yes
- No
- DON'T KNOW/REFUSED (DO NOT READ)

ASK ALL:

HOME2 **Do you own or rent your home?** Own Rent

HOME3 **What type of home do you live in? Is it a…?.**

- Single Family Residence
- Townhouse, duplex or row house
- Apartment or Condo with 2-4 units
- Apartment or Condo with 5 or more units
- Mobile Home
- Something Else; Please specify: ___________________
- DON'T KNOW/REFUSED (DO NOT READ)

HOME4 **In what year was your home built, was it built…?**

- Before 1960
- 1960 to 1979
- 1980 to 1999
- 2000 to 2005
- DON'T KNOW/REFUSED (DO NOT READ)

HOME5 **And what is the approximate square footage of this home? Please do not include non-heated garages, non-heated attics and/or non-heated basement space.**

____

- DON'T KNOW/REFUSED (DO NOT READ)

HOME6 **Where is your electric meter located? Is it…?**

- Inside
- Outside

HOME7 **How do you heat your home? Is it by…?**

- Natural Gas
- Oil
- Propane
- Electric
- Or Some other Way, Please Specify: __________________

HOME8 **What kind of heating system do you have? Is it…?** Forced air

- Hot water
- Steam
- Electric baseboard
- Heat pump
- Or Some Other System, Please Specify: _________________

HOME14 **What is the age of your heating system?**

____

HOME9 **Where is your gas meter located? Is it…?**

- ☐ Inside
- ☐ Outside

HOME10 **Do you have broadband Internet service in your home?**

- ☐ Yes
- ☐ No
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

EMAIL **What is your e-mail address? (Explain to customers that we will be sending newsletters, program updates, notice of high prices, etc. via e-mail if they have it)**

Email address ____

ASK IF CUSTOMER IS A COOL CUSTOMER PARTICIPANT (FROM DATABASE)

AWARE1 **Are you aware that you are a current participant in PSE&G's Cool Customer Program?**

- ☐ Yes
- ☐ No

ASK IF CUSTOMER IS A EQUAL PAYMENT PLAN PARTICIPANT (FROM DATABASE)

AWARE2 **Are you aware that you are on PSE&G's Equal Payment Plan?**

- ☐ Yes
- ☐ No

ASK IF COOL CUSTOMER OR EQUAL PAYMENT PLAN PARTICIPANT

AWARE3 **Are you aware that if you wish to be a myPower Sense participant, you must drop-out of this/these program (s)?**

- ☐ Yes
- ☐ No

IF CUSTOMER IS NOT AWARE OF THER COOL CUSTOMER OR EQUAL PAYMENT PLAN PARTICIPATION REVIEW Q & A QUESTIONS IN THE BROCHURE WITH THEM

Cool Customer Participants - Once they are aware, tell them that PSE&G will make arrangements to suspend their participation in Cool Customer, they will not receive the $6 monthly credit once the pilot starts, however after pilot they may resume participation in Cool Customer at no charge to them.

Equal Payment Plan Participants - Once they are aware, tell them that PSE&G will make arrangements to suspend their participation in the EPP. A PSE&G representative will be contacting them to discuss their current bill balance.

PREFCONT **By which two methods would you liked to be of a critical or high priced event? Would you like to be contacted at your home phone, your office phone, cell phone, e-mail or pager number?**

Check and complete the two (2) methods of customer notification:

- ☐ Home Phone (______)______________________
- ☐ Office Phone (______)______________________
- ☐ Cell Phone (______)________________________
- ☐ E Mail ___________________________________
- ☐ Pager (_____)_________________________

NOTE – PHONE NUMBERS WITH EXTENSIONS CANNOT BE USED FOR NOTIFICATION PURPOSES BECAUSE THE AUTOMATED SYSTEM THAT MAKES THE CUSTOMER CALLS CANNOT ACCOMMODATE EXTENSIONS

Thank you very much for your time. A PSE&G representative will contact you to change your electric meter. You will also receive in the mail a confirmation of you program enrollment and educational materials to help you make the most of your program participation.

Now, before we close, I need to ask you a few questions that will help us learn about our customer's attitudes for this important pilot:

First, let's talk about PSE&G overall.

CSAT. **Thinking about your overall day-to-day experiences with PSE&G as your electricity utility, how satisfied would you say you are with PSE&G where ONE means EXTREMELY DISSATISFIED, and TEN means EXTREMELY SATISFIED?**

_______________[RECORD NUMBER 1 - 10]

- ☐ DON'T KNOW/REFUSED

RATE. **In general, would you classify PSE&G's rates as very reasonable, somewhat reasonable, neither reasonable nor unreasonable, somewhat unreasonable, or very unreasonable?**

- ☐ Very Reasonable
- ☐ Somewhat Reasonable
- ☐ Neither Reasonable Nor Unreasonable
- ☐ Somewhat Unreasonable
- ☐ Very Unreasonable
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

PART. **What are the main reasons why you are participating in PSE&G's myPower Sense Program? (MULTPILE RESPONSES ACCEPTED/DO NOT READ RESPONSES)**

- ☐ Incentive Payment

- ☐ To Save Money On Electric Bills
- ☐ To Conserve Energy
- ☐ To Help The Environment
- ☐ Some Other Reason, Please Specify: _______________
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

IMPORT **How important is it for you to have the ability to help the environment by conserving energy? Would you say it's very important, somewhat important, neither important nor unimportant, somewhat unimportant, very unimportant?**

- ☐ Very Important
- ☐ Somewhat Important
- ☐ Neither Important Or Unimportant
- ☐ Somewhat Unimportant
- ☐ Very Unimportant
- ☐ DON'T KNOW/REFUSED

PRICE **Do you believe the price of electricity will be increasing, decreasing or staying the same over the next 3 years? (if increasing or decreasing) Do you believe they will increase a great deal or decrease a great deal? (MARK APPROPRIATE RESPONSE)**

- ☐ Increase a great deal
- ☐ Increase
- ☐ Stay the same
- ☐ Decrease
- ☐ Decrease a great deal
- ☐ REFUSED
- ☐ DON'T KNOW

CONSERVE. **In the past 2 years, have you done any of the following things to reduce your electricity consumption related to cooling your home? (ACCEPT MULTIPLE RESPONSES)**

A. Permanently set your thermostat at a higher than normal temperature

- ☐ Yes
- ☐ No

IF YES, ASK:

Why did you choose to reduce your electricity consumption? (ACCEPT MULTIPLE RESPONSES)

- ☐ To reduce the amount you pay to cool your home each month?
- ☐ Because you heard that electricity prices were going to go up?
- ☐ The summer weather was cooler than normal?
- ☐ Because you wanted to conserve electricity to help the environment?
- ☐ Some Other Reason, Please Specify: ________________________________
- ☐ DON'T KNOW/REFUSED

B. Reduced the hours during which you cool your home

- ☐ Yes
- ☐ No

IF YES, ASK:

Why did you choose to reduce your electricity consumption? (ACCEPT MULTIPLE RESPONSES)

- ☐ To reduce the amount you pay to cool your home each month?
- ☐ Because you heard that electricity prices were going to go up?
- ☐ The summer weather was cooler than normal?
- ☐ Because you wanted to conserve electricity to help the environment?
- ☐ Some Other Reason, Please Specify: ______________________________
- ☐ DON'T KNOW/REFUSED

C. Manually increased the temperature on your thermostat at times
- ☐ Yes
- ☐ No

IF YES, ASK:

Why did you choose to reduce your electricity consumption? (ACCEPT MULTIPLE RESPONSES)

- ☐ To reduce the amount you pay to cool your home each month?
- ☐ Because you heard that electricity prices were going to go up?
- ☐ The summer weather was cooler than normal?
- ☐ Because you wanted to conserve electricity to help the environment?
- ☐ Some Other Reason, Please Specify: ______________________________
- ☐ DON'T KNOW/REFUSED

D. Replaced your air conditioning system with a new, energy efficient unit
- ☐ Yes
- ☐ No

IF YES, ASK:

Why did you choose to reduce your electricity consumption? (ACCEPT MULTIPLE RESPONSES)

- ☐ To reduce the amount you pay to cool your home each month?
- ☐ Because you heard that electricity prices were going to go up?
- ☐ The summer weather was cooler than normal?
- ☐ Because you wanted to conserve electricity to help the environment?
- ☐ Some Other Reason, Please Specify: ______________________________
- ☐ DON'T KNOW/REFUSED

E. Have you done any other things to reduce your electricity consumption related to cooling your home? IF YES, PLEASE SPECIFY: ____________________________________

Now, let's talk about your energy usage and bill.

BILL1 **How much do you expect the <u>electricity</u> portion of your PSE&G bill to be this month? (in dollars)**

____

BILL2 **How familiar are you with the concept of on-peak and off-peak pricing of electricity? Would you say that you are…**

- ☐ Very Familiar
- ☐ Somewhat Familiar
- ☐ Neither Familiar Nor Unfamiliar
- ☐ Not Too Familiar
- ☐ Not At All Familiar With This Concept

BILL3 **Were you aware that the hours from 2pm to 7pm (RESIDENTIAL)/Noon to 6pm (BUSINESS) are considered peak hours, meaning that the cost of providing electricity to consumers is at its highest point? (Note to interviewer: Peak hours are when the price that the <u>utility</u> pays for the electricity that it provides to its customers is at its highest.)**

- ☐ YES
- ☐ NO

HOME11 **Is someone normally home during the day?**

- ☐ YES
- ☐ NO

IF SOMEONE IS NORMALLY HOME DURING THE DAY ASK:

HOME12 **Who is normally home? [MULTIPLE RESPONSES ACCEPTED]**

- ☐ Self
- ☐ Spouse
- ☐ Children
- ☐ Children with sitter
- ☐ Relative or Friend
- ☐ Someone Else, Please Specify: ______________________

IF NO ONE IS HOME DURING THE DAY, ASK:

HOME12 **What time does someone usually return to the house weekday afternoons/evenings?**

[APPROXIMATE TIME IS FINE]__________________

KNOW. **Do you feel that you have enough information about the rates you pay and your electricity usage to reduce the amount of your electricity bill?**

- ☐ Yes
- ☐ No

INFO WHAT ADDITIONAL INFORMATION COULD PSE&G PROVIDE TO HELP YOU REDUCE YOUR ELECTRICITY BILL?____

Thank you for your time and participation!

Appendix L

PSE&G myPower Connection Pricing Segment – Customer Phone Screening Questions

PSE&G myPower Pricing Segments – Customer Phone Screening Questions
FINAL November 8, 2005
myPower Connection
Segment - C TOU/CPP Technology Enabled - 400 customers needed

CUSTNME **Customer Name: ____**

CUSTADD **Address: ____**

CUSTTWN **□ Cherry Hill OR □ Hamilton Township,**

CUSTZIP **Zip _________________**

ACCOUNT **PSE&G account number: ___________________________________**

HOMETEL **Home Telephone number: ___________________________________**

OFFICETEL **Office Telephone number: ___________________________________**

PSE&G1 **Do you or anyone in your household work for PSE&G?**
□ Yes THANK & TERMINATE
□ No CONTINUE

HOME1 **Do you expect to remain at this address for at least one year?**
□ Yes CONTINUE
□ No THANK & TERMINATE

CUSTYPE **Is this a home or business?**
□ Home CONTINUE
□ Business THANK & TERMINATE

TEL1 **Do you have regular Phone service in your home?**
(Not voice over IP or cell phone only)
□ Yes CONTINUE
□ No THANK & TERMINATE

COND1 **Do you have air-conditioning?**
□ Yes CONTINUE
□ No THANK & TERMINATE

COND2 **Is it through central air conditioning or room units?**
□ Central AC CONTINUE
□ Electric Heat Pump CONTINUE
□ Room, window or wall units THANK & TERMINATE

COND8 **At seasons end was your central air conditioning in good working order?**
□ Yes CONTINUE
□ No THANK & TERMINATE

COND9 **What is the age of your A/C unit?** ________________

COND5 **How many condensers (which are the outside units) do you have? _____________**

THANK & TERMINATE IF MORE THAN TWO

THERM3 **How many thermostats do you have? #____________**

THERM1 **What kind of thermostat(s) do you have?**

(ACCEPT MULTIPLE RESPONSES)
- Round dial
- Rectangular box
- Digital display
- Something Else, Please Specify: ______________________
- DON'T KNOW/REFUSED (DO NOT READ)

IF CUSTOMER HAS A DIGITAL DISPLAY THERMOSTAT, ASK:

THERM2 **Is your digital display thermostat a programmable thermostat, meaning that you can program it?**
- Yes
- No
- DON'T KNOW/REFUSED (DO NOT READ)

THERM4 **Does any single thermostat control both the heating and cooling systems?**
- Yes
- No

THERM5 **How many thermostats control the cooling?**
THANK & TERMINATE IF MORE THAN ONE PER #___________
- DON'T KNOW/REFUSED **(DO NOT READ)**

THERM6 **How many thermostats control the heating? #___________**
- DON'T KNOW/REFUSED **(DO NOT READ)**

CONDENSE **Does Trane manufacture your condenser?**
- Yes
- No

AIRHAND1 Where is each air handler (a/c blower) located? (MULTIPLE RESPONSE ACCEPTED)

- Attic
- Basement
- Utility room
- Somewhere Else, Please Specify ______________________________
- DON'T KNOW/REFUSED **(DO NOT READ)**

ASK AIRHAND2 THROUGH AIRHAND5 FOR ALL AIR HANDLERS IN AIRHAND1.

IF IN THE ATTIC ASK:

AIRHAND2 **Is the air handler accessible?**

- ☐ Yes
- ☐ No THANK & TERMINATE
- ☐ DON'T KNOW/REFUSED **(DO NOT READ)**

IF IN THE ATTIC ASK:

AIRHAND3 **How is the attic accessed?**

____

IF IN THE ATTIC ASK:

AIRHAND4 **Will we need a ladder?**

- ☐ Yes
- ☐ No

IF IN THE ATTIC ASK:

AIRHAND5 **Is the attic floored?**

- ☐ Yes
- ☐ No THANK & TERMINATE

HOME7 **How do you heat your home?**

- ☐ Natural Gas
- ☐ Oil
- ☐ Propane
- ☐ Electric
- ☐ Other; Please specify ____

HOME8 **What kind of heating system do you have?**

- ☐ Forced air
- ☐ Hot water
- ☐ Steam
- ☐ Electric baseboard
- ☐ Heat pump
- ☐ Other; Please specify ____

HOME13 **If you have electric heat – is it "strip" heat (baseboard?)**

- ☐ Yes THANK & TERMINATE
- ☐ No CONTINUE

HOME 16 **Do you have a summer/winter switch on or near your furnace?**

- ☐ Yes THANK & TERMINATE
- ☐ No CONTINUE

HEATER1 **Where is your heater located?**

- ☐ Attic
- ☐ Basement
- ☐ Utility room
- ☐ Somewhere Else, Please Specify ______________________________
- ☐ DON'T KNOW/REFUSED **(DO NOT READ)**

HOME14 **What is the age of your heating system?** ________________

HOME2 **Do you own or rent your home?**

- ☐ Own
- ☐ Rent

IF RENT ASK:

HOME17 **Is landlord permission required?**

- ☐ Yes
- ☐ No

HOME10 **Do you have broadband Internet service in your home?**

- ☐ Yes
- ☐ No
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

HOME3 **What type of home do you live in? Is it a…?.**

- ☐ Single Family Residence
- ☐ Townhouse, duplex or row house
- ☐ Apartment or Condo with 2-4 units
- ☐ Apartment or Condo with 5 or more units
- ☐ Mobile Home
- ☐ Something Else; Please specify: ___________________
- ☐ DON'T KNOW/REFUSED (DO NOT READ)

HOME6 **Where is your electric meter located? Is it…?**

- ☐ Inside
- ☐ Outside

IF CUSTOMER LIVES IN A TOWNHOUSE OR CONDO AND HAS A METER OUTSIDE ASK:

HOME18 Is your meter located in a bank of meters, meaning that it is surrounded by your neighbor's meters?

- ☐ Yes
- ☐ No
- ☐ DON'T KNOW **(DO NOT READ)**

HOME9 **Where is your gas meter located?**

- ☐ Inside
- ☐ Outside

HOME15 **Do you have an electric water heater?**

- ☐ Yes
- ☐ No

IF CUSTOMER HAS AN ELECTRIC WATER HEATER ASK:

HOME19 **How old is the water heater?_________________**

IF CUSTOMER HAS AN ELECTRIC WATER HEATER ASK:

HOME 20 **Is the water heater in good condition?**

- ☐ Yes (Meaning it is not leaking)

- ☐ No

HOME23 **Do you have an in ground pool?**

- ☐ Yes
- ☐ No

IF YES ASK:

HOME21 **How many months was the pool pump in use?________________**

HOME22 **Was the pool pump in good working order at the end of the season?**

- ☐ Yes
- ☐ No

IF NO THEN EXCLUDE POOL PUMP FROM LOAD CONTROL

EMAIL **What is your e-mail address? (Explain to customers that we will be sending newsletters, program updates, notice of high prices, etc. via e-mail if they have it)**

Email address ____

ASK IF CUSTOMER IS A COOL CUSTOMER PARTICIPANT (FROM DATABASE)

AWARE1 **Are you aware that you are a current participant in PSE&G's Cool Customer Program?**

- ☐ Yes
- ☐ No

ASK IF CUSTOMER IS AN EQUAL PAYMENT PLAN PARTICIPANT (FROM DATABASE)

AWARE2 **Are you aware that you are on PSE&G's Equal Payment Plan?**

- ☐ Yes
- ☐ No

ASK IF COOL CUSTOMER OR EQUAL PAYMENT PLAN PARTICIPANT

AWARE3 **Are you aware that if you wish to be a myPower <u>Connection</u> participant, you must drop-out of this/these program (s)?**

- ☐ Yes
- ☐ No

IF CUSTOMER IS NOT AWARE OF THEIR COOL CUSTOMER OR EQUAL PAYMENT PLAN PARTICIPATION REVIEW Q & A QUESTIONS IN THE BROCHURE WITH THEM

<u>Cool Customer Participants</u> - Once they are aware, tell them that PSE&G will make arrangements to suspend their participation in Cool Customer, they will not receive the $6 monthly credit once the pilot starts, however after pilot they may resume participation in Cool Customer at no charge to them.

<u>Equal Payment Plan Participants</u> Once they are aware, tell them that PSE&G will make arrangements to suspend their participation in the EPP. A PSE&G representative will be contacting them to discuss their current bill balance.

PREFCONT **By which two methods would you like to be contacted about a critical or high priced event? Would you like to be contacted at your home phone, your office phone, cell phone, e-mail or pager number?**

Check and complete the two (2) methods of customer notification:

- ☐ Home Phone (______)____________________________________
- ☐ Office Phone (______)____________________________________
- ☐ Cell Phone (______)____________________________________
- ☐ E Mail ____
- ☐ Pager (______)____

NOTE – PHONE NUMBERS WITH EXTENSIONS CANNOT BE USED FOR NOTIFICATION PURPOSES BECAUSE THE AUTOMATED SYSTEM THAT MAKES THE CUSTOMER CALLS CANNOT ACCOMMODATE EXTENSIONS

Thank you very much for your time. A PSE&G representative will contact you to change your electric meter. You will also receive in the mail a confirmation of your program enrollment and educational materials to help you make the most of your program participation.

Now, before we close, I need to ask you a few questions that will help us learn about our customer's attitudes for this important pilot:

ASK QUESTIONS AFTER CUSTOMER HAS BEEN QUALIFIED AND ENROLLED.

First, let's talk about PSE&G overall.

CSAT **Thinking about your overall day-to-day experiences with PSE&G as your electricity utility, how satisfied would you say you are with PSE&G where ONE means EXTREMELY DISSATISFIED, and TEN means EXTREMELY SATISFIED?**

____

[RECORD NUMBER 1 - 10]

- ☐ DON'T KNOW/REFUSED

RATE **In general, would you classify PSE&G's rates as very reasonable, somewhat reasonable, neither reasonable nor unreasonable, somewhat unreasonable, or very unreasonable?**

- ☐ Very Reasonable
- ☐ Somewhat Reasonable
- ☐ Neither Reasonable Nor Unreasonable
- ☐ Somewhat Unreasonable
- ☐ Very Unreasonable
- ☐ DON'T KNOW/REFUSED **(DO NOT READ)**

PART **What are the main reasons why you are participating in PSE&G's myPower Connection program? (MULTIPLE RESPONSES ACCEPTED/DO NOT READ RESPONSES)**

- ☐ Free Thermostat
- ☐ Incentive Payment
- ☐ Internet Access To Thermostat

- Interested in New Technology
- To Save Money On Electric Bills
- To Conserve Energy
- To Help The Environment
- Some Other Reason, Please Specify: ___________________________
- DON’T KNOW/REFUSED **(DO NOT READ)**

IMPORT **How important is it for you to have the ability to help the environment by conserving energy? Would you say it’s very important, somewhat important, neither important nor unimportant, somewhat unimportant or very unimportant?**

- Very Important
- Somewhat Important
- Neither Important Nor Unimportant
- Somewhat Unimportant
- Very Unimportant
- DON’T KNOW/REFUSED **(DO NOT READ)**

PRICE **Do you believe the price of electricity will be increasing, decreasing or staying the same over the next 3 years? (if increasing or decreasing) Do you believe they will increase a great deal or decrease a great deal? (MARK APPROPRIATE RESPONSE)**

- Increase a great deal
- Increase
- Stay the same
- Decrease
- Decrease a great deal
- DON”T KNOW/REFUSED **(DO NOT READ)**

Thank you for your time and participation!

Appendix M

Sample myPower Billing Statement

Sample of myPower October 2006 bill

The format of the myPower bill is similar in many aspects to that of a "regular" PSE&G bill.

Monthly Statement
October 2006
Account Number

24-hour customer service
1 800 436-PSEG (7734)

Thank you for participating in myPower Connection.

Visit our
Website
www.myPowerNJ.com

Inquiries by mail
PSE&G
PO Box 14444
New Brunswick, NJ 08906

Important Dates
Your payment is due
October 28, 2006.

Your next meter reading
is scheduled for
November 7.

Meter reading scheduling
1 800 832-0079

Account Summary

PSE&G Balance from last bill	319.25
Payment Received - Thank You	-300.68
Current PSE&G - Gas	36.13
Current PSE&G - Electric	184.79
Other PSE&G Charges and Credits	-18.57
Total Amount Due On October 28, 2006	**$220.92**

The myPower bill displays the various Pricing Tiers under the Supply section of the bill along with the applicable kWh usage – Medium (Base charge), Low (Night Discount), High (On-Peak Adder) and Critical Peak Adder. The service charges and distribution charges remain the same on the myPower bill as in normal CIS bills.

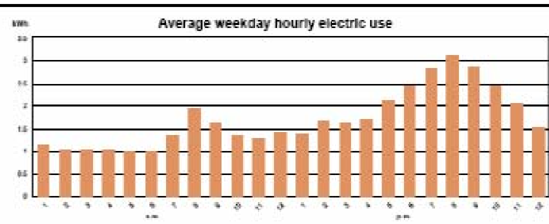
PSE&G Electric

Usage	Meter 126799297
Total kWh	1,330

Charges		Rate - RSP
Delivery		
Service charge		$2.43
Distribution charges		
kWh charges	1,330 kWH @ $0.054135338	72.00
Sub-Total Delivery		**$74.43**
Supply		
BGS Energy - myPower Connection		
Service from Sep 8 to Oct 9		
Base Charge (Medium)	1,330 kWH @ $0.089210526	$118.65
Night Discount (Low)	415.500 kWH @ $-0.05	-19.80
On-Peak Adder (High)	143.860 kWH @ $0.08	11.51
Critical Peak Adder	0.000 kWH @ $0.00	0.00
Sub-Total Supply		**$110.36**
Total electric charges		**$184.79**

Program Energy Use Comparison

myPower bills also provide customers with a Program Comparison section. The program comparison allows the customer to see what they were billed under the myPower program according to their usage, verses what they would have paid has they not participated in myPower and remained on the standard billing plan.



