NAVIGANT

POWER SMART PRICING
2010 ANNUAL REPORT

Prepared for:
Ameren Illinois Utilities

Ameren

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Acknowledgments

CNT Energy prepared the 2010 Power Smart Pricing Operational Report. Their complete report is included as Appendix A in this document. Highlights from their report are included within the main body text of this document whenever the facts are relevant to the discussion. Readers who are not familiar with the Power Smart Pricing program may find it helpful to review Appendix A before reading this evaluation report.

Special thanks go to CNT Energy for their preparation of the chapter on participant bill savings in the evaluation report.

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1 Executive Summary

The Illinois legislature was one of the first legislative bodies to encourage real-time pricing (RTP) rates for residential customers. Illinois Public Act 94-0977 required that electric utilities which serve more than 100,000 customers must have RTP available to residential customers as a rate option. This act led to the Illinois Commerce Commission (ICC) Docket 06-0961, which found that a residential RTP program would be likely to provide a net economic benefit to the residential community as a whole. As part of this docket, the Ameren Illinois Utilities[1] (Ameren Illinois) received approval to launch Power Smart Pricing (PSP).

PSP presents “de-averaged” electricity supply prices that are a direct pass-through of Midwest Independent System Operator (MISO) hourly prices without markup. These prices provide a day-ahead price signal to customers about the real cost of their electricity use.[2] The program also provides information regarding opportunities to control electricity bills through energy efficiency and peak load management. A key component of that information is the targeted use of “high price alerts” via email or phone on the evenings before expected high price days.

PSP is an optional program for the Ameren Illinois’ residential customers who participate through the program administrator, CNT Energy. CNT Energy provides all aspects of the enrollment process as well as ongoing participant support. That support includes a web interface that allows customers to compare bills, view and analyze their hourly energy use, and conduct a home energy self-audit.

Part of ICC Docket 06-0961 was a requirement to perform an economic evaluation of the RTP programs after the end of calendar year 2010 to assess if there were net benefits for Illinois residential customers. The main purpose of this evaluation report is to perform and present the required net benefits assessment for PSP.

The summary results of the net benefits assessment will now be presented, followed by summaries of other important findings from this year’s impact evaluation of the PSP program.

Net Benefits Assessment

The total net benefits for the PSP program are calculated for three different populations:

1. All MISO customers
2. All Ameren Illinois customers

[1] The Ameren Illinois Utilities merged into the Ameren Illinois Company on October 1, 2010.
[2] The Ameren Illinois Utilities began billing day-ahead prices on June 1, 2008, under the PSP program. Before that date, program participants were billed the real-time price.

3. Ameren Illinois residential customers

The net benefits that accrue to all MISO customers are considered to be the best indicator of overall economic benefits for consumers from the PSP program. However, the subset of benefits that accrue to Ameren Illinois residential customers are also reported based on the specific requirements of Public Act 094-0977 which created PSP, and were incorporated in the order from the Illinois Commerce Commission (ICC) in Docket 06-0961, which implemented that legislation. That docket required an economic evaluation of the RTP program be conducted after the implementation period of 2007–2010, and further required that the net economic benefits to the residential community be specifically identified.

This assessment considers the net benefits of the program looking both at historical program years and at a ten-year projected lifetime (2011 to 2020) for existing PSP participants.

Historical Program Years. Table 1 provides the annual program costs and benefits over the 2007–2010 time frame, which covers the first four years of actual implementation. These results are presented separately for each year since there are dramatic changes from year to year. In the start-up years of the program, net benefits are negative going from -$1,040,000 in 2007 to -$394,000 in 2008. This reflects the significant investment needed to develop the processes and IT systems required for program start-up. In 2009 and 2010 these start-up costs are done and we see regular on-going program implementation costs. Customer enrollments increase each year, meaning benefits also increase. The overall effect is positive net benefits on an annual basis, going from $744,200 in 2009 to $741,800 in 2010. This view is looking strictly at benefits that accrue to the Illinois Residential customers, as required in Docket 06-0961. Considering initial start-up costs, the program is close to a break-even point after the first four years of operation. Looking only at the nominal costs presented here without adjustment for the time value of money, total net benefits over the four year period are $51,800.

Table 1. Historical Benefits and Costs for PSP Program 2007-2010

	2007	2008	2009	2010
Participant Benefits: Avoided Capacity Costs	$0	$7,200	$9,800	$14,000
Participant Benefits: Consumer Surplus	$0	$170,800	$1,666,000	$1,872,000
Non-Participant Benefits: Residential Customers	$0	$5,200	$2,100	$14,800
TOTAL BENEFITS	$0	$183,200	$1,677,900	$1,900,800
TOTAL COSTS	$1,040,000	$577,400	$933,700	$1,159,000
NET BENEFITS	**-$1,040,000**	**-$394,200**	**$744,200**	**$741,800**

Program start-up costs and incremental meter costs are included.
Source: Navigant analysis

Ten-Year Projected Lifetime. This historical analysis leads to the question of what program net benefits would be if the program were to be extended over a longer timeframe. Table 2 provides the net present values of the major costs and benefits over the 2007–2020 time frame, along with the net present values of the overall net benefits. These results show positive net benefits of $5,913,000 at the MISO level. Net benefits are greatly reduced from the Ameren Illinois view and the Ameren Illinois residential customer view; however, both views still show positive net benefits. From the long-term economic perspective of all consumers and Ameren Illinois residential customers, the PSP program creates net benefits.

Table 2. Net Present Value of Benefits and Costs for Program Inception Through 2020

	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Participant Benefits: Avoided Capacity Costs	$3,452,000	$3,452,000	$3,452,000
Participant Benefits: Consumer Surplus	$10,097,000	$10,097,000	$10,097,000
Non-Participant Benefits: Market Effects	$5,844,000	$411,000	$201,000
TOTAL BENEFITS	$19,393,000	$13,960,000	$13,750,000
TOTAL COSTS	$13,480,000	$13,480,000	$13,480,000
NET BENEFITS	**$5,913,000**	**$480,000**	**$270,000**

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The societal discount rate is 1%.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

A series of sensitivity studies were conducted on key assumptions in the net benefits model. Allowing participation to grow increases net benefits substantially. Changing the societal discount rate to 2 or 3 percent creates little difference, because many of the costs of this program are front-loaded. Similarly, excluding start-up costs shows a large increase in net benefits for the Ameren Illinois residential customers for the same reason. Excluding incremental meter costs causes substantial increases in net benefits in all years, both historical and forecasted.

The sensitivity variable with the greatest impact on whether net benefits are positive or negative is the assumption of what the hedging premium is. The hedging premium represents a proportion of bill savings that PSP participants will always receive because they take on the risk of paying market rates. The hedging premium is assumed to be 10 percent in the base scenario presented above. If it is reduced to 5 percent, net benefits become negative from the Ameren Illinois and Ameren Illinois residential views, although the net benefits remain positive from the MISO view. If the hedging premium is actually 15 percent, net benefits from the program increase substantially in the form of additional consumer surplus for PSP participants.

There are two additional important points to make about the net benefit results. First, there is a trade-off that occurs between non-participant benefits and participant benefits, depending on the relationship of market energy prices to the flat rate. In years like 2008 where market prices were relatively high, non-participants gained large benefits when program impacts reduced market prices. Participants received lower bill savings in that year. Alternatively, in years like 2009 and 2010 when market prices are low compared to the flat rate, non-participant benefits from the program drop and participant consumer surplus gains soar. In short, when non-participant benefits are high, participant benefits are low, and vice versa. There are always benefits from the program in each year. The relationship between market prices and the flat rate determines whether those benefits go primarily to non-participants or participants.

Second, if market prices do dramatically exceed the flat rate in some future years, it is possible that participants would respond by reducing their load even more than what has been seen in the past three years of relatively low market prices, and supply curves would shift upwards to match or exceed 2008 curves. If this happens, non-participant benefits would be greater than what is currently in the forecast. Likewise, if the market prices continue to stay well below the flat rate, participants will reap more benefits than what is in the current forecast. For these reasons, the current forecast should be considered a conservative estimate of total future benefits. If there are large deviations between the flat rate and market prices in future years, in either direction, program benefits will be greater than what is shown here.

Other Benefits

The existing published literature makes clear that there are additional benefits associated with RTP that are difficult to quantify. These include benefits associated with improvements in electricity markets – namely, improved power quality and reliability, lower price volatility, and market power mitigation – that could prove significant in certain circumstances, but which are unlikely to be substantial in the case of the PSP program due to current market conditions and the small size of the program. A change in either the size of the program or the conditions of the market –note, for instance, that the MISO Independent Market Monitor states that local market power does exist in MISO, but that currently this market power does not appear to be exercised—could create a situation in which these benefits are substantial and warrant efforts to carefully quantify.

Navigant Consulting, Inc. (Navigant), also considered health and environmental benefits. Using existing peer-reviewed studies, Navigant approximates the benefit of the PSP program in reducing SO_2, NO_x, and CO_2 emissions to be about $62,000 per year. This value reflects recent published estimates indicating that the per-ton health costs of SO_2 and NO_x emissions are quite high—much higher than understood when Title IV of the 1990 Clean Air Act was passed—as well as the conclusion that the PSP program generates only small annual reductions in these pollutants. Importantly, Navigant's estimate pertains to the *overall* social benefit of emissions reduction, not to Ameren Illinois customers in particular; therefore, Navigant has not included it in its net benefit assessment.

A final benefit that was quantified was the reduction in consumption-related deadweight loss. Deadweight loss is a measure of inefficiency in an economic market. Moving to a real-time pricing regime generates a reduction in deadweight loss that does not necessarily accrue directly to customers. This reduction applies to the case when the day-ahead price is higher than the fixed-rate price, and arises because the PSP household consumes less than it would under the fixed-rate price, and thus spares

Ameren Illinois the purchase of energy at a higher price than it is worth to the household. The value of the reduction in deadweight loss is calculated to be $6.14 per participant in 2008, $0.00 in 2009, $0.73 in 2010, and $0.60 in forecast years.

Elasticity

Over the past three years of the PSP program, participants have displayed two different types of responses to prices, or elasticities: medium run and short run.

In the medium run, households respond to differences in *average hourly price* with a broad shift in energy consumption behavior as compared to their behavior under the fixed-price regime, forming new habits and modes of operation, such as running dishwashers at night. Such broad shifts in behavior are consistent with the information provided to PSP customers, indicating that shifting energy consumption to overnight hours, when prices are low, reduces energy bills.

Medium-run elasticities are measured based on hourly average differences between participants and a control group, and were found to vary from a low of -0.04 during weekday nighttime hours to a high of -0.29 during late afternoon weekday hours.

Even after shifting their daily energy consumption routine to exploit variation in average hourly prices, households can potentially benefit still more **in the short run** –on an hour-to-hour basis—by responding when prices deviate significantly from their hourly means. The extent of the response depends on both the extent of the price deviation and the cost of short-term behavioral adjustments, including the cost of closely monitoring prices. Programs that provide price information cheaply serve to reduce this cost.

Short-run elasticities were measured using the Generalized Almost Ideal (GAI) demand system. As the medium elasticity model captures the "rules of thumb" behavioral changes in response to seasonal average prices, the GAI demand system focuses on very short-run elasticities: how do participants respond to especially high prices? Frequently checking electricity prices is time consuming; hence, information is costly. Navigant therefore expects customers to respond to high prices only on days when the cost of information is reduced and the potential benefits are high. The High Price Alerts (HPAs) serve exactly this purpose. On HPA days, participants are alerted that prices are exceptionally high, creating an opportunity to lower their bill by reducing their load during the high-priced hours. For this analysis, we estimate the GAI demand system using only the 28 HPA days that occurred during summer 2008. The short-run own-price elasticities were found to range from a low of -0.21 in the hour of 3 pm to 4 pm, to a high of -0.89 in the hours of noon to 2 pm. These elasticities are larger than estimates reported elsewhere in other studies of dynamic pricing programs for residential customers however, this is not unexpected, because the short-run nature of the estimate captures only customer response to very high prices during limited time periods (HPA days).

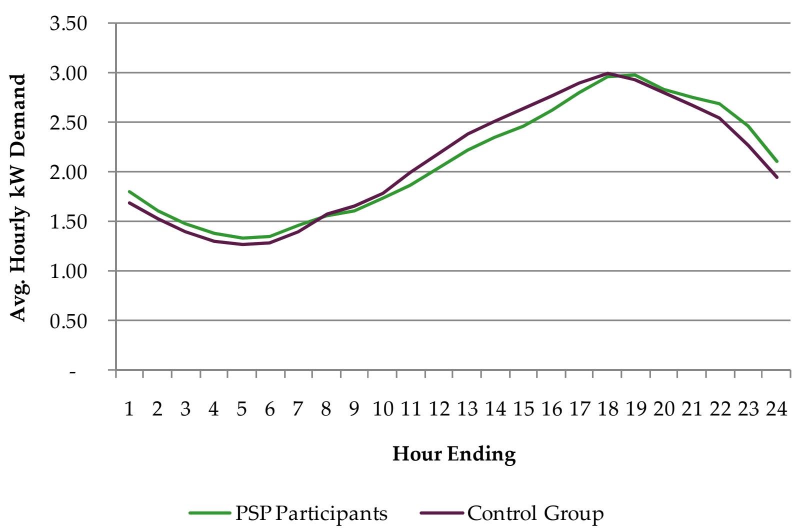
Navigant believes that the use of two separate elasticity estimates, one medium run and one short run, is the best way to characterize residential customers' true response to dynamic prices.

Hourly Demand Impacts

In the spring, winter, and fall, PSP participants generally use less energy during the day and more in the overnight period compared to a matched control group. This response is slight, but generally persistent over the seasons and the years. This is related to the medium-run elasticity concept that customers learn about general price patterns and establish habits that persistently shift some electric use into known off-peak periods of the day and week.

The summer season is when most hourly demand impacts occur from the PSP program. Figure 1 shows that in the 2010 summer season, PSP participants continued their characteristic response of lowering use between 10 am and 5 pm by an average of -0.15 kilowatt(kW). This compares to an average load reduction of -0.21 kW in 2008 and -0.13 kW in 2009 for the same period of the day. Again, this consistency from year to year is representative of the medium-run elasticity response as practiced on all weekdays during the summer season.

Figure 1. Indexed Summer Weekday Load Shapes for 2010



Source: Navigant analysis

2008 was the only year with HPA days. In that year, customers increased their daytime load reductions from an average of -0.21 kW/customer on weekdays to an average of -0.26 kW/customer on HPA days. Looking at weather data for 1990 through 2010, 2008 stood out as one of the coolest summers in that 21-year period, and 2010 was the hottest. There was an average difference of 0.7 kW in use during the daytime hours when comparing 2008 summer use to 2010 summer use for the control group. The weather was cool in 2008 and usage was low, but HPAs were called because market prices for electricity were high. This means that when participants responded by turning down their air-conditioning, there often wasn't much air-conditioning in use. Consequently, Navigant modeled HPA day response related to weather and predicts that if HPAs were called during summers of normal temperatures, expected load reductions on HPA days would be closer to -0.45 kW per customer than -0.26 as observed in 2008.

Conservation Effects

Monthly billing data from January 2007 through January 2011 was used to estimate the conservation effect from the PSP program. Billing data was available for 953 control group residential customers and more than 1,000 current or past participants in the PSP program. Although the 2008 and 2009 PSP evaluation studies reported some net annual conservation savings from the program, those previous estimates were based on single-year analyses of the data. The current multiyear dataset was used to measure conservation effects over the entire program period. These are considered to be much more robust estimates of conservation effects from the program.

Table 3. Annual Change in kWh Consumption for PSP Participants

Season	Annual kWh Change	Percentage Change
Spring	-47	-1.8%
Summer	-139	-3.2%
Fall	-94	-3.4%
Winter	309	9.2%
Total Year	29	0.2%

Source: Navigant analysis

As Table 3 shows, the PSP program encourages conservation effects among participants in the spring, summer, and fall seasons. Over these three seasons, an average of 280 kWh per year is saved per participant. However, the situation changes in the winter season when participants face relatively low winter market prices. Their use increases by 309 kWh per participant, and this negates the savings from the rest of the year to create an overall net increase of 29 kWh per participant. Given the results of this multiyear study, Navigant recommends that the conservation effect be considered zero on average for the PSP program. However, if in the future winters were to become milder and summers warmer and more humid, the PSP program could induce a mild conservation effect.

Bill Savings

In 2010 the aggregate savings for PSP participants was $1,724,959.78, which represents a 12.35 percent total savings compared to what the same bills would have been under the standard rate. Average customer savings were slightly negative in the months of July and August, primarily due to a very hot summer and moderate hourly electricity prices, which did not encourage extraordinary efforts to shift air-conditioning loads.

During discussions on the bill savings estimates shown in the 2009 PSP evaluation report, some members of the ICC staff expressed interest in understanding the components contributing to the overall estimate of bill savings. In response to that interest, Navigant estimated three major components of the bill savings:

1. Avoidance of the hedging premium
2. Savings related to shifts in usage

3. Remaining savings, primarily due to the difference between the flat rate and the market rate

The hedging premium can be thought of as the insurance premium that must be paid so regular residential customers can pay a predictable flat rate every month and be protected from both high and low price swings in the electric energy market. Although this hedging premium is known to exist as a portion of the flat rate, there are no straightforward methods for estimating exactly what the value of this premium is. General consensus is that it is likely to be in the 5 to 15 percent range when estimated as a percentage of the energy charge. Given the uncertainty around this variable, it was treated as a sensitivity variable and tested at the 5, 10, and 15 percent levels.

The ability to **shift usage** from high-price hours to lower price hours is an important component of bill savings in an RTP program. The amount of bill savings attributable to this kind of shifting can be estimated by comparing the PSP participants' actual bills to what their bills would have been if they had not shifted any use but had been billed on day-ahead prices. The control group load shape is our best estimate of what PSP participants would have consumed if they were not in the program. By billing control group consumption on day-ahead prices and then comparing that to PSP participant consumption on day-ahead prices, an estimate is made of how much annual bill savings comes strictly from shifting behavior. The estimated annual bill savings per participant from shifting behavior ranged between $2.05 and $12.99 over the historical period.

If savings from shifting of use and avoidance of the hedging premium is subtracted from the total annual bill savings, the **remaining savings** can be considered a good approximation of the benefits PSP participants receive when the average annual market price is lower than the equivalent energy component of the flat rate. Of course, this estimate of remaining savings due to the price differential is highly contingent on the assumed hedging premium, which is uncertain.

In an ideal world, the flat rate energy component is expected to be in alignment with market prices so that the price differential will be zero over the long run. When looking at bill savings in forecast years, Navigant recommends using a value of zero for the annual bill savings that come from the price differential. In other words, in future years the total bill savings should be modeled as the sum of the bill savings from avoidance of the hedging premium and load shifting; however, here should be no future bill savings from the difference between market prices and the equivalent component of the flat rate.

Relationship between Day-Ahead Prices, Real-Time Prices, and System Peak Hours

The results for 2010 will be summarized here, and these results are fairly consistent from year to year:

1. The top 20 day-ahead price (DAP) days can correctly predict 40 percent of the top 20 RTP days.
2. The top 20 DAP days can correctly predict 65 percent of the top 20 system peak days.
3. The top 20 RTP days can correctly predict 35 percent of the top 20 system peak days.

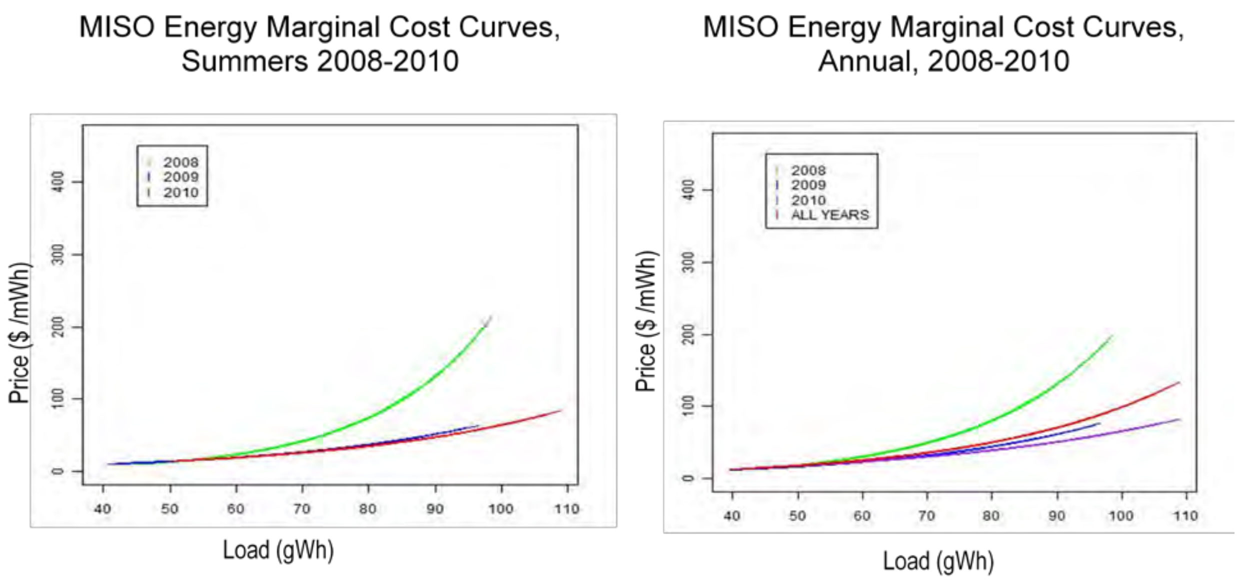
Of most interest here is the finding that DAP is much more reliable than RTP for predicting when system peak days will occur. Because the PSP program uses DAP, customers will be correctly called to action to reduce system peaks more often than would occur using RTP. Because of the high volatility in the RTP compared to the DAP, RTP does not have a predictable relationship with either DAP or system peaks.

Market Effects

Hourly changes in demand that are the result of the PSP program exert influence on MISO prices. This is most significant during peak price periods, such as summer afternoons, when the PSP program causes reductions in demand that contribute to reductions in MISO Locational Marginal Prices. These price reductions apply to all customers in the market, not just PSP participants. These non-participant benefits are called the market effect.

The LMPs for the Ameren Illinois service area are composed of three components: an energy price component that is the market clearing price of energy in the MISO market; a congestion price component reflecting the impact of Ameren Illinois loads on the routing of transmission to avoid congestion; and a loss component associated with transmission. Historical price and load data for MISO and the Ameren Illinois system was used to estimate the energy supply curves needed to translate a load reduction into a price reduction on the MISO system.

Figure 2. Estimated MISO Energy Supply Curves

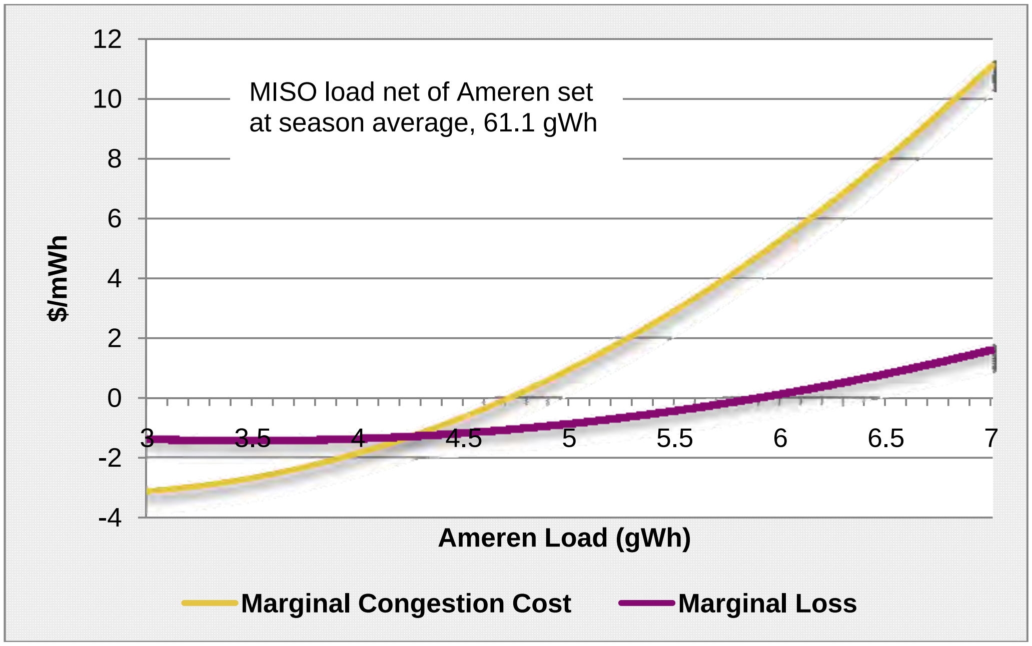


Source: Navigant analysis

Figure 2 displays a set of graphs. The first graph presents the energy supply curves for each summer, 2008–2010, and the second presents annual supply curves, 2008–2010, along with an overall supply curve estimated on all data, 2008–2010. A striking feature of the results is that the supply curve was much higher in summer 2008 than in other seasons. This possibly reflects the spike in gas prices in the middle of 2008. Navigant used the individual historical seasonal supply curves to estimate non-participant benefits in those years, and used the average of all years by season for forecast years.

Figure 3 shows Navigant's estimation of the transmission congestion and loss marginal cost curves. There was little variance across years or seasons for these curves; therefore, the average of 2008–2010 is used for modeling non-participant benefits in all historical and forecast years. There is no variation by season.

Figure 3. Estimated Ameren Illinois Transmission Congestion and Loss Curves



Source: Navigant analysis

Note that all of these marginal cost curves have the traditional "hockey stick" shape (i.e., their slope becomes steeper at higher system loads). It is this characteristic that makes PSP participants' load reductions in summer create overall price reductions for non-participants even as their increased use at non-peak times, such as winter, creates price increases. The price increases during non-peak times are near zero because they tend to occur when the marginal cost curves are flatter.

2 Introduction

Ameren Illinois Utilities[3] (Ameren Illinois) engaged Navigant Consulting, Inc. (Navigant),[4] to perform three years of impact evaluation on the Power Smart Pricing (PSP) real-time pricing (RTP) program for residential customers. The first-year evaluation covered program participation impacts from the inception of the program in mid-year 2007 through the end of calendar year 2008. The report was filed with the Illinois Commerce Commission (ICC) in May of 2009. The second-year evaluation covered program participation impacts for calendar year 2009 and was filed with the ICC in May of 2010. This report is the final in the series of three annual impact evaluations and it presents results for program participation during calendar year 2010, as well as a summary of the net benefits of the program.

The introduction to this report starts with a recounting of background information on the potential benefits of RTP rate designs, and a description of the unique characteristics of the PSP program. This is followed by a discussion of the objectives for the 2010 impact evaluation, and a summary of the organization of the remainder of this report.

2.1 Background: The Potential Benefits of Real-Time Pricing

Electricity prices are among the most volatile of any market commodity. Driving this volatility is the fact that electricity cannot be stored in significant quantities. As a result, during periods of high demand (hot summer days, for example), hourly electric prices can vary substantially over just a 12-hour period. On extreme days, price spikes during resource-constrained periods can see increases of 100-fold or more if there is not enough demand-side response to mitigate the system and supply-side factors that are driving prices up. These extremely high prices, even though they may occur only during a few hours each summer, can represent a substantial cost to all the customers in the regional electricity market.

Although the costs of electricity in wholesale markets can vary dramatically, retail pricing, particularly for residential and small commercial customers, has largely remained subject to regulated tariffs. These tariffs typically have provided customers with fixed rates (i.e., they pay the same price for electricity regardless of when and how much is used). This fixed rate does not reflect the true cost to the economy of consuming electricity at a given point in time, and, therefore, it distorts key market decisions.

An important near-term challenge facing electricity markets is the rational pricing of retail electricity. The goal of any market — regulated or unregulated — is to allocate resources equitably, promote efficient investment, and provide incentives for innovation. Prices provide the market signals that are used to allocate resources. Specifically, the key is to appropriately price what is scarce. For electricity markets, what is scarce is on-peak energy. If the market is not designed to appropriately price what is scarce, the market will not be efficient and disconnects between demand and supply can occur, resulting in price spikes. Clearly, non-time-differentiated electricity rates cannot reflect the true costs at the wholesale level of on-peak electricity. With standard rates, customers have no idea what the actual cost

[3] The Ameren Illinois Utilities merged into the Ameren Illinois Company on October 1, 2010.

[4] Formerly, Summit Blue Consulting. The latter became a part of Navigant Consulting, Inc., on January 1, 2010.

of electricity is at any given time and they are not able to make choices regarding conserving a scarce resource. As a result, they cannot make decisions regarding the appropriate use of electricity required for an efficient market.

Innovative pricing, such as RTP, is one method of allowing for the interaction of demand and supply needed for efficient markets. Research on time-differentiated pricing is growing as the benefits of these pricing options are becoming better recognized. These options allow customers to see the real wholesale costs of electricity and make decisions regarding their energy use based on market conditions. Overall, customers who see real prices and adjust their demand in response to these price signals can make the electricity system more efficient and stable. As a result, retail electric prices that better reflect the costs of obtaining power in wholesale markets can provide benefits to electricity markets, including the following:

- **Increased system reliability** as price mitigates demand when resources become scarce
- **Reductions in costs** of electricity to all customers in a regional market as a result of better management of scarce supplies and reductions in capital costs incurred to meet peak demands
- **Risk management** by allowing customers to manage a portion of the electricity price and commodity risks and be compensated for this service
- **Environmental benefits** by promoting efficient use of resources and price signals to manage demand
- **Customers benefit** from being on an RTP rate because now their ability to use electricity flexibly across on-peak and off-peak periods is valued (i.e., a key attribute of their energy use—flexibility in time-of-use (TOU)— is given a value).
- **Market power mitigation** by providing a demand response to offset high prices for generated electricity
- Providing the **incentives for innovation** needed to create technologies and value propositions for load management and peak demand response
- RTP better reflects the actual cost of service, allowing a **more equitable distribution of costs** across customers and customer classes.
- Unlike conventional load control or curtailable/interruptible incentives, dynamic tariffs such as RTP can be made **available to all customers,** regardless of usage level or appliance ownership.

These potential benefits from RTP options can accrue to a number of entities:

- **Participants.** RTP participants can benefit by having the ability to make more informed choices regarding how they use electricity. This provides them the opportunity to lower their monthly bills.
- **Electricity customers not participating.** The RTP rate can also benefit all customers (participants and non-participants) in a regional electricity system because a relatively small fraction of price-responsive demand can have sizeable impacts on market-wide price spikes and electric system efficiency.

» **Utilities.** Utilities can benefit through load reductions on their delivery network during peak periods, and delaying or avoiding the need to make additional capital investments.

Recognition of these potential benefits has led to a number of pilot programs and a move towards time-differentiated rates for large customers. The Illinois legislature was one of the first legislative bodies to encourage RTP rates for residential customers. Illinois Public Act 94-0977 required that electric utilities that serve more than 100,000 customers must have RTP available to residential customers as a rate option. This act led to the ICC Docket 06-0961, which found that a residential RTP program would be likely to provide a net economic benefit to the residential community as a whole. As part of this docket, the Ameren Illinois received approval to launch PSP.

2.2 *Power Smart Pricing Program*

PSP presents "de-averaged" electricity supply prices that are a direct pass-through of Midwest Independent System Operator (MISO) hourly prices without markup. These prices provide a day-ahead price (DAP) signal to customers about the real cost of their electricity use.[5] The program also provides information regarding opportunities to control electricity bills through energy efficiency and peak load management. A key component of that information is the targeted use of "high price alerts" via email or phone on the evenings before expected high-price days. MISO day-ahead prices are used as the basis of the high price alerts and they provide information on which hours are most critical for taking additional energy management actions.

PSP is an optional program for the Ameren Illinois residential customers who participate through the program administrator, CNT Energy. In early 2007, Ameren Illinois conducted a competitive solicitation to select the administrator for the program. CNT Energy (formerly the Community Energy Cooperative) was selected. CNT Energy provides all aspects of the enrollment process as well as ongoing participant support. That support includes a web interface that allows customers to compare bills, view, and analyze their hourly energy use, and conduct a home energy self-audit.

The Ameren Illinois residential customer base is approximately one million households and customers were selectively targeted for enrollment in the PSP program over the 2007 to 2010 contract period. Specific principles that applied to this enrollment are as follows:

» Participants in PSP pay an additional $2.25 per month to participate. This charge covers a portion of the $5 a month incremental cost of their interval demand meter. The additional cost of the meter and the other program expenses are not recovered from participants; instead, they are recovered via Rider PSP, which is applied to all residential customers. The charge is currently at nine cents per Residential customer account per month for January through June, 2011. The Rider PSP charge has typically been in the five to seven cent range during 2007 through 2010.

» The emphasis of the marketing approach is on customer education and a satisfactory experience.

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[5] The Ameren Illinois Utilities began billing day-ahead prices on June 1, 2008, under the PSP Program. Before that date, program participants were billed the real-time price.

» Enroll participants that fully understand the PSP concept and program and therefore understand the associated risks and rewards.

» Although the entire Ameren Illinois customer base is eligible for participating in PSP, certain customer segments may not be good candidates for participation because they are not likely to receive any economic benefit from participating in PSP. Experience has shown that these segments include customers with very low usage (due to the $2.25 monthly fee being a large part of their bills), customers with health issues (due to the risks involved in reducing energy consumption), and customers on particular electric space heat rates.[6]

» Incorporate basic energy efficiency and conservation awareness as a goal for ongoing customer education.

The costs of the PSP program consist of the incremental cost of metering to collect hourly usage data, additional Ameren Illinois expenses for software and data processing systems, and the program administrator and evaluation contracts.

2.3 *Evaluation Objectives*

There are two categories of objectives for the impact evaluation of the PSP program. The first category focuses on determining how PSP participants are responding to the real-time rates. The second category looks at assessing the net benefits of the program.

For Category One objectives, determination of participant response has been repeated annually for the 2008, 2009, and 2010 program year reports. Several basic evaluation objectives are covered each year:

» DAP vs. RTP – Does billing on DAPs meet the need of providing demand response during hours of high RTPs? Do these prices appropriately reflect hours of high system use?

» Elasticity – How much do participants change their use in response to changing prices?

» Changes in hourly demand – When does most response occur? What time? What season?

» Conservation effect – Does participation in the program reduce overall energy use?

» Bill savings – How much do participants actually save on their electric bill?

» Participation in other Ameren Illinois energy efficiency programs – How do savings from PSP participation interact with savings from other Ameren Illinois energy efficiency programs?

» Each annual report also offers opportunity for the in-depth evaluation of particular issues.

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[6] Customers at premises served under the former space heat rates prior to 2007 continue to receive subsidized space heat rates and are not good candidates for PSP. A special Supplemental Space Heat Credit (SSHC) was provided to customers who use electric space heat at premises where permanent service was activated in 2007 and 2008. The SSHC expired in December 2010. In order to receive the SSHC, the customers had to remain on Ameren Illinois' flat rate electric supply service and they could not receive service under PSP. As of January 2011, former SSHC customers became good candidates for PSP.

» In the 2008 program year, a test group of 120 customers had PriceLights—tabletop glass orbs that glow different colors to reflect current electric price levels. For example, a red glow indicates a high price alert. The 2008 evaluation assessed differences in load reduction for customers with PriceLights.

» The 2008 PriceLight program was a special offering funded by a one-year grant from the Illinois Clean Energy Community Foundation. A small number of customers who were willing to contribute a portion of the subscription fee continued to use their PriceLights in 2009. However, because there was so little variation in price across the summer, the PriceLights never changed their color. Anecdotally, CNT Energy received calls from several customers who thought their PriceLights were broken. Given that there was so little use of the PriceLights, it did not make sense to do a special study of their impacts in 2009.

» However, other opportunities for in-depth evaluation were explored in the 2009 report. Examination of impact differences between two-year (experienced) participants and one-year (new) participants was an enhancement in the 2009 evaluation, as well as an identification of participants who were using the PSP rate to benefit from pre-cooling their home during nighttime hours in the summertime.

The second category of evaluation objectives, assessment of net benefits, is presented as a completed analysis in this 2010 report. The 2008 report started work on this objective by presenting the methodology to be used, including an approach for estimating market benefits for non-participants. The 2009 report tested the proposed approach for estimating market benefits and presented a preview of what the net benefits assessment would look like. As stated previously, this 2010 report includes the required final net benefits assessment based on analysis of program data from 2007 through 2010, as well as a look at net benefits if the program continues through the year 2020.

2.4 *Report Organization*

Section 3 of this report presents the program impacts found from analysis of program participants' electric energy use during 2010, with some review of average impacts over the full 2007–2010 program period when appropriate. It answers the evaluation questions about participants' demand response posed in the previous section.

Section 4 presents the final estimation of economic benefits from the program.

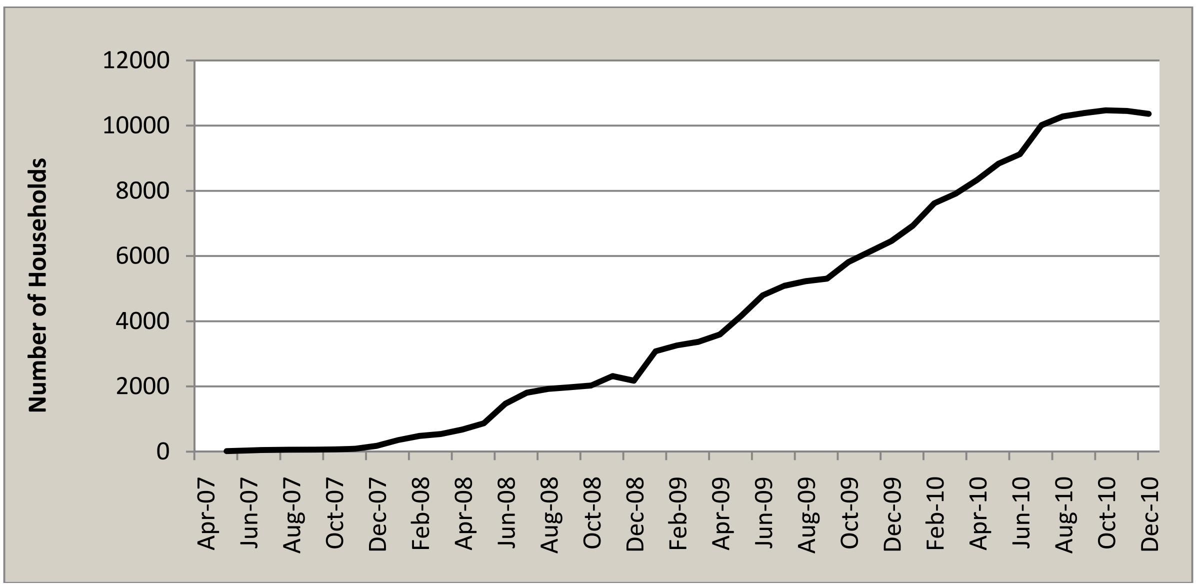
Section 5 presents conclusions and recommendations.

The appendices present supporting detail for the impact evaluation sections of this report.

3 Program Impacts for 2010

2010 continued to show growth in participation in the PSP program. At the end of 2008 there were 3,147 participants. By December 31 of 2009, the number of participants had grown to 7,422, and by December 31 of 2010 the number of program participants was more than 10,000, as shown in Figure 4.

Figure 4. Growth in PSP Participation Over Time



Source: Navigant analysis

This rest of this chapter will present findings on how participants changed their electric energy use in response to real-time rates.

3.1 *Price Elasticity*

The defining feature of the PSP program is that households no longer face a fixed price for energy, but instead face DAP that change hourly. Consequently, observed behavioral changes in energy consumption are due to changes in prices. In the discussion here we focus on what the PSP program reveals about household demand for energy, in particular the price responsiveness of households. Such analysis provides insights to how future changes in the distribution of prices can be expected to affect the energy consumption behavior of PSP households.

In general, PSP households can be expected to respond to prices in a number of ways:

- **In the long run** they respond to the distribution of prices in their decisions concerning capital investments, such as energy-efficient appliances. For instance, the opportunity to run appliances when prices are relatively low may reduce the incentive to buy an energy-efficient appliance.

» **In the medium run,** households respond to differences in *average hourly price* with a broad shift in energy consumption behavior as compared to their behavior under the fixed-price regime, forming new habits and modes of operation, such as running dishwashers at night. Such broad shifts in behavior are consistent with the information provided to PSP customers, indicating that shifting energy consumption to overnight hours, when prices are low, reduces energy bills.

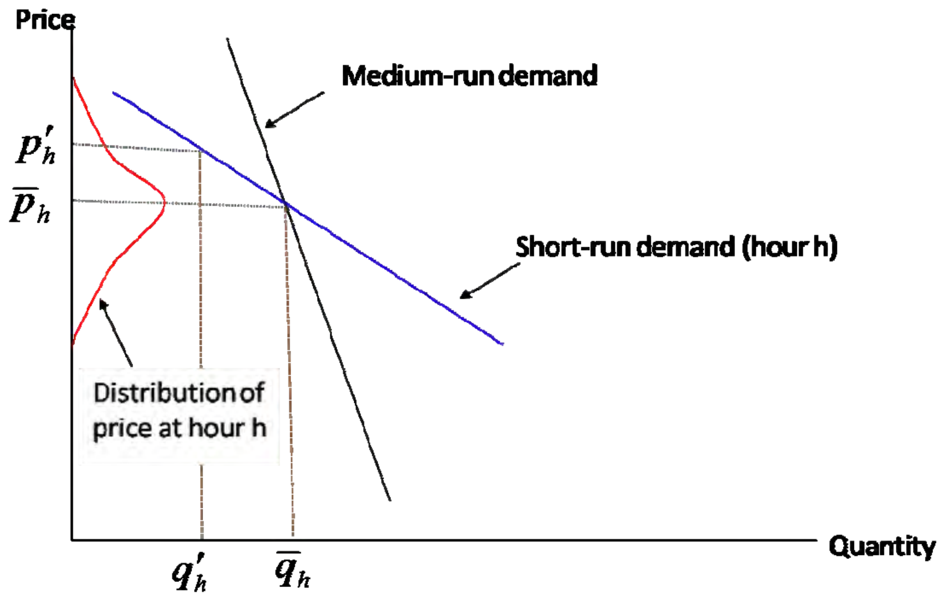
» Even after shifting their daily energy consumption routine to exploit variation in average hourly prices, households can potentially benefit still more **in the short run** –on an hour-to-hour basis—by responding when prices deviate significantly from their hourly means. The extent of the response depends on both the extent of the price deviation and the cost of short-term behavioral adjustments, including the cost of closely monitoring prices. Programs that provide price information cheaply serve to reduce this cost.

In this analysis, Navigant focuses on medium-run and short-run demand. The relationship between the two is shown in Figure 5. The medium-run demand curve reflects the response of households to the average hourly price. So, for instance, referring to Figure 5, if the average price in hour h is $\bar{p}_h$, the average quantity consumed in the hour is $\bar{q}_h$.

Households may depart from this average consumption in response to deviations in hourly prices from the hourly mean price. Each point on the medium-run demand curve is intersected by a short-run demand curve that captures the response of households to these price deviations at given mean price-quantity levels. The short-run demand curve for hour h is presented in Figure 5. If price were to rise to p_h', consumption would fall to q_h'.

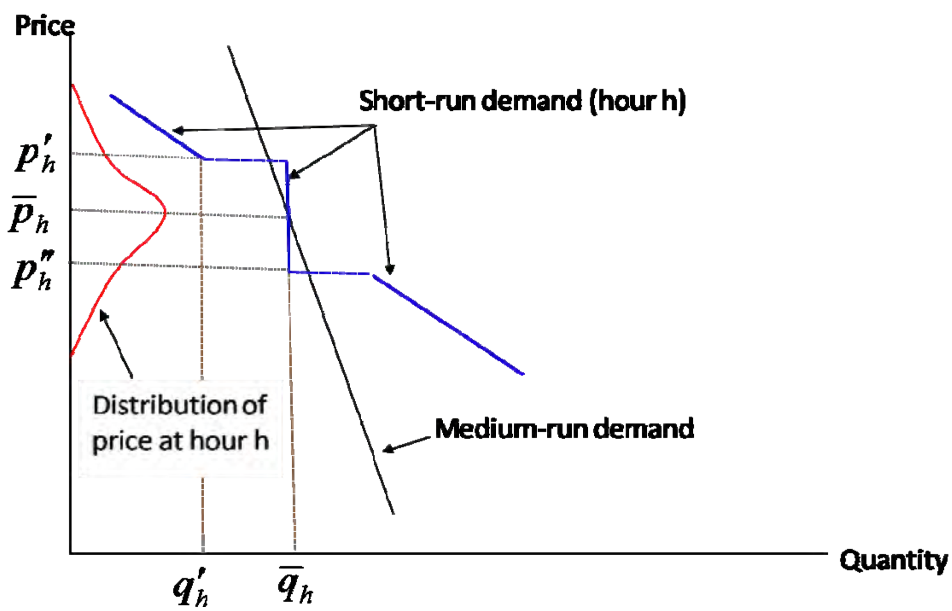
In reality, we might expect that short-run demand is essentially inelastic unless the deviation of price from the hourly mean is “large enough” to be perceptible by the households and to make a behavioral change worthwhile. This “demand stickiness” is shown in Figure 6, where short-run demand is infinitely inelastic (vertical) between prices p_h' and p_h'' , and discontinuous at these prices.

Figure 5. Medium-Run and Short-Run Household Energy Demand



Source: Navigant analysis

Figure 6. Medium-Run and Short-Run Household Energy Demand When Short-Run Demand Is "Sticky"



Source: Navigant analysis

3.1.1 Estimation of Medium-Run Demand

Estimation of medium-run demand requires a control group to isolate the effect of an hour's average price on average consumption, because average consumption in each hour of the day depends on other variables, such as the "rhythm of daily life"—households tend to sleep at night, for instance, and therefore use less energy overnight—which is reflected in hour-specific constants, the average temperature for the hour, and so forth. The ideal control group is a set of households that is the same as the set of PSP households but is *not* enrolled in the PSP program. In the analysis here, we use the normalized consumption of the Ameren Illinois load research group as a control group.

Suppose average consumption by participant households in hour t, $\overline{y}_{tp}$, takes the semi-log form,

$$\ln \overline{y}_{tp} = \alpha_{0p} + \alpha_1 \overline{\mathbf{X}}_t + \alpha_2 \overline{p}_t + \varepsilon_{tp}, \tag{0.1}$$

where the vector $\overline{\mathbf{X}}_t$ is a vector of mean values in hour *t* of variables influencing energy consumption, including such variables as an hour-specific constant and average temperature for the hour; and $\overline{p}_t$ is the average price in hour *t*. The counterpart expression for the control group is,

$$\ln \overline{y}_{tc} = \alpha_{0c} + \alpha_1 \overline{\mathbf{X}}_t + \alpha_2 p^f + \varepsilon_{tc}, \tag{0.2}$$

where p^f is the fixed-rate price of energy. Subtracting (0.2) from (0.1) generates the equation,

$$\ln \overline{y}_{tp} - \ln \overline{y}_{tc} = \tilde{a}_0 + \alpha_2 \overline{p}_t + \tilde{\varepsilon}_t; \tag{0.3}$$

in this equation, $\tilde{\alpha}_0 = \alpha_{0p} - \alpha_{0c} - \alpha_2 p^f$. We have, for each season for which estimation is appropriate, 24 observations (corresponding to the 24 hours of the day) of differences in average household energy consumption between PSP households and load research households, and 24 mean prices. The price elasticity of demand is $\alpha_2 p$, indicating that on a percentage basis demand is more responsive to price at high prices than at low prices.

The analysis in section 3.2 below indicates that calculations of medium-run elasticities are most relevant for the three summer seasons, 2008–2010, in which load-shifting by PSP households is especially apparent. Navigant estimated equation (0.3) for weekdays and weekends for each of these summer seasons. Table 4 provides estimation results. All coefficients are highly statistically significant. Table 5 provides elasticities for every hour of the day.

So, for instance, the elasticity for 1 pm on a weekday in 2009, -.149, indicates that a 10 percent increase in the *mean* price for 1 pm would reduce household consumption by 1.49 percent. These elasticity calculations refer to changes in *mean* prices, as would happen if, for instance, energy prices were to shift up for an extended period due to higher fuel costs. These elasticities do not capture the short-run response of households to price spikes, which is the topic of the next section. The results in Table 5 indicate that demand is generally more price elastic in the middle of the afternoon when prices are high, and on weekdays.

Table 4. Coefficient Estimates of Medium-Run Demand Equations (Standard Errors in Parentheses)[a]

Model Variable	Model					
	2010		2009		2008	
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
Intercept	0.1049 (0.0170)	0.1059 (0.0155)	0.1468 (0.01531)	0.1024 (0.0152)	0.1655 (0.0110)	0.1604 (0.0121)
Average Price	-2.236 (0.351)	-1.430 (0.386)	-5.425 (0.552)	-3.380 (0.665)	-2.351 (0.147)	-2.420 (0.214)

[a]All coefficient estimates statistically significant at the .01 level.

Source: Navigant analysis

Table 5. Hourly Medium-Run Elasticities, Summers, 2008–2010

Hour Ending	Year					
	2010		2009		2008	
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
1	-0.056	-0.035	-0.078	-0.049	-0.054	-0.057
2	-0.049	-0.032	-0.064	-0.040	-0.046	-0.047
3	-0.047	-0.029	-0.055	-0.035	-0.041	-0.040
4	-0.047	-0.028	-0.046	-0.029	-0.041	-0.038
5	-0.049	-0.027	-0.049	-0.031	-0.048	-0.038
6	-0.054	-0.026	-0.044	-0.027	-0.056	-0.035
7	-0.060	-0.029	-0.065	-0.040	-0.063	-0.043
8	-0.074	-0.035	-0.093	-0.058	-0.091	-0.058
9	-0.083	-0.040	-0.106	-0.066	-0.125	-0.079
10	-0.101	-0.048	-0.118	-0.074	-0.169	-0.112
11	-0.116	-0.057	-0.130	-0.081	-0.201	-0.140
12	-0.127	-0.064	-0.141	-0.088	-0.230	-0.168
13	-0.141	-0.071	-0.149	-0.093	-0.250	-0.180
14	-0.154	-0.077	-0.157	-0.098	-0.266	-0.191
15	-0.163	-0.083	-0.166	-0.103	-0.279	-0.206
16	-0.174	-0.091	-0.173	-0.108	-0.295	-0.223
17	-0.163	-0.090	-0.176	-0.110	-0.271	-0.230
18	-0.145	-0.082	-0.172	-0.107	-0.241	-0.211
19	-0.127	-0.073	-0.156	-0.097	-0.211	-0.176
20	-0.119	-0.066	-0.148	-0.092	-0.180	-0.156
21	-0.119	-0.069	-0.151	-0.094	-0.202	-0.174
22	-0.096	-0.058	-0.134	-0.083	-0.147	-0.128
23	-0.072	-0.042	-0.097	-0.060	-0.095	-0.080
24	-0.060	-0.036	-0.082	-0.051	-0.067	-0.061

Source: Navigant analysis

3.1.2 Short-Run Elasticity Methodology

Navigant developed a demand system approach to estimating the short-run price elasticities of demand for participants in the PSP program. This approach corresponds to the notion that electricity consumption under a variable pricing program may be considered a time-distinguished good; all else equal, and due to their daily behavior patterns, consumers are willing to pay more for electricity at 6 pm than at 3 am.[7] Following this framework, the price elasticity of demand for electricity also varies with the time of day, which necessitates the use of multiple demand equations to capture the changes in price response throughout the day. A demand system facilitates the estimation of separate demand equations, while maintaining the notion that demand at different times of day is interrelated.

Navigant specified the model using the Generalized Almost Ideal (GAI) demand system. Variations of the Almost Ideal demand system are widely used, due in large part to its flexibility and ability to model how a price change in one period affects load in other periods. The GAI demand system uses expenditure shares as the dependent variable, which calls for breaking up the time series into distinct decision-making periods. Navigant used a decision-making period of 24 hours. Conceptually, the decision maker allocates their electricity consumption, and thus their electricity expenditures, across the 24 hours based on prices and daily consumption patterns. Theoretically, the decision maker follows the decision rules of cost minimization and utility maximization.

The GAI demand system is specified by:

$$w_i = \frac{s_i p_i}{x} + \frac{\tilde{x}}{x}\left[\alpha_i + \sum_j \gamma_{ji}\log(p_j) + \beta_i \log\left(\frac{\tilde{x}}{P}\right)\right] + \epsilon_i$$

where

w_i	= the expenditure share for equation i, defined below
s_i	= the parameter representing the "pre-committed quantity" for equation i
p_i	= the average price ($ per kilowatt-hour [kWh]) for equation i
x	= the electricity expenditures in a given 24-hour period
$\tilde{x}$	= the "supernumerary expenditure" for a given 24-hour period, defined below
$\alpha_i, \gamma_{ji}, \beta_i$	= parameters to be estimated, corresponding to equation i
P	= the price index for a given 24-hour period, defined below
ϵ_i	= the error term for equation i, resulting from unobserved random variables

More specifically,

$$w_i = \frac{q_i * p_i}{\sum_j q_j * p_j}$$

$$\tilde{x} = x - \sum_i s_i p_i$$

[7] For further discussion, see Price Elasticity of Demand for Electricity: A Primer and Synthesis. EPRI, Palo Alto, CA: 2007, 1016264.

$$\log(P) = \alpha_0 + \sum_i \alpha_i \log(p_i) + \frac{1}{2}\sum_i \sum_j \gamma_{ij} \log(p_i) \log(p_j)$$

Additionally, the pre-committed quantity (s_i) may be specified as a function of demand shifting variables. Navigant chose to include the cooling degree hours[8] (CDH) for equation i and the maximum temperature from the previous day.

To ensure the results are consistent with economic theory, Navigant imposed the homogeneity and symmetry restrictions via the following set of constraints.

$$\sum_i \alpha_i = 1,\ \sum_i \beta_i = 0,\ \sum_i \gamma_{ij} = 0,\ \sum_j \gamma_{ij} = 0,\ \gamma_{ij} = \gamma_{ji}$$

Due to the large number of parameters in each equation of the GAI demand system, Navigant opted to investigate the price elasticities of demand for blocks of consecutive hours, rather than for each hour individually.[9] This makes sense for several reasons. Behaviorally, electricity consumption patterns tend to be similar for groups of consecutive hours. Within these groups of hours, there is little variety in the end uses of electricity, and thus the electricity consumed can be thought of as a homogenous good. For example, an average customer might consider blocking his day as follows:

6 am to 8 am	Getting ready for work.
8 am to noon	Low consumption hours while the house is vacant.
noon to 5 pm	The AC is running more and the house remains vacant.
5 pm to 10 pm	High consumption when family members are home cooking dinner, watching TV, etc.
10 pm to 6 am	Overnight hours when consumption is low.

Secondly, we expect little to no price response during the overnight and early morning hours. Given that most customers are asleep during these hours, we do not expect them to make short-run behavioral changes in response to price during this time. Furthermore, the overnight and early morning hours are characterized by low price variation. With relatively stable prices during these hours, customers face prices very similar to their expected prices, leaving little or no room for short-run price response. As the expected price response is low during these hours, Navigant combined the overnight hours into a large block of hours, spanning from midnight to 9 am.

Lastly, electricity prices from hour to hour tend to be correlated. If the price is high at 2 pm on a given day, it is likely to be high at 3 pm as well. This is especially true with the day-ahead electricity prices, which are used in the PSP program. A matrix of correlation coefficients for hourly prices is given in the appendix titled "Hourly Price Correlation." If consecutive hours have highly correlated prices, little information is lost in combining the hours into a block of hours. Navigant combined the information

[8] Cooling degree hours are calculated by $CDH = MAX(temperature - 65{,}0)$. When applied to a block of hours, CDH is calculated for each hour and then summed across the hours within a given block.
[9] The blocks were formed by summing consumption across hours and calculating the consumption-weighted average price. Cooling degree hours (CDH) for the block were calculated by summing the CDH across hours.

given by the price correlation coefficients with the intuitive daily consumption patterns to determine the appropriate blocking scheme for use in the GAI demand system.

Block 1:	midnight – 9 am
Block 2:	9 am – noon
Block 3:	noon – 2 pm
Block 4:	2 pm – 3 pm
Block 5:	3 pm – 4 pm
Block 6:	4 pm – 5 pm
Block 7:	5 pm – 7 pm
Block 8:	7 pm – 9 pm
Block 9:	9 pm – midnight

As the medium elasticity model captures the "rules of thumb" behavioral changes in response to seasonal average prices, the GAI demand system focuses on very short-run elasticities: how do participants respond to especially high prices? Frequently checking electricity prices is time consuming; hence, information is costly. We therefore expect customers to respond to high prices only on days when the cost of information is reduced and the potential benefits are high. The High Price Alerts (HPAs) serve exactly this purpose. On HPA days, participants are alerted that prices are exceptionally high, creating an opportunity to lower their bill by reducing their load during the high-priced hours. For this analysis, Navigant estimated the GAI demand system using only the 28 HPA days that occurred during summer 2008.[10]

A common approach to measuring the responsiveness of demand to changing prices is the calculation of price elasticities. The price elasticities of demand can be interpreted as:

$$\eta_{ij} = \frac{\%\ change\ in\ Q_i}{\%\ change\ in\ P_j}¶$$

Said another way, if the price doubles, what is the percentage change in load? The elasticity formula derived from the GAI demand system may be found in Appendix D – GAI Demand System Price Elasticity Formulas. The expected sign for the own-price elasticity of demand is negative: as the price of electricity increases for a given block, we expect consumption of electricity at that block to decrease, holding all other variables constant.

For the cross-price elasticity of demand, the elasticity may take either a positive or negative value. A positive value suggests that the goods are substitutes: as the price increases for block i, consumption is shifted from block i to block j, resulting in increased consumption during block j. This corresponds to households shifting consumption from one period to the next in response to prices.

Likewise, a negative value suggests that the goods are complements: as the price increases for block i, consumption decreases during block i, causing consumption to decrease during block j as well, due to

[10] There were 8 HPA days in June, 16 in July, 3 in August, and 1 in September of 2008.

the complementary nature of the goods. We can think of electricity consumed during two consecutive periods as complementary if the value of the electricity in one period depends on consumption of electricity in the other, as happens when consumption for a particular period "spills over" into a subsequent period. For example, running the dishwasher is an end use that might start in one period and continue into the next period. If the participant decides to forgo washing their dishes due to high prices in the first period, they also reduce their load in the second period. This behavior corresponds to households reducing overall electricity consumption in response to a price increase.