Program Comparison

The table below compares your current electric bill as a participant in the myPower program and your bill on the standard electric rate. based on the same usage. For best results. bill comparisons should be measured over a one year period. For detailed billing usage and energy saving tips. go to: www.myPowerNJ.com

	Current Month	Program to Date
myPower charges	$184.79	$1,173.65
Standard charges	$198.36	$1,210.13
Difference	$-13.57	$-36.48

Get better results by moving your electricity usage to times when electricity prices are lower.

Energy Use Comparison

This chart represents your energy use for the billing months shown in the current year compared to last year.

	Average Temperature		Gas CCF		Electric kWH	
	2005	2006	2005	2006	2005	2006
Oct	72	65	20	21	2304	1330
Sep	79	73	18	18	3487	1737
Aug	81	82	22	16	4105	2745

Appendix N

Overview of the myPower Website

This site is used to:

1. Input Clean Power data
2. Approve myPower bills by billing month and route and upload to customer website for viewing by customer
3. Record Bill diverts when received
4. View and approve monthly sales adjustments
5. Manage all myPower accounts
6. Process and reprocess bills
7. View printed customer bills via PDF
8. Produce reports including monthly reporting that shows percentage of myPower bills sent to date and monthly average savings on myPower vs. CIS bill averages.
9. Input of monthly rates and temperatures used to calculate monthly bills
10. Produce ad-hoc or specialized reports

Website for Administrative Users

Administrator Screen

The myPower customer simulated website for use by administrators allows customer inquiry representatives to view customer accounts for inquiry purposes. Administrators also have the ability to change customer information upon customer request, and simulate what the customer sees for ease of access. The customer's login information including email address is required to view the website screens. If a customer has forgotten their log-in password, an automated feature will send the password to the customers email address they used when they registered. The administrator function can also "unlock" users as well as monitor customer website usage patterns.

The administrative function for the myPower website allows the myPower billing team and customer care staff to access the site for numerous reasons.

Interval data is sent via FTP interface to myPower customer website directories that will post to customer accounts for viewing monthly, daily and hourly usage. Pricing information is also sent via file interfaces to the customer website. Secure FTP transmissions ensure that all data is secure and follows all safety protocols required by Public Service IT security department.

Home Page of the myPower Customer Website and the myThermostat tab used for website interface

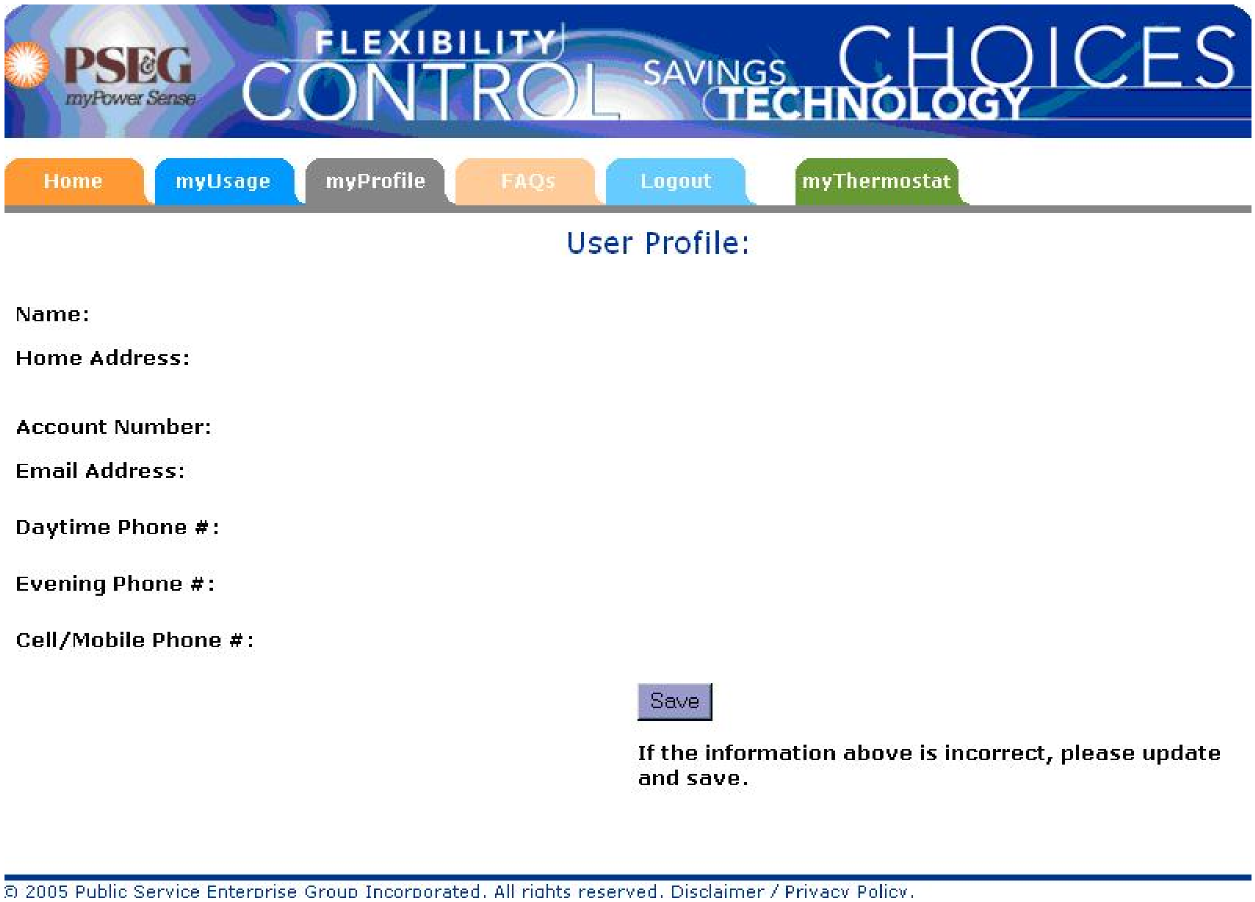
Website Interface for Programming Smart Thermostats

Customers are able to view and change their thermostat settings at the myPower website, via secure links to either the Itron or Comverge websites, depending on the technology installed in their home and segment in which they participate in. (myPower Connection Itron REMS customers link to the Itron website and myPower Connection customers with Comverge technology link to the Comverge website). myPower Sense customers do not have access to the thermostat programming feature of the site because they do not have programmable thermostats as part of their program participation.

Webpage for Customer Profile

myPower customers were given a login ID and initial password (prompted to change upon login) via introduction of the website. On the myProfile screen, customers are able to view their account information as well as to update their “profile” information in a secure environment such as their telephone number and email address.

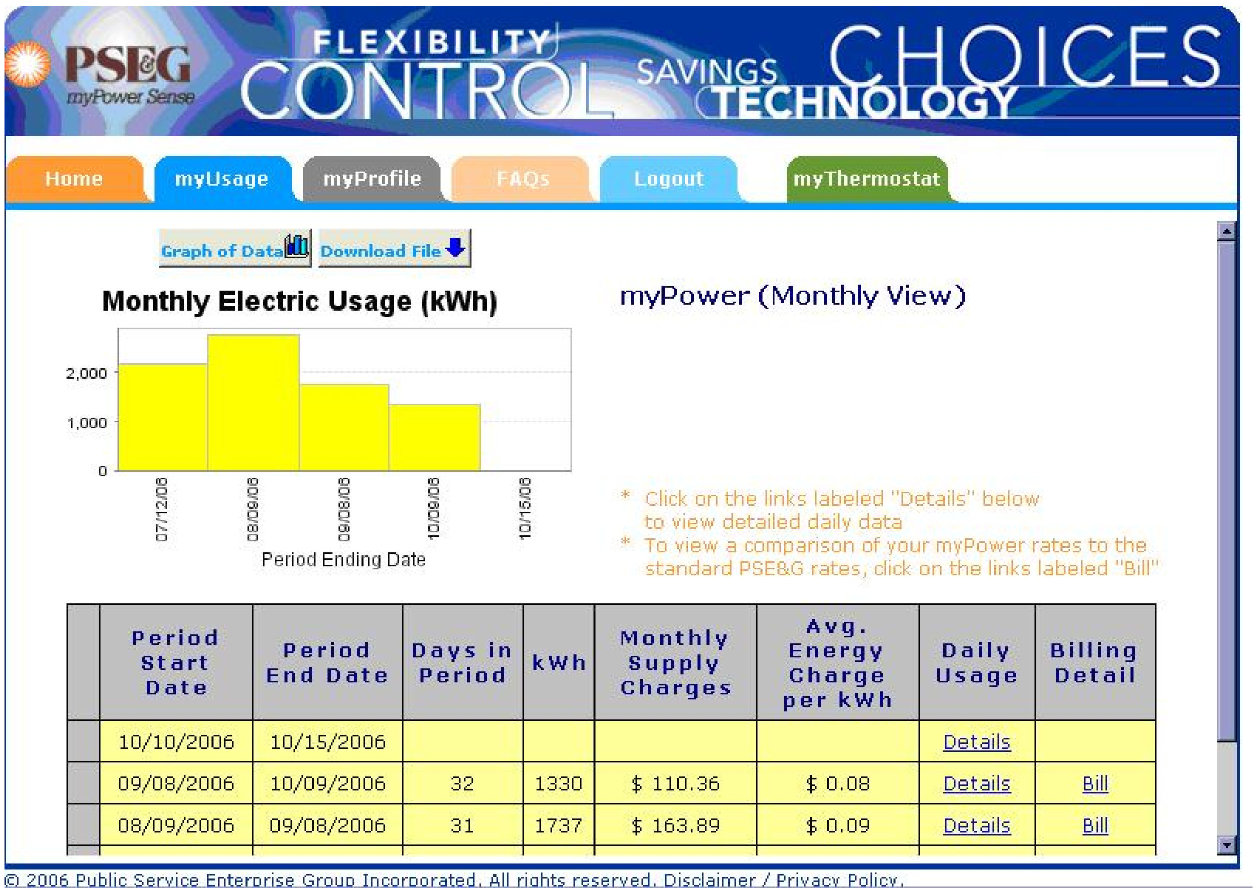
myProfile Screen of the Website



Webpage for Customer Usage

The myUsage tab on the website allows the customer to view monthly, daily and hourly data for their electric account. The tab provides bar chart displays of usage and buttons at the top of each screen give customers the ability to either graph or download their data. Customers are also able to select a link that will allow them to view and print a PDF of their monthly bill.

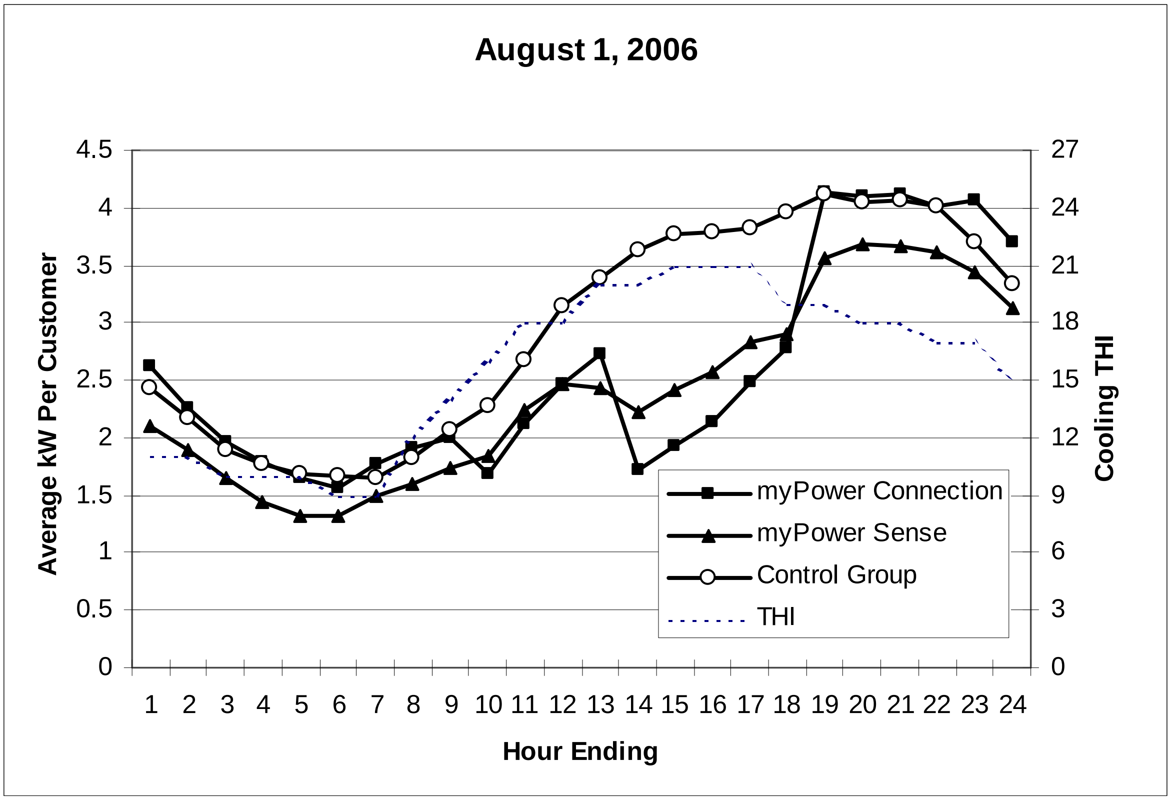
Website Monthly myUsage Screen

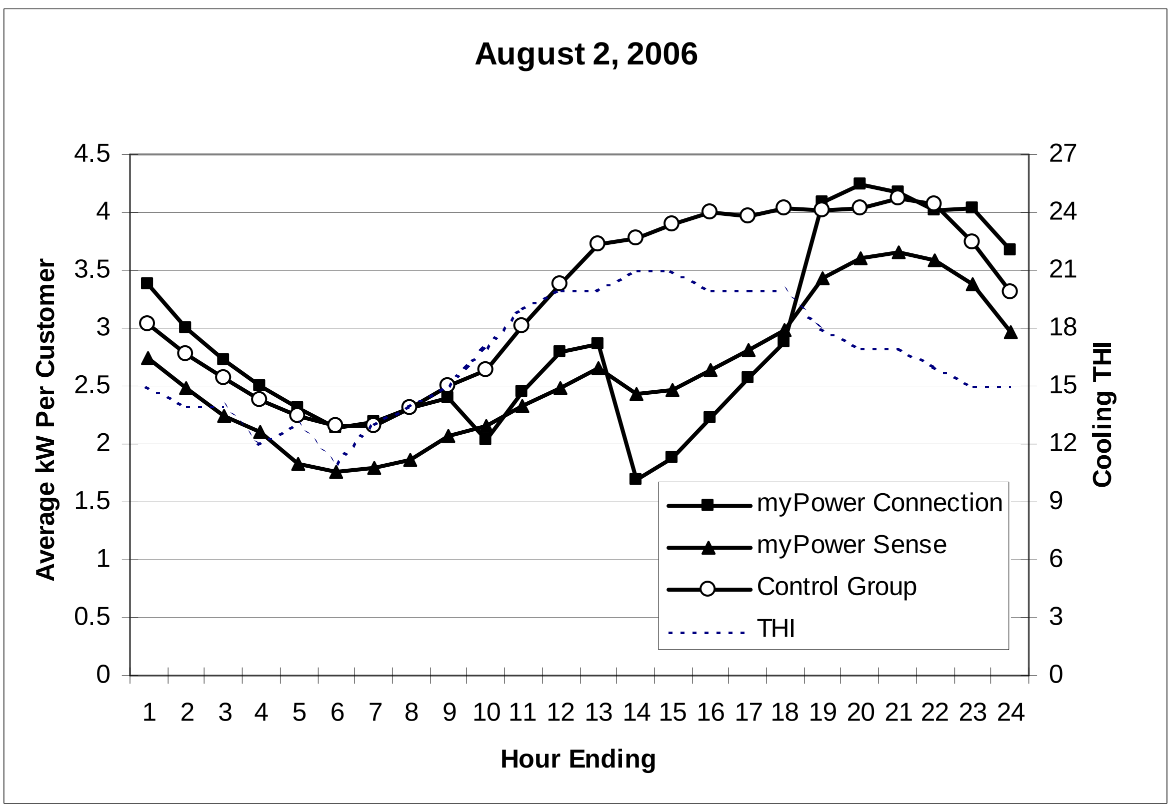


Appendix O

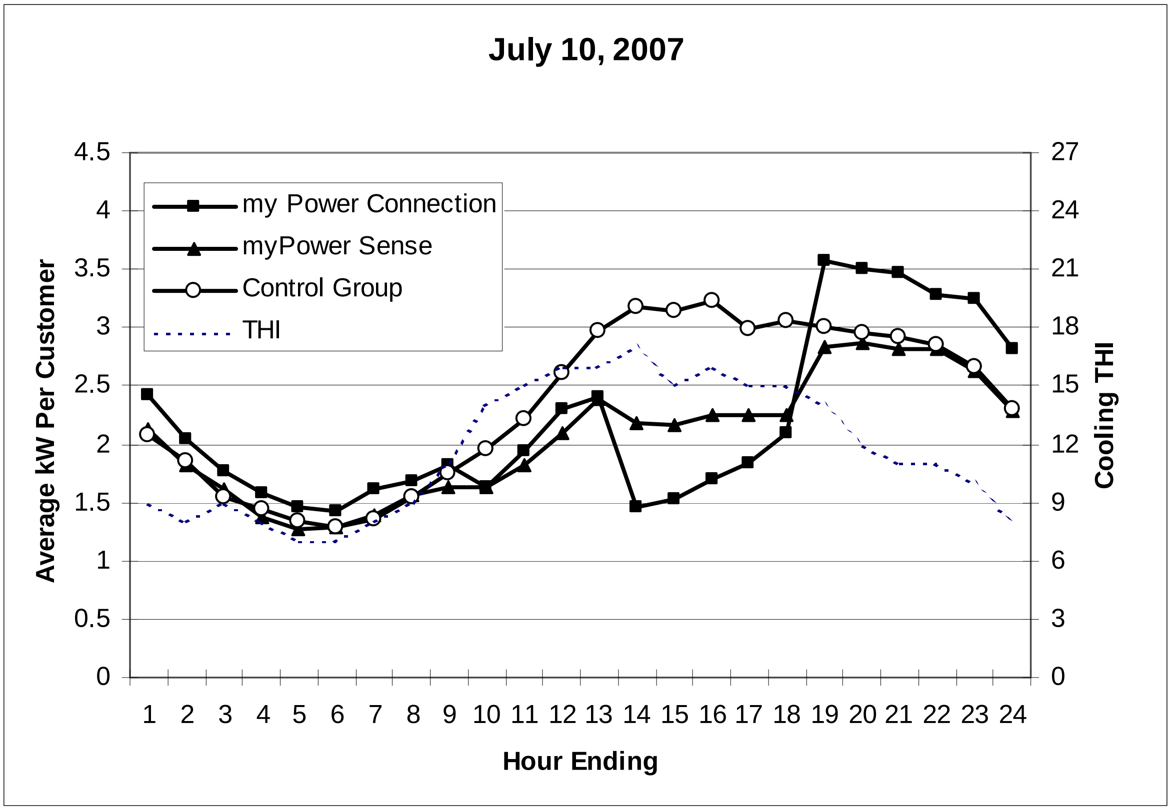
Daily Load Curves for Critical Peak Event Days

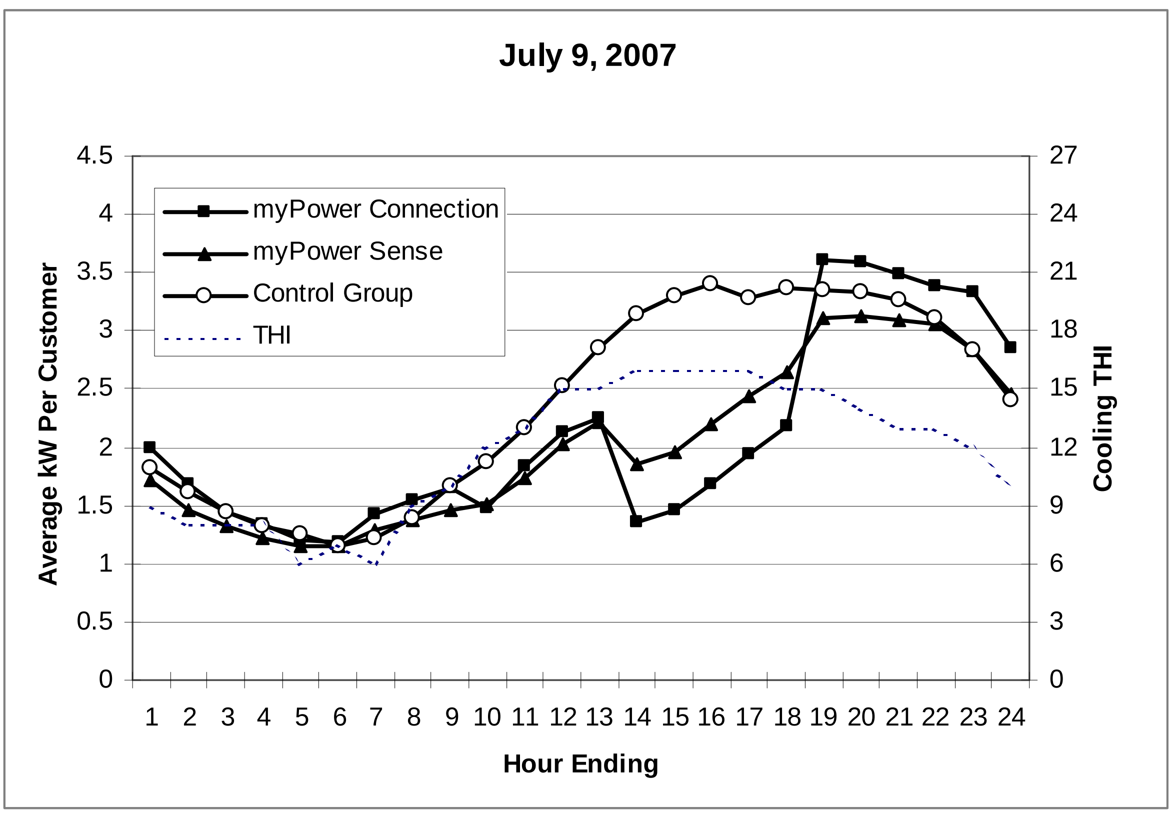
Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Summer Months



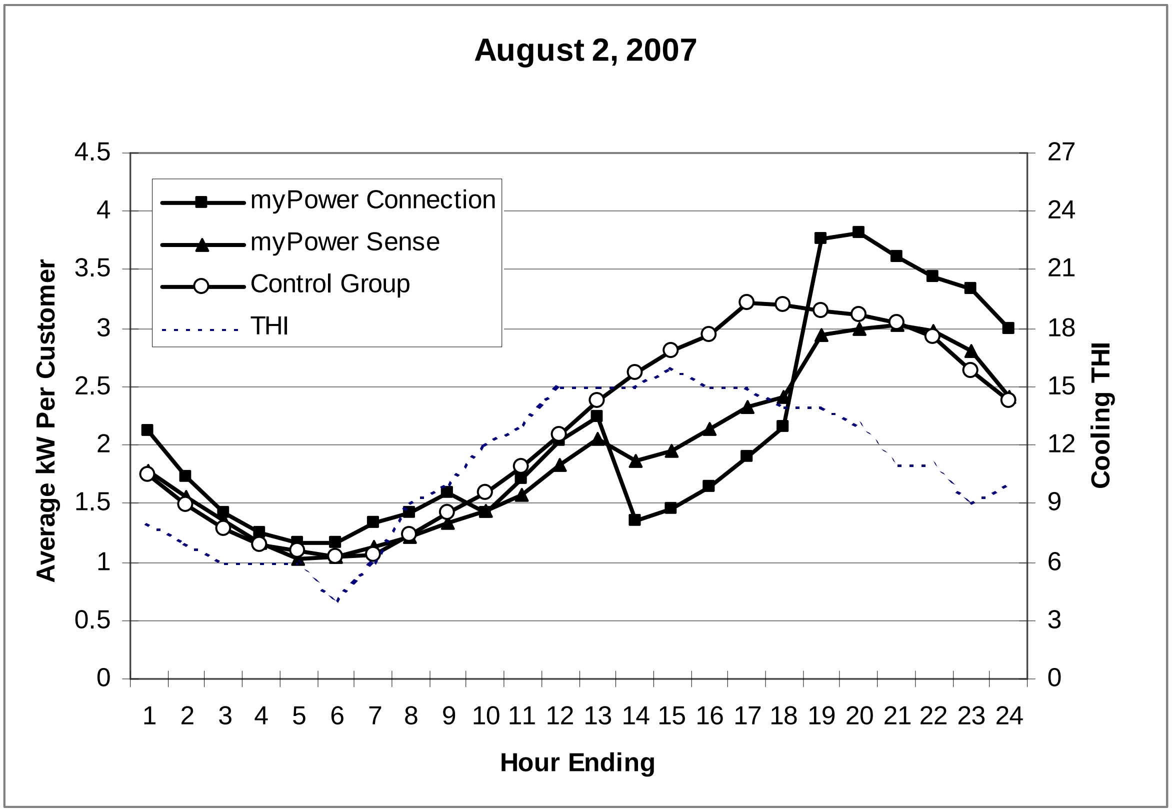


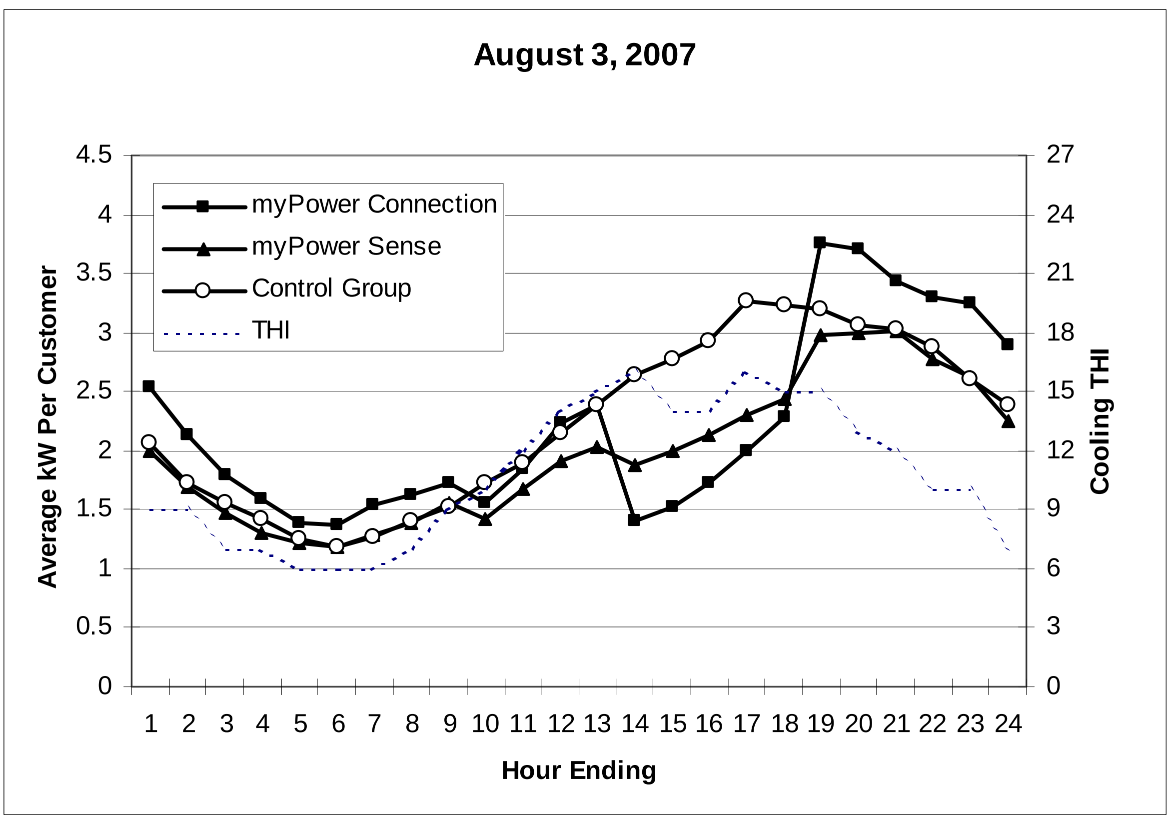
Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Summer Months



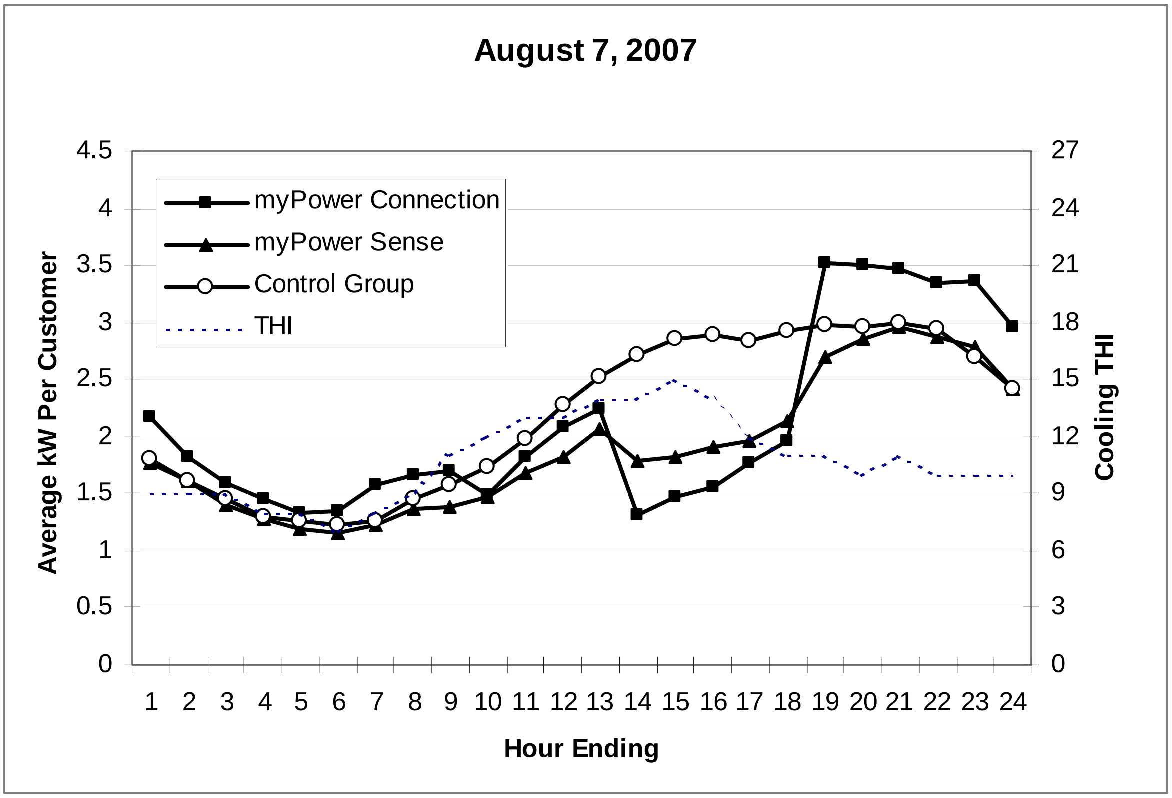


Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Summer Months

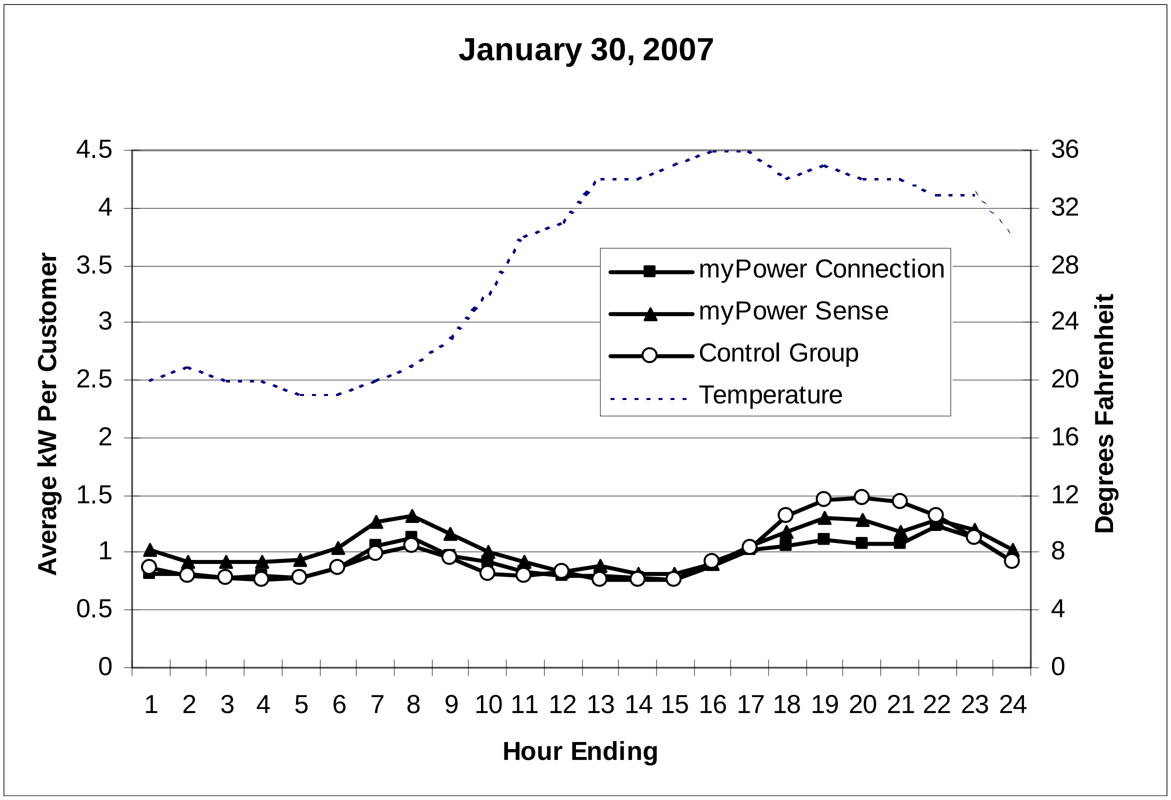


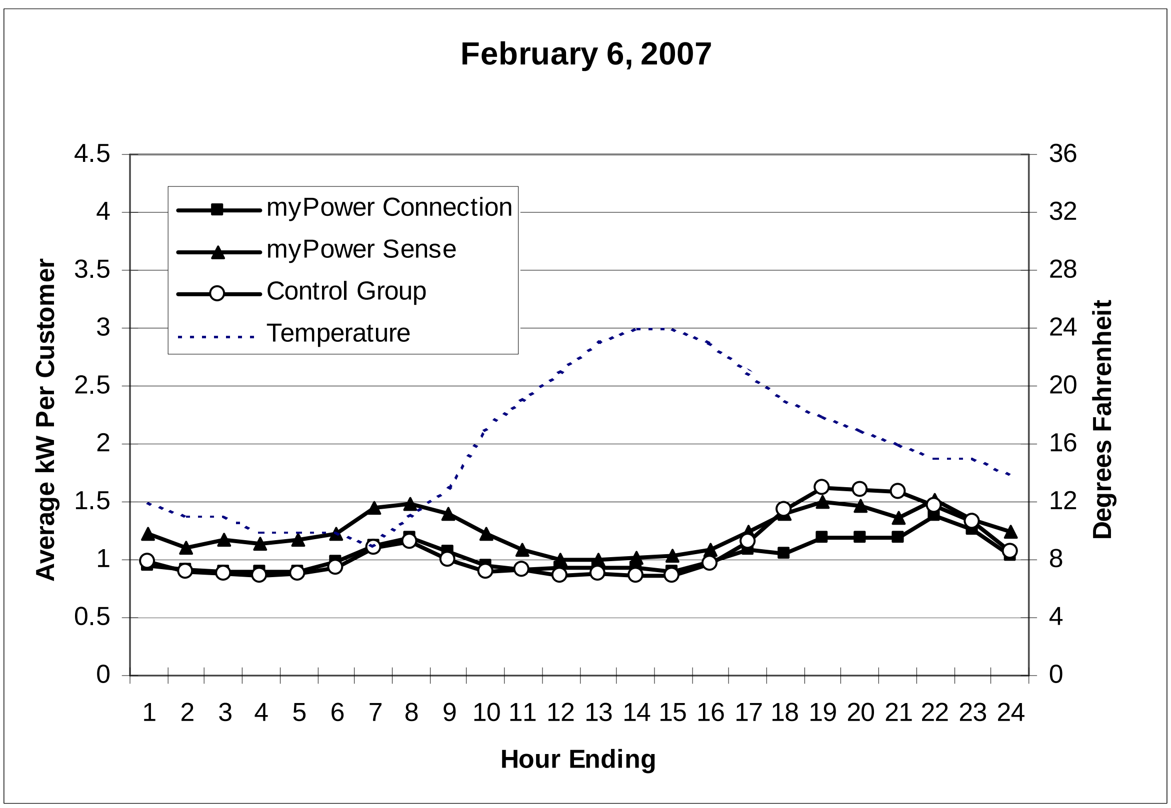


Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Summer Months

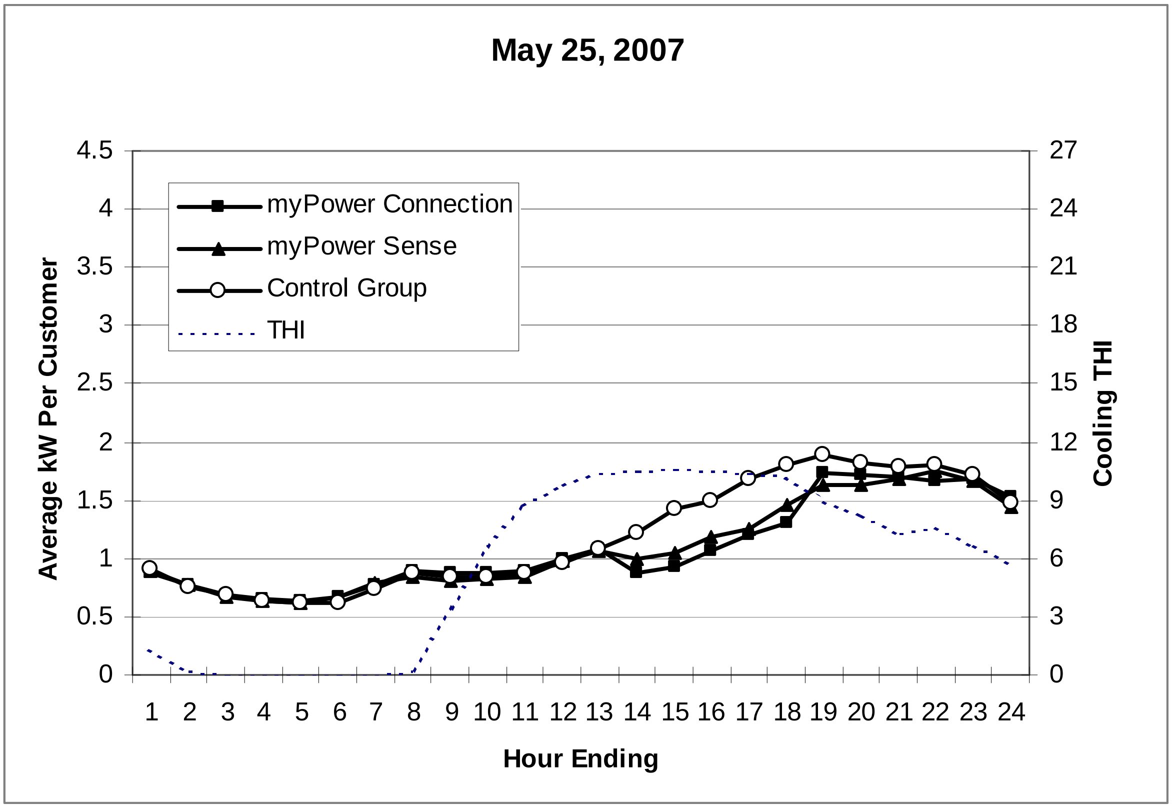


Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Winter Months

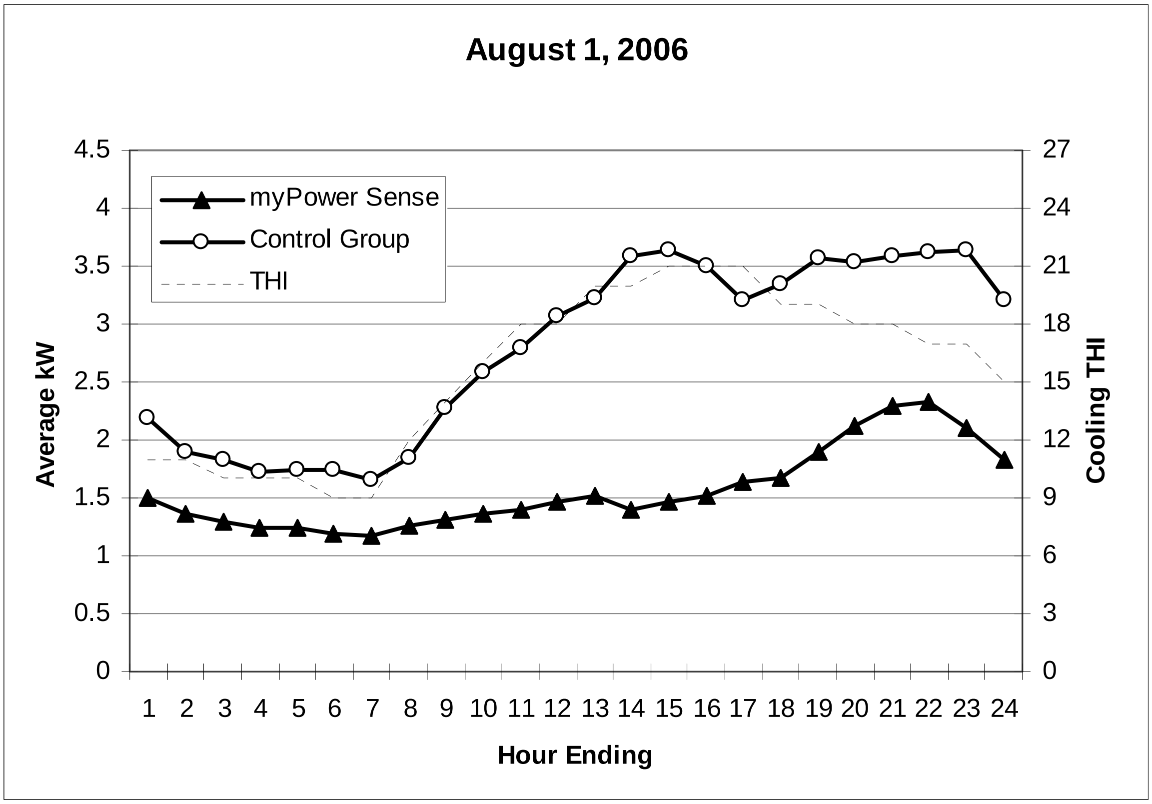


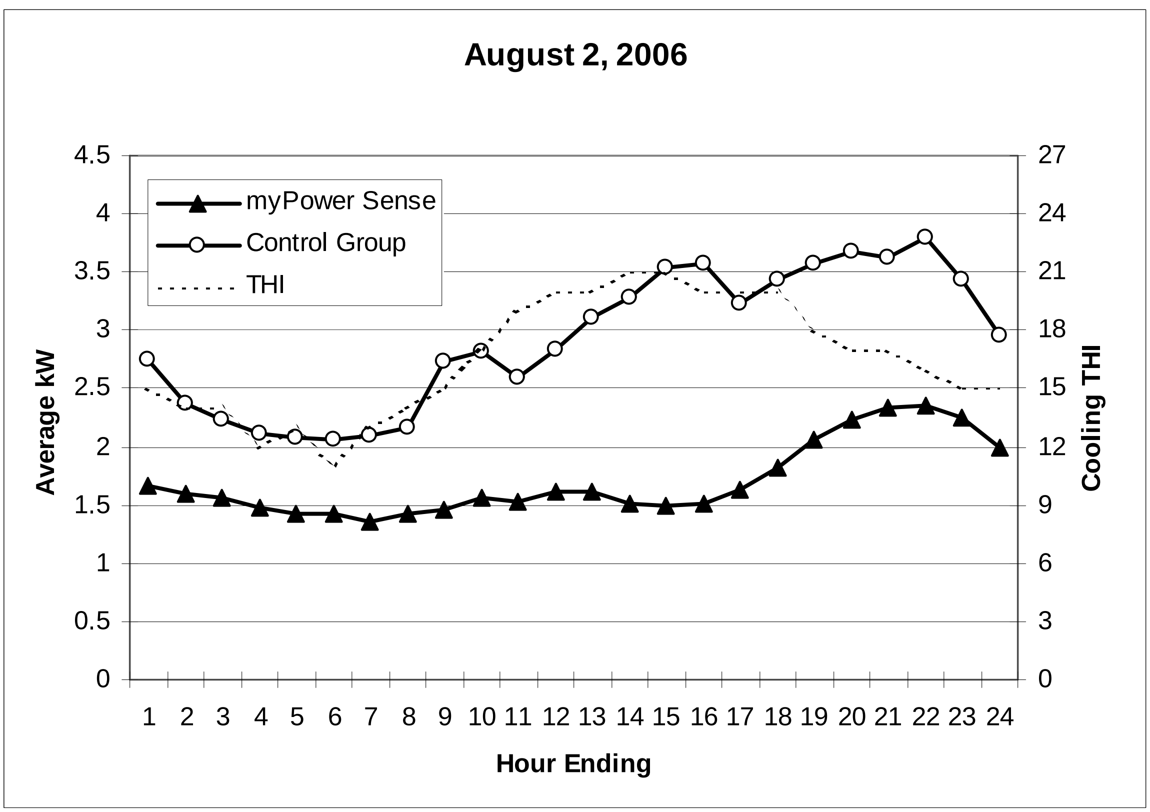


Daily Load Curves for Critical Peak Event Days
Customers with Central Air Conditioning – Shoulder Months