3.1.3 Short-Run Elasticity Results

For the short-run elasticity analysis, Navigant used the following blocks of hours in the GAI demand system:

Block 1:	midnight – 9 am
Block 2:	9 am – noon
Block 3:	noon – 2 pm
Block 4:	2 pm – 3 pm
Block 5:	3 pm – 4 pm
Block 6:	4 pm – 5 pm
Block 7:	5 pm – 7 pm
Block 8:	7 pm – 9 pm
Block 9:	9 pm – midnight

Table 6 presents the estimated own- and cross-price elasticities from the nine-equation GAI demand system, evaluated at the mean of the data.[11] More detailed information about parameter estimates and model performance can be found in Appendix F – GAI Demand System Parameter Estimates.

[11] The GAI demand system elasticity formulas are non-linear in form, meaning that the elasticity value varies based on the point of evaluation. In the table above, the elasticities were evaluated at the mean of the data; that is, using the average values of price and quantity. However, if a high or low value for price were used instead of the mean value, the elasticity estimates would change.

Table 6. Short-Run Price Elasticities of Demand

Change in Quantity for Block j	Change in Price for Block i								
Hours	12a-9a	9a-12p	12p-2p	2p-3p	3p-4p	4p-5p	5p-7p	7p-9p	9p-12a
12a-9a	-0.274 ***	0.461 ***	-0.037 ***	-0.016 *	-0.015 *	-0.03 ***	-0.156 ***	-0.311 ***	-0.297 ***
9a-12p	0.371 ***	-0.765 ***	0.573 ***	-0.042 **	-0.196 ***	-0.236 ***	-0.011	-0.491 ***	-0.191 ***
12p-2p	-0.083 ***	0.57 ***	-0.891 ***	0.03	-0.011	0.227 ***	-0.694 ***	0.041 *	-0.287 ***
2p-3p	-0.08 ***	-0.09 ***	0.046	-0.369 ***	-0.007	-0.283 ***	-0.189 ***	0.043 *	-0.205 ***
3p-4p	-0.077 ***	-0.313 ***	-0.022	-0.007	-0.203 ***	-0.527 ***	0.135 ***	0.067 ***	-0.197 ***
4p-5p	-0.078 ***	-0.365 ***	0.318 ***	-0.245 ***	-0.52 ***	-0.57 ***	0.531 ***	-0.114 ***	-0.086 ***
5p-7p	-0.151 ***	-0.019	-0.52 ***	-0.08 ***	0.075 ***	0.285 ***	-0.536 ***	-0.16 ***	0.032 ***
7p-9p	-0.289 ***	-0.459 ***	0.051 ***	0.034 *	0.054 ***	-0.061 ***	-0.181 ***	-0.755 ***	0.613 ***
9p-12a	-0.306 ***	-0.197 ***	-0.286 ***	-0.112 ***	-0.122 ***	-0.048 ***	0.087 ***	0.765 ***	-0.611 ***

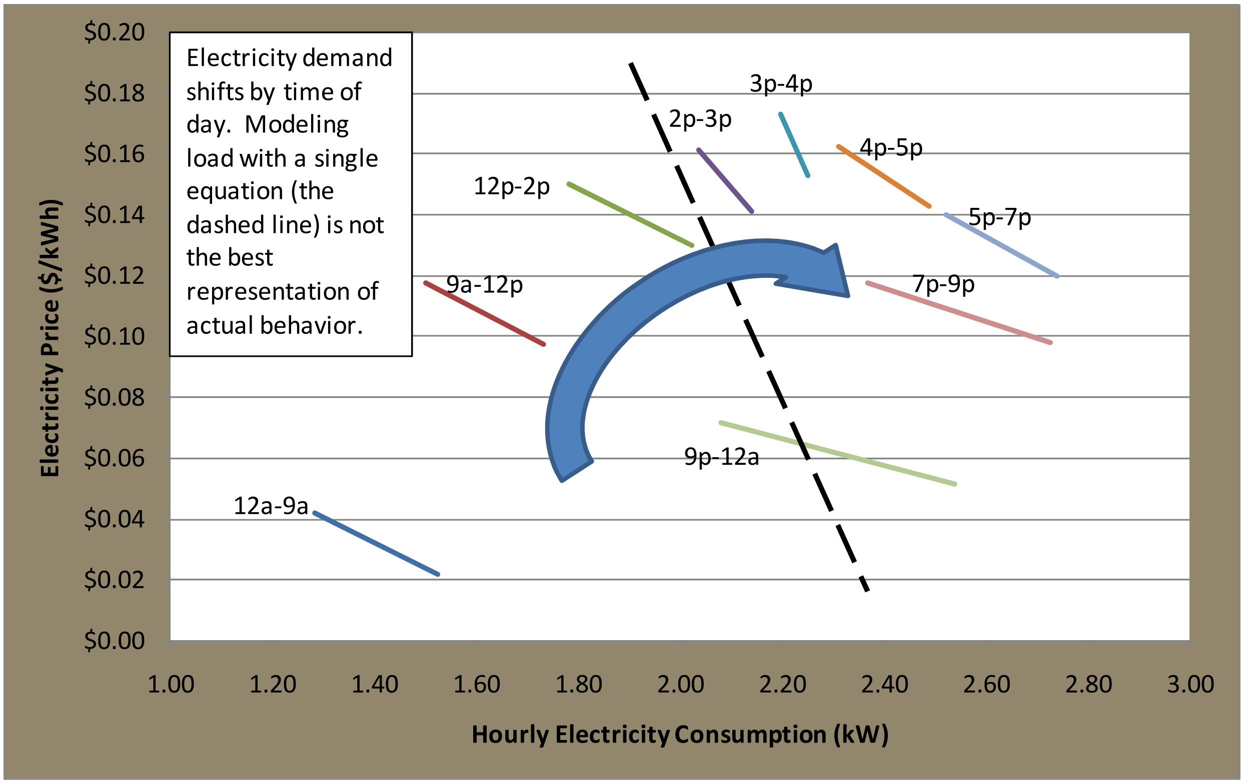
*Statistical significance indicated by: *** p<0.001, ** p<0.01, * p<0.05*

Source: Navigant analysis

The own-price elasticities, found along the diagonal and shaded dark brown, are all negative and statistically significant, as expected. Recall that price elasticities are interpreted as the percentage change in quantity demanded for a percentage change in price. For example, to investigate a doubling of price from 2–3 pm, look at the "2–3 pm" column. Reading down this column gives the percentage change in load throughout the day. Looking at the cell on the diagonal, the elasticity of -0.369 means that the load from 2–3 pm will decrease by 36.9 percent.

The own-price elasticities reported in Table 6 are larger than estimates reported elsewhere in other studies. This is not unexpected. The elasticities estimated using the GAI demand system represent short-run price response to substantial deviations in price on HPA days. Moreover, elasticity analyses using a single demand equation implicitly assume that demand does not shift throughout the course of the day as one would expect to be the case in light of daily behavioral routines (sleeping at night, returning home from work in the late afternoon or early evening). This is shown by the black dashed line in Figure 7. In reality, though, the demand for energy changes during the course of the day, as shown in the figure. A single demand equation essentially conflates several distinct demand equations –the equations associated with time-dependent preferences for energy consumption—in a single, misidentified equation. In general, because demand tends to be high at the times of day when prices are high, the result is the underestimation of price elasticity of demand.

Figure 7. Electricity Demand Shifts by Time of Day



Source: Navigant analysis

The cross-price elasticities, found in the off-diagonal elements of Table 6, have both positive (shaded tan) and negative (not shaded) signs. For any cross-price elasticity, the column number gives the block in which the price change occurs, and the row number gives the block in which quantity demanded changed. Recall that a positive cross-price elasticity means that the electricity consumed during the two blocks are considered substitutes: a price increase during block j causes the participant to consume less electricity in block j, and consume more electricity in block i. Likewise, a negative cross-price elasticity means that the electricity consumed during the two blocks are considered complements: a price increase during block j causes the participant to consume less electricity in block j and in block i. The key load shifting and complementary load results are highlighted in Tables 6 and 7 below.

Table 7. Key Results—Load Shifting

If price is high…	Load is shifted to…
In the afternoon (noon – 5pm)	The early evening (5-9pm)
In the evening (5-9 pm)	The late afternoon (3-5pm) and late evening (9pm – midnight)

Source: Navigant analysis

Table 8. Key Results—Complementary Load

If price is high…	Load is also reduced in…
In the afternoon (3-4 pm)	Adjacent afternoon periods (2-3 pm and 4-5 pm)
In the evening (5-7 pm)	Adjacent evening periods (7-9pm)

Source: Navigant analysis

Combining all of the information about own-price elasticities and cross-price elasticities, we can look at changes in load due to price increases. Using the HPA day average price and quantity consumed for each block of time, Navigant calculated the change in load resulting from an increase in price of one standard deviation (1–2 cents per kW).

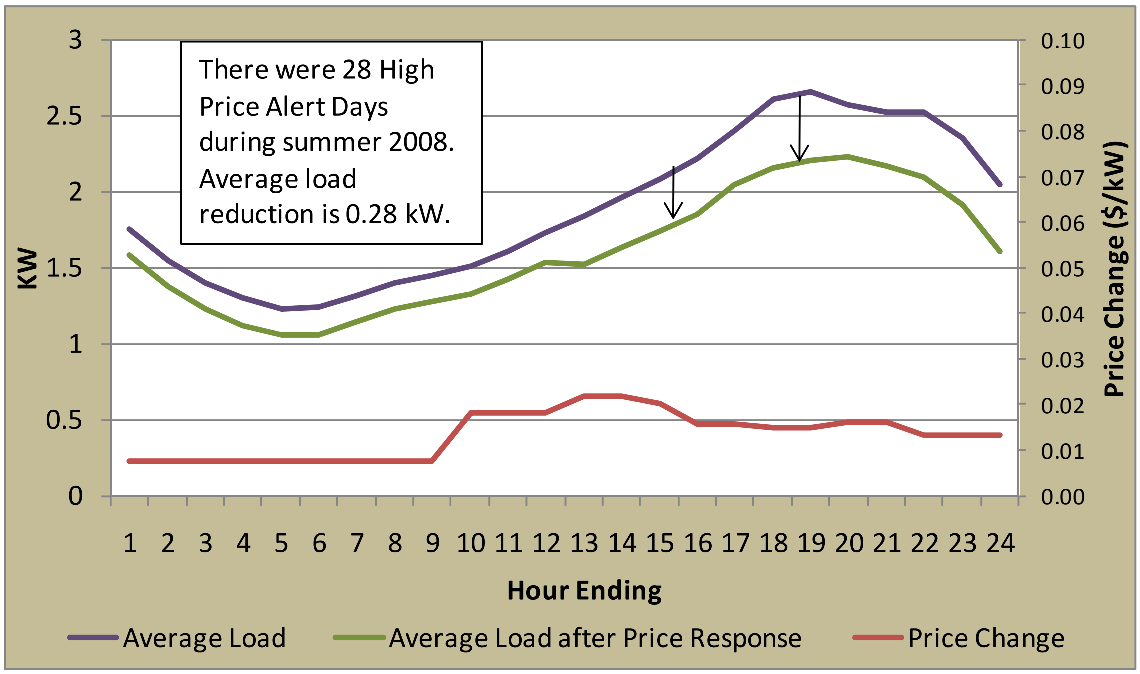
Table 9. Impact of a Price Increase, by Time of Day

Hours	Avg Price	Avg Load (KW)	Price Change	% Price Change	% Load Change	Load Change (KW)
12a-9a	$0.03	1.41	$0.01	24%	-13%	-0.18
9a-12p	$0.11	1.62	$0.02	17%	-12%	-0.19
12p-2p	$0.14	1.90	$0.02	16%	-17%	-0.33
2p-3p	$0.15	2.09	$0.02	13%	-16%	-0.34
3p-4p	$0.16	2.22	$0.02	10%	-17%	-0.37
4p-5p	$0.15	2.40	$0.02	10%	-15%	-0.35
5p-7p	$0.13	2.63	$0.01	12%	-17%	-0.45
7p-9p	$0.11	2.55	$0.02	15%	-14%	-0.35
9p-12a	$0.06	2.31	$0.01	21%	-19%	-0.44

Source: Navigant analysis

In the figure below, the purple line represents the average hourly load on HPA days. After increasing the price by one standard deviation in all hours of the day, the load decreases in all hours (shown by the green line). The largest decreases in load occur during the afternoon and evening hours. In conclusion, PSP participants are responding to extremely high prices on HPA days with behavioral changes *in addition to* their "rule-of-thumb" behavioral changes.

Figure 8. Load Reductions Due to a Price Increase of One Standard Deviation



Source: Navigant analysis

3.2 Hourly Demand Impacts

The discussion in the previous section focuses on the relationship between price and consumption to provide insight about the degree to which households are responding to the price signal that is the centerpiece of the PSP program. Following the typical elasticity analysis, it focused on the consumption response to *incremental* (marginal) changes in price. We now focus on the overall consumption impacts of the program. After discussing these impacts, we examine the impact of a demand response innovation in the summer of 2010 not present in the summers of 2009 and 2008: some PSP participants were enrolled in Ameren Illinois' direct load control program, for which there was one event in 2010.

3.2.1 Methodology – Hourly Demand Impacts

As in the previous two years of this study, Navigant has, for the 2010 PSP data, compared the average load curves for PSP participants to a matched control group. In the 2008 evaluation, hourly demands were estimated for eight different types of days: regular weekdays for three seasons[12], regular weekends for three seasons, and HPA weekdays and weekends (summer only).

Because there have been no HPA days since 2008, no demand impacts were estimated for HPA days in 2009. In 2010 there were also no HPA days, so again for 2010, no demand impacts will be estimated for these types of days.

For the report concerning the 2009 data, although they were estimated, no demand impacts were presented for weekends. Again, this year's study will not report weekend demand impact estimates. Capacity concerns that RTP programs such as PSP are designed to mitigate do not arise on weekends, making such demand impacts of little importance from a system benefit/cost standpoint.

The basis for the average load curves developed for PSP participants was the same collected and cleaned hourly load data that was used for the development of the elasticity models. Although the driving purpose of this section of the study is the estimation of the demand impacts made by PSP in 2010, Navigant has made use of PSP participant hourly load data going back to 2007 for this analysis.

The hourly data for the control group was provided by the Ameren Illinois load research group. Average load curve information was supplied for 12 different customer groups. The 12 customer groups covered four strata for each of three regions in Ameren Illinois' territory. These three regions were formerly three companies: CIPS, CILCO, and IP. The four strata are defined in the following way:

Strata 1: Customers with a low level of summer and winter electricity consumption

Strata 2: Customers with low levels of summer, but high level of winter electricity consumption

Strata 3: Customers with a high level of summer, but a low level of winter consumption

Strata 4: Customers with a high level of summer and winter electricity consumption

For these strata designations, summer is defined as June, July, August, and September. Winter is defined as December, January, and February and the shoulder months are April, May, October, and November. A customer with a low level of summer consumption is defined as one who uses less than 1,300 kWh per month in all months. A customer with a high level of summer consumption is defined as one who uses 1,300 kWh or more per month, in any of the summer months. Whether a customer has a high or low level of winter consumption is determined by the ratio of winter to shoulder season consumption. If the ratio of winter daily average consumption is less than or equal to 1.6, then that customer is considered to

[12] It should be noted that although demands were estimated for all four seasons, spring and autumn were conflated into a single shoulder "season" for demand impact estimating purposes.

have a low level of winter consumption. The exception is for customers residing in the region that was formerly CILCO's territory. In this region, the ratio used is 1.8 rather than 1.6.[13]

Demand impacts are estimated by comparing the PSP average load curve to a well-calibrated mix of the control group load curves. The mix of control group load curves is calibrated according to the distribution of PSP participants by strata. PSP customers are assigned to strata according to the same criteria outlined above for the control group – based on consumption, given the region in which they reside.

In previous years of this study, strata were applied anew each year, based on each customer's consumption in the year under analysis. What this meant was that, effectively, it was possible for a participant to be in a different stratum in each year. The control group customers, however, had been assigned their strata once, in 2006.[14] During the analysis of the 2010 data, Navigant noted that a very high proportion of PSP participants had shifted from one stratum to another, due in part to the mild winter and very warm summer of that year. Navigant believed, given this finding, that a more consistent method of assigning participants to strata was called for so that a given customer could only inhabit one stratum over the course of the entire data set (beginning in 2007). In this way, PSP strata assignment would be more consistent with that of the control group who, once assigned their strata by the Ameren Illinois load research group, do not shift, regardless of how their consumption changes from year to year based on changing weather patterns.

The ideal solution in this case would have been to assign all PSP participants into the respective strata based on their 2006 consumption profiles. Unfortunately, Navigant did not have access to this data. Navigant, therefore, adopted what it believes to be the most robust strata-assignment method possible under the circumstances.

PSP participants were assigned to strata based on the most common strata designation from year to year based on all available monthly consumption data for that customer. If, for example, a participant that had been in the program for three years had been a Strata 1 participant one year and a Strata 2 participant the second and third year, he or she was assigned to Strata 2. In cases when there was a tie (e.g., Strata 1 in year 1, Strata 2 in year 2, Strata 3 in year 3), then the participant was assigned to the highest frequency for the population to which he had belonged. In the example above, this customer would have been assigned to Strata 3 because there are more participants in this group than in either Strata 1 or Strata 2.

This resulted in a significant, but not dramatic, shift in the distribution of PSP participants by strata. Part of Table 6 from the 2009 program year PSP impact evaluation is reproduced as Table 10, for comparison purposes. The distribution of PSP customers by strata in the various years of the program using the improved assignment algorithm as well as the distribution of Ameren Illinois residential customers by strata is shown in Table 11.

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[13] The ratio of 1.8 for this region was determined by the Ameren Illinois load research team based on differences in weather patterns and base electricity consumption in the region that was formerly CILCO's service territory.
[14] E-mail correspondence with Ameren Services Forecasting and Load Research.

Table 10. Strata Distribution—Old Assignment Method

Strata	Strata Description	All Residential Customers	PSP Participants 2008	PSP Participants 2009
Strata 1	Low Summer - Low Winter	52%	43%	44%
Strata 2	Low Summer - High Winter	12%	11%	12%
Strata 3	High Summer - Low Winter	31%	40%	36%
Strata 4	High Summer - High Winter	5%	5%	8%

Source: Navigant analysis

Table 11. Strata Distribution—Current Assignment Method

Strata	Strata Description	All Residential Customers	PSP Participants 2008	PSP Participants 2009	PSP Participants 2010
Strata 1	Low Summer - Low Winter	52%	44%	44%	38%
Strata 2	Low Summer - High Winter	12%	7%	7%	8%
Strata 3	High Summer - Low Winter	31%	46%	45%	50%
Strata 4	High Summer - High Winter	5%	3%	5%	5%

Source: Navigant analysis

As can be seen from above, the principal effect is the reassignment of participants from Strata 2 and 4 to Strata 3. Because the PSP program has historically been targeted at customers without electric heat, this reassignment seems credible. Of the 7,327 PSP participants active in 2009 for which Navigant has clean hourly observations, only 142, or fewer than 2 percent, indicated that they used electricity as their primary space-heating fuel.

The distribution of PSP participants by strata in 2010 compared to 2008 and 2009 is noteworthy in that there seems to have been a significant shift from Strata 1 to Strata 3. This is likely due to two factors: the first, that the very warm 2010 summer resulted in higher than average air-conditioning (A/C) use, which meant many new participants who might otherwise have been assigned to Strata 1 were edged into Strata 3, and the second, that historically the PSP program has attracted customers with higher than average levels of consumption. (More discussion on this follows.) Indeed, it is customers with high levels of summertime discretionary consumption (i.e., those that use A/C a lot) who stand to benefit the most from participation in this program and so it should come as no surprise that the plurality of participants come from that demographic.

Using the weights provided by the distribution shown in Table 11, Navigant calibrated the load control group load curves to those of the PSP customers and estimated the demand impact.

3.2.2 Results – Hourly Demand Impacts

As of the drafting of this report, load research control data was available only until the end of August 2010. Hourly demand impacts in 2010 were, therefore, estimated only for winter, summer, and spring.

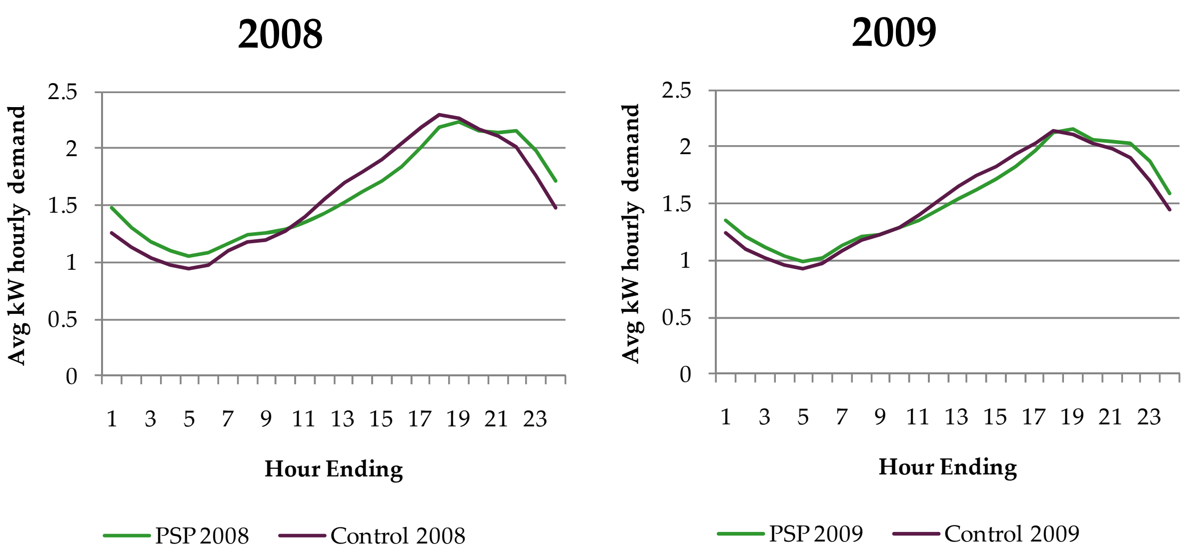
Summer: June, July, and August[15]
Winter: January and February
Spring: March, April, and May

Results for each season will be presented separately.

Summer Weekdays

The change in the strata assignment algorithm makes it a worthwhile exercise to revisit the load curves of previous years in the program to observe what difference the reassignment has made.

Figure 9. Summer Weekday Load Curves: 2008 and 2009 (Actual – Not Indexed)



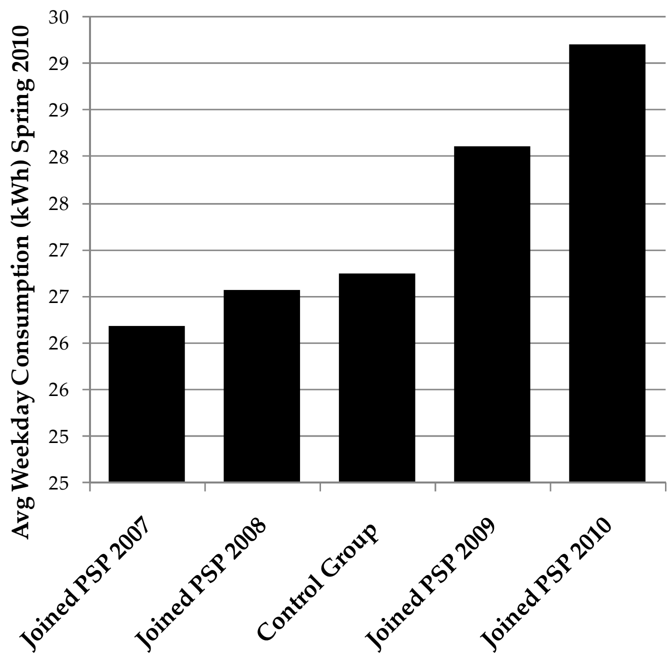
Source: Navigant analysis

As can be seen in Figure 9, with the strata reassigned there is an observable difference in the consumption patterns of the PSP participants and the control groups, even without normalizing the control group's overall level of consumption to the same level as that of the PSP participants. The demand response effect of the PSP program does appear to be of a smaller magnitude in 2009 compared with 2008. This is for two reasons. The first is that prices were, on average, considerably lower in 2009 compared with 2008, reducing the incentive to PSP participants to practice demand response. The second, which was identified in last year's report, is that more recently recruited PSP participants tend to have higher levels of base electricity consumption than PSP participants that have been in the program for some time.

[15] Season for load curve comparisons was defined based on the similarity of consumption patterns, not standard rate tariff definitions.

A relatively robust method for assessing changes in the base level of electricity consumption is to look at levels of consumption during the shoulder (i.e., spring and autumn) seasons. The largest drivers of discretionary electricity use—A/C in the summer, space-heating and lighting in the winter—are quite moderate during the shoulder months. Temperatures tend neither very high nor low, and the hours of daylight are longer than in winter. Figure 10 shows the average spring weekday consumption of PSP participants that joined the program in 2007, 2008, 2009, and 2010 as well as the average spring weekday consumption of the control group[16]. As can clearly be seen in this chart, the average daily spring consumption of PSP customers is higher the later that they joined the program.

Figure 10. Average Weekday Consumption, Spring 2010, by Year in Which Participant Joined PSP

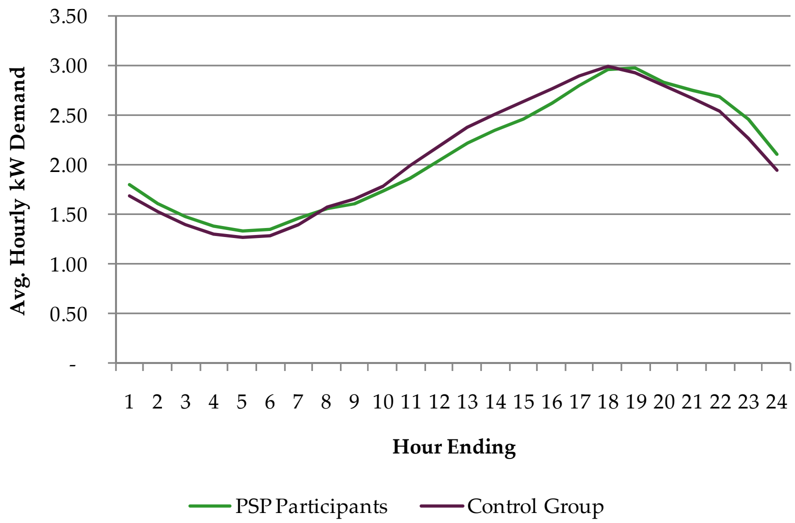


Source: Navigant analysis

Given the disparity between the daily average levels of energy consumption, evaluating the demand impacts of the PSP program based on the absolute average levels of demand in each hour would underestimate the true demand impact of the program. The best method for estimating the hourly summer impacts—indeed the hourly demand impacts in all seasons—for 2010 is to index the control group load profile to the average daily level of energy consumption of the PSP participants. The indexed summer load curves for PSP participants and the control group are shown in Figure 11.

[16] As of the drafting of this report, no load research control group data was available beyond August 2010.

Figure 11. Indexed Summer Weekday Load Shapes for 2010



Source: Navigant analysis

In the 2009 program year PSP evaluation, Navigant revised its demand impact estimates based on the new approach of indexing the load curves. In this year's (program year 2010) PSP evaluation, Navigant once more is presenting revised estimates, as shown in Table 12. In this case the revision is due to the improved strata assignment algorithm, which has effectively changed the load shape of the control group to one which is a better comparison to the PSP participants.

Table 12. Average Load Reduction for PSP Participants Between Noon and 5 pm

	2009 Estimates		2010 Estimates		
	2008	2009	2008	2009	2010
High Price Summer Day	-0.27 kW/Cust	N/A	-0.26 kW/Cust	N/A	N/A
Average Summer Day	-0.18 kW/Cust	-0.13 kW/Cust	-0.21 kW/Cust	-0.13 kW/Cust	-0.15 kW/Cust

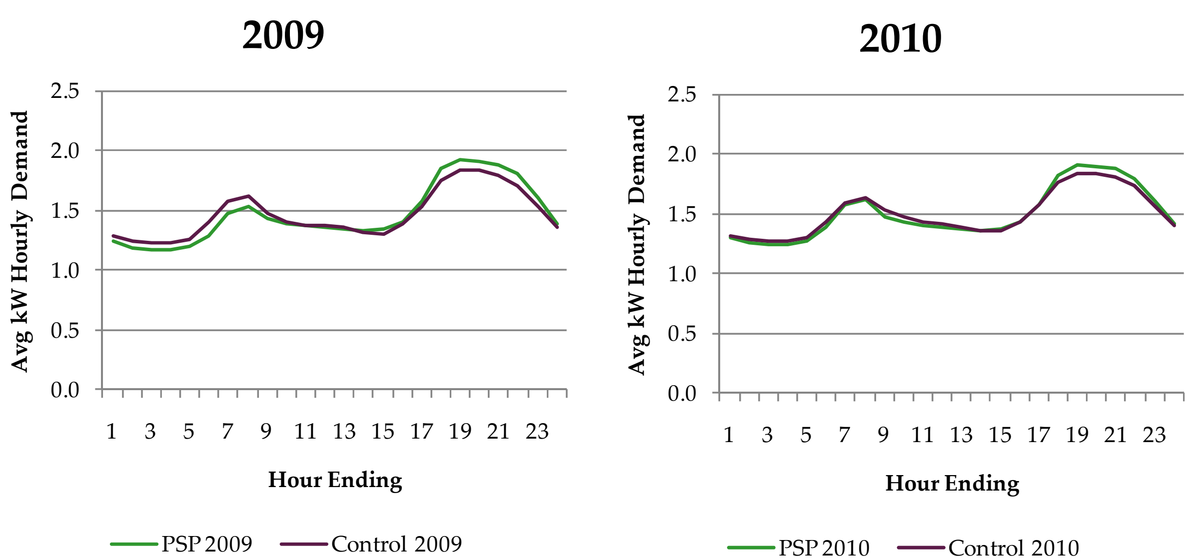
Source: Navigant analysis

Winter Weekdays

The single-hump load shape for summer changes to the traditional double-hump load shape in winter for both the PSP participant group and the control group. There is a morning peak between 6 am and 8 am when customers are getting ready for their day and before many of them leave their home, and a second peak in the evening from 5 pm to 9 pm when many come back home again and everyone is turning on lights, cooking dinner, and being active within their homes.