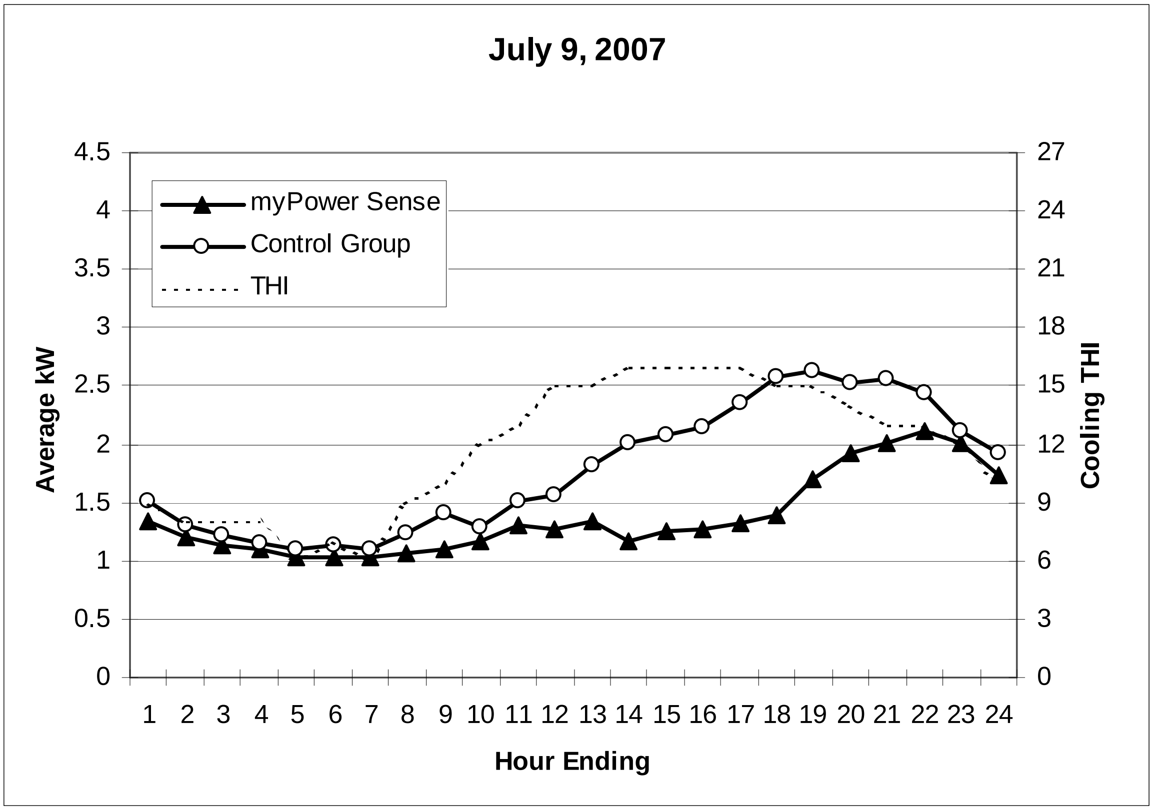


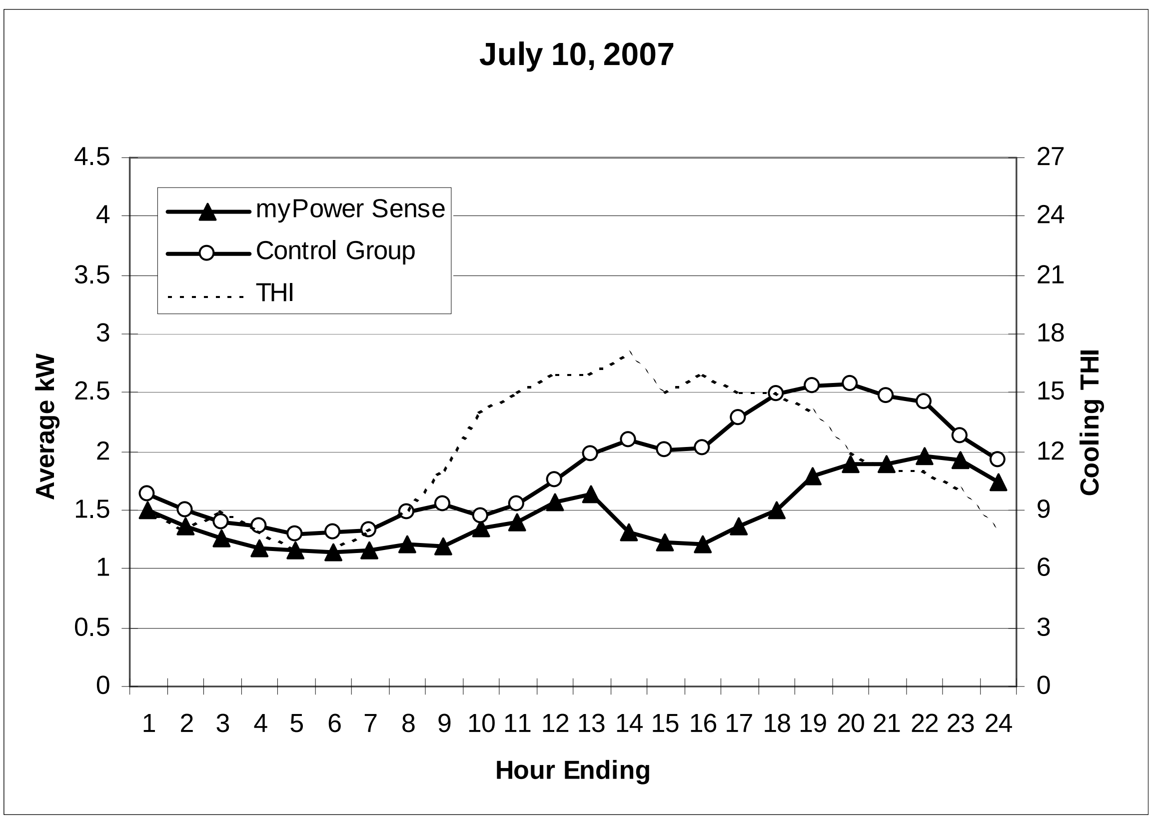
Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Summer Months



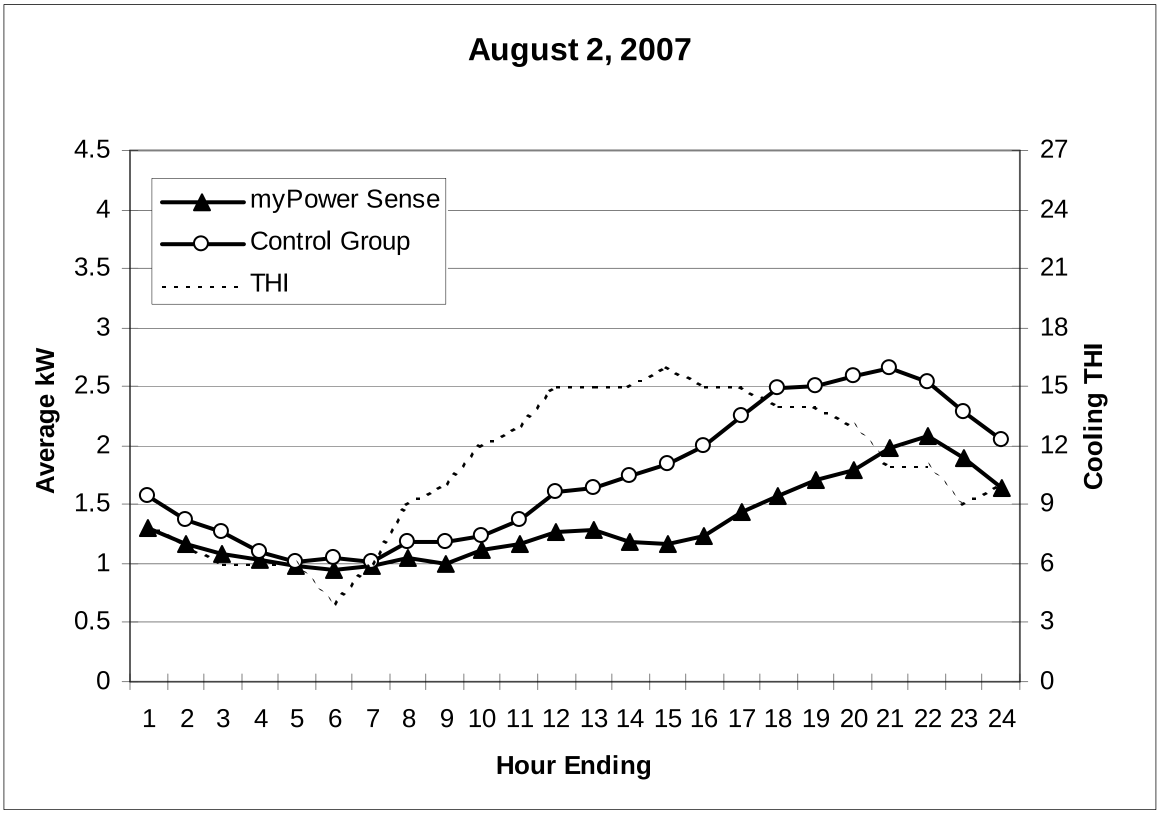


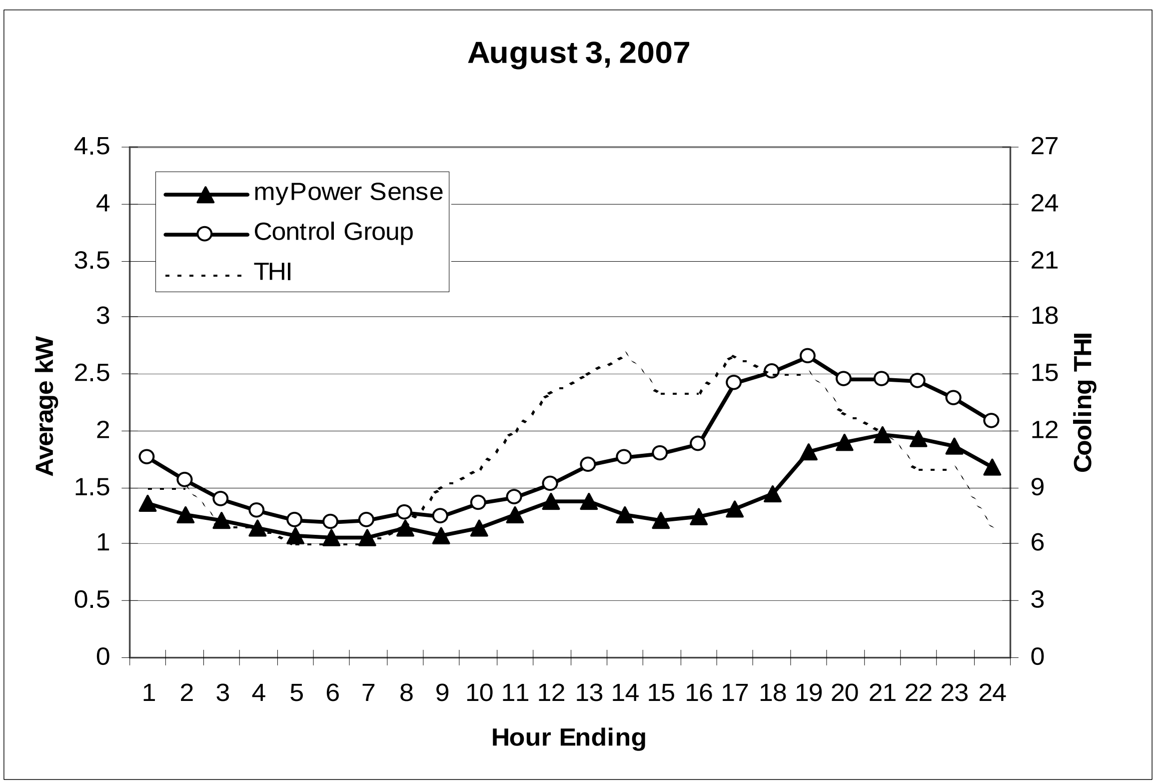
Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Summer Months



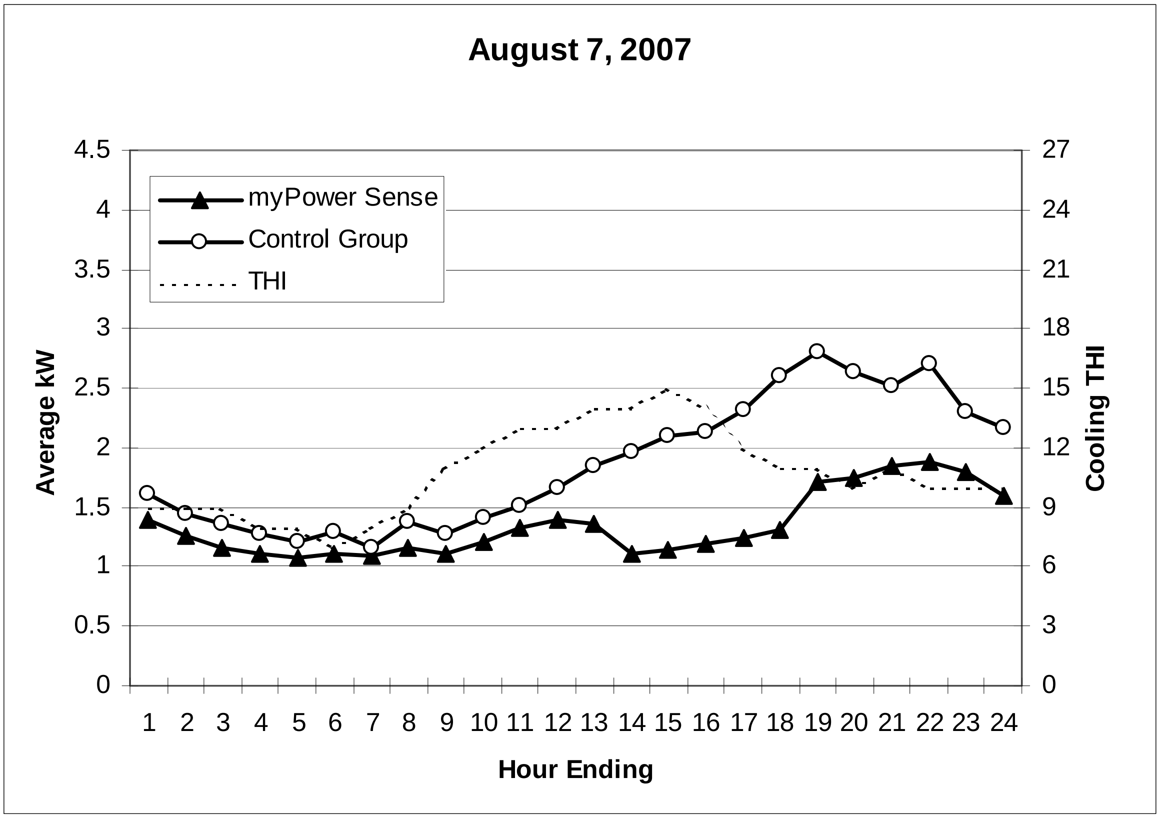


Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Summer

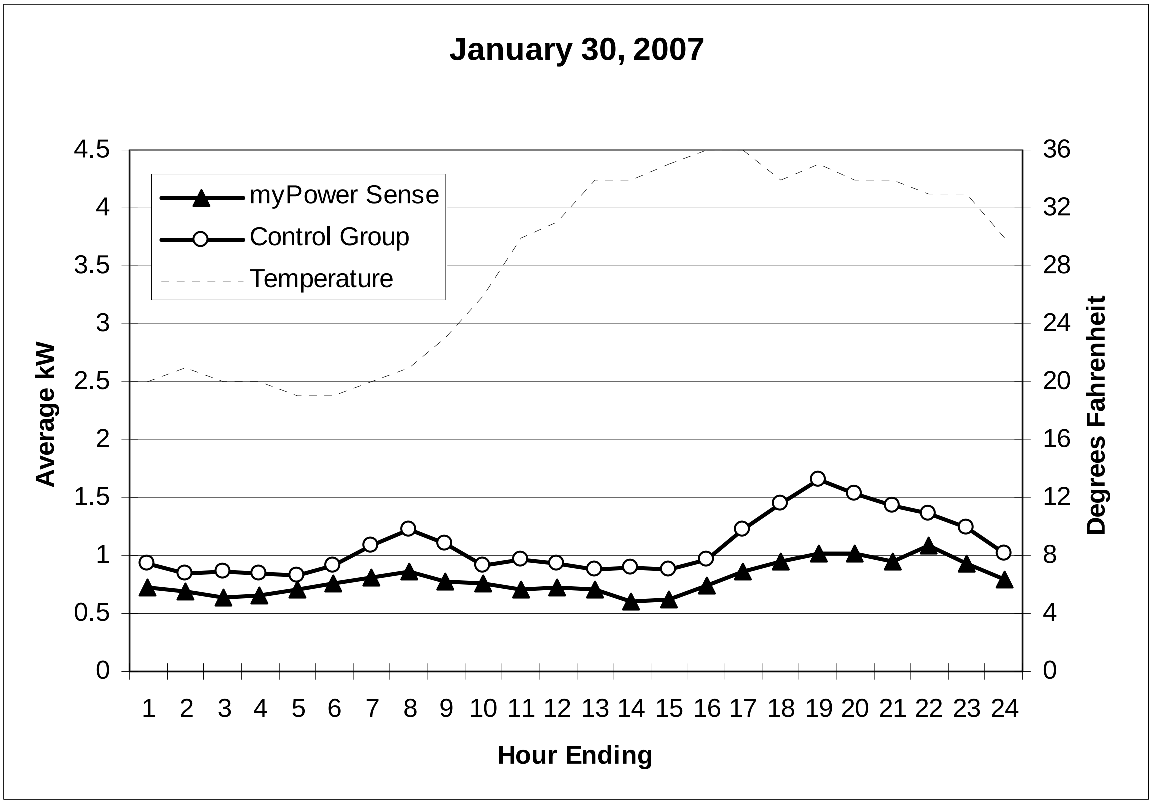


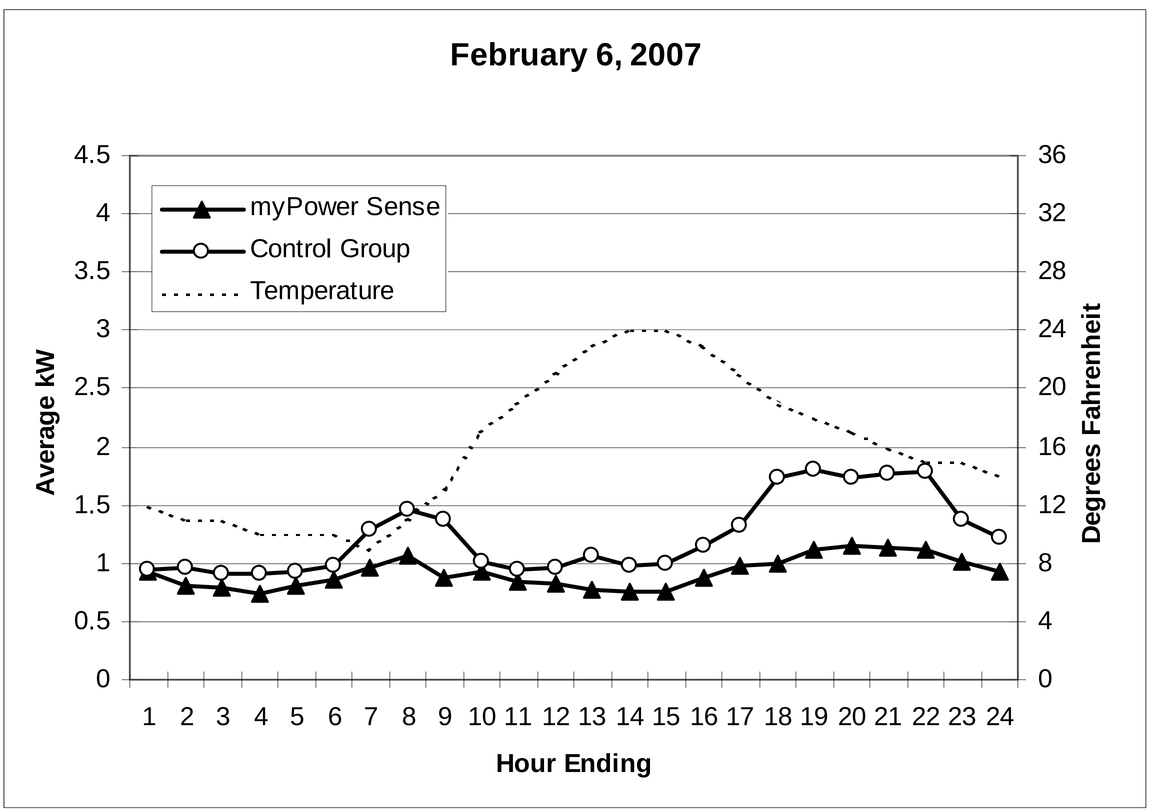


Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Summer Months

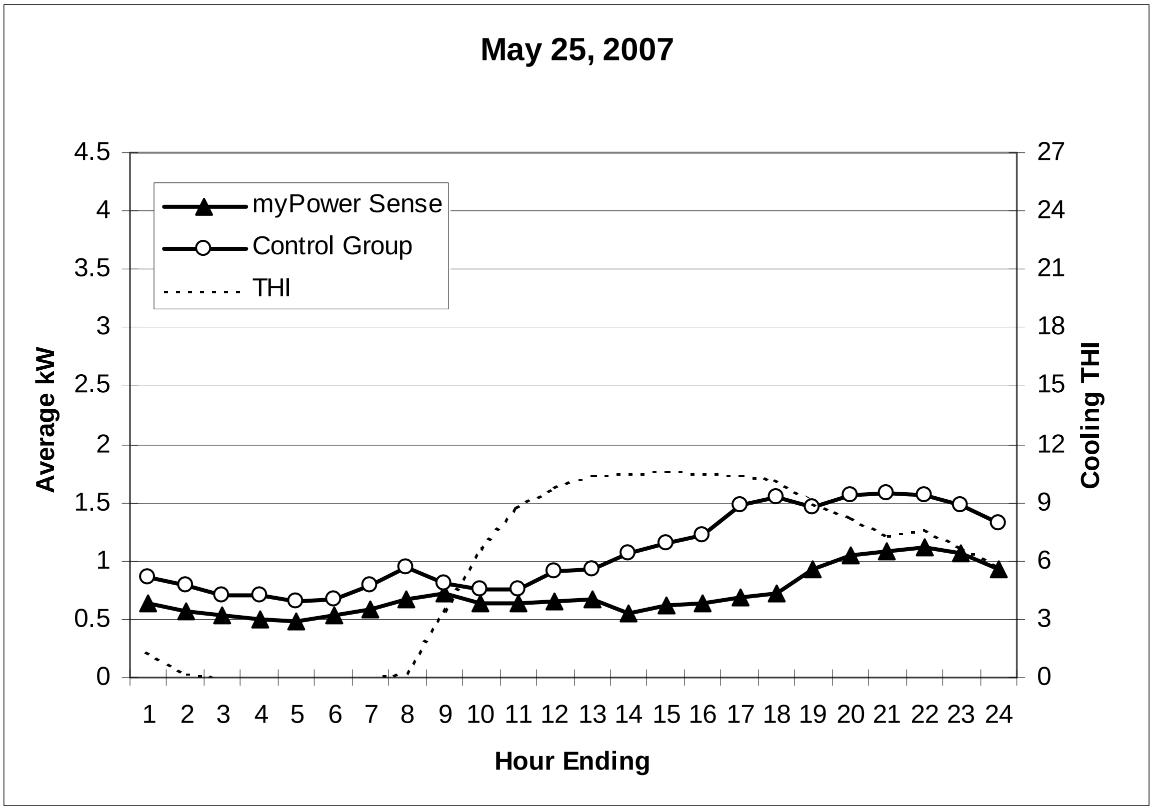


Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Winter Months





Daily Load Curves for Critical Peak Event Days
Customers with No Central Air Conditioning – Shoulder Months



Appendix P

Hourly TOU and CPP Load Impacts for Summer Peak Days

myPower TOU Summer Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with summer peak weather for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Connection Customer

		kW Change by Customer Size			
	Rate Period	Very Low	Low	Medium	High
Hour Ending 100	Night	0.05	0.10	0.21	0.54
Hour Ending 200	Night	-0.14	-0.02	0.22	0.36
Hour Ending 300	Night	-0.17	-0.05	0.12	0.28
Hour Ending 400	Night	-0.18	-0.06	0.08	0.20
Hour Ending 500	Night	-0.26	-0.05	0.06	0.14
Hour Ending 600	Night	-0.25	-0.02	0.05	0.12
Hour Ending 700	Night	-0.15	0.11	0.15	0.20
Hour Ending 800	Night	-0.05	0.09	0.19	0.19
Hour Ending 900	Night	0.22	0.16	0.27	0.18
Hour Ending 1000	Base	0.02	-0.12	-0.26	-0.38
Hour Ending 1100	Base	-0.17	-0.05	-0.24	-0.19
Hour Ending 1200	Base	-0.07	-0.07	-0.09	-0.15
Hour Ending 1300	Base	-0.07	-0.04	-0.13	-0.22
Hour Ending 1400	On-Peak	0.02	-0.52	-1.04	-1.35
Hour Ending 1500	On-Peak	-0.01	-0.52	-0.86	-1.00
Hour Ending 1600	On-Peak	-0.35	-0.51	-0.64	-0.67
Hour Ending 1700	On-Peak	0.04	-0.22	-0.35	-0.50
Hour Ending 1800	On-Peak	0.18	-0.15	-0.25	-0.30
Hour Ending 1900	Base	0.00	0.56	0.47	0.44
Hour Ending 2000	Base	0.08	0.44	0.38	0.34
Hour Ending 2100	Base	0.27	0.28	0.27	0.32
Hour Ending 2200	Base	0.22	0.12	0.27	0.31
Hour Ending 2300	Night	0.54	0.32	0.55	0.52
Hour Ending 2400	Night	0.20	0.23	0.56	0.64
AVERAGE IMPACTS PER HOUR:					
Night		0.00	0.08	0.25	0.33
Morning Base		-0.07	-0.07	-0.18	-0.24
On-Peak		-0.02	-0.38	-0.63	-0.77
Evening Base		0.14	0.35	0.35	0.35
Sample Size:					
Participants		6	164	164	166
Control Group		4	71	85	69
Upper Limit on Summer kWh for Size Strata:		1000	3325	4975	

Notes:

The days included in this analysis all had an average hourly THI > 14 for hours ending 1200-2000, they were weekdays, and they did not have a CPP event.
The days are:

7/17/2006
7/18/2006
7/31/2006
8/3/2006
6/26/2007
6/27/2007
8/8/2007

myPower TOU Summer Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with summer peak weather for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Sense Customer with Central AC

		kW Change by Customer Size			
	Rate Period	Very Low	Low	Medium	High
Hour Ending 100	Night	0.07	-0.09	-0.04	0.04
Hour Ending 200	Night	-0.02	-0.12	-0.09	0.05
Hour Ending 300	Night	-0.07	-0.06	-0.06	0.03
Hour Ending 400	Night	-0.07	0.03	-0.08	0.04
Hour Ending 500	Night	-0.08	0.04	-0.06	0.09
Hour Ending 600	Night	-0.08	0.08	-0.06	0.05
Hour Ending 700	Night	0.00	0.13	0.00	0.13
Hour Ending 800	Night	0.00	0.24	-0.14	0.12
Hour Ending 900	Night	-0.04	0.44	0.05	0.00
Hour Ending 1000	Base	-0.04	0.28	0.08	0.02
Hour Ending 1100	Base	-0.05	0.20	0.13	-0.07
Hour Ending 1200	Base	-0.04	0.13	0.12	-0.08
Hour Ending 1300	Base	-0.09	-0.01	0.09	-0.20
Hour Ending 1400	On-Peak	-0.12	-0.28	-0.06	-0.33
Hour Ending 1500	On-Peak	-0.09	-0.45	0.01	-0.23
Hour Ending 1600	On-Peak	-0.40	-0.46	-0.03	-0.21
Hour Ending 1700	On-Peak	-0.02	-0.21	-0.05	-0.16
Hour Ending 1800	On-Peak	-0.09	-0.24	-0.02	-0.03
Hour Ending 1900	Base	0.06	-0.04	0.02	0.09
Hour Ending 2000	Base	0.28	0.03	0.08	0.09
Hour Ending 2100	Base	0.23	0.14	0.05	0.11
Hour Ending 2200	Base	0.30	0.17	-0.01	0.14
Hour Ending 2300	Night	0.25	0.08	-0.01	0.15
Hour Ending 2400	Night	0.10	-0.01	0.05	0.16
AVERAGE IMPACTS PER HOUR:					
Night		0.03	0.08	-0.04	0.09
Morning Base		-0.05	0.15	0.11	-0.08
On-Peak		-0.14	-0.33	-0.03	-0.19
Evening Base		0.22	0.07	0.04	0.11
Sample Size:					
Participants		16	62	69	66
Control Group		7	37	70	114
Upper Limit on Summer kWh for Size Strata:		1000	2560	3992	

Notes:
The days included in this analysis all had an average hourly THI > 14 for hours ending 1200-2000, they were weekdays, and they did not have a CPP event.
The days are:
7/17/2006
7/18/2006
7/31/2006
8/3/2006
6/26/2007
6/27/2007
8/8/2007

myPower TOU Summer Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with summer peak weather for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Sense Customer without Central AC

		kW Change by Customer Size			
	Rate Period	Very Low	Low	Medium	High
Hour Ending 100	Night	0.15	-0.12	0.12	0.05
Hour Ending 200	Night	0.10	-0.04	0.13	0.10
Hour Ending 300	Night	0.14	-0.07	0.14	0.14
Hour Ending 400	Night	0.12	0.02	0.17	0.17
Hour Ending 500	Night	0.13	0.03	0.14	0.17
Hour Ending 600	Night	0.16	0.03	0.04	0.20
Hour Ending 700	Night	0.14	-0.04	-0.06	0.20
Hour Ending 800	Night	-0.25	-0.01	-0.02	0.19
Hour Ending 900	Night	-0.28	-0.20	0.10	0.19
Hour Ending 1000	Base	-0.27	0.11	0.11	0.07
Hour Ending 1100	Base	-0.18	0.17	0.16	0.17
Hour Ending 1200	Base	-0.17	0.03	0.16	0.16
Hour Ending 1300	Base	-0.03	0.02	0.15	0.04
Hour Ending 1400	On-Peak	-0.18	-0.06	0.13	-0.09
Hour Ending 1500	On-Peak	-0.19	-0.11	0.08	-0.11
Hour Ending 1600	On-Peak	-0.15	-0.27	0.05	-0.17
Hour Ending 1700	On-Peak	0.08	0.02	-0.30	-0.11
Hour Ending 1800	On-Peak	-0.02	0.08	-0.33	-0.20
Hour Ending 1900	Base	0.02	0.05	-0.30	-0.25
Hour Ending 2000	Base	0.05	0.12	-0.24	-0.28
Hour Ending 2100	Base	0.20	0.02	-0.28	-0.42
Hour Ending 2200	Base	0.20	-0.03	-0.05	-0.29
Hour Ending 2300	Night	0.12	0.21	-0.06	-0.01
Hour Ending 2400	Night	0.12	0.03	-0.04	0.07
AVERAGE IMPACTS PER HOUR:					
Night		0.08	-0.02	0.05	0.11
Morning Base		-0.16	0.08	0.15	0.11
On-Peak		-0.09	-0.07	-0.07	-0.14
Evening Base		0.11	0.04	-0.22	-0.31
Sample Size:					
Participants		21	37	37	42
Control Group		4	7	12	40
Upper Limit on Summer kWh for Size Strata:		1000	1800	3000	

Notes:

The days included in this analysis all had an average hourly THI > 14 for hours ending 1200-2000, they were weekdays, and they did not have a CPP event.

The days are:

7/17/2006
7/18/2006
7/31/2006
8/3/2006
6/26/2007
6/27/2007
8/8/2007

myPower CPP Summer Peak Day Demand Impacts

These impacts show the expected change in load on a day when a Critical Peak event is called.
Impacts shown here are for a single Residential customer
and they are incremental to impacts that occur due to the Time-of-Use rate.

Connection Customer

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1400	Critical Peak	-0.87	0.13	-0.57	-0.82	-1.25
Hour Ending 1500	Critical Peak	-0.84	0.12	-0.57	-0.80	-1.20
Hour Ending 1600	Critical Peak	-0.76	0.19	-0.51	-0.69	-1.12
Hour Ending 1700	Critical Peak	-0.69	0.20	-0.43	-0.61	-1.08
Hour Ending 1800	Critical Peak	-0.55	0.19	-0.36	-0.42	-0.89
Hour Ending 1900	Snapback	0.34	0.36	0.66	0.48	-0.11
Hour Ending 2000	Snapback	0.53	0.52	0.72	0.63	0.24
Hour Ending 2100	Snapback	0.55	0.43	0.63	0.60	0.41
Hour Ending 2200	Snapback	0.58	0.43	0.59	0.61	0.54
Hour Ending 2300	Snapback	0.52	0.98	0.58	0.54	0.41
Hour Ending 2400	Snapback	0.58	0.69	0.52	0.65	0.55
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.74	0.16	-0.49	-0.67	-1.11
Snapback		0.51	0.57	0.62	0.59	0.34
Sample Size		322	6	105	105	106
Upper Limit on Summer kWh			1000	3325	4975	

Sense Customer with Central AC

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1400	Critical Peak	-0.41	-0.18	-0.21	-0.45	-0.62
Hour Ending 1500	Critical Peak	-0.41	-0.14	-0.25	-0.47	-0.57
Hour Ending 1600	Critical Peak	-0.34	-0.10	-0.18	-0.41	-0.50
Hour Ending 1700	Critical Peak	-0.34	-0.13	-0.20	-0.44	-0.44
Hour Ending 1800	Critical Peak	-0.31	0.00	-0.14	-0.44	-0.42
Hour Ending 1900	Snapback	0.12	0.34	0.22	0.04	0.06
Hour Ending 2000	Snapback	0.29	0.21	0.39	0.33	0.21
Hour Ending 2100	Snapback	0.33	0.34	0.37	0.34	0.29
Hour Ending 2200	Snapback	0.33	0.29	0.29	0.36	0.36
Hour Ending 2300	Snapback	0.34	0.29	0.26	0.43	0.36
Hour Ending 2400	Snapback	0.31	0.18	0.19	0.42	0.37
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.36	-0.11	-0.19	-0.44	-0.51
Snapback		0.29	0.27	0.29	0.32	0.27
Sample Size		233	31	67	67	68
Upper Limit on Summer kWh			1000	2560	3992	

Sense Customer without Central AC

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1400	Critical Peak	-0.25	-0.12	-0.14	-0.22	-0.43
Hour Ending 1500	Critical Peak	-0.26	-0.11	-0.14	-0.26	-0.44
Hour Ending 1600	Critical Peak	-0.25	-0.11	-0.08	-0.26	-0.46
Hour Ending 1700	Critical Peak	-0.23	-0.15	-0.06	-0.20	-0.43
Hour Ending 1800	Critical Peak	-0.18	-0.09	-0.03	-0.21	-0.31
Hour Ending 1900	Snapback	0.06	0.12	0.13	0.05	-0.01
Hour Ending 2000	Snapback	0.20	0.24	0.20	0.20	0.18
Hour Ending 2100	Snapback	0.25	0.27	0.22	0.27	0.26
Hour Ending 2200	Snapback	0.30	0.34	0.27	0.29	0.32
Hour Ending 2300	Snapback	0.25	0.30	0.26	0.26	0.20
Hour Ending 2400	Snapback	0.21	0.25	0.19	0.24	0.19
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.23	-0.12	-0.09	-0.23	-0.41
Snapback		0.21	0.25	0.21	0.22	0.19
Sample Size		151	30	39	38	44
Upper Limit on Summer kWh			1000	1800	3000	

Appendix Q

Detail on Summer kWh Shift Impacts

myPower TOU Summer kWh Shift Impacts

These impacts show the expected change during a summer season (June through September)
for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Connection Customer

	Per Cent Change			
	Very Small	Small	Medium	Large
Night Hours	-5%	5%	10%	10%
Base Hours	5%	1%	0%	0%
On-Peak Hours	-1%	-12%	-19%	-19%
Sample Size:				
Participants	5	104	103	104
Control Group	5	103	104	82
Upper Limit on Summer kWh for Size Strata:	1000	3325	4975	

kWh Change			
Very Small	Small	Medium	Large
-29	46	148	218
32	6	-10	2
-3	-52	-138	-219

Sense Customer with Central AC

	Per Cent Change			
	Very Small	Small	Medium	Large
Night Hours	-5%	3%	4%	6%
Base Hours	6%	0%	-1%	-1%
On-Peak Hours	-5%	-5%	-5%	-8%
Sample Size:				
Participants	21	60	62	64
Control Group	11	57	92	133
Upper Limit on Summer kWh for Size Strata:	1000	2560	3992	

kWh Change			
Very Small	Small	Medium	Large
-28	25	52	114
41	-3	-17	-31
-13	-21	-35	-83

Sense Customer without Central AC

	Per Cent Change			
	Very Small	Small	Medium	Large
Night Hours	16%	1%	6%	8%
Base Hours	0%	1%	-3%	-5%
On-Peak Hours	-27%	-6%	-6%	-5%
Sample Size:				
Participants	25	36	37	42
Control Group	5	9	17	49
Upper Limit on Summer kWh for Size Strata:	1000	1800	3000	

kWh Change			
Very Small	Small	Medium	Large
66	4	70	138
-2	10	-46	-105
-64	-15	-24	-34

Notes:

myPower TOU rates were different in 2006 and 2007, but the impacts were nearly identical.

*These numbers were derived from summer data for July 15, 2006 through September 30, 2007,
but they reflect impacts for a summer season with a normal number of days (122).*

*TOU impacts increase with hot weather.
The impacts in this report reflect the average weather over the study period.
Average hourly THI is 3.02 for night hours, 5.90 for base hours and 7.13 for on-peak hours.
It is unknown how close this is to normal summer weather.*

Data for days with critical peak events were excluded from this analysis. These impacts are for TOU only.

Appendix R

Outliers and Extreme Cases in the Summer Energy Savings Analysis

1 OUTLIERS AND TAILS

Measuring energy savings for a TOU program is always difficult since the expected value of the energy savings is small (5% or less), and the normal variation in customer bills is large. Customer bills can vary for many reasons: weather, new appliances, addition or loss of household members, changing schedules, vacations, guests, household events, etc. Having large sample sizes for both the participant groups and the control groups helps reduce the uncertainty around the estimates of average monthly kWh use before and after starting on the TOU program. Small sample sizes allow outliers and cases within the tails of the distribution to have greater influence on the averages.

The sample size for the central air-conditioning customer savings model was 814, which included 294 Connection customers, 318 Control Group customers, and 202 Sense customers. The sample size for the savings model for customers without central air-conditioning was much smaller at 215 total. There were 125 Sense customers and 90 Control Group customers in this model. Each of these groups was examined for the influence of outliers and cases within the tails of the distributions.

Some data cleaning work was done before running the original models to eliminate bills with unusual kwh readings, and customers with an irregular number of bills. That work removed outliers from the original set of billing data. This next phase of analysis is not looking for outliers in billing data, but rather for outliers in the difference between bills before and after the start of the TOU program. A regression model must be built for each customer to estimate individual weather-normalized program impacts.

The individual customer weather-normalized program impact model has the following relationship:

Monthly KWH = f (Monthly THI, Billing Days, Before or After Start of TOU Program)

The coefficient on the TOU program variable indicates the weather-normalized average change in monthly kWh use after the start of the program. This kWh change estimate can be compared to the average monthly kWh use before the start of the program to get a percentage change for that single customer.

Chart 1 shows the frequency distribution for the percent change in use after the start of the program for each customer in the central air-conditioning group. These distributions clearly show that the mode for the Control Group is an increase in use after the start of the program while both the Connection group and the Sense group have modes showing a decrease in use. The fact that both participant groups show a similar tendency towards decreased use is good support for the assumption that the program was the cause of the change.

Chart 2 presents a similar frequency distribution for customers without central air-conditioning. Once again, the mode of the participant group shows decreased use while the mode of the Control Group shows increased use.

Chart 2 shows two points that are obvious outliers, one at 295% and the other at 360%. However, there is one for each customer group so their influence on the difference of the estimated means for each group would be very small. They should be removed as outliers, but their removal will not change the model results.

More influential on model results than these two outliers are the cases within the tails shown between 25% and 110% increased usage. The Sense group has many more customers in this range than the Control Group. This heavy loading of Sense customers within the high tail of the distribution is what caused the previous memo's estimate of increased program usage for Sense customers without central air-conditioning. This heavily weighted tail shifts the average usage for the Sense group higher than the average use for the Control Group, even though Sense customers are more likely to have lowered their energy use when you look within the middle range of the distribution.

Chart 1.

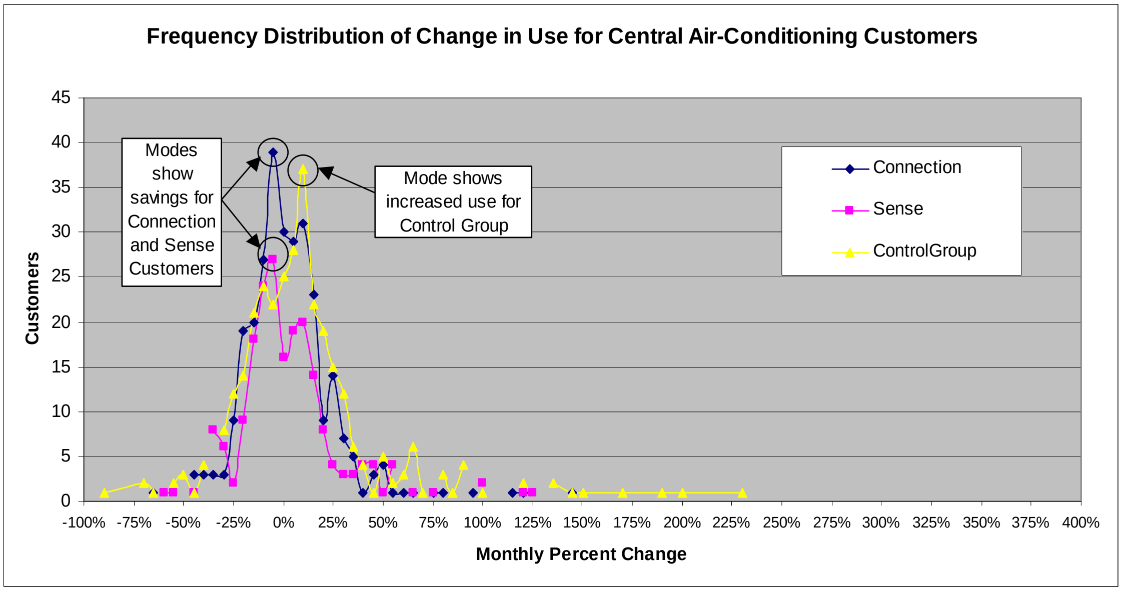


Chart 2.

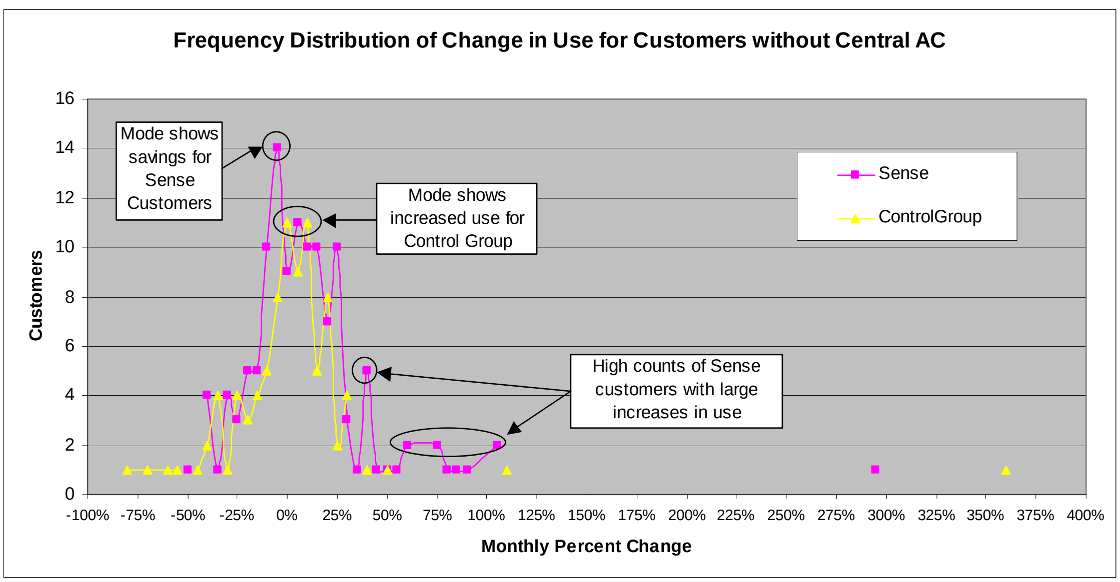


Chart 1 does not show any obvious outliers. Rather, the cases within the high tail of the distribution are continuous for 25% to 150%. For the Control Group, they are continuous from 25% to 230%. This heavily weighted tail for the Control Group in Chart 1 has the same effect as the heavily weighted tail for Sense customers in Chart 2; it increases the estimated average kWh for the group. But now in Chart 1 the Control Group average is being increased and the Control Group already has a higher average within the middle range. This has the effect of inflating the estimated savings from the program for the central air-conditioning customers.

It appears that a small number of cases within the high tail of the distribution are causing over-estimation of program savings for central air-conditioning customers and under-estimation of program savings for customers without central air-conditioning. The important question is whether or not these cases within the tails are valid data points which should be included in the savings estimation models. Answering this question requires an examination of expected changes in overall energy savings from TOU load shifting.

The primary purpose of TOU rates is to shift energy use from one period of time to another through price signals. It is common to find estimated elasticities of substitution for TOU rates that document kWh shifts. Previous work done for the myPower TOU rate found kWh shifts. It is less common to find studies of energy savings from TOU rates. In comparative studies that have been summarized, Arizona Public Service residential TOU customers who used more than 1000 kwh/month saved 8% on their bills,[1] Puget Sound residential TOU pilot customers achieved 5% energy savings during winter months with high electric space-heating saturation,[2] and Chicago Community Energy Cooperative real-time-pricing customers showed summer energy savings of 3-4%.[3] None of these study results are directly comparable to the myPower program, but they do indicate that the expected overall average savings from a TOU program will probably be less than 10%.

If the expected average savings from a TOU rate is less than 10%, what range of savings can be expected for individual customers? What would be a reasonable range of savings to expect from the time shifts that an individual TOU customer makes in their energy usage because of the TOU rate?

In the myPower pilot, the primary load shifted to take advantage of TOU rates was central air-conditioning. Approximately 80% of Connection customers and 65% of Sense customers reported that their thermostat was programmed to increase the temperature during the high price periods of the day. The next most-shifted loads were clothes washers, clothes dryers and dishwashers cited by 50 to 65% of participants. Other cited loads for shifting were lights, computers, pool pumps and dehumidifiers but each of these were mentioned by less than 10% of customers.

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[1] Assessment of Demand Response & Advanced Metering-Staff Report, Federal Energy Regulatory Commission, August 2006, p. 55.

[2] Ibid, p. 69.

[3] Impact Analysis of Chicago Community Energy Cooperative Real-Time Pricing Pilot Final Report, Summit Blue Consulting, August 1, 2006.

Would any of these shifted loads create large energy savings for a particular customer? The only shifted load that is 100% energy savings is lighting. If a customer foregoes lighting during a peak period, it is unlikely that they will use more lighting later in the day to make up for it. Other shifted loads, like clothes washers, clothes dryers and dishwashers, do not create any energy savings. The same amount of energy is used at a different time and the total number of loads done is probably not affected. In between these two extremes of 100% energy savings and 0% energy savings are loads like air-conditioning, dehumidifiers, computers and pool pumps. Less energy use during on-peak periods is offset by additional use during off-peak periods for these end uses, so the savings is the net difference in use. Given that each of these end uses is a fraction of the total bill, and savings come from the net difference between on-peak and off-peak use, it is unlikely that an energy use shifting strategy could change an individual's overall energy use enough to make TOU impacts the primary reason for large changes in energy usage.