In the 2008 evaluation, it was found that PSP participants have slightly more nighttime use in winter than regular customers. This increased nighttime use extended over both the evening and the deep night hours. In the 2009 evaluation, it was observed that this relationship did not appear to persist in 2009. With the new strata assignment algorithm however, it appears that PSP participants continued to use more energy during the winter evening hours in both 2009 and 2010, as shown in Figure 12. However, deep night use changes in comparison to the control group. In 2009, PSP customers switch from using more energy than the control group in the evening hours to using less energy than the control group after midnight. In 2010, this moderates back to where PSP customers are still using more energy in the evening compared to the control group, but are using the same level of energy in the deep night hours after midnight. The conclusion is that PSP customers consistently use more energy in the evening hours, but their deep night use does not follow any recognizable pattern from year to year.

Figure 12. Winter Weekday Load Curves: 2009 and 2010



Source: Navigant analysis

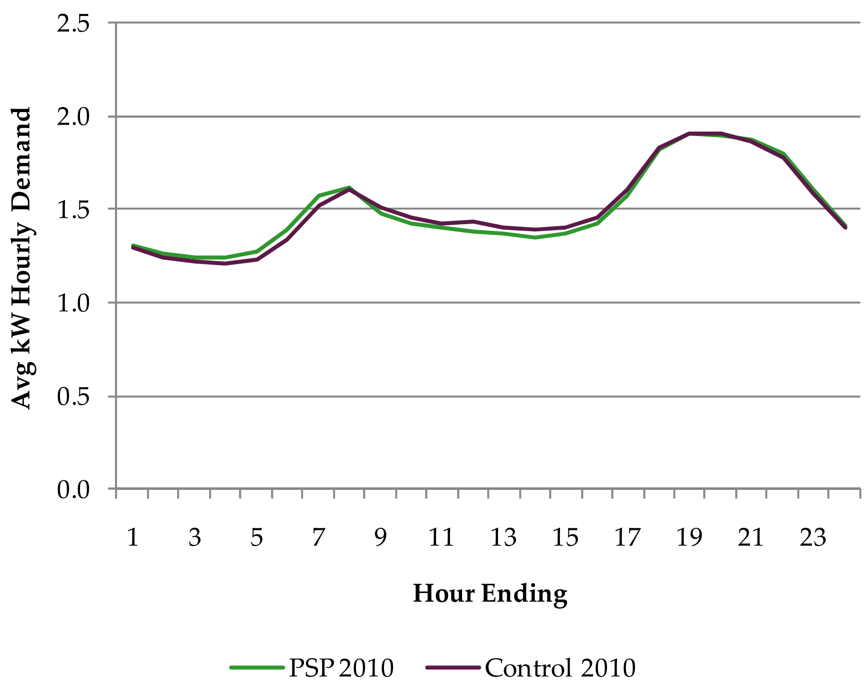
It was hypothesized in the 2009 evaluation report that the observed difference in consumption patterns is due in some way to the number of PSP participants that have electric space heat. In fact, as was noted above, very few—fewer than 2 percent—of PSP participants report using electricity as their primary space-heating fuel. Many of those PSP participants assigned to Strata 2 and 4 have been assigned to those strata not because of high levels of winter consumption due to space-heating, but because of high levels of winter consumption due to other end uses, most likely lighting and possibly consumer electronics.

Conversely, although Navigant does not know the makeup of the control group strata at the individual level, it seems likely that Strata 2 and 4 of the control group include—on average—a higher percentage of electric space-heating customers. This assumption springs principally from the observation that recruitment efforts for the PSP program have historically sought to not include electric space-heating participants.

Because Navigant has adopted the indexed method of comparing the hourly average demands of the control and the PSP participants, the main purpose of calibrating the control group by strata to reflect the distribution of PSP participants by strata is to obtain a comparable load shape—not necessarily a comparable level of average daily energy consumption. If we accept the assumption that the Strata 2 and 4 control groups include proportionally more electric space-heating customers than the PSP participants in those strata and that customers that use electric space-heating will have a differently shaped load curve than those who do not, a more robust comparison may result if only Strata 1 and 3 load shapes are used. To make this comparison, Navigant has, therefore, calibrated the control group load shape in the following way: the control group load shape is the weighted average (by strata and company) of the 12 control group load shapes, but all weights that had previously been attached to Strata 2 and 4 are re-assigned to Strata 1 and 3, respectively.

The results of this reweighting of the control group load curve are shown in Figure 13.

Figure 13. Winter 2010 Weekday Load Curve, Controlling for Electric Space Heating



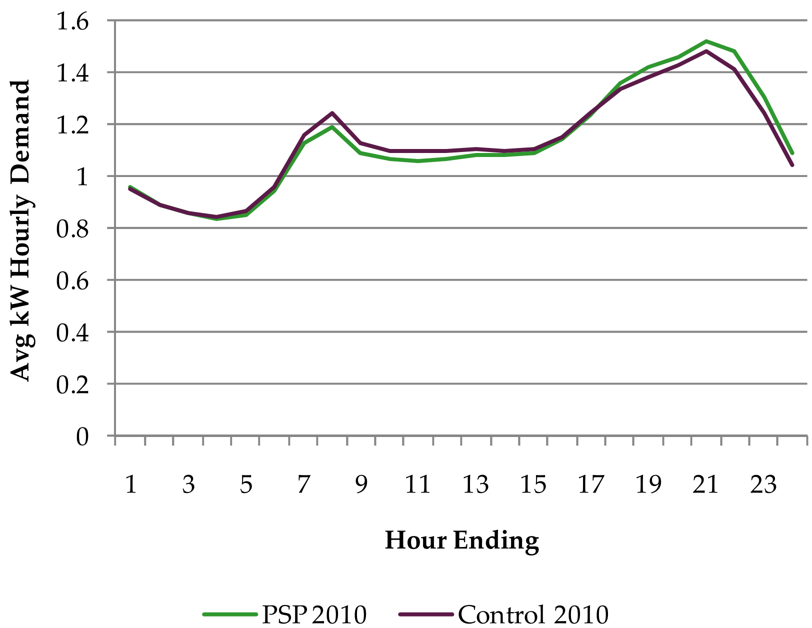
Source: Navigant analysis

Following the recalculation of the control group load shape, there are subtle differences between it and the PSP participants' average load shape. However, they are, on the whole, remarkably similar. The slight reduction of PSP participants' consumption during the working day compared with the early morning, could perhaps be due to participants continuing to follow the summer PSP "rules of thumb" (i.e., reduce consumption weekday afternoons in favor of morning or evening consumption) rather than the winter "rules of thumb." In any case, as in previous years of this evaluation, there does not appear to be any significant demand impact from PSP hourly pricing during winter weekdays. The little bit there is reflects the expected pattern of less use during the daytime hours and more use during the night hours.

Spring Weekdays

As of the drafting of this evaluation report, no load research control data had been made available to Navigant beyond August 31, 2010; thus, shoulder season demand impacts may only be estimated for the spring, rather than both spring and autumn, of 2010. The average load curve of PSP participants, and the weighted average load curve (weighted by all four strata) for spring 2010, are shown in Figure 14.

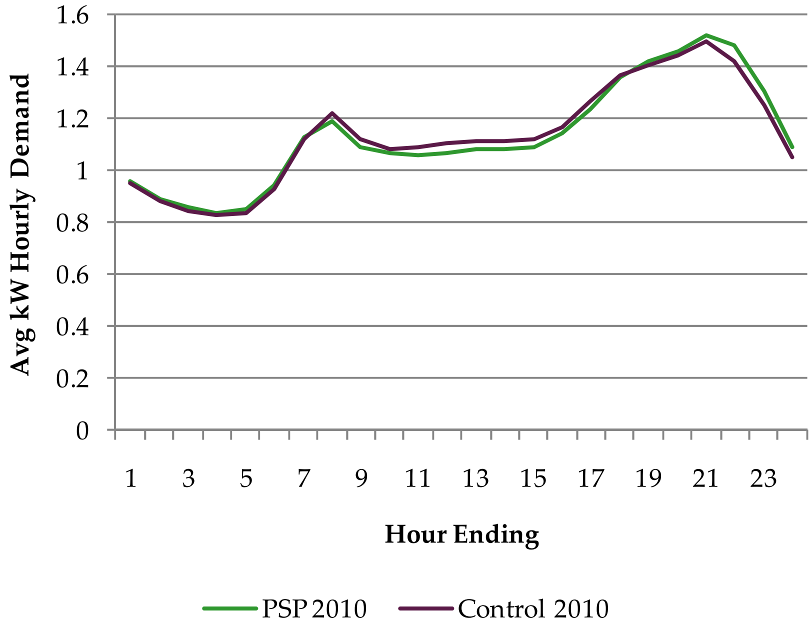
Figure 14. Spring 2010 Weekday Load Curve



Source: Navigant analysis

Figure 15 exhibits the same pattern as the winter load curves shown in Figure 13: PSP customers appear (on a normalized or indexed basis) to be consuming less in the morning and more in the evening than their control group counterparts. Applying the same logic as for the winter load curves, Navigant has re-calculated the weighted average control group load curve to reflect the assumption that Strata 2 and 4 in the control group contain a higher percentage of electric space-heating customers than do the corresponding PSP strata. Interestingly, although applying the new weighting brings the two load shapes more in line with one another, it does so slightly less dramatically than for the winter load shapes. This is likely due to the fact that the assumed higher percentage of electric space-heating consumers in the control group Strata 2 and 4 will tend to distort the load curve less in spring (when less electricity is required for space heating) than in the winter.

Figure 15. Spring 2010 Weekday Load Curve, Controlling for Electric Space Heating



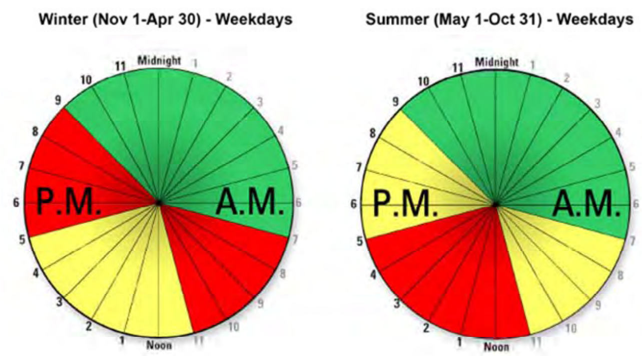
Source: Navigant analysis

As with the winter, the result is somewhat ambiguous: is the lower level of consumption during the working day exhibited by the PSP participants due to participants changing their consumption patterns using season-inappropriate rules of thumb, or is it not a significant difference?

Although, with the data available to Navigant, it is impossible to conclusively determine which possibility is the case, evidence observed in other jurisdictions may be informative. In a study on the impact of time-of-use (TOU) rates in a large suburban community near Toronto, Ontario, Navigant found that, on average, when exposed to a three-period TOU rate schedule that varied by season (summer on-peak period: 11 am to 5 pm, winter on-peak period: 7 am to 11 am and 5 pm to 9 pm – see Figure 16) with consistent prices by period (summer on-peak price is identical to winter on-peak price), customers reduced summertime on-peak consumption by approximately 5percent, but did not reduce winter on-peak consumption[17] at all (see Figure 17). Navigant concluded that the lack of response to the winter on-peak price signal was due principally to the lack of discretionary consumption available for shifting or curtailment at those times in the winter.

[17] Navigant Consulting, prepared for Newmarket-Tay Power Distribution, *The Effects of Time-of-Use Rates on Residential Electricity Consumption*, April 2010, http://www.nmhydro.ca/pdf/NMH_TOU_FINAL.PDF

Figure 16. Ontario's TOU Schedule



Source: "The Effects of Time-of-Use Rates on Residential Electricity Consumption", Navigant Consulting, April 9, 2010

Figure 17. Seasonal Demand Response to TOU Rates—Newmarket, Ontario

	7am–11am	11am–5pm	5pm–9pm
Winter	0.0%	- 2.6%	0.0%
Summer	- 0.4%	- 5.4%	- 0.4%

On-peak period (Winter 7am–11am and 5pm–9pm; Summer 11am–5pm)
Mid-peak period (Winter 11am–5pm; Summer 7am–11am and 5pm–9pm)

Source: "The Effects of Time-of-Use Rates on Residential Electricity Consumption", Navigant Consulting, April 9, 2010

Given the evidence, it seems likely that, as in the winter, there is, on average, no significant demand impact on spring consumption due to the PSP program.

3.2.3 Impact of the August 10, 2010, Direct Load Control Event

In 2010, 704 PSP customers enrolled in a Direct Load Control (DLC) program for which there was one event, occurring August 10, from 1 pm to 5 pm, Central Prevailing Time. Of the 704 participants, 657 were active in the program at the time the curtailment event was called. The analysis that follows makes use only of their data.

As with many of the other impacts estimated by Navigant for this report, the econometric framework used was linear fixed-effects regression. This technique allows the analyst to control for individual heterogeneity without explicitly modeling time-invariant household characteristics by essentially assigning a dummy variable to each household in the sample and thus, to a degree, controlling for each individual's average level of consumption. In this way, the analyst does not need to control household characteristics that are time invariant, such as a house's size, the direction it faces, or the quality of its building envelope.

In addition to estimating the average impact on demand of participating households during the control event, an important aspect to the impact estimation of direct load control events is the estimation of what is known in the industry as "snapback." Snapback refers to the increase in participating household demand (relative to what would be expected absent the curtailment) that occurs following a curtailment event. When air-conditioning is cycled to reduce demand, following the end of the curtailment period, the air-conditioning unit must work harder than it usually would at that time of the day to restore the home to the set-point temperature and humidity.

Although snapback is universally accepted as a phenomenon, there remains some discussion as to its magnitude and to the length of time (in relation to the length of the curtailment event) over which it applies, following a curtailment event. In order to make an initial assessment of what hours to control for (and thus estimate) this snap-back effect, Navigant began by making an inspection of the hourly consumption patterns of DLC participants on the day of the curtailment event. To somewhat control for the effects of summer weather, Navigant compared the average hourly consumption of DLC participants for the day on which curtailment occurred (August 10) with the average hourly consumption of DLC participants on all summer 2010 days in which the daily cumulative temperature-humidity index (THI) was between 10 percent higher and 10 percent lower than on the control day.

The THI used is analogous to a cooling degree hour except that it incorporates a measure of humidity (a major driver of A/C use) as well as temperature. The THI is calculated in the following manner:

$$THI = Max\left\{0.55 \times DryBulb + 0.2 \times Dew - 48.5, 0\right\}$$

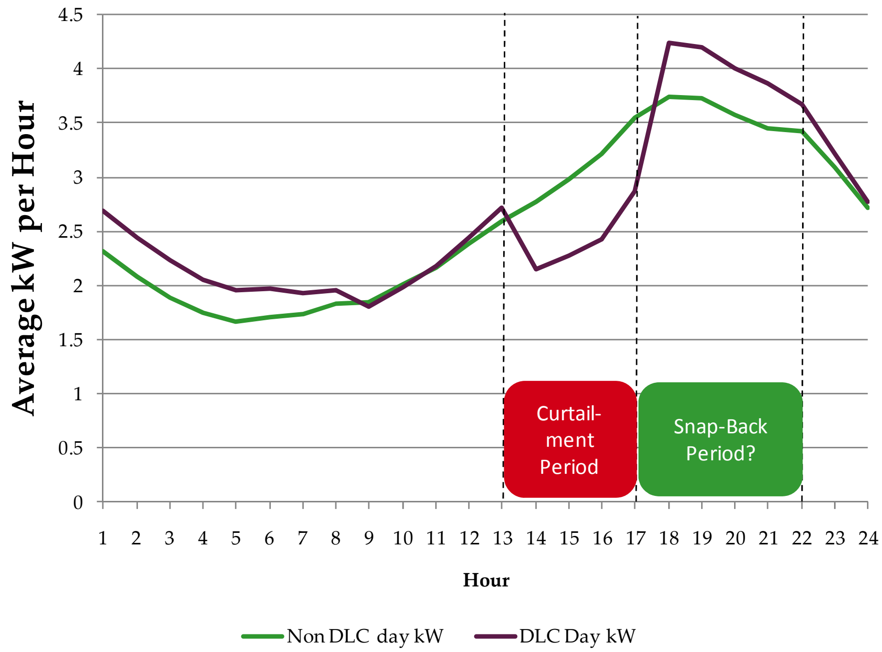
where

THI	=	the temperature humidity index for a given hour in a given location
DryBulb	=	the dry bulb temperature (in Fahrenheit) for a given hour in a given location
Dew	=	the dew point temperature (in Fahrenheit) for a given hour in a given location.

Note that the THI can only ever take a positive value.

The average hourly consumption of DLC participants that were active in the program on the curtailment event day of August 10 is presented in Figure 18 below for both the day of curtailment and for all days in which the cumulative THI was within 10 percent of the THI on the curtailment day.

Figure 18. Plot of DLC Participants' Consumption—DLC Day and Comparable Non-DLC Days



Source: Navigant analysis

Three interesting observations may be made of Figure 18.

First, early morning consumption (from hour ending 1 through hour ending 9[18]) is slightly higher at all hours on the day of curtailment than on average comparable days.

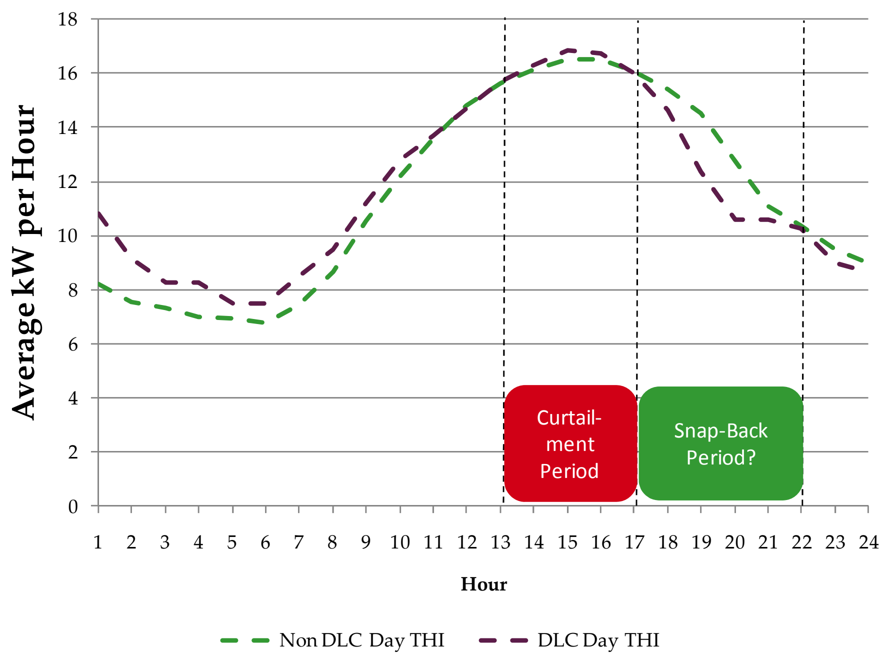
Second, there is a clearly observable curtailment effect between 1 pm and 5 pm (hours ending 14 to 17).

Third, the snap-back effect appears (when compared to the comparable average) to be smaller than the curtailment effect, but, surprisingly appears to last about an hour *longer* than the curtailment period (i.e., five hours rather than four).

One must be careful not to draw too many conclusions from a plot such as that in Figure 1818, particularly as the consumption of a single day is being compared to an hourly average across many days. It may be instructive, however, to also examine the hourly average THI experienced by DLC participants both on the curtailment day and on average comparable days (i.e., summer 2010 days in which the daily cumulative THI was within 10 percent of the cumulative daily THI observed on August 10). A plot of average THIs experienced by DLC participants on both the curtailment day and average comparable days is presented in Figure 19.

[18] Corresponding to midnight through to 9 am

Figure 19. Plot of THI-DLC Day and THI Comparable Non-DLC Days



Source: Navigant analysis

Comparing Figure 18 and Figure 19 sheds some light on the three points noted regarding Figure 18.

First, the higher average consumption observed in the early morning hours is likely explained by the fact that it was, on average, warmer and/or more humid in those hours on the curtailment day than on the comparable days.

Second, the average THIs during the period of curtailment were very similar on the day of curtailment and the average comparable days, with the hourly THIs being slightly higher on the day of curtailment than on the average of the comparable days. This implies that the true kW demand reduction during the period of curtailment is likely somewhat greater than what Figure 18 might suggest.

Most intriguingly, the average THIs during the possible snapback period are higher on the average comparable days than on the curtailment day. This suggests firstly that the snapback effect (in terms of average kW increase) is actually greater than that implied by Figure 18 and secondly that the counter-intuitive length of the snapback period is *not* due to more elevated evening temperatures/humidity levels on the day of curtailment compared with the average comparable days.

Possible reasons for the counterintuitive length as well as the magnitude of the snapback effect will be discussed in more detail later in this section.

Eight different model specifications were estimated and compared to estimate the impact of the curtailment and of the snapback effect. A summary is presented in Table 13. Full descriptions of the variables may be found in the model specification equation that follows it.

Table 13. Model Specifications Estimated

Model Name	Dependent Variable	Independent Variables
A1	Hourly consumption (kWh)	- Hourly Dummies (23) - THI - HDH - WKND - DLC_Event - DLC_Snapback
A2	Natural log of hourly consumption (ln{kWh})	
B1	Hourly consumption (kWh)	- Hourly Dummies (23) - THI - THI^2 - HDH - WKND - DLC_Event - DLC_Snapback
B2	Natural log of hourly consumption (ln{kWh})	
C1	Hourly consumption (kWh)	- Hourly Dummies (23) - Hourly Dummies x THI (23) - THI - HDH - WKND - DLC_Event - DLC_Snapback
C2	Natural log of hourly consumption (ln{kWh})	
D1	Hourly consumption (kWh)	- Hourly Dummies (23) - Hourly Dummies x THI (23) - THI - THI^2 - HDH - WKND - DLC_Event - DLC_Snapback
D2	Natural log of hourly consumption (ln{kWh})	

Source: Navigant analysis

The generalized model specification estimated was:

$$\begin{aligned} y_{i,t} &= \alpha_i + X\beta + Z\gamma + \phi_1 THI_{i,t} + \phi_2 THI_{i,t}^2 + \phi_3 HDH_{i,t} \\ &+ \phi_4 WKND_t + \theta_1 DLC\_EVENT_t + \theta_2 DLC\_SNAPBACK_t + \varepsilon_{i,t} \end{aligned}$$

where

$y_{i,t}$ = the natural log (for models A2, B2, C2, and D2) of the hourly electricity kWh consumption of PSP participant *i* for hour *t*, OR the hourly electricity kWh consumption (for models A1, B1, C1, and D1) of participant *i* for hour *t*

α_i	=	the individual fixed effect for PSP participant *i*. This applies to all models.
X	=	an N × 23 matrix of dummy variables flagging hours of the day. For example: the element $x_{t,1}$ is equal to one when hour *t* is hour ending 1 and zero, otherwise, the element $x_{t,2}$ is equal to one when hour *t* is hour ending 2 and zero otherwise, etc. This applies to all models.
β	=	the 23 × 1 vector of coefficient parameters associated with the X hour ending dummy variables. This applies to all models.
Z	=	an N × 23 matrix of dummy variables flagging hours of the day multiplied by the THI experienced by customer *i* in hour *t*. For example: the element $z_{i,t,1}$ is equal to $x_{t,1} \times THI_{i,t}$. This applies only to models C1, C2, D1, and D2.
γ	=	the 23 × 1 vector of coefficient parameters associated with the Z hour ending interacted with THI dummy variables. This applies only to models C1, C2, D1, and D2.
$THI_{i,t}$	=	the THI experienced by PSP participant i during hour *t*. Note that THI varies by the location of the individual so that $THI_{i,t}$ is not necessarily the same as $THI_{j,t}$. This applies to all models.
ϕ_1	=	the coefficient parameter associated with the THI variable. This applies to all models.
$THI_{i,t}^2$	=	the square of the THI experienced by PSP participant i during hour *t*. This applies only to models B1, B2, D1, and D2.
ϕ_2	=	the coefficient parameter associated with the squared THI variable. This applies only to models B1, B2, D1, and D2.
$HDH_{i,t}$	=	the heating degree hours experienced by PSP participant *i* during hour *t*. Note that HDH varies by the location of the individual so that $HDH_{i,t}$ is not necessarily the same as $HDH_{j,t}$. This applies to all models.
ϕ_3	=	the coefficient parameter associated with the HDH variable. This applies to all models.
$WKND_t$	=	a dummy variable equal to one if hour *t* occurs on a weekend and zero otherwise. This applies to all models.
ϕ_4	=	the coefficient parameter associated with the WKND variable. This applies to all models.

DLC_EVENT_t = a dummy variable equal to one if hour *t* is the hour ending at 2 pm, 3 pm, 4 pm, or 5 pm on August 10, 2010, and zero otherwise. This applies to all models.

θ_1 = the coefficient parameter associated with the DLC_EVENT variable. This applies to all models.

$DLC\_SNAPBACK_t$ = a dummy variable equal to one if hour *t* is the hour ending at 6 pm, 7 pm, 8 pm, 9 pm, or 10 pm on August 10, 2010, and zero otherwise. This applies to all models.

θ_2 = the coefficient parameter associated with the DLC_SNAPBACK variable. This applies to all models.

Results—Direct Load Control Impacts

The parameter estimates and standard errors for the eight models shown in Table 13 are, for reasons of space, shown in detail in Appendix B – Parameter Estimates – DLC Impact Estimation.

After having estimated the models, Navigant then calculated the average consumption of the 476 PSP participants also participating in the DLC program for the hours of curtailment (1 pm to 5 pm, August 10) and for the hours in which the snapback effect is expected to happen. The parameter estimates[19] were then applied to these averages to calculate the implied absolute average level of demand impact (kW) during the curtailment and snapback periods (for the log models A2, B2, C2, and D2) and the implied percentage impacts (for the non-log models A1, B1, C1, and D1).

In Table 14, the impacts drawn directly[20] from the parameter estimates are in standard text, whereas implied or calculated impacts are in italics. Thus, for example, for model A1, the parameter estimate on DLC_EVENT is -0.58. The average hourly demand during the curtailment period was 2.43 kW. From these two values the implied average demand in each hour of the curtailment period absent the DLC curtailment event may be calculated: 2.43 – (-0.58) = 3.01. The parameter estimate on DLC_EVENT in this model implies that, absent the DLC event in those hours, the average level of hourly demand between 1 pm and 5 pm on August 10 amongst DLC participants who began participating before August 10 would have been 3.01 kW.

From this value, the average percentage reduction attributable to the DLC curtailment may be calculated as -19% = (-0.58/3.01).

[19] Or in the case of the log models (A2, B2, C2, and D2) the parameter estimates processed as required – see Appendix B for details.

[20] In the case of the log models with some minimal post-processing required for interpretation, see Appendix B for details.

Table 14. Estimated and Implied Impacts

Model	Period	Avg. Consumption During Relevant Hours of Curtailment Day	Percentage Impact	Avg kW Impact	Implied Avg. Hourly Consumption Absent DLC
A1	Curtailment	2.43	*-19%*	-0.58	*3.01*
A1	Snapback	4.07	*26%*	0.84	*3.24*
A2	Curtailment	2.43	-17%	*-0.51*	*2.94*
A2	Snapback	4.07	32%	*0.99*	*3.08*
B1	Curtailment	2.43	*-23%*	-0.72	*3.15*
B1	Snapback	4.07	*25%*	0.82	*3.25*
B2	Curtailment	2.43	-18%	*-0.52*	*2.95*
B2	Snapback	4.07	32%	*0.99*	*3.08*
C1	Curtailment	2.43	*-21%*	-0.66	*3.09*
C1	Snapback	4.07	*23%*	0.77	*3.31*
C2	Curtailment	2.43	-19%	*-0.57*	*3.00*
C2	Snapback	4.07	31%	*0.97*	*3.10*
D1	Curtailment	2.43	*-23%*	-0.71	*3.14*
D1	Snapback	4.07	*23%*	0.77	*3.31*
D2	Curtailment	2.43	-19%	*-0.56*	*2.99*
D2	Snapback	4.07	31%	*0.97*	*3.10*

Source: Navigant analysis

Which model best represents the reality?

To select from amongst the eight models the one that is likely doing the best job in estimating the impact of both the curtailment and the snapback effect, Navigant turned back to the hourly summer data for DLC participants that became active before summer 2010's single curtailment event.

Readers should note that the comparable hours used for this section of the analysis are *not* calculated in the same way as the comparable days used to produce Figure 18 and Figure 19, above. First, the average THI was calculated for each hour of the curtailment day. Each hour-of-day average THI value thus calculated was compared with all of the hourly THI observations within the sample by hour.

Algebraically:

$\bar{z}_h$ = the average THI observed by DLC participants in hour *h* (where h takes on a value between 1 and 24 for the 24 hours on the curtailment day) on the curtailment day. This variable has 24 observations.

$x_{i,d,h}$ = the THI observed by participant i in hour h (where h takes on a value between 1 and 24) on day d. This variable has 1,031,494 observations – one for each hour and each participant over the three months of summer 2010.[21]

These two series of values were then compared in order to create a data set of comparable values. A participant's hourly observations (consumption and THI) were retained only if the THI they observed in a given hour of the day was within 10 percent of the average THI observed in that same hour of the day on the curtailment day.

Algebraically, hourly observations of kWh consumption and THI were retained in the data set when:

$$x_{i,d,h} > 0.9 \times \bar{z}_h$$

OR

$$x_{i,d,h} < 1.1 \times \bar{z}_h$$

For example, the average THI impacting DLC participants in the hour ending 14 (1 pm to 2 pm) on August 10 was compared with all other observed THI that occurred between 1 pm and 2 pm throughout the sample. Those participant-hours (recall that THI may be different for different participants in the same hour) in which the THI was more than 10 percent higher or less than 10 percent lower than the average THI between 1 pm and 2 pm on August 10 were rejected from the sample. Those within the ±10 percent band were retained.

Note that for each THI observation retained, there is a corresponding hourly kWh consumption (or average hourly kW demand) observation also retained.

With the remaining sample of hourly data, those observations that occurred at the same time of day as the curtailment event (i.e., between 1 pm and 5 pm) were flagged as comparable hours for the curtailment period. Those observations that occurred at the same time of day as the snapback period (between 5 pm and 10 pm) were flagged as comparable hours for the snapback period.

This process may be thought of in the following manner: all $kWh_{i,d,h}$ observations, which were retained according to the criteria above, for which h = 14,15,16 or 17 (i.e., 1 pm to 5 pm) were pooled together as being comparable to the curtailment hours, and all $kWh_{i,d,h}$ observations, which were retained according to the criteria above, for which h = 18, 19, 20, 21 or 22 (i.e., 5 pm to 10 pm) were pooled together as being comparable to the snapback hours. The average of each pool (curtailment and snapback period) was then calculated. These two averages are, respectively:

» The average hourly consumption (or average of average hourly kW demands) observed in hours of comparable heat and humidity to those observed in the August 10 curtailment period,

[21] Note that this is somewhat fewer observations than would be expected given 24 hours per day, 92 days in June, July, and August and 476 participants. To permit the estimation of the semi-log models, all observations of all variables corresponding with kWh consumption observations that were not greater than zero were dropped.

on non-DLC control event days. This average is a reasonable approximation of the average hourly consumption that might have been observed to occur during the curtailment period of the event day had no event been called.

» The average hourly consumption (or average of average hourly kW demands) observed in hours of comparable heat and humidity to those observed in the August 10 snapback period, on non-DLC control event days. This average is a reasonable approximation of the average hourly consumption that might have been observed to occur during the snapback period of the event day had no event been called.

These averages are presented in Table 15.

Table 15. Comparable Hourly Demands

Average Demand (kW) between 1pm and 5pm for participant-hours in which the observed THI is within 10% of the average THI of the corresponding hour on the curtailment day.	**3.15**	kW
Average Demand (kW) between 5pm and 10pm for participant-hours in which the observed THI is within 10% of the average THI of the corresponding hour on the curtailment day.	**3.36**	kW

Source: Navigant analysis

Comparing these results with the far-right column of Table 14, the model that appears to best mimic what would likely have occurred – given observed levels of temperature and humidity – is model D1.

The estimated impacts in this model imply that without the DLC curtailment event, the average hourly demand during the curtailment period (1 pm to 5 pm) would have been 3.14 kW – nearly the same as suggested by the averages calculated in Table 15. The estimated impacts also imply that without the DLC curtailment event, the average hourly demand during the snapback period (5 pm to 10 pm) would have been 3.31 kW – the closest any of the implied model-estimated results come to the averages shown in Table 15.

The best model, as determined in the fashion above, estimates that the impact of the curtailment event is an average reduction in average hourly demand of 0.71 kW (or, alternatively, an average reduction in hourly consumption of 0.71 kWh) over the four hours of the event and that the impact of the snapback effect is an average increase in average hourly demand of 0.77 kW (or, an average increase in hourly consumption of 0.77 kWh) over the five hours of the snapback period. The standard errors of both estimates are so small, and the number of observations from which the impacts were estimated so large, that the 90 percent confidence interval may be observed only at the fourth digit past the decimal. The upper and lower confidence intervals are, therefore, identical to the point estimates once rounded to the second digit past the decimal, as the results presented above are.

Having chosen this model, the singularly counterintuitive result that is common to all of the models must be addressed. How is it possible that the snapback effect is both greater in magnitude (average demand increases by 0.77 kW compared with a reduction of 0.71) and lasts longer (five hours instead of four) than the curtailment event?

The most likely explanation is that there are two components to the snapback effect. The first component is the traditionally understood technological snapback whereby the central A/C unit must work to restore the house's humidity and temperature to the original thermostat set point. If this were the only component to the snapback effect, the expectation would be that the snapback effect would be bounded in terms of demand by what had been curtailed, and in terms of time by the length of curtailment.

There is, however, almost certainly a human component involved. Participants in the DLC program were not informed when their A/C units would be cycled and their consumption would be curtailed. As such, it seems highly probable that the participants noticed only that their homes were becoming more humid or hotter than was comfortable. The natural response to the discomfort of a home that is too warm and/or too humid is to adjust the thermostat of the air-conditioning unit to a cooler temperature. This made little difference during the curtailment period; however, following the end of that period, the A/C unit would then have had to recover not just to the original set point but to the new, lower temperature set by the DLC participant.

Given the consistency of the impact estimates, and the observations made based on the plots shown above, this seems the most reasonable explanation for the apparently excessive snapback.

If it is important to mitigate this snapback effect, Navigant would recommend introducing some form of day-ahead participant alert to inform PSP DLC participants when curtailment events will take place. Participants will then be able to pre-cool their homes during the morning hours when capacity is not at a premium and likely significantly mitigate the snapback effect occurring in the late afternoon and early evening.

3.3 Conservation Effects

The main purpose of allowing the price of electricity faced by residential consumers to fluctuate hourly is to promote demand response (shifting of energy use), not necessarily energy conservation (reduction in total energy use). A program designed to induce consumers to practice more energy conservation would necessarily require that the price of electricity become higher at every hour of the year, as opposed to the PSP program in which the price faced by participants is sometimes higher and sometimes lower than that paid by non-participants. There is some evidence to suggest, however, that the PSP program has induced participants to, on average, conserve more energy than they otherwise might have in some seasons, if not for the year as a whole.

For this final year of the PSP evaluation study, Navigant has used all of the monthly PSP and control group participants' consumption data that it has accumulated over the course of this study to estimate the magnitude of the conservation effect. The first observation in the data set used for this part of the evaluation begins January 1 of 2007 and ends January 26 of this year. Navigant believes that the estimated average conservation impacts are therefore quite robust, given the seasonal variation in weather that Ameren Illinois consumers have experienced over that time. The number of Ameren Illinois customers in the control and participant groups used in this analysis, as well as the first and last dates of data available, are shown in Table 16.

Table 16. Customers in Sample

	Number of Participants	First Date of Data	Last Date of Data
Control Group	953	1-Jan-07	26-Jan-11
PSP Participants	11,471	1-Jan-07	25-Jan-11

Source: Navigant analysis

3.3.1 Methodology

The conservation impact was estimated using four linear fixed-effects regression models. Using fixed effects allows the analyst to control for individual heterogeneity without explicitly modeling time-invariant household characteristics by, in effect, assigning a dummy variable to each household in the sample and thus, to a degree, controlling for each individual's conditional average level of consumption. In this way, the analyst does not need to control for household characteristics that are time invariant, such as a house's size, the direction it faces, and the quality of its building envelope.

Four models were estimated, one for each season. The generalized equation used to estimate the conservation impacts was:

$$y_{i,t} = \alpha_i + \beta_1 HDD_{t,l} + \beta_2 THI_{t,l} + \beta_3 PSP_{i,t} + \beta_4 \left(PSP_{i,t} \times THI_{t,l} \right) + \beta_5 \left(PSP_{i,t} \times HDD_{t,l} \right) + \varepsilon_{i,t}$$

where

$y_{i,t}$	= the natural log customer *i*'s average daily consumption (kWh) in billing period *t*.
α_i	= the fixed effect that applies to customer *i*.
$HDD_{t,l}$	= the average number of heating degree days (HDDs) experienced by customer *i* in billing period *t*
β_1	= the coefficient parameter associated with the HDD variable
$THI_{t,l}$	= the average temperature humidity index experienced by customer *i* in billing period *t*. The manner in which this index is calculated may be found in section 0.
β_2	= the coefficient parameter associated with the THI variable
$PSP_{i,t}$	= a dummy variable equal to one if customer *i* is participating in the PSP program during billing period *t*
β_3	= the coefficient parameter associated with the PSP dummy variable

β_4 = the coefficient parameter associated with the product of the THI and PSP variables. Like cooling degree hours (to which the THI is very similar in terms of the effect it captures), this variable is equal, or very close, to zero for many of the winter months. There is no theoretical reason to presume that the very small fluctuations in this variable would affect energy conservation by PSP customers in the winter. For this reason, this parameter is estimated only for the spring, summer, and autumn months.

β_5 = the coefficient parameter associated with the product of the HDD and PSP variables. For much of the summer period, this variable is equal, or very close, to zero. There is no theoretical reason to presume that the very small fluctuations in this variable would affect energy conservation by PSP customers in the summer. For this reason, this parameter is estimated only for the winter, spring, and autumn months.

One possible confounding factor for the estimation of the conservation effect is the participation of PSP participants in other Ameren Illinois energy efficiency programs. Ameren Illinois provided Navigant with the customer account numbers, the first date of energy efficiency program participation, and the estimated annual kWh savings for each participant by program. Navigant assigned energy savings achieved by customers participating in the Home Energy Performance, Appliance Recycling Centers of America, Inc. (ARCA) Appliance Recycling and Lighting and Appliances programs pro rata for the entire period in which they participated in the given energy conservation program. For the Heating, Ventilating, and Air-Conditioning (HVAC) and Demand Response[22] programs, savings were assigned only in the 92 days of summer, based on the average THI experienced by that customer in a given billing period.

The savings achieved by PSP participants while they were participating in the PSP program, according to savings numbers provided by Ameren Illinois, are shown in Table 17. The numbers of PSP participants that achieved savings through the various energy efficiency programs, by program, are shown in Table 18.

Table 17. Annual Energy Conservation by PSP Participants, By Year

(kWH)	Home Energy Performance	ARCA Appliance Recycling	HVAC New	Lighting & Appliances	Demand Response
2009	12,407	200,965	17,536	29,445	35
2010	82,337	713,032	572,753	132,404	60,306

Source: Navigant analysis

[22] Although the demand response is not, strictly speaking, an energy conservation program, Ameren has estimated that this program achieves a certain amount of energy conservation through encouraging thermostat set-back by participants.

Table 18. End-of-Year PSP Participants by EE Program

(No. of Participants)	Home Energy Performance	ARCA Appliance Recycling	HVAC New	Lighting & Appliances	Demand Response
2009	105	228	45	187	158
2010	249	456	217	548	713

Source: Navigant analysis

During the initial exploratory analysis carried out by Navigant, these PSP participants that participated in other energy conservation programs were included in the regression. This was found to have a confounding effect on the estimation, resulting in higher standard errors than when they were excluded from the sample. Given the very large sample size, Navigant therefore decided it was prudent to exclude all customers participating in other energy efficiency programs from the estimation in order to get a cleaner estimate of the actual PSP-induced conservation effect.

3.3.2 Results

It has been the convention in many impact evaluations of demand response and conservation technologies and pricing schemes, when estimating those impacts with a semi-log model,[23] to report the parameter estimates of dummy variables – such as the PSP participation dummy variable – as the percentage impact of the treatment represented by this dummy variable.

Conceptually, however, the parameter estimate represents the impact on the dependent variable of a marginal – or very small – change in the independent variable. Because a dummy variable carries only two possible values by construction, interpreting the parameter estimate in this manner can slightly distort the true estimated percentage impact. Parameter estimates on dummy variables in a semi-log model must therefore be transformed slightly in order to capture the estimated percentage impact of a treatment. Recall, the equation estimated was:

$$y_{i,t} = \alpha_i + \beta_1 HDD_{t,l} + \beta_2 THI_{t,l} + \beta_3 PSP_{i,t} + \beta_4 \left(PSP_{i,t} \times THI_{t,l} \right) + \beta_5 \left(PSP_{i,t} \times HDD_{t,l} \right) + \varepsilon_{i,t}$$

Because $y_{i,t}$ is the natural log of the average daily kWh consumption of customer *i* in billing period *t*, and if we define $z_{i,t}$ as simply the average daily kWh consumption of customer *i* in billing period *t*, then this implies that:

$$e^{y_{i,t}} = z_{i,t}$$

Applying this transformation to the equation above:

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[23] A semi-log model is one in which the dependent variable – that on the left-hand side of the equation – is the natural log of the behavior of interest, whereas the independent variables are not natural logs. This is to capture the hypothesized nonlinear relationship between the independent and dependent variables. Traditionally, parameter estimates on the independent variables are treated as a percentage impact. For example, if independent variable X_1's associated estimated coefficient was 0.04, then this would be interpreted as an increase in X_1 of one would lead to a 4% increase in the dependent variable, all other things being equal.

$$z_{i,t} = e^{\alpha_i + \beta_1 HDD_{t,l} + \beta_2 THI_{t,l} + \beta_3 PSP_{i,t} + \beta_4 (PSP_{i,t} \times THI_{t,l}) + \beta_5 (PSP_{i,t} \times HDD_{t,l})}$$

Which may itself be transformed to:

$$z_{i,t} = e^{\alpha_i + \beta_1 HDD_{t,l} + \beta_2 THI_{t,l}} e^{\beta_3 PSP_{i,t} + \beta_4 (PSP_{i,t} \times THI_{t,l}) + \beta_5 (PSP_{i,t} \times HDD_{t,l})}$$

The first exponent defines the baseline consumption absent the PSP program, whereas the second defines the incremental impact of participation in the PSP program. Therefore, the equation above may be redefined as:

$$z_{i,t} = z_{i,t}^{BASELINE} e^{\beta_3 PSP_{i,t} + \beta_4 (PSP_{i,t} \times THI_{t,l}) + \beta_5 (PSP_{i,t} \times HDD_{t,l})}$$

Savings, or conservation due to the PSP program, may therefore be written as:

$$z_{i,t} - z_{i,t}^{BASELINE} = z_{i,t}^{BASELINE} \left(e^{\beta_3 PSP_{i,t} + \beta_4 (PSP_{i,t} \times THI_{t,l}) + \beta_5 (PSP_{i,t} \times HDD_{t,l})} - 1 \right)$$

With percentage implied consumption reduction defined as:

$$\frac{z_{i,t} - z_{i,t}^{BASELINE}}{z_{i,t}^{BASELINE}} = e^{\beta_3 PSP_{i,t} + \beta_4 (PSP_{i,t} \times THI_{t,l}) + \beta_5 (PSP_{i,t} \times HDD_{t,l})} - 1$$

The parameters estimated by season are presented in Table 19. Red-shaded cells indicate parameter estimates that are not statistically significant.

Table 19. Conservation Effect Parameter Estimates

Season	Parameter Estimates					Standard Errors				
	HDD	THI	PSP Dummy	PSP Dummy x THI	PSP Dummy x HDD	HDD	THI	PSP Dummy	PSP Dummy x THI	PSP Dummy x HDD
SUMMER	-0.04129	0.07707	-0.02155	-0.00185	N/A	0.00255	0.00075	0.00558	0.00091	N/A
SPRING	0.01281	0.12382	-0.01844	0.00346	0.00028	0.00019	0.00163	0.00520	0.00224	0.00030
AUTUMN	0.01313	0.11880	-0.03425	0.00215	0.00025	0.00023	0.00145	0.00581	0.00216	0.00032
WINTER	0.00496	-1.17841	0.05305	N/A	0.00096	0.00027	0.06939	0.01571	N/A	0.00042

Source: Navigant analysis

The estimated impacts are all of the expected sign: the parameter estimates for the PSP dummy variables are negative for summer, spring, and autumn (indicating savings) and positive for winter (indicating increased consumption).

In last year's report on the conservation effect of the PSP program, Navigant's estimates for the conservation effect in the winter were described as not valid; however, it was speculated that given the estimated savings values observed in the summer and shoulder seasons, and those estimated for the entire year, that winter savings would be negative. That is, the estimates obtained in the second year of the study strongly implied that PSP participants on average consumed *more* electricity in the winter months than they would otherwise have done had they not been involved with the PSP program.

Using the entire sample of monthly consumption data from 2007 through the end of 2010, for the final year of the PSP evaluation study, Navigant was able to obtain statistically significant estimates of the PSP impact on consumption in all four seasons, which appears to confirm the hypothesis that energy conservation as a result of PSP in the summer is to some degree offset by increased consumption in the winter months.

The fact that neither of the interactive dummy coefficient parameters for spring or autumn were significant suggests that the weather in those seasons has no discernable impact on the conservation effect.[24] Intriguingly, the parameter estimate for the PSP Dummy x HDD interactive term in the winter was significant. This was not an expected result. Given that fewer than 2 percent of PSP participants use electricity as their principal fuel for space-heating, the initial expectation was that this estimate would not be significantly different from zero. Even when participants for whom the principal fuel for space heating was electricity were excluded, the results were very close to those presented above, and statistically significant. It is impossible to say for certain what is behind this result, but some credible hypotheses do present themselves. Although more than 98 percent of the PSP participants do not use electricity as their primary fuel for space heating, it is very likely that many, or even most of them, do use electricity for secondary space heating – in bathrooms or garage workshops, for example. Lower weekend prices, a general feeling that winter electricity prices are a bargain compared to summer prices, or a misunderstanding of the average way in which hourly prices fluctuate in the winter[25] may have led to an increased use of secondary electric space heating in the winter, resulting in participants consuming more than they otherwise might have.

In order to calculate the percentage impact, and thus the average seasonal kWh impact, the average level of heating degree days (for the winter) and temperature humidity index (for the summer) are required. Weather data was applied to PSP participants based on to which of the six possible weather regions a given PSP participant was assigned. Impacts therefore will be presented by weather region. The average THI (summer) and HDD (winter) are presented by region in Table 20.

[24] This is not to say that the weather does not affect consumption – the significant parameter estimates on the HDD and THI variables indicate that weather does affect consumption – just that it does not affect the amount of energy PSP participants conserve.

[25] In the winter months prices are typically highest in the mornings before most people leave for work, and in the early evening after they return.

Table 20. Daily Average of Weather Variables by Region

Weather Region	Average Summer THI	Average Winter HDD
BELLEVILLE	7.1	33.7
DECATUR	5.9	37.8
MARION	7.3	30.6
PEORIA	5.1	40.5
SPRINGFIELD	5.8	37.6
ST. LOUIS	7.7	33.0

Note: The "St. Louis" weather region is used for East St. Louis loads.
Source: Navigant analysis

The distribution of number of customers and total consumption over the period of analysis are presented in Table 21.

Table 21. Distribution of Participants and Total Consumption by Weather Region

		BELLEVILLE	DECATUR	MARION	PEORIA	SPRINGFIELD	ST. LOUIS
Number of Customers	Control	133	131	69	307	262	51
	PSP Participants	2,794	3,337	646	2,013	2,526	155
Percentage of Consumption	Control	15%	10%	8%	31%	31%	6%
	PSP Participants	27%	29%	6%	16%	20%	1%

Note: The "St. Louis" weather region is used for East St. Louis loads.
Source: Navigant analysis

The average percentage conservation effect impact by weather region and season and the consumption-weighted average annual impact by region and for the entire Ameren Illinois territory are presented in Table 22.

Table 22. Average Percentage Impact by Region

Season	Percentage Impact by Region						Overall Percentage Impact
	BELLEVILLE	DECATUR	MARION	PEORIA	SPRINGFIELD	ST. LOUIS	
SUMMER	-3.4%	-3.2%	-3.4%	-3.1%	-3.2%	-3.5%	-3.2%
SPRING	-1.8%	-1.8%	-1.8%	-1.8%	-1.8%	-1.8%	-1.8%
AUTUMN	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%
WINTER	8.9%	9.3%	8.6%	9.6%	9.3%	8.8%	9.2%
Annual Impact (%)	**0.1%**	**0.3%**	**0.0%**	**0.4%**	**0.3%**	**0.0%**	**0.2%**

Note: The "St. Louis" weather region is used for East St. Louis loads.
Source: Navigant analysis

The average kWh conservation effect impact by weather region and season and the total annual impact by region and for the consumption-weighted seasonal impact for the entire Ameren Illinois territory are presented in Table 23.

Table 23. Average kWh Impact by Region

Season	Avg Seasonal Impact (kWh)						Overall Seasonal kWh Impact
	BELLEVILLE	DECATUR	MARION	PEORIA	SPRINGFIELD	ST. LOUIS	
SUMMER	-146	-136	-148	-130	-136	-151	-139
SPRING	-47	-47	-47	-47	-47	-47	-47
AUTUMN	-94	-94	-94	-94	-94	-94	-94
WINTER	300	313	290	322	312	298	309
Annual Impact (kWh)	**13**	**36**	**1**	**50**	**35**	**6**	**29**

Note: The "St. Louis" weather region is used for East St. Louis loads.
Source: Navigant analysis

As can be seen in Table 22 and Table 23, although the PSP pricing is provoking a conservation effect amongst participants in the shoulder seasons and summer, this is offset on an annual basis by the increase in winter consumption due to the program.

The overall effect—an average annual increase in participants' consumption by approximately 29 kWh—is, however, trivial, in comparison with the average level of consumption per customer per year. Indeed, the statistical significance of the interaction terms for the winter and summer impact estimates and the results shown above, suggest that it is very likely that if in the future winters were to become milder and summers warmer and more humid, that the PSP program could induce a mild conservation effect.

Given the results of this multiyear study, Navigant recommends that the conservation effect be considered zero on average for the PSP program.

3.4 Bill Savings

In 2010 the aggregate savings for PSP participants was $1,724,959.78, which represents a 12.35 percent total savings compared to what the same bills would have been under the standard rate. Average annualized savings were $188.31 or 12.83 percent.[26] Average customer savings were negative in July and August, primarily due to a very hot summer and moderate hourly electricity prices.

3.4.1 Methodology

The two methods, aggregate savings and average annualized savings, used to calculate the 2010 PSP savings were the same as those used to calculate the 2008 and 2009 PSP savings. Only the aggregate savings method was used for 2007 PSP savings reporting, due to less than a full year of PSP bills (PSP

[26] Due to the growing enrollment levels over the course of the year, the overall savings percentage and the annualized average savings percentage are not the same. Annualized savings represent what the average customer would have paid if they were on the program for all 12 months of 2009.

promotional campaigns didn't start until October 2007, after the rate relief settlement) and the resultant small number of months of participants' bills. CNT Energy recalculated PSP bills to show what they would have been under the appropriate Ameren Illinois standard rate and the difference between the two was the savings (either positive or negative). Distribution charges and taxes are the same for PSP customers and standard rate customers, and were not changed. The recalculation took into account the line items in the Electric Supply portion of the bill.

Within that section, several line items (the Market Value Adjustment, the Supply Cost Adjustment, and the General Assembly Rate Relief Credit) remained the same. The hourly energy charges were replaced by multiplying the monthly kWh by the appropriate summer/non-summer standard rate tariff (prorated as needed for bills that spanned both periods), and the Transmission Service Charge was recalculated to be on a kWh basis rather than a kW-day basis. The recalculated standard rate bills also did not include the $2.25 PSP Participation Charge or the RTP Supplier Charge.

3.4.2 Results

Table 24 shows the average monthly bill and savings/loss for all PSP customers. The summer losses are the result of a very hot summer that caused an increase in customer electricity usage during peak price hours. The large early and late year savings were the direct result of low energy prices that were seen in the market and passed through directly to PSP participants.

Table 24. Overall Average Bill Impacts for 2010

Month	Usage (kWh)	Total Cost with PSP**	Total Cost with Standard Rate**	Cost Savings with PSP	Percent Savings
January	1,155	$102.49	$122.66	$20.17	16.44%
February	1,016	$89.66	$110.79	$21.13	19.08%
March	823	$69.50	$94.07	$24.57	26.12%
April	740	$61.83	$85.41	$23.58	27.61%
May	933	$85.91	$103.96	$18.05	17.37%
June	1,429	$151.41	$157.30	$5.89	3.75%
July	1,630	$181.33	$178.38	($2.95)	-1.66%
August	1,559	$171.11	$168.94	($2.17)	-1.28%
September	1,089	$107.08	$119.62	$12.54	10.48%
October	807	$71.83	$88.73	$16.90	19.05%
November	942	$79.58	$103.10	$23.51	22.81%
December	1,277	$107.72	$134.79	$27.08	20.09%
Totals:	**13,400**	**$1,279.45**	**$1,467.76**	**$188.31**	**12.83%**

Source: CNT Energy analysis

If savings/losses are broken out by utility, the impact of the various underlying standard rates (and the special Space Heat rates) can be seen in Tables 24, 25, and 26.

Savings for Ameren Illinois CIPS customers were higher than for Ameren Illinois IP customers, in large part because the underlying standard rates for Ameren Illinois CIPS were higher, in particular the non-summer first 800 kWh block (5.936 cents/kWh versus 5.619 cents/kWh).

Table 25. Ameren Illinois IP and Ameren Illinois CIPS Monthly Bill Savings for 2010

	Ameren Illinois IP (non-space heat)			Ameren Illinois CIPS (non-space heat)		
	Avg. kWh	Savings/ (Loss)	Savings / (Loss) %	Avg. kWh	Savings/ (Loss)	Savings/ (Loss) %
January	1,190	$20.20	15.55%	1,141	$25.04	21.04%
February	1,029	$20.64	17.92%	1,062	$25.88	23.02%
March	835	$23.72	24.18%	847	$28.86	31.06%
April	758	$23.28	25.91%	746	$26.14	31.7%
May	950	$18.09	16.54%	971	$20.58	19.94%
June	1,460	$6.02	3.58%	1,489	$6.63	4.33%
July	1,660	($3.09)	-1.62%	1,679	($3.11)	-1.81%
August	1,583	($2.26)	-1.26%	1,602	($2.06)	-1.27%
September	1,105	$12.51	9.85%	1,130	$13.68	11.78%
October	816	$16.54	17.83%	836	$19.60	22.32%
November	944	$23.07	21.4%	989	$27.65	26.81%
December	1,289	$27.40	19.28%	1,330	$32.45	23.82%
Totals:	**13,618**	**$ 186.12**	**12.0%**	**13,823**	**$ 221.35**	**15.4%**

Source: CNT Energy analysis

Ameren Illinois CILCO and Ameren Illinois CIPS-ME do not have special Space Heat rates and instead all standard rate customers pay a very low charge for non-summer usage over 800 kWh (3.775 cents/kWh and 1.984 cents/kWh, respectively).

Table 26. Ameren Illinois CILCO and Ameren Illinois CIPS-ME Monthly Bill Savings for 2010

	Ameren Illinois CILCO			Ameren Illinois CIPS-ME		
	Avg. kWh	Savings/ (Loss)	Savings/ (Loss) %	Avg. kWh	Savings/ (Loss)	Savings/ (Loss) %
January	970	$15.74	16.4%	1,058	$10.10	10.39%
February	839	$17.56	20.1%	904	$14.85	16.62%
March	708	$22.22	28.56%	759	$20.87	26.2%
April	634	$21.09	29.91%	676	$21.20	29.03%
May	794	$14.42	17.49%	835	$11.94	14.01%
June	1,189	$4.48	3.81%	1,424	$2.71	1.91%
July	1,421	($2.27)	-1.63%	1,602	($2.53)	-1.55%
August	1,374	($2.06)	-1.55%	1,517	($2.57)	-1.66%
September	956	$10.72	11.28%	986	$10.57	10.3%
October	720	$14.07	19.05%	719	$12.84	16.99%
November	840	$18.88	22.57%	785	$16.47	20.4%
December	1,098	$18.22	18.0%	1,054	$12.50	12.63%
Totals:	**11,542**	**$ 153.07**	**13.2%**	**12,320**	**$ 128.94**	**10.4%**

Source: CNT Energy analysis

There were 218 PSP customers eligible for the special standard rate Space Heat rates, had they not switched to PSP. For those customers, many experienced their lowest savings (or loss) in winter and summer months. But former Space Heat customers with moderate usage were still able to save money during the winter. Overall savings for Ameren Illinois CIPS former Space Heat customers were greater than Ameren Illinois IP Space Heat customers because of the difference in space heat rates for usage greater than 800 kWh (3.402 cents/kWh and 1.931 cents/kWh, respectively).