Large changes in usage for an individual customer, either positive or negative, are probably related to other factors beyond the TOU rate. The factors creating the big changes are not necessarily evenly represented in every group. For example, each group may have a different percentage of customers building on an addition or increasing the size of their family. Since the TOU savings are expected to be small for any individual customer, the best estimate of TOU savings for a group will come from a comparison of the middle range of customers. But where should the lines be drawn along the tails to remove the small number of customers who are responding to non-TOU factors and are having a large influence on the estimated savings for the group?

Charts 3 and 4 help answer that question by displaying the cumulative frequency distributions for central air-conditioning customers and customers without central air-conditioning. An arbitrary assumption of looking at the middle 80% of the range fits well with where the cumulative distribution starts dramatically changing slope. For the central air-conditioning group, customers whose usage decreases by more than 25% or increases by more than 35% should be excluded from the analysis. For the group without central air-conditioning, customers whose usage decreases by more than 30% or increases by more than 35% should be excluded from the analysis. Limiting the range of customers included in the analysis will improve the estimate of savings attributable to the TOU rate.

Chart 3.

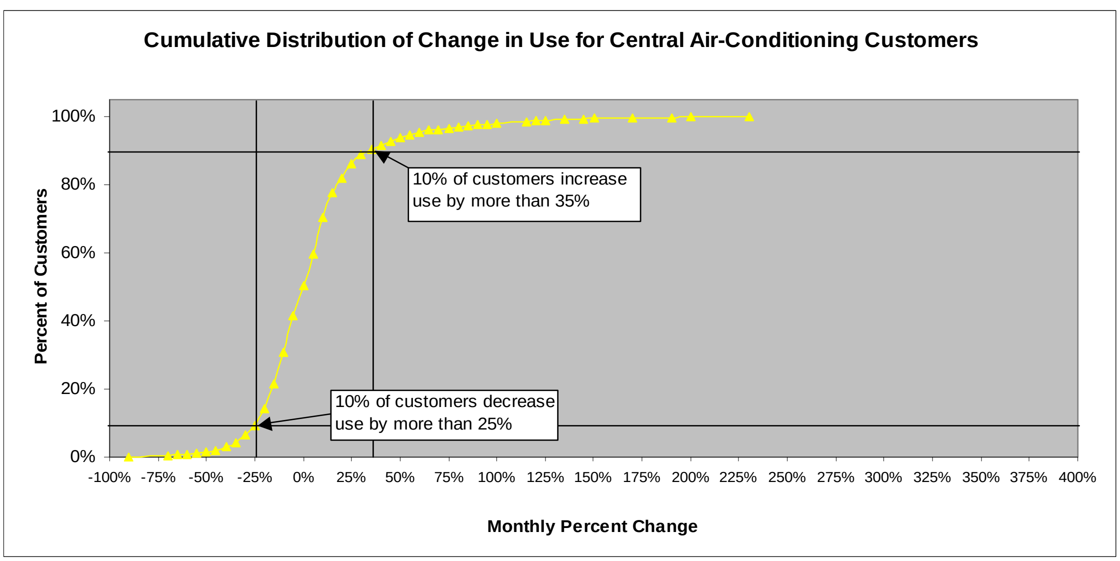
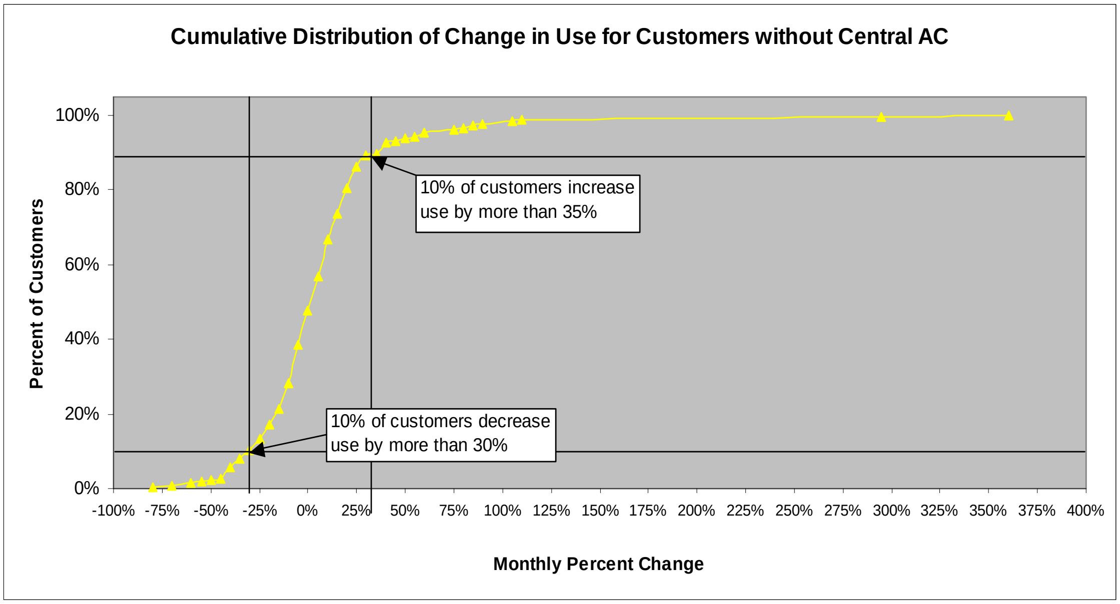


Chart 4.



In summary, after careful review of Charts 1 through 4, it is recommended that the best estimate of energy savings attributable to the myPower TOU rate would come from analysis of the 80% of customers with moderate changes in usage after the beginning of the program. Individual customers in the 10% tails of the change in use distribution should be excluded from the energy savings model. This recommendation is based on the following findings:

- Each participant group consistently shows a mode of decreased use while each control group consistently shows a mode of increased use.

- The levels of change in usage for the small number of customers in the 10% tails of the change in use distributions are significant enough to alter the estimated means for each group to a level where the basic relationship shown between the groups within the 80% mid-range is distorted.

- Distortion is greatest for customers without central air-conditioning because of the small sample size.

- Both comparative studies and enduse analysis indicate that energy savings levels that occur outside of the 80% mid-range are not likely to be the result of TOU load shifting for an individual customer.

2 REVISED ENERGY SAVINGS ESTIMATES

The basic energy savings models were re-run using only customers who do not have large changes in usage after the beginning of the program. This was defined as the 80% of customers within the mid-range of the change in use distribution. Two separate models were built, one for central air-conditioning customers and one for customers without central air-conditioning. Time-series, cross-sectional regression was used to account for fixed effects of individual customers within each group. Dummy variables were used to create difference of differences models which specified average changes for each participant group and each control group after the beginning of the TOU rates. A log transformation was used on the monthly kWh variable to compare percent changes due to the program rather than absolute kWh values. This was necessary since the average monthly kWh usage of the Sense customers without central air-conditioning was much lower than the other groups.

The energy savings models had the following specification:

Ln(Monthly kWh) = f (Monthly THI,
Billing Days,
Connection Customer after program began,
Sense Customer after program began,
Control Group Customer after program began)

Results from the two models are shown in Table 5. For each participant group, energy use increases after the beginning of the TOU program by 1-2%. For the Central Air-conditioning group, Connection customers show a 1.9% average increase in use while Sense customers show a 1.5% average increase. Sense customers without central air-conditioning show an average 2.1% increase. Both Sense group estimates are statistically significant at the 80% confidence level. The Connection group estimate is statistically significant at the 95% confidence level.

This increased usage does not mean that the TOU rate causes increased energy use. Control group customers showed much larger increases, indicating that the TOU rate has an energy saving effect on customer usage.

Table 5 shows that Control Group customers with central air-conditioning increased their usage by 5.2% on average after the beginning of the TOU rate, and Control Group customers without central air-conditioning increased their usage by 6.4%. This increase is a reflection of normal growth in usage. It has no relation to the TOU rate, but it indicates what the normal change in usage would be between the pre- and post- TOU periods. The difference between the Control Group increases and the lower increases for the TOU participant groups is the appropriate estimate of energy savings due to the TOU rate.

Table 5. myPower Pricing TOU Summer Energy Savings Models – Truncated Group (80% mid-range)

Variable	Central Air-conditioning Group Coefficient *(t-value)*	No Central AC Group Coefficient *(t-value)*
Month is after program start and the customer is in myPower **Connection**	**0.018578** ***(2.1)***	
Month is after program start and the customer is in myPower **Sense**	**0.014518** ***(1.3)***	**0.021052** ***(1.6)***
Month is after program start and the customer is a **Control Group** Customer	**0.052206** ***(5.8)***	**0.064252** ***(4.2)***
Monthly THI	0.00012 *(58.4)*	0.00011 *(27.5)*
Billing Days	0.01744 *(7.3)*	0.02614 *(5.9)*
Sample Size Customers	8,893 672	2,256 174

Comparing the differences between the participant groups and the control groups, **the best estimates of summer energy savings from the myPower Pricing program is 3.3% for Connection customers, 3.7% for Sense customers with central air-conditioning, and 4.3% for Sense customers without central air-conditioning.** These savings, shown in Table 6, are in comparison to what the participants would have used if they had not been on the TOU rate.

Table 6. myPower Pricing TOU Summer Energy Savings Estimates

Variable	Control Group Change in Use	Participant Group Change in Use	Summer Energy Savings from TOU
Connection Customers	**5.2%**	**1.9%**	**3.3%**
Sense Customers with Central AC	**5.2%**	**1.5%**	**3.7%**
Sense Customers without Central AC	**6.4%**	**2.1%**	**4.3%**

Appendix S

Methods and Results for Winter and Shoulder Month Impact Estimates

1 BACKGROUND

Summer is the season of greatest potential shifting and savings due to high air conditioning loads in residential homes and the availability of programmable and communicating thermostats to control those loads. But customers still have the opportunity to change their energy use patterns during the other seasons of the year to benefit from the time-of-use and critical peak rate structures. This report presents the impacts achieved during the winter season (November, December, January, February, March) and the shoulder season (October, April, and May).

In the summer impact studies both Sense participants and the control group were separated into two groups for analysis: those with central air conditioning and those without central air conditioning. This was done because the presence of central air conditioning has such a large effect on the summer energy use of residential customers and their opportunities for shifting and saving.

Although it is true that central air conditioning does not have a large effect on energy use during the winter or shoulder seasons, ownership of central air conditioning may be related to other household energy use characteristics that would make it worthwhile to continue looking at possible impact differences between these two groups. Also, when looking at size strata within the two groups, the size strata definitions are distinct for each of these groups. Each group was split into three size strata to create an equal number of customers in each stratum. The size definitions are different for each stratum within each group. It makes sense to continue with the summer size strata definitions for the winter and shoulder seasons so customers do not have to be re-assigned depending on the season. Maintaining groups and strata definitions will make population projections easier. For these reasons, it was decided to continue looking at the central air conditioning groupings for the winter and shoulder analyses.

It could also be argued that there would be little difference in impacts between Connection and Sense customers during the winter and shoulder months since a programmable or communicating thermostat would have no effect on electricity usage during those months. These two groups, Connection and Sense, will still be studied separately to see if there is a difference between customers who primarily relied on technology to automatically shift their energy usage during summer, and customers who had to take personal actions to benefit from the new rates. During the shoulder and winter seasons, both groups would need to take personal actions to benefit from the rates. Having previous experience doing this during the summer may make a difference.

2 SUMMARY OF RESULTS

Customers did respond to price signals on winter peak days and shift usage out of the on-peak period. However, as expected, winter kW impacts were lower than summer kW impacts. For example, Connection customers had average on-peak winter impacts of –0.41 kW compared to –1.33 kW during summer. This is largely because there is less electric load being used in residential households during winter. However, if the achieved impacts are considered as a percent of load, the summer and winter impacts are very comparable.

The one case with the largest difference between summer and winter impacts, both on a kW basis and a percent basis, is the TOU impact for Connection customers. Without automatic control of air conditioning load, the on-peak TOU impacts drop from a 21% reduction in summer to a 3% reduction in winter.

Snapback load does occur in winter after the end of the CPP control events. However, the snapback load does not exceed the normal baseline for winter peak days. Compared to a baseline day, the load reduction impacts of a CPP event linger into the evening creating an overall energy savings for the day.

Looking at CPP impacts in the shoulder months, Connection customers showed an average hourly response of –0.27 kW during the May 25 critical peak event. This is less load reduction than what was seen in both the summer and the winter CPP responses, but it indicates that there was probably some air conditioning load on the system that was automatically controlled. The two Sense customer groups did not show a statistically significant response to the event. This may be explained by the fact that there was only one CPP event called during the shoulder months and it was called on a Friday before a holiday weekend. Customers who were dependent on taking personal actions to respond to the event may have had their attention focused elsewhere on that particular day.

Moving beyond peak day analyses and looking at entire seasons, there was little overall kWh shifting for any of the customer groups during winter months and even less during the shoulder months. The observed kWh shifts in the winter and shoulder months are much lower than the summer shifts and are not large enough to create sizable changes in the load curve.

In addition to analyzing hourly data for kWh shifts which change the shape of the load curve, billing analysis was done to look for changes in total energy use after the start of the myPower pilot in both the winter and the shoulder months. There were estimated reductions in energy use for several groups, but all of the reductions were very small and most were not statistically significant at the 90% confidence level. There is a high likelihood that these impacts are actually zero and there was no real change in shoulder or winter energy use after the start of the program.

The one exception is the Sense with Central Air conditioning group. They showed a 1.65% decrease in energy use during winter months which was statistically significant at the 90% confidence level. It appears that their conscious attention to energy loads and load shifting during the summer may have become habit and carried over into the winter months.

The following sections will present the details of the analyses that were done to provide these results.

3 HOURLY TOU AND CPP IMPACTS ON WINTER PEAK DAYS

The hourly TOU impact analysis for winter peak days is based on a comparison of participant group to control group kWh usage on the coldest winter days of 2006 and 2007 that did not have critical peak events. Care was taken to create a control group of customers that closely matched the participant group in each participant segment and size strata.

The coldest winter days were identified by calculating the average daily temperature for each day from November 1, 2006 to March 30, 2007. If the average was 28 degrees or less, the day was selected as one of the coldest days. This cut-off creates a set of days with temperatures in the same range as temperatures that occurred during the winter critical peak event days. Table 1 lists the critical peak event days and the set of coldest winter weekdays, along with the average temperature for each day. Average daily temperatures on control event days ranged from 16 degrees to 28 degrees, while they ranged from 13 degrees to 28 degrees on comparison days.

Table 1. myPower Pricing Winter Critical Peak Event Days and Comparison Days

Date	Average Daily Temperature		Date	Average Daily Temperature
Winter Season Critical Peak Event Days				
January 30, 2007	28		February 6, 2007	16
Winter Season Coldest Weekdays for Peak Day Comparison				
December 8, 2006	25		February 13, 2007	25
January 17, 2007	24		February 14, 2007	22
January 25, 2007	28		February 15, 2007	19
January 26, 2007	17		February 16, 2007	21
January 29, 2007	26		March 6, 2007	17
February 5, 2007	13		March 7, 2007	17
February 7, 2007	19		March 8, 2007	25
February 8, 2007	21		March 9, 2007	24

After establishing the event days and the comparison days, average hourly load curves were developed so participant load shapes could be compared to control group load shapes. Even with close matching of the control group to the participant group for each program segment and size strata, there remained a difference in total daily usage between the control group and the participant group in each comparison. This hourly TOU impact analysis assumed no overall energy savings on winter peak days from switching to the TOU rate. To properly estimate the hourly kWh impacts, usage for each participant group and control group was indexed across all hours of the day. With indexing, the percent of use in each hour was calculated for the participant group and compared to the control group to estimate percent shifting of load. The percent shifts were translated to actual kWh shifts by applying them to the weighted average daily use for all of the sample customers in that group, both participants and control group.

The hourly CPP impact analysis for winter is based on a fixed effects regression model which compares baseline estimates of the expected kWh usage on the coldest winter days of 2006 and 2007 to the actual impacts on days with critical peak events. Baselines are created for each individual participant based on their typical response to weather and time of day over the entire winter period. Control group information is not needed.

All critical peak event days are considered winter peak conditions. As Table 1 showed, the winter critical peak event days in 2006 and 2007 occurred when the average daily temperature was 28 degrees or less. The winter CPP hourly impact model has the same specification as the summer CPP model, except that heating degree days (HDD) are used as the weather measure instead of the temperature-humidity index (THI). HDD is the difference between the average daily temperature and 65 degrees. As the average daily temperature goes down, the HDD goes up.

Table 2 summarizes the average winter impacts estimated for both the TOU and the CPP rates for each program segment over the on-peak period, and compares them to the summer impacts that were reported in previous memos. As expected, it shows that winter kW impacts are lower than summer kW impacts largely because there is less electric load being used in residential households during winter. However, if the achieved impacts are considered as a percent of load available to shift, the two seasons are very comparable.

Table 2. Summary of TOU and CPP Impacts on Peak Summer and Winter Days

	Avg On Peak kW	TOU Only		CPP		Total	
		KW	%	KW	%	KW	%
SUMMER PEAK DAYS							
Connection	2.85	-0.59	-21%	-0.74	-26%	-1.33	-47%
Sense with Central AC	2.60	-0.07	-3%	-0.36	-14%	-0.43	-17%
Sense without Central AC	1.61	-0.09	-6%	-0.23	-14%	-0.32	-20%
WINTER PEAK DAYS							
Connection	1.39	-0.04	-3%	-0.37	-27%	-0.41	-30%
Sense with Central AC	1.59	-0.11	-7%	-0.22	-14%	-0.33	-21%
Sense without Central AC	1.14	-0.02	-2%	-0.13	-11%	-0.15	-13%
Note: On Peak hours are 1:00 to 6:00 p.m. in summer, and 5:00 to 9:00 p.m. in winter.							

The one case with the largest difference in summer and winter impacts, both on a kW basis and a percent basis, is the TOU impact for Connection customers. Without automatic control of air conditioning load, the on-peak TOU impacts drop from a 21% reduction in summer to a 3% reduction in winter.

In comparison, Sense customers with Central AC show the opposite effect. Their low response of a 3% reduction in on-peak load during summer increases to a 7% reduction during winter. It appears that some Sense customers are actively shifting load out of the on-peak period on peak days during both seasons, summer and winter. Having the winter on-peak period later in the day from 5:00 to 9:00 p.m. may offer more opportunity to shift loads, both because more shiftable behavior-related loads are being used in the household during that time, and because more customers are home during those hours and are able to take action.

Chart 3 compares the TOU and CPP impacts for Connection customers on winter peak days. The TOU impacts are very small, but the CPP impacts are sizable. Customers are willing and able to reduce their evening loads occasionally, but not on a regular basis.

Chart 3.

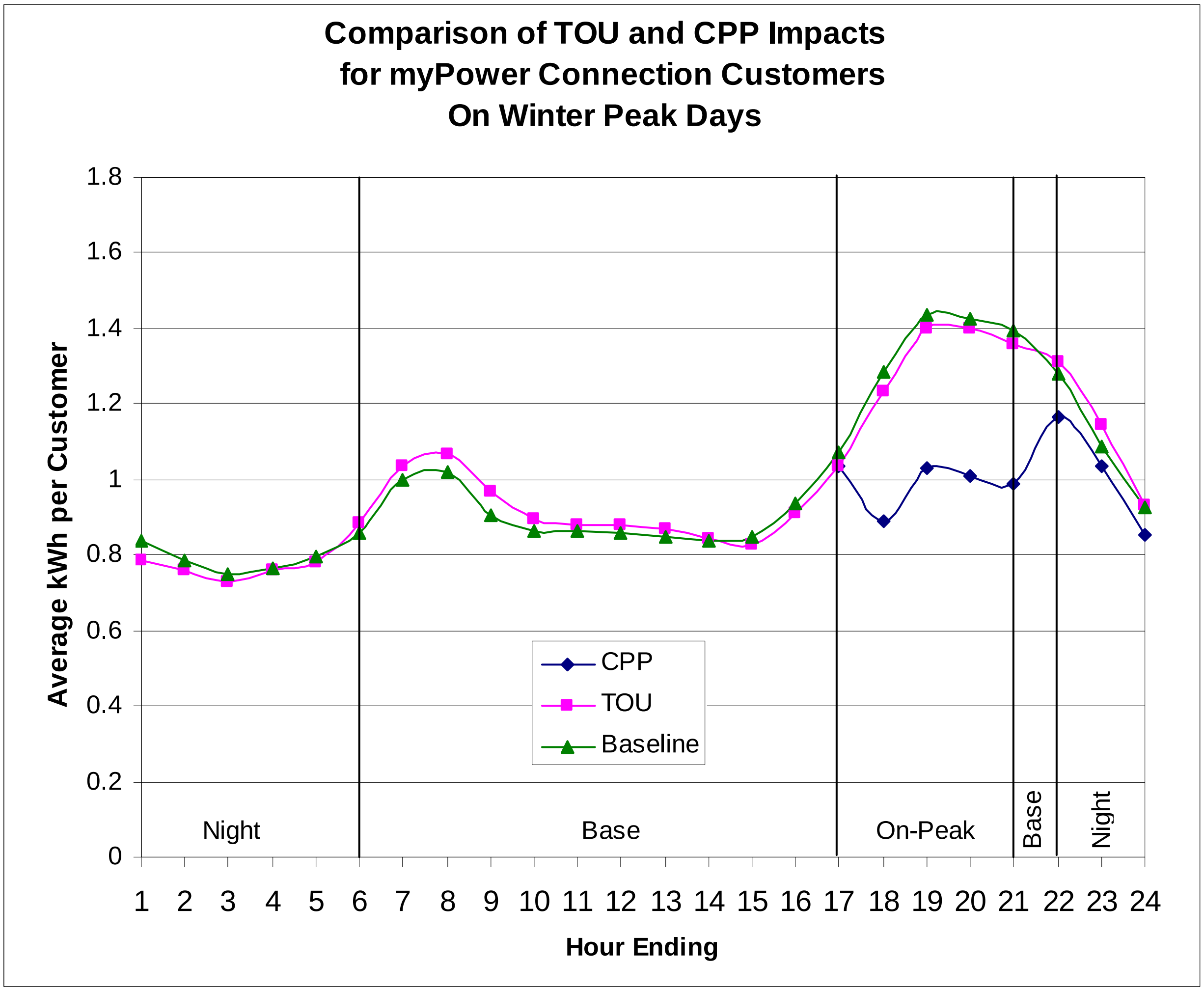
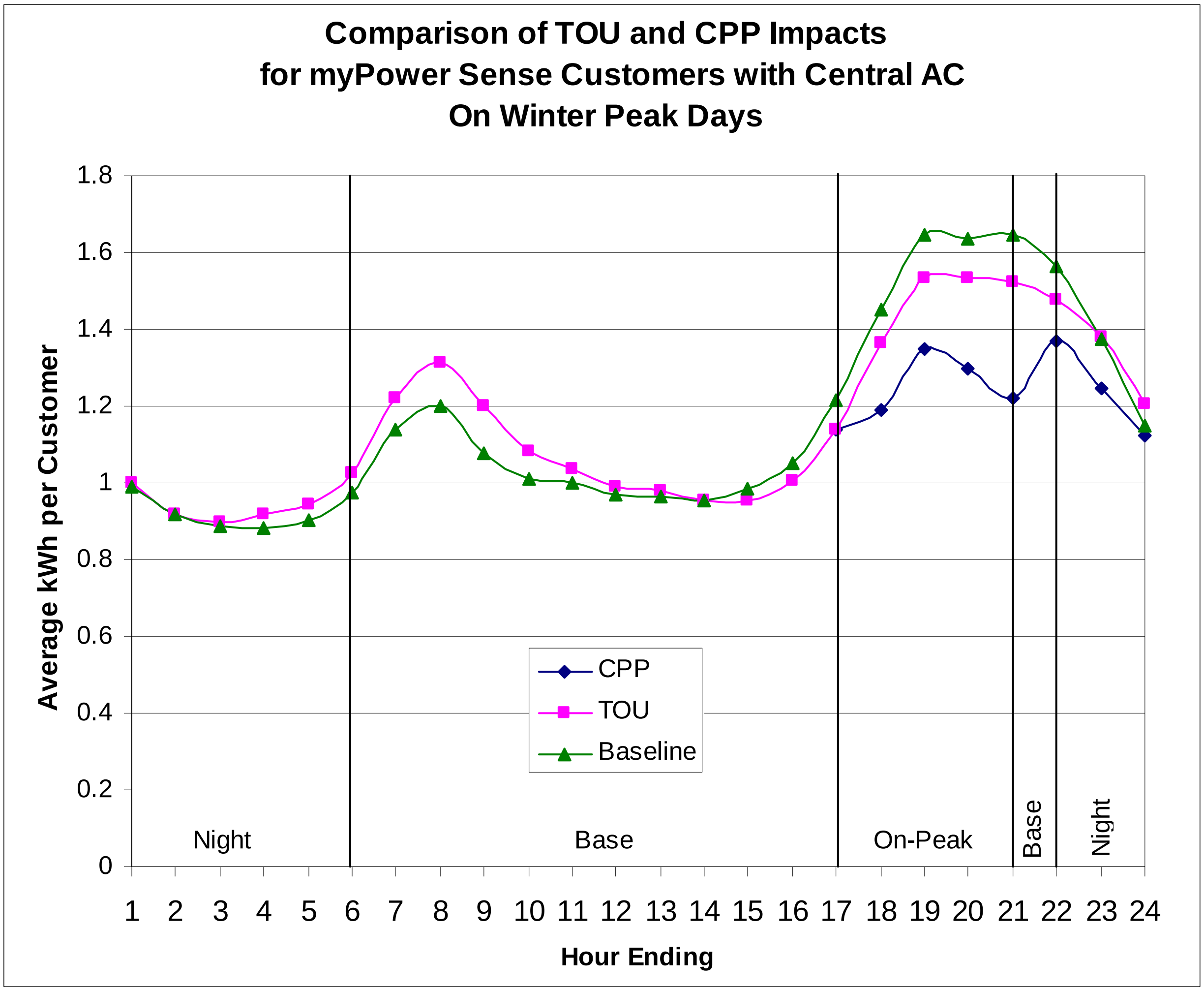


Chart 3 shows that there is a sharp increase in use starting at 9:00 p.m. (hour ending 22) after the end of the CPP control events. This may be considered a 'snapback' effect, but it is important to note that this increased use does not exceed the expected baseline use for similar peak days. In fact, there is a lingering load reduction effect throughout the rest of the day after the end of the CPP period. Some load reduction actions taken during the CPP period apparently continue past 9:00. Customers may have decided to shift some uses to a different day rather than to later in the evening.