Table 27. Ameren Illinois IP and Ameren Illinois CIPS Former Space Heat Customers' Monthly Bill Savings for 2010

	Ameren Illinois IP Former Space Heat			Ameren Illinois CIPS Former Space Heat		
	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %	Avg kWh	Savings/ (Loss)	Savings/ (Loss) %
January	1,490	($11.27)	-9.16%	1,977	$1.58	1.02%
February	1,265	$0.17	0.15%	1,778	$6.16	4.28%
March	910	$12.68	13.59%	1,224	$20.83	18.9%
April	797	$15.08	18.01%	871	$23.93	27.33%
May	852	$9.85	10.9%	964	$17.17	17.76%
June	1,193	$2.86	2.11%	1,447	$6.40	4.38%
July	1,421	($0.71)	-0.43%	1,543	($0.44)	-0.27%
August	1,363	($1.41)	-0.89%	1,544	($0.07)	-0.05%
September	942	$10.18	9.21%	1,077	$13.21	11.88%
October	726	$10.11	12.6%	880	$15.84	18.13%
November	938	$11.67	12.25%	1,236	$21.51	19.45%
December	1,423	$5.34	4.14%	1,903	$18.56	11.87%
Totals:	**13,321**	**$ 64.56**	**4.69%**	**16,444**	**$ 144.68**	**9.5%**

Source: CNT Energy analysis

3.5 Day-Ahead Prices vs. Real-Time Prices vs. System Peak Hours

In 2008, customer perception of a discrepancy between DAP and RTP was seen as "false advertising" by customers and was considered a barrier to entry for the program. In June 2008, hourly billing for participants was switched from real-time prices to day-ahead prices for the multiple objectives of removing the barrier, increasing bill predictability, and limiting the confusion caused by two different pricing information mechanisms.

In previous evaluations of the PSP program, Navigant has investigated the relationship between day-ahead and real-time prices to determine if day-ahead prices elicit the appropriate response from participants during the hours of the summer that have the highest real-time prices. In other words, are high DAP hours aligned with high RTP hours? Those investigations showed that the two price series were sufficiently correlated that high DAP hours would generally correspond with high RTP hours.

In this year's evaluation, Navigant will take the opportunity to evaluate the DAP and RTP relationship over the full three years of the PSP program's existence: 2008 through 2010. Navigant will also investigate the relationship between prices and system loads. This is related to the observation that the dynamic pricing component of the PSP rate, the DAP, is a pure energy charge and does not contain any capacity-related costs. If DAP is not aligned with system peaks, it is possible that customers are not getting the appropriate price signals they need to help reduce system capacity costs.

In summary, then, this section will be looking for answers to the following two questions:

1. Do day-ahead prices give participants the right information to respond to real-time prices effectively?
2. Are day-ahead prices and real-time prices good indicators of system peak loads?

3.5.1 Methodology

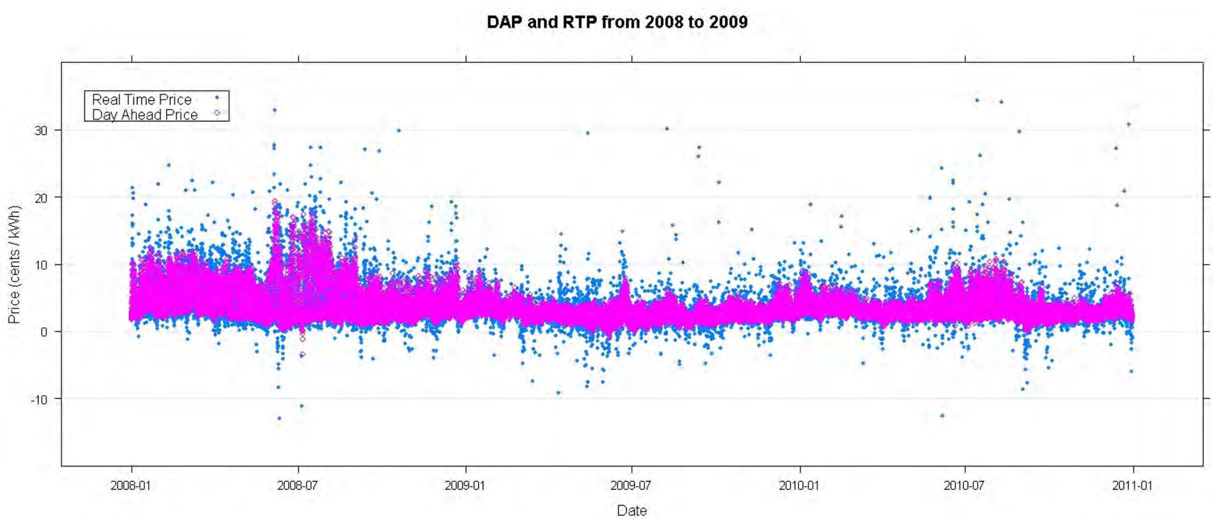
Hourly DAP, RTP, and system load data for Ameren Illinois was available for the period of 2008 through 2010. Data was plotted to start with a visual understanding of the relationship between DAP and RTP. Based on this work, subsequent analysis focused on summer (from June to September) day times (10 am to 10 pm) when prices are at their highest and are most critical for PSP participants.[27]

Correlation factors were calculated between each pair of variables to help understand the strength of their relationships to each other. To examine the reliability of the top 200 DAP hours for prediction of RTP, they were plotted against RTP values at the same hours. Predictive probabilities were then quantified to determine how often the highest values from one series predicted the highest values from the other series.

3.5.2 Results

Figure 20 is the "big picture" view of hourly DAP and RTP prices from 2008 through 2010. Due to varying weather, fuel price, and economic conditions during the period, the electricity market ran in different patterns across that time span. Both day-ahead price and real-time price varied dramatically from year to year; however, they both tended to respond in the same way to the exogenous market forces.

Figure 20. Ameren Illinois Hourly Day-Ahead and Real-Time Prices for 2008–2010



Source: Navigant analysis

Several things can be observed from the figure:

[27] See Appendix G for monthly data that justifies this selection.

1. The prices are different in each year. Prices are high in 2008, and then become low in 2009 due to mild weather conditions and economic recession. There is some price increase in 2010 with the occurrence of an extremely hot summer, but prices do not return to 2008 levels.
2. There is a seasonal variation. Summer prices are usually the highest during a calendar year.
3. The volatility of day-ahead prices and real-time prices are different. The day-ahead prices are much more regular and predictable than the RTP, which provides a protection to PSP participants from unexpected real-time price spikes. This protection is retained in every calendar year, regardless of whether the prices are low or high in general.
4. RTP prices exhibit some extreme price spikes, but the spikes are usually singular in nature, occurring for just one hour. This makes them nearly impossible to predict, or be aware of, or be responded to by a PSP participant.

Pair-wise correlation factors between the three series of interest (DAP, RTP, and Load) are shown in Table 28. The highest correlation is between DAP and RTP at 72 percent. This speaks well for using DAP as a proxy for RTP in PSP billing. The correlation is nearly as high, 69 percent, for DAP vs. Loads. This also supports the idea of using DAP for PSP billing, because it is more likely to alert customers to system peak hours than the RTP would. The correlation between RTP and system loads is only 55 percent.

Table 28. Correlation Factors for DAP, RTP, and Load

Pair	Correlation Factor
DAP vs. RTP	72%
DAP vs. Loads	69%
RTP vs. Loads	55%

Source: Navigant analysis

Although correlation factors provide a simple and general way to understand how well two series are aligned with each other, Navigant wants to know more about the ability of each series to correctly predict the high values in the other series. Navigant starts this investigation with a graphical look at the top 200 highest day-ahead prices each summer and their corresponding real-time prices between 10 am and 10 pm in June to September throughout 2008 and 2010, as shown in Figure 21.

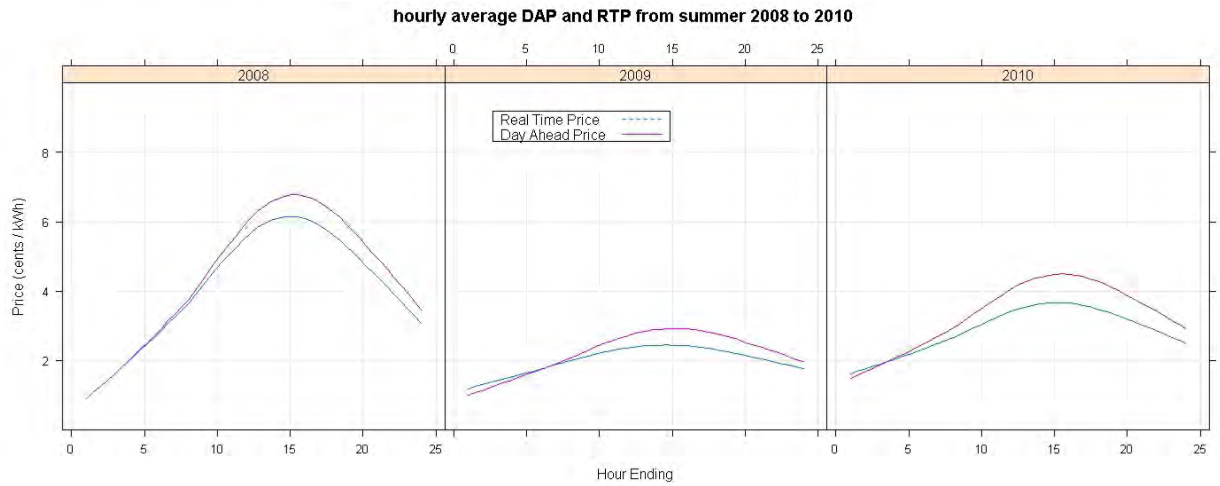
Figure 21. Correspondence of Top 200 DAP Hours to RTP

Source: Navigant analysis

We can see that the real-time prices are occasionally spiking and mostly concentrated at afternoon hours. This figure proves again that customers billed on day-ahead prices are protected from extreme random price spikes.

However, in most of these top 200 DAP hours, real-time prices are below the day-ahead prices. In fact, Figure 22 shows that across all summer days, the average DAP has consistently been a bit higher than the average RTP in the latter parts of the day.

Figure 22. Comparison of Summer Average DAP to RTP



Source: Navigant analysis

Although this difference exists in the straight comparison of the two prices, in the real operation of the market this difference is mitigated by the Revenue Sufficiency Guarantee (RSG) charge. Day-ahead demand bids provided by Ameren Illinois to MISO are financially binding. This means that the load submitted a day ahead will be assessed the day-ahead price. These purchases avoid RSG charges. Instead, RSG charges apply to unscheduled loads that are "cashed-out" at the real-time price. Ameren Illinois provides MISO a day-ahead demand bid for market purchases. Thus, the majority of the Ameren Illinois energy cost is at the day-ahead price. Forecast error is "cashed-out" at the real-time price, and is assessed the extra RSG charge. During the 2010 calendar year, MISO settlement data indicates that the DAP was on average $0.70 per megawatt-hour (MWh) lower when compared to the RTP plus RSG charges. Although it is unclear exactly how these market operations affect PSP participants, it is apparent that any claimed price differential between DAP and RTP is less than it appears to be on the surface.

The questions still remain on how well DAP prices predict the days of highest RTP prices and days of highest system loads. Appendix G presents a full set of probability tables for each year. The results for 2010 will be summarized here, and these results are fairly consistent from year to year:

1. The top 20 DAP days can correctly predict 40 percent of the top 20 RTP days.
2. The top 20 DAP days can correctly predict 65 percent of the top 20 system peak days.
3. The top 20 RTP days can correctly predict 35 percent of the top 20 system peak days.

Of most interest here is the finding that DAP is much more reliable than RTP for predicting when system peak days will occur. Because the PSP program uses DAP, customers will be correctly called to action to reduce system peaks more often than would occur using RTP. Because of the high volatility in the RTP compared to the DAP, RTP does not have a predictable relationship with either DAP or system peaks.

4 Net Benefits Assessment

Development of a method for the net benefits assessment of the PSP program began two years ago in the 2008 PSP evaluation report prepared by Navigant. After reviewing several alternatives, the 2008 report recommended the following methodology for estimating the net benefits of the PSP program in 2010:

» Create a MISO-based regression model to predict Locational Marginal Prices (LMPs) from hourly demand and other publicly available information.

» Use results from the impact evaluation of the PSP program to estimate demand reductions for different participation levels.

» Use the regression model and estimated demand reductions to estimate reduction in LMPs.

» Follow the Brattle method for estimating market benefits, but without adjusting for lost profit to suppliers.

» Add a probabilistic approach to assess future market benefits based on weather and load risks over a ten-year time frame, similar to what was done in the Summit Blue International Energy Agency study.

» Discuss additional hard-to-quantify benefits from the program, including environmental and health benefits, reductions in market power, increased reliability and power quality, and reduced price volatility.

Although the 2008 report presented a net benefits methodology for consideration, the 2009 report went one step further and presented a preview of what the net benefit assessment would look like, focusing on a realistic illustration of putting the basic methodology into action. The preview estimated single-year net benefits for the first two years of the program, 2008 and 2009. The preview offered the opportunity for a full year of review and discussion to refine the methodology before the final net benefit assessment results needed to be completed in 2010. As expected, the opportunity for careful thought and sharing of ideas led to a robust methodology for net benefits assessment that is being used in this 2010 PSP evaluation report.

The first part of this section of the report, "Estimating Market Effects", will cover work done to address items one through four. Market effects refers to the price reduction benefits that accrue to non-participants because system demand has been lowered by the program.

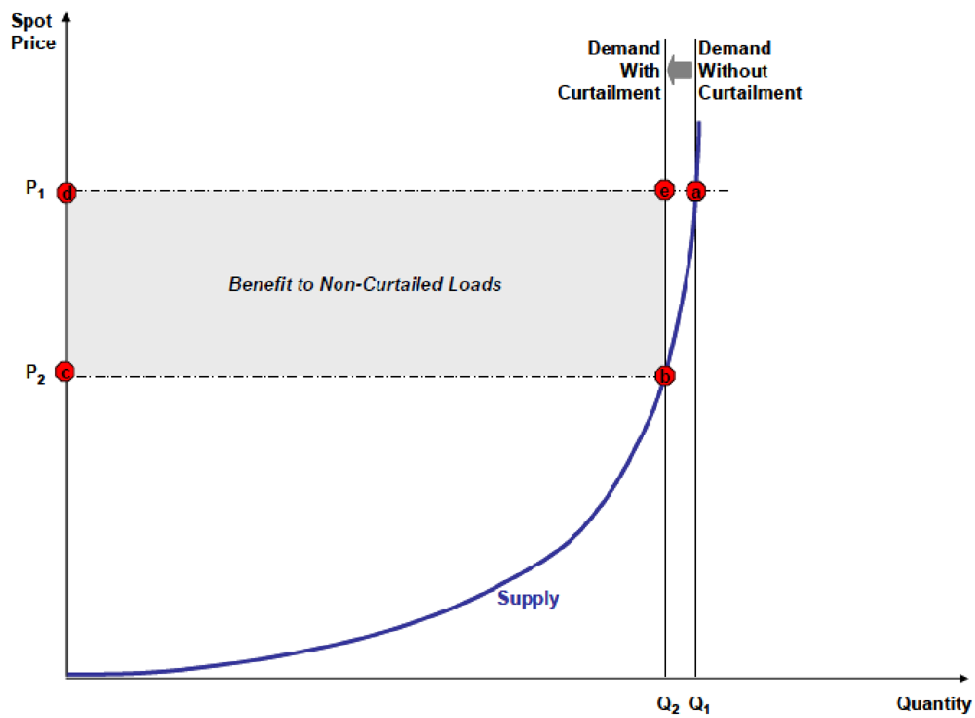
Item five, adding a probabilistic approach to assess future market benefits, is discussed in the next part of this section, titled "Summary of Program Costs and Benefits". This section provides a thorough discussion of the net benefits assessment methodology, the data that was used to forecast costs and benefits, and the net benefits results.

Item six, discussion of hard-to-quantify benefits, will be addressed in the final part of this section, titled "Other Program Benefits".

4.1 *Estimating Market Effects*

Following the approach outlined in the 2009 PSP Impact Evaluation, we use regression analysis to estimate the benefit of the PSP program that accrues to non-participants via the effect of the program on market prices. This effect is called the market effect. With reference to Figure 23, this benefit arises because a reduction in energy consumption due to the PSP program serves to reduce the LMP, and this price reduction applies to all customers in the market.

Figure 23. Conceptual Diagram of Direct Energy Benefits to Non-Curtailed Loads



Source: "Quantifying Demand Response Benefits in PJM," prepared for PJM Interconnection, LLC, and the Mid-Atlantic Distributed Resources Initiative by The Brattle Group, January 29, 2007, page 20.

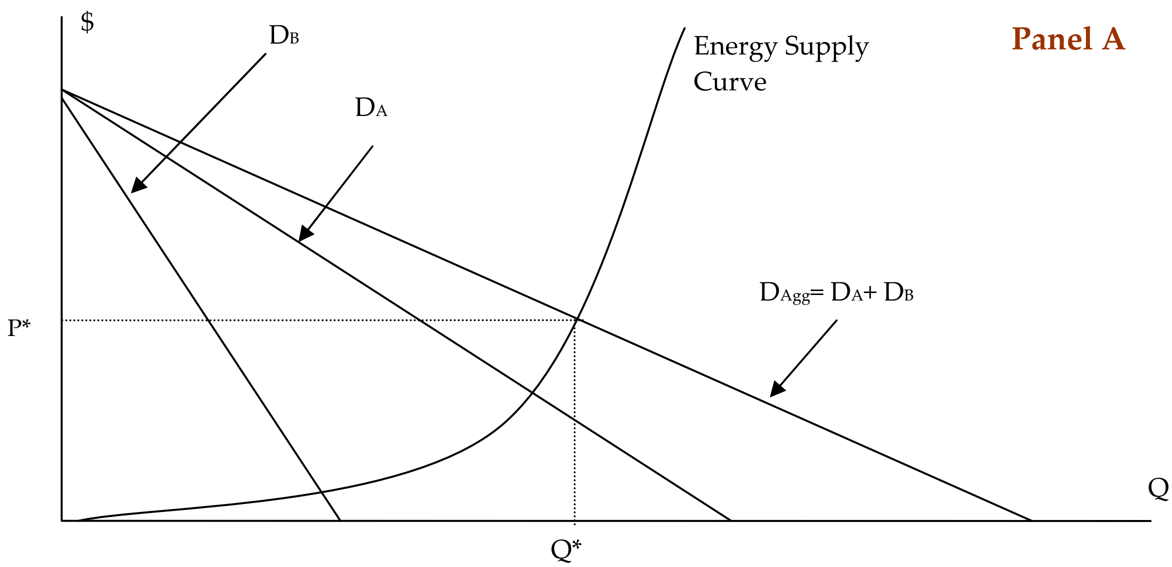
The LMPs for the Ameren Illinois service area are composed of three components: an energy price component that is the market clearing price of energy in the MISO market; a congestion price component reflecting the impact of Ameren Illinois loads on the routing of transmission to avoid congestion; and a loss component associated with transmission. In the discussion below, Navigant presents the statistical analyses used to estimate the marginal cost (i.e., supply) curves associated with each of these price components, from which the price effect of a load reduction via the PSP program can be determined in the manner illustrated in Figure 24. The energy component of the LMP is conceptually different than the congestion and loss components, because it is a MISO-wide market clearing price, whereas the congestion and loss components are essentially the result of balancing algorithms accounting for transmission costs. With this in mind, Navigant separates the discussion of the statistical estimation of the marginal cost curves for these components, discussing first the derivation of the marginal cost curve for the energy component and then discussing the derivation of the other two components.

4.1.1 Statistical Derivation of the Energy Supply (Marginal Cost) Curve

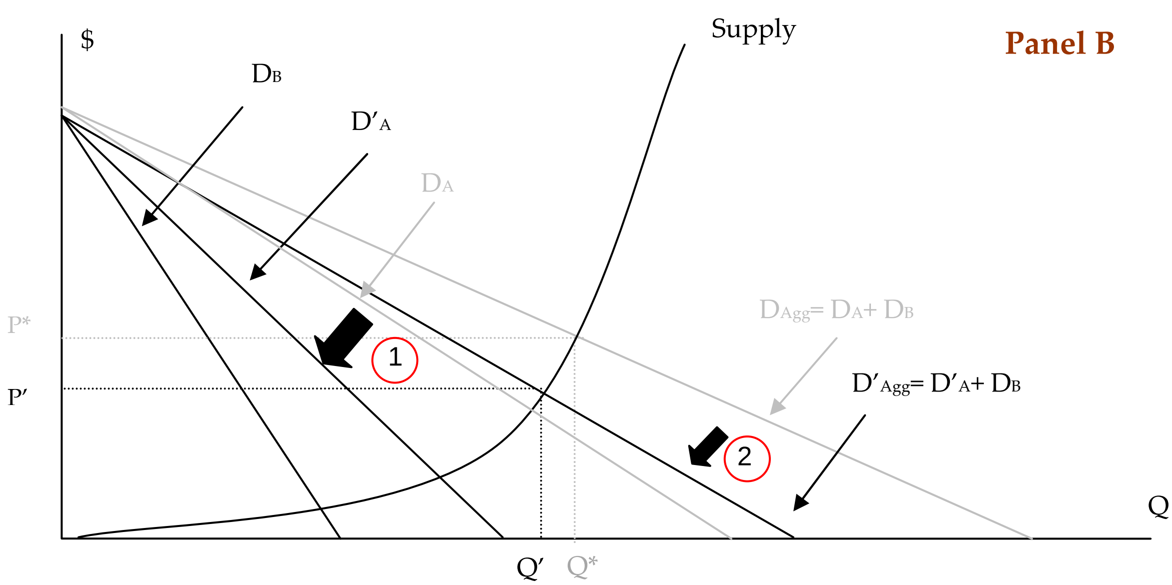
The fact that the energy price is a market clearing price implies that a demand reduction at any given hub generates a price reduction *throughout* the MISO market, because the energy price is a market clearing price for the entire MISO market. This point is illustrated in the two-hub market in Figure 24.

As shown in the figure, aggregate demand is the horizontal summation of the demands for each hub, A and B. In Panel A, the initial market clearing price P* is determined from the intersection of *aggregate* demand D_{Agg} and supply S. Panel B illustrates the overall market effect of a demand reduction program, such as the PSP program, for one of the hubs, hub A. Demand at hub A shifts down from D_A to D'_A (arrow (**1**) in the diagram), causing aggregate demand to shift down (arrow (**2**) in the diagram), which in turns moves the market clearing price from P* to P'. This price reduction applies to the entire market. In the electricity market the relationship between supply and demand is complicated by the fact that customers face a fixed price for energy, and so price is not necessarily determined by the intersection of supply and demand; however, the point remains that a downward shift in a component demand program reduces the energy price.

Figure 24. Illustration of How a Demand Reduction Influences Price in a Two-Hub Market



Source: Navigant analysis



Source: Navigant analysis

The standard supply function $Q_t(\cdot)$ takes as arguments input and output prices, as well as technological factors that may cause the supply curve to shift. Over periods short enough for little or no change in input prices (coal, natural gas) or technology factors, the function reduces to a simple relationship between the energy price and the quantity supplied at the price. Over our study horizon (2008–2010), input prices have shifted and technology may have changed; however, we avoid the necessity of fully and properly accounting for these factors by separately estimating supply equations for each of the 12 seasons of the study period. In this case, the effects of these factors are embedded in the constant term for each estimated supply equation.

Formally, we estimate for each season an inverse semi-log supply equation of the form,

$$\begin{aligned} \ln P_t &= \alpha_0 + \alpha_1 Q_t + \alpha_2 Q_{t-1} + \varepsilon_t \\ \varepsilon_t &= \rho \varepsilon_{t-1} + \phi_t, \quad \phi_t \sim IID \end{aligned} \tag{0.4}$$

Where Q_t is the MISO load in hour t, measured in gigawatts (GW); $\ln(P_t)$ is the log of real-time energy price at hour t, measured in \$/MW; Q_{t-1} is included as a technology proxy to capture the structural impediments to hourly changes in generation (e.g. high fixed costs of starting and stopping large generators); and $\boldsymbol{\varepsilon_t}$ is the error term capturing unobserved factors influencing supply. This error term is expected to be serially correlated over time, and so we model the error process as an AR(1) process. Because errors are not independent over time, estimation requires generalized (as opposed to ordinary) least squares. The elasticity of supply for the model is not constant, but instead takes the form $\frac{1}{\alpha_1 Q_t}$; the elasticity falls, in other words, as the MISO load increases. This result is consistent with the "hockey stick" shape typically expected for supply curves in the electricity market.

Estimation of the seasonal supply equations confronts two critical statistical issues arising, because the market clearing price reflects the intersection of energy supply and energy demand. The first is that the observed load Q_t , treated as an explanatory variable in (0.4), is itself a function of the observed price, because the quantity demanded by energy buyers depends on the market price P_t. To the extent this is true, coefficient estimates are biased. This particular type of bias is often called simultaneous equation bias. In the energy market, though, the demand for energy essentially is *not* a function of the energy price, because the vast majority of MISO energy users face a fixed price for energy and therefore the effect of the real-time price on the quantity of energy demanded is nominal.

A second and related issue is identification of the supply equation. A set of price-quantity data can be used to estimate either supply *or* demand, which raises the question of whether, in single-equation estimation as done here, the estimated equation truly is a supply equation, or whether it is instead a demand equation, or a conflation of demand and supply. In the energy market this issue is likely minor, because the energy supply equation is relatively stable over time, while the energy demand equation shifts dramatically in response to weather variables such as the hour of the day and the day of the week; therefore, these shifts essentially "trace out" the supply equation.[28] The logic of this "tracing out" of the

[28] In his econometrics text, Kennedy (2003) observes that a similar structural relationship in agricultural markets was unwittingly exploited by early applied economists: "Before the identification problem was recognized by economists, demand studies for agricultural products were undertaken using OLS. They gave good results, though, because the demand curve was relatively stable whereas the supply curve was quite erratic." (pg. 193) In the case at hand, the relationship is reversed –the energy supply curve is relatively stable, while the demand curve is quite variable—but the logic for identification remains the same. (*Kennedy, P. A Guide to Econometrics, 5th Edition. MIT Press, 634 pages*).

supply function requires that the analyst does not include as explanatory variables those factors expected to have much greater effects on demand than on supply, such as those mentioned above – weather variables, and indicator variables for the hour of the day.

4.1.2 Energy Supply Equation Estimation Results

Energy supply equations were estimated for each season of the program period, winter 2008–fall 2010. To illustrate the general nature of the results, Table 29 presents estimated energy supply equations for each of the three summers of the program period (June–August, 2008–2010). Results for all seasons are reported in Table 30. Results are all strongly statistically significant. Recalling that, with reference to (0.4), the price elasticity of supply is $\frac{1}{\alpha_1 Q_t}$, the load statistics in Table 29 can be used to calculate price elasticity of supply at key loads. At mean loads, the price elasticity of supply was 0.16 in 2008, 0.22 in 2009, and 0.30 in 2010. These values indicate that supply is relatively inelastic.[29] For instance, at the mean load in summer 2008, a 10 percent increase in price increases supply by approximately 1.6 percent. At the 95 percentile loads, estimated elasticities fall to 0.12 for summer 2008, 0.16, and 0.23, respectively.

The negative coefficients on the lagged MISO load indicate that, as expected, the higher the load at time t-1, the lower the price at time t, because adding and reducing load to the system is expensive and thus creates "stickiness" in the market. Consequently, supply is not as responsive to demand increases and decreases as it would be in the absence of the high fixed costs of generation.

Figure 25 displays two sets of graphs. The first presents the energy supply curves for each summer, 2008–2010, and the second presents annual supply curves, 2008–2010, along with an overall supply curve estimated on all data, 2008–2010. A striking feature of the results is that the supply curve was much higher in summer 2008 than in other seasons. This possibly reflects the spike in gas prices in the middle of 2008.

[29] Goods with an elasticity > 1 are generally referred to as 'elastic', while goods with an elasticity < 1 are generally considered 'inelastic'. Under this general terminology, both the electric supply elasticities cited here and the customer electric demand elasticities cited previously in this report would be considered inelastic goods. However, they each do show some elasticity, but in both cases it is < 1.

Table 29. MISO Energy Supply Equation Estimation Results, Summers 2008–2010 (The dependent variable is the natural log of price.)[a]

Variable	2008	2009	2010
	Coefficient Estimate (Standard Error)		
Intercept	-0.2616 (0.09112)	1.033 (0.06423)	1.159 (0.05823)
MISO Load	0.091 (0.004571)	0.07365 (0.003761)	0.04444 (0.002766)
Lagged MISO Load	-0.0339 (0.004567)	-0.0413 (0.003758)	-0.01439 (0.002766)
Lagged Error (ε_{t-1})	0.45641 (0.01898)	0.31938 (0.02019)	0.34424 (0.01999)
Load Statistics			
Load Mean/St. Dev. (GWh)	70/12	63/11	77/14
Load Percentiles 25/50/75/95 (GWh)	61/71/79/90	54/63/72/83	66/78/87/100
Load Min./Max. (GWh):	44/99	40/97	50/109

[a]All coefficient estimates are statistically significant at the .01 level.

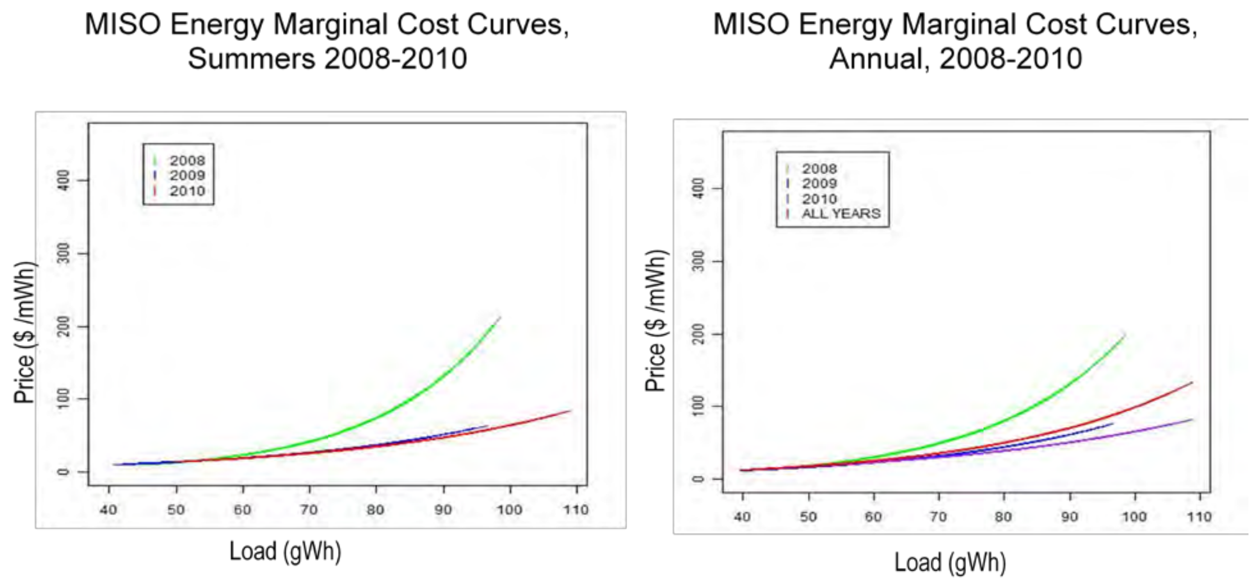
Source: Navigant analysis

Table 30. Coefficient Estimates and Standard Errors of Estimated MISO Seasonal Energy Supply Equations

	Variable			
Season	Intercept	MISO Load	Lagged MISO Load	Lagged Error
Winter 2008	0.02314 (0.106)	0.08150 (0.004236)	-0.02769 (0.004236)	0.4967 (0.01873)
Spring 2008	-0.4801 (0.1243)	0.1239 (0.005353)	-0.0540 (0.005353)	0.4821 (0.01866)
Summer 2008	-0.2616 (0.09112)	0.0910 (0.004571)	-0.03390 (0.004567)	0.4565 (0.01898)
Fall 2008	0.1966 (0.1060)	0.1220 (0.004590)	-0.06908 (0.004588)	0.4741 (0.01886)
Winter 2009	0.9456 (0.09761)	0.06956 (0.003422)	-0.03226 (0.003423)	0.5518 (0.01866)
Spring 2009	0.6681 (0.1007)	0.09379 (0.004934)	-0.04928 (0.004936)	0.3243 (0.02014)
Summer 2009	1.033 (0.06423)	0.07365 (0.003761)	-0.04130 (0.003758)	0.3194 (0.02019)
Fall 2009	0.9887 (0.08914)	0.08839 (0.004100)	-0.05303 (0.004102)	0.3255 (0.02026)
Winter 2010	0.8556 (0.1212)	0.0607 (0.003919)	-0.02415 (0.003926)	0.5380 (0.01856)
Spring 2010	1.388 (0.07538)	0.06724 (0.003811)	-0.03590 (0.003815)	0.3735 (0.01976)
Summer 2010	1.159 (0.05823)	0.04444 (0.002766)	-0.01439 (0.002766)	0.34424 (0.01999)
Fall 2010	1.202 (0.0908)	0.07703 (0.004017)	-0.04502 (0.004017)	0.3674 (0.01993)
Average Supply, 2008–2010	-0.72986 (0.022129)	0.078554 (0.001424)	-0.04251 (0.001424)	0.4479 (0.009610)

Source: Navigant analysis

Figure 25. Estimated MISO Energy Supply Curves, Seasonal Curves for 2008, and Annual Curves for 2008–2010



Source: Navigant analysis

4.1.3 Derivation of the Marginal Cost Curves for Transmission Congestion and Loss

The marginal cost curves for transmission congestion and loss depend on loads at both Ameren Illinois and elsewhere in the MISO system, and ultimately reflect transmission optimization across many transmission nodes. Navigant distills this highly nonlinear relationship to relatively simple but flexible marginal cost equations expected to provide unbiased estimates of the average effect of Ameren Illinois load changes on Ameren Illinois marginal congestion and loss prices.

Formally, letting $Q_{t,AM}$ denote the Ameren Illinois load in hour *t*, and letting $Q_{t,MISO^-}$ denote the load in the rest of MISO at time *t*, for both transmission congestion and loss, Navigant estimated marginal cost equations of the form,

$$\begin{aligned} P_t &= \alpha_0 + \alpha_1 Q_{t,AM} + \alpha_2 Q_{t,AM}^2 + \alpha_3 Q_{t,MISO^-} + \alpha_4 \alpha_3 Q_{t,MISO^-}^2 + \varepsilon_t \\ \varepsilon_t &= \rho \varepsilon_{t-1} + \phi_t, \quad \phi_t \sim IID \end{aligned} \quad , \qquad (0.5)$$

where P_t is either the congestion or loss price, and as with the energy supply equation the error structure is AR(1). Whereas Navigant used a semi-log form for the energy supply equation, here it was not used because of the many negative prices in the data.

One would not expect these equations to vary much across years or seasons, and in fact our estimates of these equations varied only slightly across years and seasons; therefore, in its analysis, Navigant used the equations estimated on data for all three years of the program period, 2008–2010. These equations are presented in Table 31 and graphed in Figure 26. Summarizing the equations:

» Both generate negative prices at low Ameren Illinois loads.

» Both are *increasing* in the Ameren Illinois load and *decreasing* in the load in the rest of MISO.

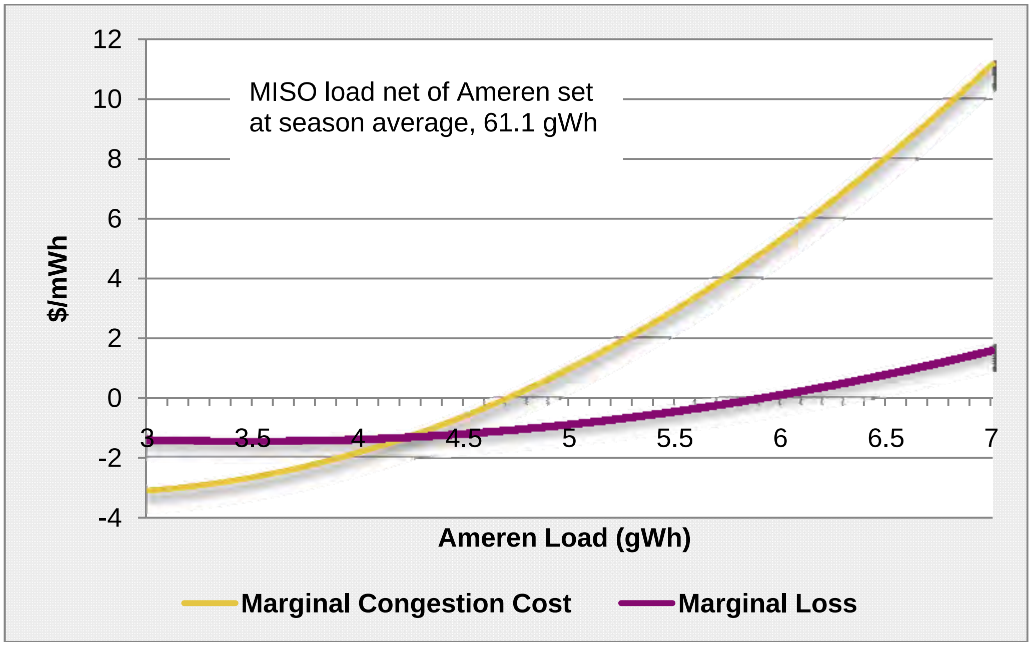
» The marginal congestion cost curve is much less elastic than the marginal loss curve, as indicated by its steeper slope.

Table 31. Ameren Illinois Marginal Cost Curves for Transmission Congestion and Loss, 2008–2010 (The dependent variable is price.)[a]

Variable	Coefficient (Standard Error)	
	Congestion Cost Equation	Loss Equation
Intercept	1.321 (1.70)	2.475*** (0.278)
Ameren Illinois Load (GWh)	-4.055*** (1.37)	-1.709*** (0.211)
Squared Ameren Illinois Load (GWh^2)	0.7622*** (0.142)	0.2459*** (0.0221)
$MISO^-$ Load (GWh)	0.2412** (0.0986)	0.06440*** (0.0151)
Squared $MISO^-$ Load	-0.003718*** (0.000769)	-0.001303*** (0.000119)
Lagged Error (ε_{t-1})	-0.5519*** (0.00445)	-0.6857*** (0.00389)

*Statistically significant at the .10 level;
**Statistically significant at the .05 level;
***Statistically significant at the .01 level.
Source: Navigant analysis

Figure 26. Estimated Ameren Illinois Marginal Cost Curves, Transmission Congestion and Loss, 2008–2010



Source: Navigant analysis

4.2 *Summary of Program Costs and Benefits*

4.2.1 Methodology

The first step in the net benefits methodology is to identify the separate benefits and costs that are part of an RTP program. Although there are many such costs and benefits that were discussed in the 2008 report, this assessment will focus on those which are most important and quantifiable. In addition to identification of program costs, there are three basic benefit components that have been determined to be quantifiable for this study.

The second step in determining net benefits is to compare total benefits to total costs to determine if there are positive net benefits for the program. Net benefits will be calculated both for the historical period, 2007 through 2010, and for the entire expected lifetime of the program.

The assessment of net benefits for the historical period is required by Public Act 094-0977 which created PSP and led to the order from the Illinois Commerce Commission (ICC) in Docket 06-0961, which implemented that legislation. As stated in subsection (b-20) of that order:

> *"(b-20) The Commission shall monitor the performance of programs established pursuant to subsection (b-15) and shall order the termination or modification of a program if it determines that the program is not, after a reasonable period of time for development not to exceed 4 years, resulting in net benefits to the residential customers of the electric utility."*

In addition to the historical perspective, it is also important to look at the impacts of this program over future years because an RTP program is expected to be an ongoing enterprise. Start-up costs are high relative to maintenance costs, and customers generally expect stability in all rate design offerings.

In addition to a base net benefits assessment for both the historical and on-going program, there will also be several scenarios developed and reported on in the results section that will allow a look at other variations around this set of base assumptions. These scenarios will be described below in more detail within the context of the discussion of each component of the net benefits model.

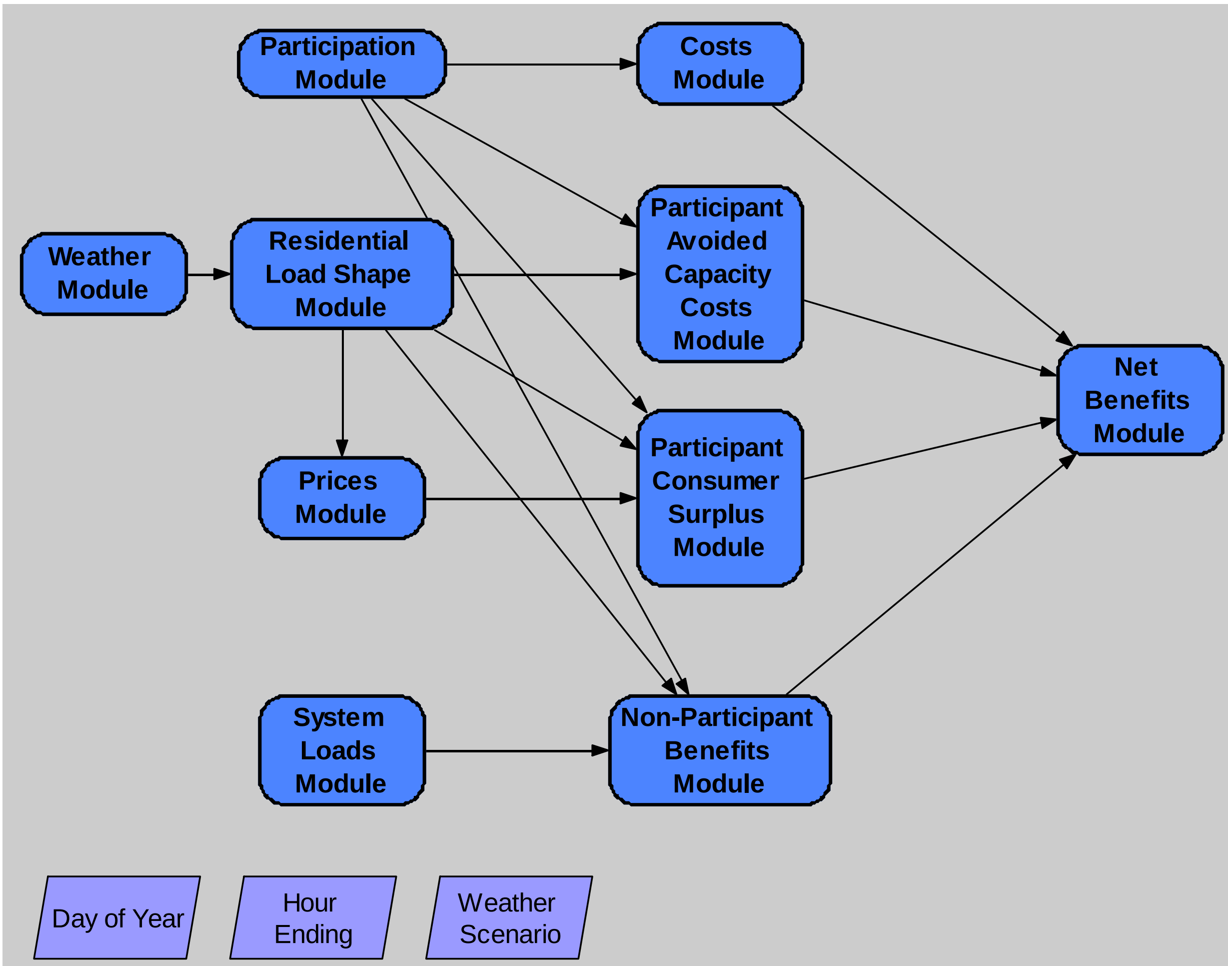
Figure 27 shows the basic components of RTPsim, the net benefits assessment model used for this study.[30] Although there is one cost module, there are three benefits modules:

1. Participant Avoided Capacity Costs
2. Participant Consumer Surplus
3. Non-Participant Benefits

The methodology contained within each of these modules will be described in more detail below. The diagram also shows, however, that many of these modules share inputs like participation rates, load shapes, and prices. The methodology for development of each of these shared inputs will be presented before talking about each of the cost and benefit modules.

[30] Navigant created the RTPsim model to assess the net benefits of RTP programs using Analytica® software from Lumina Decision Systems.

Figure 27. Basic Components of Net Benefits Assessment Model



Source: Navigant analysis

Participation Module

The participation module starts with historical end-of-year participant counts for the PSP program. These are compared to general estimates of the number of residential customers in the Ameren Illinois service territory to derive the actual program participation rates. For the base scenario, there is no forecasted growth in the number of program participants over the next ten years. This will allow for an assessment of costs and benefits related to the current set of customers, assuming they are allowed to continue on the PSP program through 2020.

However, two scenarios will be included to test changes in net benefits if the program grows over time.

Table 32. Historical and Forecasted PSP Program Participation Rates

Year	Residential Customers	PSP Participants	Participation Rate
2008	1,065,000	3,147	0.3%
2009	1,065,000	7,422	0.7%
2010	1,075,000	10,320	1.0%
2015 Base Scenario	1,075,000	10,320	1.0%
2015 PSP Growth Scenario	1,075,000	50,000	4.6%
2015 PSP High-Growth Scenario	1,075,000	100,000	9.3%

Source: Navigant analysis

Table 32 shows that the PSP program reached a participation rate of 1 percent of all residential customers by the end of 2010 after three years of program implementation. The participation Growth Scenario looks at reaching approximately 50,000 participants by 2015, while the High-Growth Scenario reaches 100,000 participants by 2015. In both of the Growth Scenarios, participation in the PSP program is maintained at the 2015 participation rate for the years 2016-2020, with a small increase of 0.4% per year in the number of participants to represent expected growth in the number of residential customers.

Residential Load Shape Module

The Residential Load Shape Module creates annual hourly load shapes for both PSP participants and the control group. The control group represents how PSP participants would have used energy on an hourly basis if they had not joined the PSP program. The difference between these two curves in each hour represents the load impacts from the program. During high price hours like summer afternoons, these load impacts tend to be load reductions. During low price hours, like overnight, these load impacts can be increases in use. The basis of these load curves for the historical years of 2008 through 2010 has been detailed in Section 3.2 of this report. The foundation of the load curves comes from the actual hourly metered consumption data for the PSP customers and from the hourly metered consumption data for a matched set of Ameren Illinois Load Research customers.

Although the historical load shapes come essentially from metered data, predicting what those load curves will be in the future is a greater challenge. It is known, however, that two of the primary influences on load shapes are weather and price. The elasticity studies presented previously in this report detail how price affects hourly electricity consumption. Three different levels of elasticity response are cited: long-run, medium-run, and short-run. We will now examine each of these three elasticities and discuss how they relate to forecasted load shapes.

Long-run elasticities are based on changes in appliance stock as customers make purchases over time. These purchases can alter their basic end-use equipment and potentially allow them to benefit from real-time prices in ways they can't accomplish with their existing appliances. Three years of program implementation, with most participants being active for only one or two years of the program, is not a sufficient amount of time to measure long-run elasticities. Consequently, long-run elasticities cannot be considered in the forecast models of load shapes at this time.

Medium-run elasticities are based on general knowledge of daily price patterns. Customers change their behavior using their existing appliance stock and develop habits that allow them to benefit from regular daily, weekly, and seasonal real-time price patterns. There is no reason to expect that these fundamental daily, weekly, and seasonal price patterns will change during the forecast period. Consequently, Navigant expects normal, everyday PSP load shapes for the forecast period to reflect the average load shapes seen during the normal, everyday periods of the historical years. In other words, the average historical year load shape differences between PSP participants and the control group are not expected to change in future years. The past consumption differences reflect medium-run elasticity responses and these responses will continue in the same way into the future.

Short-run elasticities show how participants respond to short periods of high prices, particularly when information costs are low (HPA days). Short-run elasticities are known, and they do show a response to price changes, so a price forecast could be used to build load shape changes for forecast years. However, this solution replaces the problem of forecasting load shapes with the problem of forecasting prices. We know that some of the primary factors influencing electricity prices are fuel costs, general levels of economic activity, and weather. Can we forecast these factors to create a good electric price forecast?

Fuel costs are difficult to predict in the short term, and are even more unpredictable over a ten-year forecast horizon. Natural gas costs are particularly volatile, and they are one of the most important fuel costs related to electric prices since natural gas is a prime fuel during periods of peak electric production. We saw higher electric prices in 2008 than in 2009 and 2010, and this matched the general level of natural gas prices during those periods. Fuel costs would be difficult to forecast with any accuracy.

Similarly, we saw higher electric prices in 2008, the year before the current economic recession began. Lower electric prices in 2009 and 2010 correspond both to lower natural gas prices and lower levels of economic activity, with its related reduction in demand for electricity. Forecasting the end of the recession or the emergence of a strong economic recovery is highly speculative, particularly over a ten-year time frame.

The prospects for creating a good weather forecast are more promising. Although it is just as problematic to forecast what weather will be like in any single upcoming year, we can be fairly certain that over a longer time frame, such as the ten years in this study, we will be likely to see a range of weather that matches the range and probability of weather that has occurred in the past.

This leaves us with a lackluster response to our original question: "Can we forecast fuel costs, economic activity, and weather to create a good electric price forecast?". We can only do one of the three, weather, with any hope of accuracy within the scope of this project. Given this situation, Navigant determined there was little to be gained by creating a price forecast for the purpose of forecasting changes in participant load curves.

For this net benefits model, it will be assumed that future prices will be the same as what was seen in 2010, because Navigant has no solid information on which to base changes to that assumption.

Even the development of load curve scenarios based on different price forecasts was considered to be too speculative to be worthwhile. This is particularly apparent when looking at the historical data we have to work with, as shown in Table 33. Although 2008 was the year with the highest prices, it was also one of the coolest years in the last 21 years. There is not sufficient historical information to give us confidence in predicting load responses to different price forecasts. Some actual high price/hot weather years would be needed to give us the full range of expected response needed to do a good job of forecasting.

Table 33. Comparison of Electric Prices and Weather over Historical Program Years

Year	Average Summer Day-Ahead Price Hour Ending 15	Cooling Degree Days	Number of Days with Average THI >=10
2008	6 cents/kWh	917	2
2009	2.5 cents/kWh	763	6
2010	3.5 cents/kWh	1,511	23
Average 1990 to 2010		1,097	8

Source: Navigant analysis

Although we may not have the degree of confidence we would like to model load changes in response to future prices, we do have the information we need to do a good job of modeling load changes in response to weather. The weather module will describe how load shapes were built for different weather scenarios in forecast years.

To summarize the Load Shape Module, historical metered data was used to create hourly load shapes for both PSP participants and a matched control group for the years of 2008 to 2010. For forecasted years, load shapes for each customer group were based on different weather scenarios. Distribution loss factors for each hour of the year were developed from 2010 data and applied to all of the historical and forecasted load curves. This created a set of hourly impacts at the distribution system level, in addition to the hourly impacts at the customer meter level. Each of these sets of impacts are used for different purposes within the overall net benefits model.

Weather Module

Previous analyses presented in this report have shown that weather is not a significant influence on hourly load impacts during the seasons of autumn, winter, or spring. For these seasons, the day-type load curves from each historical year were averaged together to create the forecasted load curves. These day-type loads were assigned to days that followed the 2010 weekday/weekend template. The three-year average was considered to be better for forecasting than any single year because any weather differences that did occur and affect the load curves even to a small degree would be averaged.

The story is different, though, for the summer. During the summer season, weather has consistently contributed to differences in customer load curves and impacts from the program. Due to the strong influence of weather on program impacts, along with the information we have on the likelihood of different weather conditions occurring over a series of years, a probability-based set of weather scenarios was included in the net benefits model.

Other scenarios in the model, such as the No Growth, Growth and High Growth participation scenarios, are modeled in a deterministic fashion. Results are calculated for each different scenario and the reviewer determines which of the scenarios they feel are the most likely to occur. The weather scenarios are modeled differently, as probabilistic scenarios. This is because we know with high certainty what the range of weather scenarios will be, based on historical observation and the belief that future weather will be like past weather over the long run.[31] All that is unknown is which particular weather pattern will occur in each year. In other words, we know that over the next ten years we will have some cool summers and some very hot summers, but most summers will be near normal. What we don't know is whether or not next summer will be a hot or a cool summer.

We can accurately model this situation within the context of the net benefits assessment by following these steps:

1. Review historical weather data and develop probabilities for different summer weather scenarios.
2. Randomly assign one weather scenario to each forecast year based on the probability that it will occur.
3. Calculate net benefits for that particular combination of future weather years.
4. Repeat steps 2 and 3 for multiple iterations. Each iteration is like one sample point for possible net benefits based on a probabilistic series of weather conditions.
5. Average the net benefits over all iterations to get the best estimate of expected net benefits given all possible future weather scenarios and their known probabilities.

This method was used within the RTPsim model. It is possible to run the model with 15 weather forecast iterations before reaching the memory limits of the computing environment. These probabilistic results from the weather scenarios carry through the whole model whenever a calculation is done that involves the load shape information, and they become part of the final net benefits results.

Reviewing the historical weather data and developing different summer weather scenarios is a key step in this modeling process. Historical weather data for the Ameren Illinois service territory was available for 1990 through 2010. The first review of the weather history provided the astonishing results already shown in Table 33: although 2008 and 2009 were two of the coolest summers over the last 21 years, 2010 was by far the hottest summer over the same time period. What we have in our historical program data are two "bookends" for the weather extremes we are likely to face over the forecast period. This becomes convenient because we have hourly load curves for each of those "bookends," and this simplifies hourly modeling of the different weather scenarios.

[31] Consideration of climate change is not within the scope of this analysis.

In addition to modeling general summer weather conditions based on cooling degree days that occur over the summer, a key component of RTP impacts is the response on HPA days, the individual hottest days of the summer. HPAs are triggered by prices, but we know that summer prices are highly correlated to high demand, and high demand in the summer is highly correlated to hot weather. Therefore, we will look for the hottest weather days each summer as a proxy for probable HPA days.

The goal is to find a weather threshold that will identify probable HPA days during the historical weather years. Previous work done by Navigant on many other summer demand response programs, like Direct Load Control and Critical Peak Pricing, has shown that residential air-conditioning loads are highly correlated to the THI. Assuming that the predominant summer load for PSP customers on HPA days is air-conditioning, the THI was used as a measure for finding probable HPA days in the historical weather data. Different THI thresholds were tested, with the goal of being able to identify some HPA days in every summer but no more than twenty or so in any particular summer. This criterion is based on typical human response patterns. Something that occurs more than 20 days within a summer loses its uniqueness and its ability to elicit a special response from the customer. Likewise, if the threshold is so high that HPA events are rarely called, customers become "out of practice" for the special actions they should take when the event occurs.

Using this criterion, an average daily THI greater than or equal to 10 was found to be the best threshold for identifying an appropriate number of HPA days each summer during the historical period. This is roughly equivalent to an average daily temperature of 82 degrees with high humidity. Note that this is average temperature for the whole day, not just for afternoon hours. Because temperatures regularly drop into the sixties during nighttime hours in the summer, a daily average THI of 10 or more is a very hot day.

Although there were some small discrepancies (such as 2008 and 2009), in general, lower cooling degree days for a summer corresponded to a lower number of HPA days for the same summer.[32] Looking at standard deviations from the mean, four distinct weather scenarios were drawn from the historical data.

Table 34. Weather Scenarios and Probabilities

Weather Scenario	Average Number of HPA Days	Standard Deviation from the Mean	Probability of Occurrence
Low	4	-1	20%
Mid	8	0	60%
High	10	+1	10%
Extra High	18	+2	10%

Source: Navigant analysis

Table 34 shows that the historical weather distribution is slightly skewed towards the high end. Sixty percent of summers have weather conditions near normal, averaging eight HPA days based on the

[32] 2009 had fewer cooling degree days than 2008, while it had more hypothetical High Price Alert days. Even so, both years qualify as being among the four coolest summers over the last 21 years.

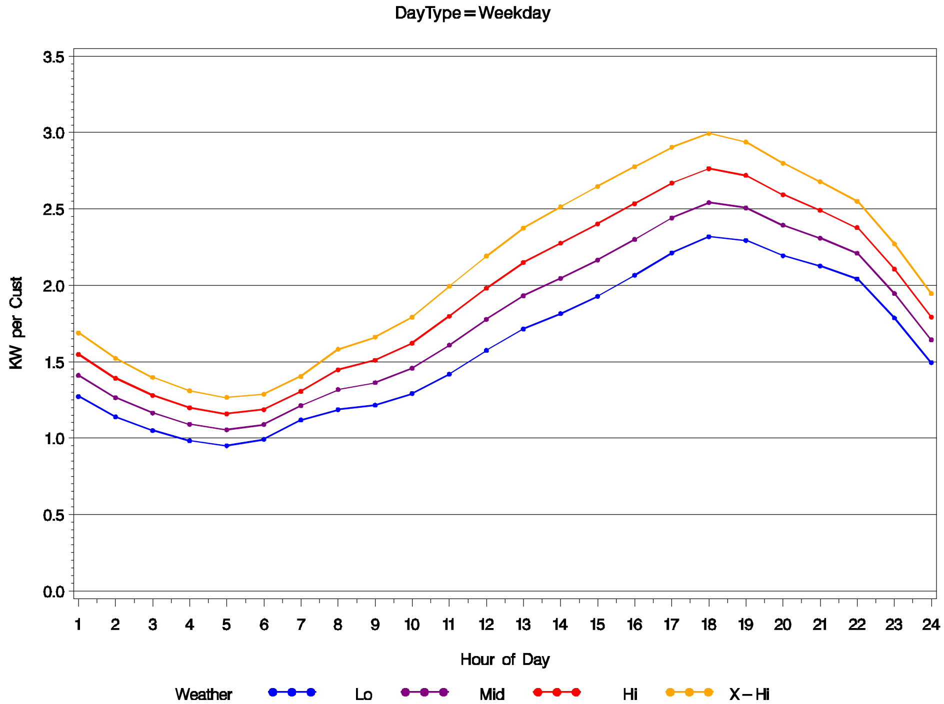
threshold of average daily THI of 10 or more. Twenty percent of summers are cooler, with an average of only four HPA days. Twenty percent of summers are hotter, but here the effect is skewed towards some extremely hot summers. Ten percent of summers are expected to be hotter than normal with an average of ten HPA days, while the remaining ten percent are extremely hot with an average of 18 HPA days. Note that 2010 was one of these extremely hot summers that would have had 23 HPA events based on the weather threshold. However, since prices were low due to economic conditions and other factors, there were no HPA days actually called. Consequently, we were unable to measure what load reductions would occur under extreme weather conditions like this during an actual HPA event.

Based on these findings, the following method was followed for estimating load curves for the Control Group for each of the four weather scenarios:

1. The Low weather scenario matches the 2008 load curve, 20 percent probability.
2. The Mid weather scenario is the 2008 load curve plus one-third of the difference between 2008 and 2010, 60 percent probability.
3. The High weather scenario is the 2008 load curve plus two-thirds of the difference between 2008 and 2010, 10 percent probability.
4. The Extra High weather scenario is the 2010 load curve, 10 percent probability.