Chart 4 presents a similar comparison for Sense customers with central air conditioning. This group of customers shows a stronger response to the TOU rate on peak days, as well as a strong load reduction during CPP control events.

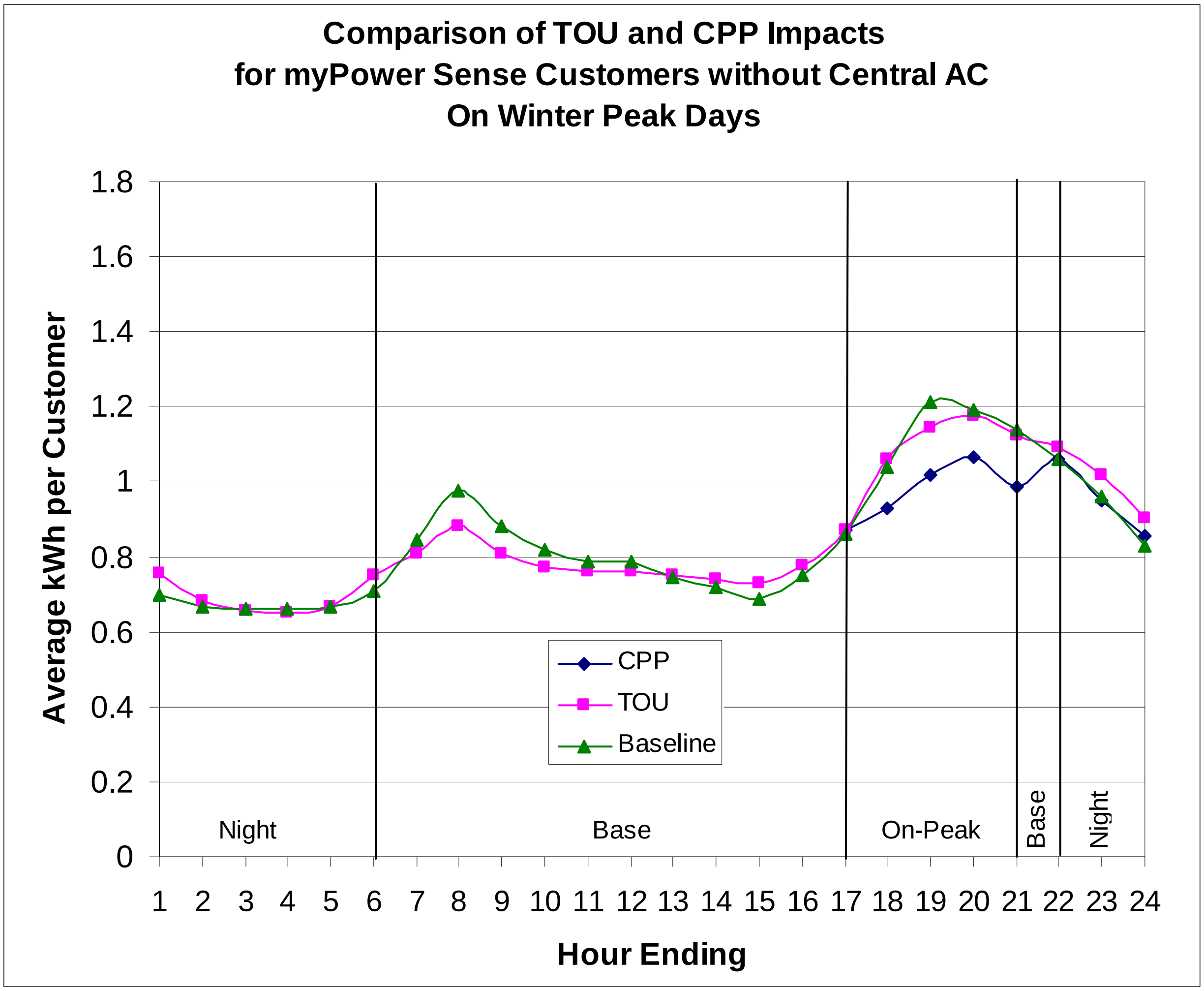
Chart 4.



Once again, there is a snapback effect but it does not exceed the baseline. The load reduction effects of the control event continue at some level throughout the rest of the day.

Chart 5 shows comparable data for Sense customers without central air conditioning. While the presence or lack of central air conditioning does not have a direct effect on winter electric load, Sense customers without central air conditioning have a noticeably smaller overall electric energy use even in winter. For this reason it is useful to examine them separately from Sense customers with central air conditioning. They show less of a response to the TOU rate, but still exhibit response to CPP control events.

Chart 5.



Detailed hourly TOU and CPP impact estimates for all of the customer groups and the different size strata within each group can be found in Tables 6 through 10.

Table 6.

myPower TOU Winter Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with winter peak weather for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Connection Customer

		kWh Change	kWh Change by Customer Size			
	Rate Period	All Customers	Very Low	Low	Medium	High
Hour Ending 100	Night	-0.05	-0.23	-0.03	-0.11	0.00
Hour Ending 200	Night	-0.03	-0.14	-0.03	-0.06	0.00
Hour Ending 300	Night	-0.02	-0.19	-0.01	-0.03	-0.01
Hour Ending 400	Night	-0.01	-0.10	0.01	-0.02	0.00
Hour Ending 500	Night	-0.02	-0.08	0.01	-0.03	-0.02
Hour Ending 600	Night	0.02	-0.01	0.01	0.01	0.05
Hour Ending 700	Base	0.03	0.10	0.02	-0.02	0.10
Hour Ending 800	Base	0.04	-0.05	0.05	0.04	0.05
Hour Ending 900	Base	0.06	0.10	0.07	0.07	0.04
Hour Ending 1000	Base	0.03	0.15	0.04	0.03	0.02
Hour Ending 1100	Base	0.01	0.15	0.01	0.02	0.01
Hour Ending 1200	Base	0.02	0.19	0.02	0.01	0.02
Hour Ending 1300	Base	0.02	0.12	0.01	0.03	0.00
Hour Ending 1400	Base	0.01	0.06	0.01	0.02	0.00
Hour Ending 1500	Base	-0.02	-0.06	-0.01	0.00	-0.04
Hour Ending 1600	Base	-0.02	0.05	-0.02	0.00	-0.06
Hour Ending 1700	Base	-0.03	-0.01	0.01	0.01	-0.12
Hour Ending 1800	On	-0.05	0.10	-0.03	0.01	-0.14
Hour Ending 1900	On	-0.04	0.16	-0.03	-0.02	-0.07
Hour Ending 2000	On	-0.03	0.18	-0.04	-0.01	-0.04
Hour Ending 2100	On	-0.04	0.05	-0.03	-0.01	-0.07
Hour Ending 2200	Base	0.03	-0.15	0.00	0.07	0.04
Hour Ending 2300	Night	0.06	-0.23	0.00	0.04	0.15
Hour Ending 2400	Night	0.01	-0.14	-0.02	-0.03	0.09
AVERAGE IMPACTS PER HOUR:						
Night		0.00	-0.14	-0.01	-0.03	0.03
Base		0.01	0.07	0.02	0.02	0.00
On-Peak		-0.04	0.12	-0.04	-0.01	-0.08
Evening Base		0.03	-0.15	0.00	0.07	0.04
Sample Size:						
Participants		319	6	104	104	105
Control Group		309	4	102	111	92
Upper Limit on Summer kWh for Size Strata:			1000	3325	4975	

Notes:

The days included in this analysis all had an average daily temperature of 28 degrees or less.
They were all weekdays, and they did not have a CPP event or holiday rates.
The winter peak days and their average daily temperatures are:

Dec 8 2006	25	*Feb 7 2007*	19	*Feb 16 2007*	21
Jan 17 2007	24	*Feb 8 2007*	21	*Mar 6 2007*	17
Jan 25 2007	28	*Feb 9 2007*	25	*Mar 7 2007*	17
Jan 26 2007	17	*Feb 13 2007*	25	*Mar 8 2007*	25
Jan 29 2007	26	*Feb 14 2007*	22	*Mar 9 2007*	24
Feb 5 2007	13	*Feb 15 2007*	19		

For comparison, here are the average daily temperatures for the critical peak days:

Jan 30 2007	28	*Feb 6 2007*	16

Table 7.

myPower TOU Winter Peak Day Demand Impacts
These impacts show the expected change in load each hour on a day with winter peak weather
for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Sense Customer

		kWh Change	kWh Change by Customer Size			
	Rate Period	All Customers	Very Low	Low	Medium	High
Hour Ending 100	Night	0.02	-0.06	0.02	0.04	0.03
Hour Ending 200	Night	0.00	-0.09	0.02	0.03	0.00
Hour Ending 300	Night	0.01	-0.10	0.03	0.04	0.00
Hour Ending 400	Night	0.02	-0.10	0.04	0.01	0.04
Hour Ending 500	Night	0.02	-0.09	0.07	-0.01	0.05
Hour Ending 600	Night	0.05	-0.09	0.14	0.00	0.06
Hour Ending 700	Base	0.05	-0.01	0.06	0.00	0.08
Hour Ending 800	Base	0.05	0.00	0.05	0.00	0.09
Hour Ending 900	Base	0.06	0.04	0.09	0.06	0.05
Hour Ending 1000	Base	0.04	0.02	-0.01	0.06	0.05
Hour Ending 1100	Base	0.02	0.00	0.01	0.04	0.01
Hour Ending 1200	Base	0.01	-0.03	0.00	0.02	0.01
Hour Ending 1300	Base	0.01	-0.04	-0.06	0.03	0.04
Hour Ending 1400	Base	0.01	0.00	-0.04	0.03	0.03
Hour Ending 1500	Base	-0.01	-0.02	-0.06	0.03	0.00
Hour Ending 1600	Base	-0.03	-0.01	-0.04	-0.01	-0.03
Hour Ending 1700	Base	-0.05	-0.01	-0.07	-0.07	-0.03
Hour Ending 1800	On	-0.05	0.08	-0.02	-0.07	-0.08
Hour Ending 1900	On	-0.10	0.10	-0.04	-0.11	-0.16
Hour Ending 2000	On	-0.08	0.10	-0.04	-0.10	-0.12
Hour Ending 2100	On	-0.09	0.11	-0.07	-0.08	-0.16
Hour Ending 2200	Base	-0.05	0.02	-0.05	-0.01	-0.09
Hour Ending 2300	Night	0.02	0.05	-0.02	0.02	0.04
Hour Ending 2400	Night	0.06	0.11	0.00	0.06	0.09
AVERAGE IMPACTS PER HOUR:						
Night		0.03	-0.04	0.04	0.02	0.04
Base		0.01	-0.01	-0.01	0.02	0.03
On-Peak		-0.08	0.10	-0.04	-0.09	-0.13
Evening Base		-0.05	0.02	-0.05	-0.01	-0.09
Sample Size:						
Participants		381	61	105	103	112
Control Group		403	14	69	117	203
Upper Limit on Summer kWh for Size Strata:			1000	mix	mix	

Notes:

The days included in this analysis all had an average daily temperature of 28 degrees or less.
They were all weekdays, and they did not have a CPP event or holiday rates.
The winter peak days and their average daily temperatures are:

Dec 8 2006	25	*Feb 7 2007*	19	*Feb 16 2007*	21
Jan 17 2007	24	*Feb 8 2007*	21	*Mar 6 2007*	17
Jan 25 2007	28	*Feb 9 2007*	25	*Mar 7 2007*	17
Jan 26 2007	17	*Feb 13 2007*	25	*Mar 8 2007*	25
Jan 29 2007	26	*Feb 14 2007*	22	*Mar 9 2007*	24
Feb 5 2007	13	*Feb 15 2007*	19		

For comparison, here are the average daily temperatures for the critical peak days:

Jan 30 2007	28	*Feb 6 2007*	16

Table 8.

myPower TOU Winter Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with winter peak weather
for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Sense with Central AC

		kWh Change	kWh Change by Customer Size			
	Rate Period	All Customers	Very Low	Low	Medium	High
Hour Ending 100	Night	0.01	-0.10	0.05	0.02	0.00
Hour Ending 200	Night	0.00	-0.12	0.03	0.02	-0.01
Hour Ending 300	Night	0.01	-0.15	0.04	0.05	-0.01
Hour Ending 400	Night	0.03	-0.13	0.05	0.04	0.05
Hour Ending 500	Night	0.04	-0.15	0.10	0.02	0.04
Hour Ending 600	Night	0.05	-0.16	0.14	0.04	0.04
Hour Ending 700	Base	0.08	-0.03	0.08	0.05	0.13
Hour Ending 800	Base	0.11	0.13	0.09	0.02	0.19
Hour Ending 900	Base	0.12	0.20	0.18	0.08	0.11
Hour Ending 1000	Base	0.07	0.22	0.02	0.09	0.07
Hour Ending 1100	Base	0.04	0.18	0.01	0.03	0.03
Hour Ending 1200	Base	0.02	0.12	0.00	0.01	0.02
Hour Ending 1300	Base	0.01	0.08	-0.06	0.01	0.04
Hour Ending 1400	Base	0.00	0.04	-0.06	0.02	0.02
Hour Ending 1500	Base	-0.03	-0.02	-0.10	0.01	-0.02
Hour Ending 1600	Base	-0.05	-0.02	-0.07	-0.03	-0.06
Hour Ending 1700	Base	-0.07	-0.09	-0.09	-0.06	-0.07
Hour Ending 1800	On	-0.08	-0.02	-0.04	-0.07	-0.14
Hour Ending 1900	On	-0.11	0.03	-0.08	-0.12	-0.15
Hour Ending 2000	On	-0.11	-0.06	-0.09	-0.11	-0.12
Hour Ending 2100	On	-0.12	0.05	-0.12	-0.11	-0.17
Hour Ending 2200	Base	-0.09	-0.10	-0.09	-0.05	-0.11
Hour Ending 2300	Night	0.01	-0.03	-0.03	0.00	0.04
Hour Ending 2400	Night	0.05	0.14	0.04	0.03	0.06
AVERAGE IMPACTS PER HOUR:						
Night		0.03	-0.09	0.05	0.03	0.03
Base		0.03	0.07	0.00	0.02	0.04
On-Peak		-0.11	0.00	-0.08	-0.10	-0.14
Evening Base		-0.09	-0.10	-0.09	-0.05	-0.11
Sample Size:						
Participants		230	31	66	65	68
Control Group		309	7	58	96	148
Upper Limit on Summer kWh for Size Strata:			1000	1800	3000	

Notes:

The days included in this analysis all had an average daily temperature of 28 degrees or less.
They were all weekdays, and they did not have a CPP event or holiday rates.
The winter peak days and their average daily temperatures are:

Dec 8 2006	25	*Feb 7 2007*	19	*Feb 16 2007*	21
Jan 17 2007	24	*Feb 8 2007*	21	*Mar 6 2007*	17
Jan 25 2007	28	*Feb 9 2007*	25	*Mar 7 2007*	17
Jan 26 2007	17	*Feb 13 2007*	25	*Mar 8 2007*	25
Jan 29 2007	26	*Feb 14 2007*	22	*Mar 9 2007*	24
Feb 5 2007	13	*Feb 15 2007*	19		

For comparison, here are the average daily temperatures for the critical peak days:

Jan 30 2007	28	*Feb 6 2007*	16

Table 9.

myPower TOU Winter Peak Day Demand Impacts

These impacts show the expected change in load each hour on a day with winter peak weather for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Sense without Central AC

		kWh Change	kWh Change by Customer Size			
	Rate Period	All Customers	Very Low	Low	Medium	High
Hour Ending 100	Night	0.06	-0.02	-0.03	0.09	0.11
Hour Ending 200	Night	0.01	-0.05	0.00	0.03	0.03
Hour Ending 300	Night	0.00	-0.05	0.02	-0.02	0.01
Hour Ending 400	Night	-0.01	-0.06	0.03	-0.09	0.03
Hour Ending 500	Night	0.00	-0.03	0.03	-0.10	0.05
Hour Ending 600	Night	0.04	-0.01	0.13	-0.13	0.12
Hour Ending 700	Base	-0.03	0.00	0.02	-0.15	0.00
Hour Ending 800	Base	-0.10	-0.12	-0.09	-0.06	-0.12
Hour Ending 900	Base	-0.07	-0.11	-0.14	0.01	-0.08
Hour Ending 1000	Base	-0.05	-0.17	-0.10	-0.01	0.01
Hour Ending 1100	Base	-0.03	-0.17	-0.01	0.05	-0.03
Hour Ending 1200	Base	-0.02	-0.17	-0.04	0.05	-0.01
Hour Ending 1300	Base	0.00	-0.14	-0.05	0.10	0.02
Hour Ending 1400	Base	0.03	-0.04	0.01	0.07	0.03
Hour Ending 1500	Base	0.04	-0.03	0.03	0.11	0.03
Hour Ending 1600	Base	0.03	0.01	0.03	0.05	0.02
Hour Ending 1700	Base	0.01	0.08	-0.01	-0.06	0.05
Hour Ending 1800	On	0.02	0.18	0.04	-0.09	0.02
Hour Ending 1900	On	-0.07	0.16	0.05	-0.10	-0.20
Hour Ending 2000	On	-0.01	0.24	0.06	-0.07	-0.11
Hour Ending 2100	On	-0.01	0.16	0.06	0.01	-0.13
Hour Ending 2200	Base	0.03	0.12	0.06	0.10	-0.05
Hour Ending 2300	Night	0.06	0.12	0.01	0.08	0.05
Hour Ending 2400	Night	0.07	0.08	-0.12	0.12	0.15
AVERAGE IMPACTS PER HOUR:						
Night		0.03	0.00	0.01	0.00	0.07
Base		-0.02	-0.08	-0.03	0.01	-0.01
On-Peak		-0.02	0.18	0.05	-0.06	-0.10
Evening Base		0.03	0.12	0.06	0.10	-0.05
Sample Size:						
Participants		151	30	39	38	44
Control Group		94	7	11	21	55
Upper Limit on Summer kWh for Size Strata:			1000	1800	3000	

Notes:

The days included in this analysis all had an average daily temperature of 28 degrees or less.
They were all weekdays, and they did not have a CPP event or holiday rates.
The winter peak days and their average daily temperatures are:

Dec 8 2006	25	*Feb 7 2007*	19	*Feb 16 2007*	21
Jan 17 2007	24	*Feb 8 2007*	21	*Mar 6 2007*	17
Jan 25 2007	28	*Feb 9 2007*	25	*Mar 7 2007*	17
Jan 26 2007	17	*Feb 13 2007*	25	*Mar 8 2007*	25
Jan 29 2007	26	*Feb 14 2007*	22	*Mar 9 2007*	24
Feb 5 2007	13	*Feb 15 2007*	19		

For comparison, here are the average daily temperatures for the critical peak days:

Jan 30 2007	28	*Feb 6 2007*	16

Table 10.

myPower CPP Winter Peak Day Demand Impacts
These impacts show the expected change in load on a day when a Critical Peak event is called.
Impacts shown here are for a single Residential customer
and they are incremental to impacts that occur due to the Time-of-Use rate.

Connection Customer

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1800	Critical Peak	-0.35	-0.38	-0.26	-0.40	-0.38
Hour Ending 1900	Critical Peak	-0.37	-0.31	-0.24	-0.43	-0.45
Hour Ending 2000	Critical Peak	-0.39	-0.29	-0.21	-0.45	-0.51
Hour Ending 2100	Critical Peak	-0.37	-0.17	-0.20	-0.45	-0.47
Hour Ending 2200	Snapback	-0.15	0.07	-0.08	-0.14	-0.23
Hour Ending 2300	Snapback	-0.11	0.01	-0.05	-0.10	-0.18
Hour Ending 2400	Snapback	-0.08	0.04	-0.07	-0.13	-0.06
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.37	-0.29	-0.23	-0.44	-0.45
Snapback		-0.11	0.04	-0.07	-0.12	-0.16
Sample Size		322	6	105	105	106
Upper Limit on Summer kWh			1000	3325	4975	

Sense Customer

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1800	Critical Peak	-0.16	-0.07	-0.13	-0.21	-0.18
Hour Ending 1900	Critical Peak	-0.16	-0.03	-0.14	-0.20	-0.22
Hour Ending 2000	Critical Peak	-0.18	-0.03	-0.10	-0.22	-0.32
Hour Ending 2100	Critical Peak	-0.24	-0.10	-0.09	-0.29	-0.40
Hour Ending 2200	Snapback	-0.08	0.03	0.04	-0.11	-0.22
Hour Ending 2300	Snapback	-0.11	-0.10	-0.02	-0.09	-0.21
Hour Ending 2400	Snapback	-0.07	-0.04	-0.04	-0.06	-0.12
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.19	-0.06	-0.12	-0.23	-0.28
Snapback		-0.08	-0.04	0.00	-0.09	-0.18
Sample Size		384	61	106	105	112
Upper Limit on Summer kWh			1000	mix	mix	

Sense Customer with Central AC

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1800	Critical Peak	-0.17	-0.14	-0.16	-0.20	-0.17
Hour Ending 1900	Critical Peak	-0.18	-0.04	-0.12	-0.19	-0.31
Hour Ending 2000	Critical Peak	-0.23	-0.09	-0.10	-0.26	-0.40
Hour Ending 2100	Critical Peak	-0.30	-0.19	-0.12	-0.37	-0.47
Hour Ending 2200	Snapback	-0.11	0.08	0.06	-0.18	-0.29
Hour Ending 2300	Snapback	-0.13	-0.16	-0.01	-0.15	-0.23
Hour Ending 2400	Snapback	-0.08	-0.16	-0.04	-0.06	-0.11
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.22	-0.12	-0.13	-0.26	-0.34
Snapback		-0.11	-0.08	0.00	-0.13	-0.21
Sample Size		233	31	67	67	68
Upper Limit on Summer kWh			1000	2560	3992	

Sense Customer without Central AC

		kWh change	kWh Change by Customer Size			
Hour	**Hour Type**	**All Customers**	**Very Low**	**Low**	**Medium**	**High**
Hour Ending 1400	Critical Peak	-0.25	-0.12	-0.14	-0.22	-0.43
Hour Ending 1800	Critical Peak	-0.13	0.00	-0.08	-0.22	-0.20
Hour Ending 1900	Critical Peak	-0.13	-0.01	-0.17	-0.22	-0.09
Hour Ending 2000	Critical Peak	-0.11	0.02	-0.08	-0.15	-0.19
Hour Ending 2200	Snapback	-0.03	-0.03	0.02	0.00	-0.11
Hour Ending 2300	Snapback	-0.07	-0.03	-0.02	-0.01	-0.19
Hour Ending 2400	Snapback	-0.05	0.09	-0.05	-0.05	-0.14
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.13	0.00	-0.10	-0.18	-0.19
Snapback		-0.05	0.01	-0.02	-0.02	-0.15
Sample Size		151	30	39	38	44
Upper Limit on Summer kWh			1000	1800	3000	

Yellow	Values in Yellow have a 5% to 50% probability of actually being zero
Orange	Values in Orange have greater than 50% probability of actually being zero

4 HOURLY TOU AND CPP IMPACTS DURING SHOULDER MONTHS

During the shoulder months of October, April and May, system loads and customer loads are generally at their lowest points of the year. The TOU rate reflects this by not having any on-peak rate periods during the shoulder months. Customers still have the option of saving money by shifting load from the base period to the night period, but this shift is not expected to be large. The overall impact of the shifting that occurs will be summarized later in this report in the kWh shift analysis and in the energy savings analysis. An hour-by-hour analysis of the TOU shift was not considered to be useful, so it was not done for this section of the report.

There was one CPP control event called during the shoulder months. It occurred on Friday, May 25, from 1:00 to 6:00 p.m. This was the Friday before the Memorial Day weekend. It was a very hot May day and it is likely that air conditioning was being used in some households. Due to the suspected presence of air conditioning load, a CPP regression model for shoulder months was created that followed the same form as the summer model. The control event hours were 1:00 to 6:00 p.m. and the weather variable was the THI. The impact estimates from the model are shown in Table 11 and compared to the summer and winter CPP impacts.

Table 11. Comparison of CPP Impacts in Summer, Winter and Shoulder Months

	Average kW Reduction During CPP Control Events		
	Summer Months	Winter Months	Shoulder Months
Connection	-0.74	-0.37	-0.27
Sense with Central AC	-0.36	-0.22	0.00*
Sense without Central AC	-0.23	-0.13	-0.05*
** These values are not statistically significant at the 95% confidence level*			

Connection customers showed an average hourly response of –0.27 kW during the May 25 critical peak event. This is less load reduction than what was seen in both the summer and the winter responses, but it indicates that there was probably some air conditioning load on the system that was automatically controlled. The two Sense customer groups did not show a statistically significant response to the event. This may be explained by the fact that there was only one CPP event called during the shoulder months and it was called on a Friday before a holiday weekend. Customers who were dependent on taking personal actions to respond to the event may have had their attention focused elsewhere on that particular day.

Detailed hourly CPP impact estimates for each of the customer groups and the different size strata within each group can be found in Table 12.

Table 12.

myPower CPP Shoulder Month Demand Impacts

These impacts show the expected change in load on a day when a Critical Peak event is called.
Impacts shown here are for a single Residential customer
and they are incremental to impacts that occur due to the Time-of-Use rate.
(Time-of-Use rate impacts for the Shoulder Months are assumed to be zero since there are no on-peak price periods.)

Connection Customer

		kWh change	kWh Change by Customer Size			
Hour	Hour Type	All Customers	Very Low	Low	Medium	High
Hour Ending 1400	Critical Peak	-0.31	-0.11	-0.05	-0.28	-0.62
Hour Ending 1500	Critical Peak	-0.29	0.01	-0.01	-0.26	-0.63
Hour Ending 1600	Critical Peak	-0.26	-0.01	-0.03	-0.28	-0.50
Hour Ending 1700	Critical Peak	-0.25	0.15	-0.07	-0.28	-0.45
Hour Ending 1800	Critical Peak	-0.24	0.07	-0.11	-0.34	-0.35
Hour Ending 1900	Snapback	0.21	0.03	0.10	0.22	0.25
Hour Ending 2000	Snapback	0.19	-0.01	0.07	0.27	0.19
Hour Ending 2100	Snapback	0.17	0.01	0.10	0.17	0.19
Hour Ending 2200	Snapback	0.16	0.01	0.12	0.19	0.14
Hour Ending 2300	Snapback	0.27	0.08	0.14	0.37	0.25
Hour Ending 2400	Snapback	0.35	-0.11	0.22	0.40	0.41
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.27	0.02	-0.06	-0.29	-0.51
Snapback		0.23	0.00	0.13	0.27	0.24
Sample Size		322	6	105	105	106
Upper Limit on Summer kWh for Size Strata			1000	3325	4975	

Sense Customer

		kWh change	kWh Change by Customer Size			
Hour	Hour Type	All Customers	Very Low	Low	Medium	High
Hour Ending 1400	Critical Peak	-0.08	-0.05	-0.13	0.04	-0.18
Hour Ending 1500	Critical Peak	-0.04	-0.08	0.00	0.00	-0.08
Hour Ending 1600	Critical Peak	0.02	-0.01	0.01	0.10	-0.02
Hour Ending 1700	Critical Peak	0.00	-0.05	0.00	0.06	-0.04
Hour Ending 1800	Critical Peak	0.01	-0.03	-0.03	0.11	-0.02
Hour Ending 1900	Snapback	0.13	0.09	-0.04	0.31	0.16
Hour Ending 2000	Snapback	0.14	0.03	-0.04	0.39	0.13
Hour Ending 2100	Snapback	0.16	-0.02	0.01	0.35	0.22
Hour Ending 2200	Snapback	0.22	0.07	0.10	0.38	0.26
Hour Ending 2300	Snapback	0.24	0.10	0.14	0.27	0.38
Hour Ending 2400	Snapback	0.23	0.12	0.09	0.24	0.42
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.02	-0.04	-0.03	0.06	-0.07
Snapback		0.19	0.06	0.04	0.32	0.26
Sample Size		384	61	106	105	112
Upper Limit on Summer kWh for Size Strata			1000	2560	3992	

Sense Customer with Central AC

		kWh change	kWh Change by Customer Size			
Hour	Hour Type	All Customers	Very Low	Low	Medium	High
Hour Ending 1400	Critical Peak	-0.08	-0.05	-0.19	0.14	-0.21
Hour Ending 1500	Critical Peak	-0.05	-0.12	-0.03	0.09	-0.18
Hour Ending 1600	Critical Peak	0.05	0.05	-0.04	0.22	-0.04
Hour Ending 1700	Critical Peak	0.02	0.00	-0.03	0.17	-0.07
Hour Ending 1800	Critical Peak	0.09	0.09	-0.04	0.35	-0.03
Hour Ending 1900	Snapback	0.20	0.11	-0.13	0.56	0.22
Hour Ending 2000	Snapback	0.16	-0.04	-0.10	0.59	0.08
Hour Ending 2100	Snapback	0.20	-0.06	-0.02	0.51	0.22
Hour Ending 2200	Snapback	0.27	0.07	0.12	0.52	0.25
Hour Ending 2300	Snapback	0.30	0.10	0.20	0.37	0.41
Hour Ending 2400	Snapback	0.28	0.13	0.08	0.35	0.46
AVERAGE IMPACTS PER HOUR:						
Critical Peak		0.00	-0.01	-0.07	0.20	-0.11
Snapback		0.23	0.05	0.03	0.48	0.28
Sample Size		233	31	67	67	68
Upper Limit on Summer kWh for Size Strata			1000	2560	3992	

Sense Customer without Central AC

		kWh change	kWh Change by Customer Size			
Hour	Hour Type	All Customers	Very Low	Low	Medium	High
Hour Ending 1400	Critical Peak	-0.09	-0.05	-0.02	-0.14	-0.13
Hour Ending 1500	Critical Peak	-0.01	-0.04	0.04	-0.15	0.08
Hour Ending 1600	Critical Peak	-0.02	-0.07	0.11	-0.14	0.00
Hour Ending 1700	Critical Peak	-0.04	-0.09	0.05	-0.15	0.01
Hour Ending 1800	Critical Peak	-0.11	-0.15	-0.01	-0.32	-0.01
Hour Ending 1900	Snapback	0.02	0.07	0.10	-0.15	0.06
Hour Ending 2000	Snapback	0.10	0.10	0.06	0.01	0.19
Hour Ending 2100	Snapback	0.10	0.02	0.05	0.06	0.21
Hour Ending 2200	Snapback	0.14	0.06	0.07	0.13	0.27
Hour Ending 2300	Snapback	0.15	0.10	0.05	0.08	0.35
Hour Ending 2400	Snapback	0.16	0.10	0.09	0.05	0.36
AVERAGE IMPACTS PER HOUR:						
Critical Peak		-0.05	-0.08	0.04	-0.18	-0.01
Snapback		0.11	0.08	0.07	0.03	0.24
Sample Size		151	30	39	38	44
Upper Limit on Summer kWh for Size Strata			1000	1800	3000	

Yellow	Values in Yellow have a 5% to 50% probability of actually being zero
Orange	Values in Orange have greater than 50% probability of actually being zero

The detailed report provides hourly impacts for during and after the CPP event. The snapback impacts are suspiciously high for the Sense customers, in the range of 0.13 to 0.24 kW, and they are all statistically significant at the 95% confidence level. High snapback loads are not expected if there were no load reductions during the critical peak period. This high load difference during the snapback hours may be indicating that Friday loads on a holiday weekend are higher than normal weekday loads at the same temperature. If this is true, Sense customers may actually have responded to the CPP event, but the demand reduction was masked by the increased load of the Friday holiday. Additional modeling work using Friday and holiday variables, or comparison to the control group, would need to be done to test this theory, but it would be a significant effort. It was determined that this amount of detailed modeling work was not worthwhile to increase understanding of an unusual CPP event that occurred only once during the non-peak shoulder months. The additional modeling work can be done at a later date if it is deemed of value.

5 TOU KWH SHIFTS DURING WINTER MONTHS

The TOU kWh shift studies for the winter and shoulder months followed the same method that was used for estimation of the summer kWh shifts. The kWh shift estimates are based on a comparison of participant group to control group kWh usage during days without critical peak events. Care was taken to create a control group of customers that closely matches the participant group in each participant segment and size strata.

The winter study used weekday data for November 1, 2006 through March 31, 2007. The shoulder month study used weekday data for the months of October 2006, April 2007 and May 2007. Holidays and CPP control event days were excluded.

Average kWh usage per customer for each hour of the study period for each study group was estimated. Using average kWh usage per customer per hour minimized the problem of missing data. If a kWh reading was missing for a particular customer during a particular hour, the impact on the calculated average for that hour was small.

Even with close matching of the control group to the participant group for each program segment and size strata, there remained a difference in total usage between the control group and the participant group in each comparison. This analysis assumed no overall energy savings from switching to the TOU rate. To properly estimate the kWh switched, usage for each participant group and control group was indexed across the rate periods. With indexing, the percent of use in each rate period was calculated for the participant group and compared to the control group to estimate percent shifting of load. The percent shifts were translated to actual kWh shifts by applying them to the weighted average seasonal use for all of the sample customers in that group, both participants and control group.

These estimates of kWh shift due to TOU rates have not been normalized for weather. This present analysis of kWh shifting assumes that the weather seen over the study period is close to normal. During the winter study period, the average outdoor temperature was 37.8 for night hours, 42.3 for base hours, and 42.6 for on-peak hours. During the shoulder month study period, the average outdoor temperature was 51.8 for night hours and 56.5 for base hours. There were no on-peak hours during the shoulder months. If it is determined that these temperatures are very different from normal weather, a weather-normalization adjustment should be applied to the results of these analyses.

In general, there was very little kWh shifting for any of the customer groups during winter months and even less during the shoulder months. Table 13 compares the total kWh shifted over each season for the largest size strata within each group. The impacts for the largest size strata are shown because this group exhibited the greatest shifts and, even at this level, the kWh shifts in the winter and shoulder months will not create sizable changes to the load curve.

Table 13. Comparison of TOU kWh Shift Impacts for the Largest Size Strata in each Customer Group

	Average kWh per customer shifted from one rate period to another over the entire season		
	Summer Months *(4 months)*	Winter Months *(5 months)*	Shoulder Months *(3 months)*
Connection	242	39	14
Sense with Central AC	104	26	1
Sense without Central AC	154	65	21

Detailed estimates of kWh shifts for each of the customer groups and the different size strata within each group can be found in Tables 14 and 15. This information is provided for review and is not expected to be of value for projecting population impacts because the impacts are so small.

Table 14.

myPower TOU Winter kWh Shift Impacts

These impacts show the expected change during a winter season (November through March) for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Connection Customer

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-22%	-3%	-2%	3%	-145	-17	-19	39
Base Hours	10%	2%	0%	-1%	109	24	8	-26
On-Peak Hours	12%	-2%	2%	-2%	36	-7	11	-13
Sample Size:								
Participants	5	104	104	105				
Control Group	4	110	108	87				
Upper Limit on Summer kWh for Size Strata:	1000	3325	4975					

Sense Customer

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-3%	1%	2%	3%	-21	6	19	38
Base Hours	1%	0%	-1%	0%	13	-3	-11	-2
On-Peak Hours	3%	-1%	-1%	-5%	9	-3	-8	-36
Sample Size:								
Participants	61	106	103	112				
Control Group	15	76	116	192				
Upper Limit on Summer kWh for Size Strata:	1000	mix	mix					

Sense Customer with Central AC

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-8%	2%	2%	2%	-59	16	18	26
Base Hours	6%	0%	-1%	0%	77	1	-11	13
On-Peak Hours	-5%	-4%	-1%	-5%	-18	-17	-7	-39
Sample Size:								
Participants	31	67	65	68				
Control Group	9	65	96	141				
Upper Limit on Summer kWh for Size Strata:	1000	2560	3992					

Sense Customer without Central AC

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	1%	-3%	0%	5%	5	-17	2	65
Base Hours	-5%	-1%	0%	-1%	-51	-15	-3	-35
On-Peak Hours	22%	11%	0%	-4%	46	32	1	-30
Sample Size:								
Participants	30	39	38	44				
Control Group	6	11	21	51				
Upper Limit on Summer kWh for Size Strata:	1000	1800	3000					

Notes:

These numbers were derived from winter data for November 1, 2006 through March 31, 2007.

The impacts in this report reflect the average weather over the study period.
The weather unit is Degree Hours = max(0,(65-Hourly Temperature).
Average Degree Hours is 27.2 for night hours, 22.7 for base hours and 22.4 for on-peak hours.
It is unknown how close this is to normal summer weather.

Data for days with critical peak events were excluded from this analysis. These impacts are for TOU only.

Table 15.

myPower TOU Shoulder Months kWh Shift Impacts
These impacts show the expected change during the shoulder months (October, April and May)
for a single Residential customer that switches from a regular rate to the myPower TOU rate.

Connection Customer

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-18%	-4%	-2%	2%	-48	-15	-9	14
Base Hours	8%	2%	1%	-1%	48	15	9	-14
On-Peak Hours	NA	NA	NA	NA	NA	NA	NA	NA
Sample Size:								
Participants	6	105	104	106				
Control Group	6	112	102	81				
Upper Limit on Summer kWh for Size Strata:	1000	3325	4975					

Sense Customer

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-4%	-3%	2%	1%	-11	-11	8	6
Base Hours	2%	1%	-1%	0%	11	11	-8	-6
On-Peak Hours	NA	NA	NA	NA	NA	NA	NA	NA
Sample Size:								
Participants	61	106	104	112				
Control Group	18	78	113	176				
Upper Limit on Summer kWh for Size Strata:	1000	mix	mix					

Sense Customer with Central AC

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	-8%	-3%	0%	0%	-27	-9	1	-1
Base Hours	4%	1%	0%	0%	27	9	-1	1
On-Peak Hours	NA	NA	NA	NA	NA	NA	NA	NA
Sample Size:								
Participants	31	67	66	68				
Control Group	12	67	93	128				
Upper Limit on Summer kWh for Size Strata:	1000	2560	3992					

Sense Customer without Central AC

	Per Cent Change				kWh Change			
	Very Small	Small	Medium	Large	Very Small	Small	Medium	Large
Night Hours	4%	-7%	2%	3%	9	-20	11	21
Base Hours	-2%	3%	-1%	-1%	-9	20	-11	-21
On-Peak Hours	NA	NA	NA	NA	NA	NA	NA	NA
Sample Size:								
Participants	30	39	38	44				
Control Group	6	12	20	48				
Upper Limit on Summer kWh for Size Strata:	1000	1800	3000					

Notes:

These numbers were derived from shoulder month data for October 2006, April 2007 and May 2007.

The impacts in this report reflect the average weather over the study period.
The weather unit is Degree Hours = max(0,(65-Hourly Temperature).
Average Degree Hours is 13.2 for night hours and 8.5 for base hours. There are no on-peak hours in the shoulder months.
It is unknown how close this is to normal shoulder month weather, but weather does not have much effect in these months.

Data for days with critical peak events were excluded from this analysis. These impacts are for TOU only.

6 ENERGY SAVINGS ESTIMATES

Energy savings for the winter and shoulder seasons were estimated using the same method used for estimating summer energy savings. An October 21, 2007 memo describes the details of the method. The only difference in the model specification was the use of heating degree days (HDD) instead of the temperature-humidity index (THI) for quantifying the weather. HDD is the difference between the average daily temperature and 65 degrees. As the average daily temperature goes down, the HDD goes up. HDD generally has a good correlation with weather-sensitive energy use during months that require heating.

In general, two separate models were built for each season, one for central air conditioning customers and one for customers without central air conditioning. Time-series, cross-sectional regression was used to account for fixed effects of individual customers within each group. Dummy variables were used to create difference of differences models which specified average changes for each participant group and each control group after the beginning of the TOU rates. A log transformation was used on the monthly kWh variable to compare percent changes due to the program rather than absolute kWh values. This was necessary since the average monthly kWh usage of the Sense customers without central air conditioning was much lower than the other groups.

The energy savings models had the following specification:

Ln(Monthly kWh) = f (Monthly HDD,
Billing Days,
Connection Customer after program began,
Sense Customer after program began,
Control Group Customer after program began)

Results from the two models for the Winter season are shown in Table 16. For both Connection and Sense customers in the Central Air conditioning group, energy use decreases after the beginning of the TOU program. Energy use for the control group goes up. In the No Central Air conditioning group, energy use increases for both Sense customers and the control group. However, all of these changes are very small. In fact, they are so small that most of them are not statistically significant at the 90% confidence level. There is a high likelihood that these impacts are actually zero and there was no real change in energy use after the start of the program. The only exception is the Sense with Central Air conditioning group. Their 1.65% decrease is statistically significant at the 90% confidence level.

Table 16. myPower Pricing TOU Winter Energy Savings Models – Truncated Group (80% mid-range)

Variable	Central Air conditioning Group Coefficient *(t-value)*	No Central AC Group Coefficient *(t-value)*
Month is after program start and the customer is in myPower **Connection**	**-0.00389** ***(-0.5)***	
Month is after program start and the customer is in myPower **Sense**	**-0.01653** ***(-1.7)***	**0.008166** ***(0.7)***
Month is after program start and the customer is a **Control Group** Customer	**0.00530** ***(0.7)***	**0.000514** ***(0.0)***
Monthly HDD	0.000168 *(17.0)*	0.000161 *(7.9)*
Billing Days	0.039968 *(26.1)*	0.039836 *(12.9)*
Sample Size Customers	8,420 622	2,310 172

Comparing the differences between the participant groups and the control groups, **the best estimates of winter energy savings from the myPower Pricing program is 0% for Connection customers, 1.65% for Sense customers with central air conditioning, and 0% for Sense customers without central air conditioning.** These savings, shown in Table 17, are in comparison to what the participants would have used if they had not been on the TOU rate.

Table 17. myPower Pricing TOU Winter Energy Savings Estimates

Variable	Control Group Change in Use	Participant Group Change in Use	Winter Energy Savings from TOU
Connection Customers	**0.0%**	**0.0%**	**0.0%**
Sense Customers with Central AC	**0.0%**	**-1.65%**	**1.65%**
Sense Customers without Central AC	**0.0%**	**0.0%**	**0.0%**

Results from the two models for the Shoulder season are shown in Table 18. For both Connection and Sense customers in the Central Air conditioning group, energy use decreases after the beginning of the TOU program. Energy use for the control group goes up. In the No Central Air conditioning group, energy use increases slightly for Sense customers and decreases slightly for the control group. However, all of these changes are very small. In fact, they are so small that none of them are statistically significant at the 90% confidence level. There is a high likelihood that all of these impacts are actually zero and there was no real change in energy use after the start of the program during the Shoulder months. Interestingly, the coefficient on the HDD variable is negative. This indicates that increased use due to air conditioning on occasional hot days during the Shoulder months is more significant than the increased energy use due to cold outdoor temperatures during the same time period.

Table 18. myPower Pricing TOU Shoulder Season Energy Savings Models – Truncated Group (80% mid-range)

Variable	Central Air conditioning Group Coefficient *(t-value)*	No Central AC Group Coefficient *(t-value)*
Month is after program start and the customer is in myPower **Connection**	**-0.01067** ***(-1.0)***	
Month is after program start and the customer is in myPower **Sense**	**-0.00806** ***(-0.6)***	**0.001844** ***(0.1)***
Month is after program start and the customer is a **Control Group** Customer	**0.01147** ***(1.1)***	**-0.00818** ***(-0.4)***
Monthly HDD	-0.0003 *(-17.9)*	-0.00016 *(-3.8)*
Billing Days	0.054523 *(18.0)*	0.05184 *(7.6)*
Sample Size Customers	5,109 653	1,445 185

Comparing the differences between the participant groups and the control groups, **the best estimates of Shoulder month energy savings from the myPower Pricing program is 0% for Connection customers, 0% for Sense customers with central air conditioning, and 0% for Sense customers without central air conditioning.** These savings, shown in Table 19, are in comparison to what the participants would have used if they had not been on the TOU rate.

Table 19. myPower Pricing TOU Shoulder Season Energy Savings Estimates

Variable	Control Group Change in Use	Participant Group Change in Use	Shoulder Month Energy Savings from TOU
Connection Customers	**0.0%**	**0.0%**	**0.0%**
Sense Customers with Central AC	**0.0%**	**0.0%**	**0.0%**
Sense Customers without Central AC	**0.0%**	**0.0%**	**0.0%**