Figure 28 shows the results. It is important to note that the Low weather scenario, which matches the actual average 2008 load curve for the Control Group, shows a peak demand at Hour Ending 18 of approximately 2.3 kW per customer. This is nearly 0.7 kW below the peak demand at the same hour on summer weekdays in 2010 when the weather scenario was Extra High. This observation leads one to wonder what the response to an HPA would have been if it had been called in 2010. If customers responded with the same action taken in 2008, and that action was to reduce their air-conditioner use, it is likely that the load response would have been much higher than what was observed in 2008 because there was much more air-conditioning load on the system that could be curtailed.

Figure 28. Control Group Summer Weekday Non-Event Load Curves for each Weather Scenario



Source: Navigant analysis

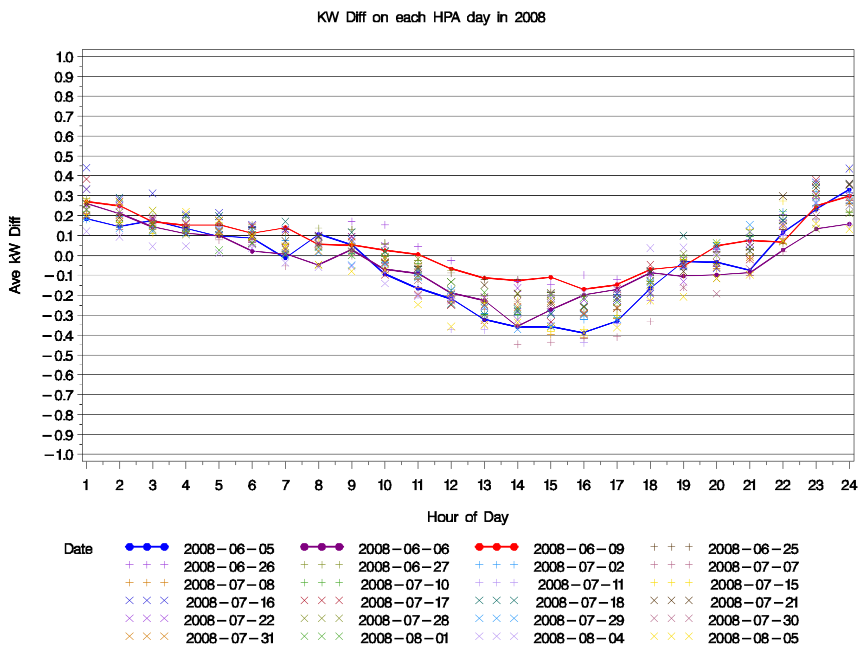
After developing Control Group load curves for each summer weather scenario, the next step was to develop PSP Participant load curves for each weather scenario. To maintain consistency between the Control Group and PSP Participant load curves, this was done by estimating the load differences for each hour for PSP Participants. The load differences were then applied to the Control Group load curves to create the PSP Participant load curves.

There are two types of PSP load differences that need to be modeled for each weather scenario. One is the expected load difference on regular summer days and the other is the expected load difference on HPA event days.

Simple regression models were built to check how the average difference between Control Group use and PSP Participant use on regular summer weekdays was influenced by weather. The results were inconclusive. Differences in average load impacts among the three years were minimal, compared to differences by time of day, which were very pronounced and consistent from year to year. This is consistent with the findings of the medium-run elasticity model. It was also not possible to tell if the small differences from year to year were actually due to weather differences or to differences in the composition of the participant population as it grew over time. Given the uncertainty of the correlation to weather and the very small differences across the three years, it was decided that the best forecast model for hourly PSP load differences on regular summer days would be the average hourly differences from the three historical years. This average is the same for all regular summer days in each weather scenario.

Results were different for PSP responses on HPA days. Hourly data from 2008 for each individual HPA day was used to develop load differences between the Control Group usage and PSP Participant usage for each hour. These kW differences were regressed against hourly THI values. Because there were more than 24 weekday HPA days in 2008, there was a wide range of THI values and load responses included in this data set. Although the average load impact between the hours of noon and 5 pm averaged -0.23 kW per customer on these days, matching results found in the 2008 PSP evaluation report, on some days this load impact was nearly -0.50 kW per customer. This can be seen in Figure 29.

Figure 29. Variation in PSP Customer Response on Different HPA Days in 2008



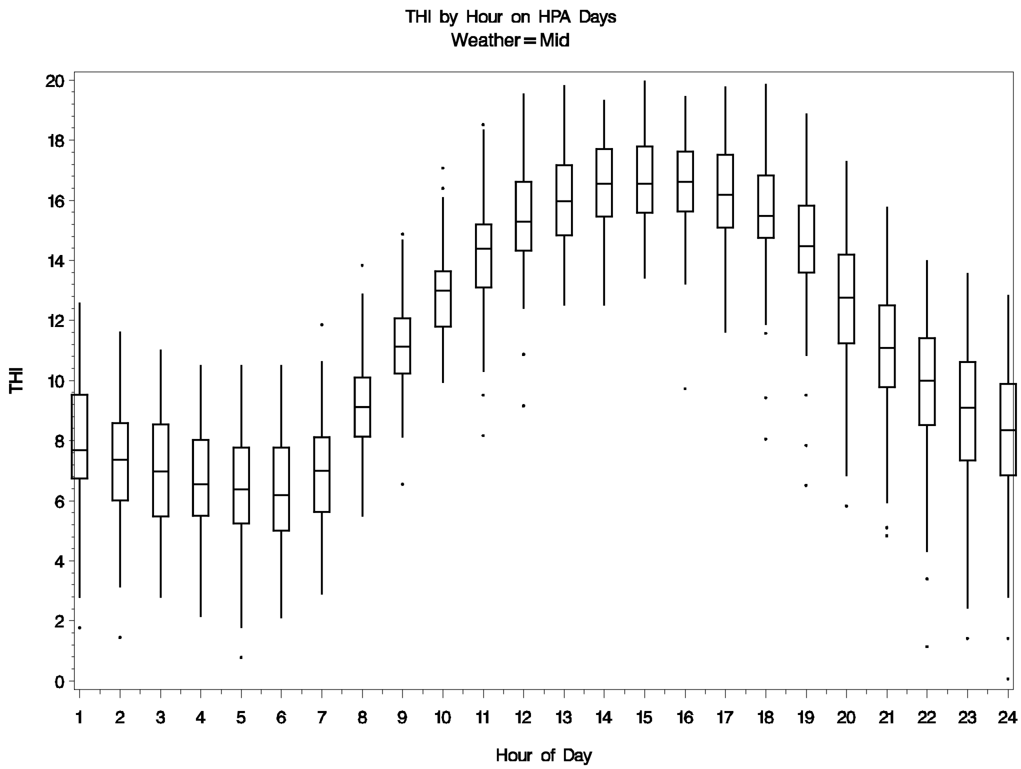
Source: Navigant analysis

The coefficients on the THI variables for each hour are all statistically significant at the 95 percent confidence level or higher, and the R-squared for the model is 80 percent. Given these strong statistics, the model was used to estimate load reductions for HPA days based on expected THI values within each of the four weather scenarios.

Modeling load response on HPA days in this way required the development of THI values for HPA days within each weather scenario. The hypothetical HPA days (based on the threshold value of average daily THI of 10 or more) within each of the 21 historical weather years were used to develop the expected THI distribution for HPA days within each weather scenario.

Figure 30 illustrates the results for the Mid weather scenario, which was based on data from 100 hypothetical HPA days over 13 historical years that fell within the Mid weather scenario definition. It shows that while the average THI value during the afternoon hours on these days was around 16, some days had THI values as low as 14 and as high as 20.

Figure 30. Historical Distribution of Hourly THI Values for the Mid Weather Scenario



Source: Navigant analysis

Given the nature of benefits from RTP programs, the high THI value HPA days are of particular interest. It is on these days when system loads are likely to be highest, prices are likely to be highest, and customer response is likely to be highest. All of these factors combine with the supply curves, which have a steeper slope on peak days to create greater-than-average system price reductions and non-participant benefits. Given this nonlinear response between demand reductions and program benefits, it is important to model the highest days and the lowest days according to their probability of occurrence rather than modeling the same average response for all HPA days.

To accomplish this, the mean and standard deviation of the observed THI distribution for each hour within each weather scenario were calculated. As Figure 30 illustrates, the assumption of normality for each of these distributions is reasonable. A daily THI curve was then constructed for each modeled HPA day based on the probability of its occurrence within the historical data.

The year of 2010 was used as the template for modeling hourly load differences in future years. The 18 highest price weekdays were identified in 2010. To model hourly load differences for the Low weather scenario, the four highest price days were assumed to be HPA days in a Low Weather year. Each of these days had a different set of hourly THI values assigned, based on the probabilities that those THI values occurred in Low Weather years. The regression model coefficients were then used to translate the THI forecast into expected hourly load differences based on the weather and the fact that it was an HPA day.

This similar type of modeling was done for each weather scenario, with the difference being that the Mid weather scenario had 8 HPA days modeled, the High weather scenario had 10 HPA days modeled, and the Extra High weather scenario had 18 HPA days modeled.

These HPA day load differences then replaced the average summer day load differences for the appropriate high price days in each weather scenario. The result is a fixed set of PSP hourly load responses for HPA days based on the weather scenario, and within each scenario some HPA days have extremely hot weather and some HPA days have lower hot weather based on the probability of those individual weather days occurring. These four separate summer load curves for PSP responses get fed back into the net benefits model where one is randomly selected for each forecast year, based on the probabilities for each weather scenario.

Table 35 gives an example of how the weather scenarios are used within the net benefits model. This shows two different iterations of the model.

In Iteration 1, one of the four weather scenarios is randomly assigned to each year based on the historical probabilities (i.e., there is a 60 percent probability that any given year will be in the Mid weather scenario). When a particular weather scenario is chosen for a particular year, it brings with it a fixed load curve, which reflects expected hourly differences for PSP customers. Within that fixed load curve, there is a fixed set of HPA days that span different expected values for THI and associated load differences. For example, whenever the Mid weather scenario is chosen, it includes eight modeled HPA days. The kW/customer differences on those HPA days vary from a low of -0.31 kW/customer demand reduction during hour ending 15 to a high of -0.54 kW/customer demand reduction. The average demand reduction during hour ending 15 over all eight HPA days in the Mid weather scenario is -0.43 kW/customer.

In Iteration 2, the same methodology is followed but there is a different assignment of weather scenarios to each year. Within the net benefits assessment model, this type of iteration can be done 15 times to get average net benefits over all scenarios. It is important to model different weather scenarios because the hotter weather scenarios can create proportionately greater program benefits than lower weather scenarios, and what year they occur in over the future time frame for analysis can affect the net present value calculation of benefits. This methodology accomplishes the objective of measuring expected net benefits over a variety of possible weather futures.

Table 35. Example of Weather Forecast Random Iterations

Forecast Year	Iteration 1 Weather Scenario	Iteration 1 No. of HPA Days	Iteration 1 Smallest Load Diff. HPA Day Hr 15	Iteration 1 Largest Load Diff. HPA Day Hr 15	Iteration 2 Weather Scenario	Iteration 2 No. of HPA Days	Iteration 2 Average Load Diff. HPA Day Hr 15	Iteration 2 Largest Load Diff. HPA Day Hr 15
2011	Mid	8	-0.31	-0.54	Mid	8	-0.31	-0.54
2012	Mid	8	-0.31	-0.54	Lo	4	-0.36	-0.49
2013	Mid	8	-0.31	-0.54	Xhi	18	-0.27	-0.54
2014	Mid	8	-0.31	-0.54	Hi	10	-0.31	-0.53
2015	Mid	8	-0.31	-0.54	Lo	4	-0.36	-0.49
2016	Hi	10	-0.31	-0.53	Mid	8	-0.31	-0.54
2017	Hi	10	-0.31	-0.53	Mid	8	-0.31	-0.54
2018	Xhi	18	-0.27	-0.54	Mid	8	-0.31	-0.54
2019	Mid	8	-0.31	-0.54	Mid	8	-0.31	-0.54
2020	Mid	8	-0.31	-0.54	Mid	8	-0.31	-0.54

Source: Navigant analysis

There are two additional important points to make related to the information in this table. First, there is a wider range in possible load differences for Extra High weather years because there are 18 HPA days in those years rather than 10 or less. This means the random draw from historical THI values has a greater chance of dipping into lower THI days than occurs when there are only a few draws in other years.

Second, the load differences reported for the Low weather scenario on HPA days is consistent with what was observed on HPA days in 2008, which was a Low weather scenario year. Although at first glance these modeled load differences appear higher (a range of -0.36 to -0.49 kW/customer in this model compared to a reported difference of -0.23 kW/customer in the 2008 report), it must be remembered that there were over 20 actual HPA days called in 2008 and they were based on price thresholds, not weather thresholds. The average THI value over all HPA days in 2008 was considerably lower than the threshold value of average daily THI of 10 or more used in this model. Also, the reported -0.23 kW/customer impact reported for 2008 was the average over the hours of noon to 5 pm. Hour Ending 13, reported in the table above, is the high point for kW reductions during that span of hours.

A final adjustment is made to the control group load curves to account for the conservation effects from the program. All of the previous discussion of load shape differences comes from the comparison of normalized load shapes; i.e. – energy use was set at equivalent levels for each group so the difference in shape could be compared (as reported in Section 3.2). The results of the conservation analysis presented previously in Table 23 showed that there were some small differences in annual energy use due to participation in the program. While the net conservation effect for the year was near zero (a net increase of 29 kWh), there were more significant effects by season. Not knowing the exact source of these conservation effects, they were spread evenly across all hours within each season. For example, there are 139 kWh of expected conservation during the summer season. There are 2,208 hours during the summer season (92 days x 24 hours), so the average conservation per hour is 0.06 kW per hour. Control group loads were increased by 0.06 kW every hour of the summer to reflect the conservation effect in the difference between control group and participant hourly loads.

Prices Module

As stated previously, for this net benefits model, it will be assumed that future hourly day-ahead prices will be the same as what was seen in 2010, since Navigant has no solid information on which to base changes to that assumption. This means that the results of the net benefits model will show what to expect if electric prices stay generally at the current level.

Keeping the hourly price curve for 2010 constant in future forecast years is helpful because it keeps the high price hours aligned with the hours of load response in the forecast years where the basis is also 2010.

In addition to needing hourly day-ahead prices in the net benefits model, there is also the need to compare future PSP customer bills to the portion of the flat rate that is equivalent to the energy charges covered by the day-ahead prices. The previous section of this report on bill savings looked at this in detail for the historical years. The historical bill savings results were used to determine the equivalent average flat rate energy charge to be used in the model. The values reported in Table 36 show the equivalent average energy charge component that would explain the overall estimated bill savings reported for previous years.

Table 36. Estimated Energy Charge Component within the Residential Flat Rate

Year	Cents per kWh
2008	6.43
2009	5.75
2010	5.47
All Forecast Years (Average of 2009 and 2010)	5.61

Source: Navigant analysis

To forecast this value, the average of 2009 and 2010 was used as representative of what to expect given that future energy prices stay near current energy prices. Both 2009 and 2010 had general energy price levels considerably below 2008 price levels. Given the many factors that influence this estimate, using the average of 2009 and 2010 rather than just the 2010 value was considered a less biased estimate of what this value will likely be in the future.

One final estimate needed in the price module is the development of the comparable flat rate energy charge component without any hedging premium included. The hedging premium can be thought of as the insurance premium that must be paid so regular residential customers can pay a predictable flat rate every month and be protected from both high and low price swings in the electric energy market.

While this hedging premium is known to exist as a portion of the flat rate, there are no straightforward methods for estimating exactly what the value of this premium is. General consensus is that it is likely to be in the 5 percent to 15 percent range when estimated as a percentage of the energy charge. Given the uncertainty around this variable and the inability to calculate it, it will be treated as a sensitivity value within the net benefits model. Table 37 shows that a value of 10 percent will be used for the hedging premium in the base scenario estimation of net benefits. Additional scenarios will include a low case where the hedging premium is 5 percent and a high case where the hedging premium is 15 percent. These will be deterministic scenarios, not probabilistic scenarios, because the probabilities for each scenario are unknown. It will be left to the reviewer to determine which scenario is most likely.

Table 37. Scenario Values for Hedging Premium

Year	Hedging Premium
Low Scenario	5%
Base Scenario	10%
High Scenario	15%

Source: Navigant analysis

System Loads Module

The system loads module is the collection of historical data on hourly MISO and Ameren Illinois system loads for 2008 through 2010. MISO loads without Ameren Illinois and lagged MISO loads are also calculated within this module from the two separate load series. This is data that will be needed in the estimation of non-participant benefits from market effects.

Costs Module

All program implementation costs are assigned to one of the following cost categories within the net benefits model:

1. Start-up costs (one-time costs to develop systems and processes)
2. Fixed program administration costs (annual fixed costs required to keep the program operating)
3. Variable program administration costs (costs related to the number of active participants)
4. Meter costs (costs related to installing a meter for each new participant)
5. Marketing costs (average cost of attracting a new participant into the program)
6. Program evaluation costs

As program implementer, CNT Energy is responsible for administration and marketing of the PSP program. They provide an accounting of their program-related expenses each year in their annual report. Their costs are divided between fixed and variable program administration costs and marketing costs.

Ameren Illinois handles meter acquisition and installation as well as billing for the PSP program. These activities required start-up costs and also contribute to fixed program administration costs, meter costs, and program evaluation costs on an ongoing basis.

Ameren Illinois chooses to account for their meter costs on an amortized basis, so there are ongoing monthly charges related to meter costs for all active PSP participants, rather than a single full-price equipment and installation cost for each new PSP participant. This practice is based on the assumption that interval meters removed from the PSP program could be put to use within other customer groups and there is no need to charge the PSP program with the full cost of the meter up-front. There is also the possibility that a widespread Smart Grid implementation in the future could make the type of meter needed for the PSP program standard issue for all customers. If this happens, the incremental meter costs for the PSP program would drop to zero. A scenario which excluded all meter costs was added to the net benefits assessment to allow for consideration of the net benefits impact of this possibility.

Start-up costs are high for RTP programs because they require complicated modifications to the utility billing system. However, once those billing system modifications are made, the annual costs for maintaining the rate option within the billing system are small. Initial costs for modifying the billing system are not recoverable should the rate option end. Given this situation, a scenario option was added to the net benefits model so net benefits could be assessed both with and without start-up costs. The base scenario will include start-up costs; however, a look at ongoing program costs without start-up costs included gives a better indication of the value of continuing the program from this point forward.

The Illinois Power Agency Act SB1592 defines components that must be included in the net benefits assessment of energy efficiency programs in the state of Illinois. Evaluation costs are one of those required cost components, and for consistency it will be included in this net benefits assessment also. Evaluation costs will be assumed to be zero for the forecast period. Although evaluations can be valuable for understanding and improving program impacts, they are not essential to implementation.

Benefit #1: Participant Avoided Capacity Costs Module

Following the MISO resource adequacy requirement, Ameren Illinois secures capacity to cover their monthly load requirements. Contracts for this capacity are made at the beginning of the year, with the ability to buy or sell in the month-ahead capacity markets as needed. This means there is an advance benefit (both annual and month ahead) related to demand reductions from the PSP program. Demand reductions caused by the PSP program reduce Ameren Illinois capacity costs.

Within the construct of the net benefits model, it is assumed that these avoided capacity costs translate back as benefits to program participants, although the exact mechanism for this transfer is unknown. It is known, however, that there is no capacity value embedded within the day-ahead LMP prices that PSP customers pay for their energy. Consequently, the benefits of avoided capacity costs are additional to any avoided energy benefits that are calculated for participants.

The avoided capacity cost benefits are estimated as the expected kW demand reduction in the system summer peak due to the program times the cost per kW to provide that capacity. In the previous study years of 2008 and 2009, avoided capacity costs were estimated based on contracts in the BGS 3b – BGS 4 capacity market. Based on these monthly contracts, avoided capacity costs for the summer months of June, July, and August were reported as $14.57 for 2008 and $8.49 for 2009. The similar contract value for 2010 was $6.10. We consider these capacity market values appropriate to use for valuing capacity in years where we are looking backwards.

However, this capacity market is primarily dealing with short-term capacity values. When working with a ten-year forecast of net benefits, it is more appropriate to deal with long-term capacity values. In the long-term, the avoided cost for capacity is considered to be the cost of new entries (CONE) into the generation capacity market plus appropriate avoided transmission and distribution (T&D) capacity costs. The combination of market values for 2008, 2009 and 2010 and publicly available CONE and T&D avoided capacity values for the forecast years is shown in Table 38. These are the avoided capacity values used in the net benefits model.

Table 38. Avoided Capacity Costs for PSP Net Benefits Assessment

Year	$/kW
2008	14.57
2009	8.49
2010	6.10
2011	30.00
2012	39.50
2013	49.00
2014	58.50
2015	68.00
2016	77.50
2017	87.00
2018	96.50
2019	106.00
2020	115.50

Source for 2008-2010: AIU work papers and monthly filings with the ICC

Source for 2011-2020:

Capacity Component: MISO filing of Annual CONE Recalculation, FERC Docket Nos. ER08-394-007 and ER08-394-009; T&D Component: "Energy Efficiency & Customer-Sited Renewable Resource Potential in Wisconsin",Energy Center of Wisconsin, 2009.

The expected summer peak reductions from the program are estimated as the average demand reductions from the program at hour ending 15 on HPA days in each forecasted year. For historical years, the peak demand reduction from the program matches the maximum hourly difference between the Control Group load curve and the PSP Participant load curve when looking at summer afternoons. Conservation adjustments and hourly distribution loss factors are applied to each of these impacts at the customer meter to create the kW change per PSP participant at the distribution system level, as shown in Table 39. The distribution losses during these peak hours are close to 7 percent.

Table 39. Summer System Peak kW Change per PSP Participant

Year	kW per Participant at Distribution System Level
2008	-0.3130
2009	-0.2184
2010	-0.2594
2011–2020	-0.5242

Source: Navigant analysis

As a reminder, forecasted peak responses are greater than observed historical peak responses because there were no HPAs called in 2009 or 2010 and in 2008 the weather was very cool even though HPAs were called. If HPAs are called in future years when weather is normal, the expected response will be higher than what was seen in 2008.

Benefit #2: Participant Consumer Surplus

In the design of the PSP program, the ability of participant households to use more energy when it is relatively cheap, and less when it is expensive, is a major source of participant benefits. Due to this unique characteristic of the program, there is a straightforward and simple way to closely approximate the consumption-related benefits from the program. Because the PSP program is all about having customers pay the real-time energy costs on an hourly basis, their bills represent actual energy costs. The difference between what they paid for energy on a real-time basis and what they would have paid on the standard rate alternative – that is, their bill savings - is a close approximation of what economists consider to be the correct measure of consumption-related participant benefits, consumer surplus.

Economists consider consumer surplus to be the appropriate measure of consumption-related net benefits that accrue to participants because it fully captures both the benefits to participants when day-ahead prices are relatively low *and* the costs to participants when day-ahead prices are relatively high. As presented graphically below, these benefits and costs involve the difference between the value that a customer places on energy consumption and the amount that must be paid for consumption. So, for instance, a relatively high day-ahead price causes the PSP household to reduce consumption below what it would have consumed under the fixed-rate price, allowing it to reduce its bill but at the cost of consuming less energy.

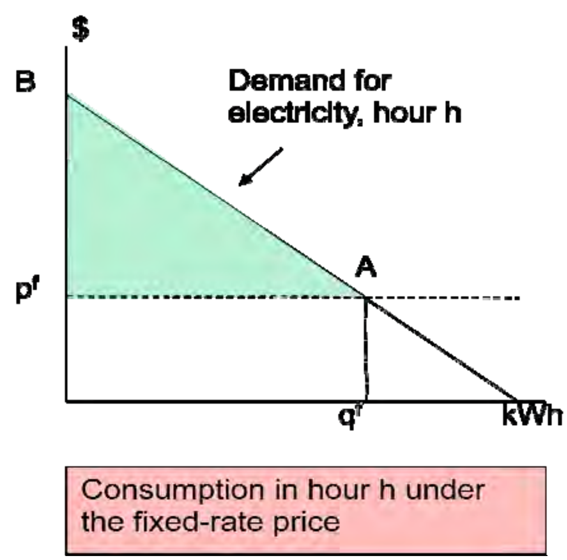
Bill savings are presented in Section 3.4 of this report. That bill savings are an approximation of consumption-related benefits is due to two factors: first, bills associated with the PSP program include a participant charge. Second, even after accounting for the participant charge, bill savings are not an exact measure of what economists consider to be the true measure of the benefit of a price change to consumers, consumer surplus. In our net benefit assessment, we account for these factors to obtain our best estimate of direct consumption-related participant benefits.

Participant Charge. When the bill savings were reported, it was a straight comparison of PSP total bills to the same kWh usage billed on the standard rate tariff. The PSP bills include a $2.25 charge per month to cover approximately half of the incremental metering costs required for participation in the program. This meter charge offsets benefits that came from avoided energy costs. To get the total avoided energy costs the meter charge should be added back. In the net benefits assessment, the total cost of the additional metering will be accounted for as a cost of the program.

Calculating Consumer Surplus from Bill Savings. The original estimate of bill savings is based on the observed energy consumption behavior of PSP households. Navigant argues that this provides a reasonably good approximation of the "true" benefits of the PSP program to participants. The deviation between the original calculation of bill savings and the true benefit of the program to PSP participants arises because the bill savings calculation effectively assumes that energy consumption patterns under the PSP program are the same as under the alternative fixed-rate plan. In reality, PSP customers change their behavior compared to that exhibited under the fixed-rate plan to avoid high day-ahead prices and take advantage of low day-ahead prices.

To clarify the issue, consider the three graphs shown below. **The first graph, in Figure 31**, considers the case where in hour *h* the household faces the fixed-rate price p^f. The household consumes q^f units of energy at a cost of $p^f \cdot q^f$. The demand for energy reflects the household's marginal (incremental) willingness to pay for energy, and the area under the demand curve up to consumption level q^f is the household's benefit from energy consumption. It follows that under the fixed-rate price regime, the net benefit to the household from consuming q^f units of electricity is the amount given by the area p^fAB –the difference between the benefit and the cost of the electricity consumed. Economists call this net benefit "consumer surplus", and argue that it is the appropriate measure of consumer benefit from a price change.

Figure 31. The General Case of PSP Customer Response to Price Differences

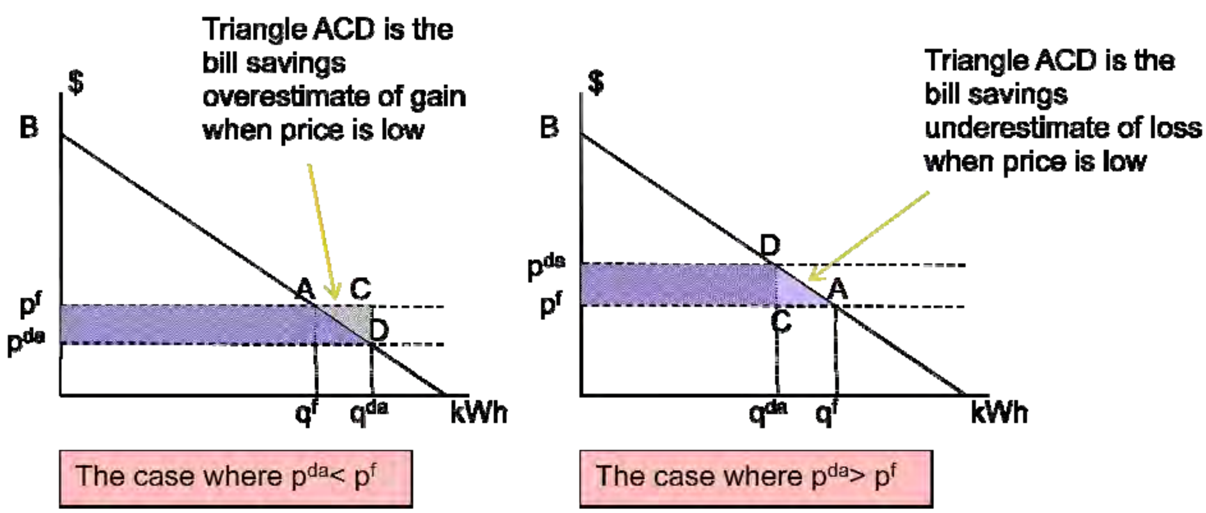


Source: Navigant analysis

Now suppose that under the PSP program the price of energy faced by the household is the relatively low day-ahead price p^{da}, as shown **in the first graph of Figure 32.** Consumption increases to q^{da} and the net benefit to the consumer from the price difference is the shaded area p^fADp^{da}. In other words, this is the net benefit to the PSP household in hour *h* from participating in the program. A reasonable approximation of this benefit is the original bill savings calculation, the difference between the household's bill for the hour under the new price and the old price, *given the new consumption level* q^{da}; this is the cross-hatched rectangle, p^fCDp^{da}.[33] This value somewhat *overstates the benefit* of the PSP program for the hour. The more inelastic the household's demand for electricity, though, the better the approximation, because inelastic demand implies a steep demand curve, and as the demand curve steepens the bill savings calculation p^fCDp^{da} approaches the true net benefit p^fADp^{da}.

Moving to the **second graph in Figure 32**, if the PSP day-ahead price is *higher* than the fixed-rate price, household consumption falls, and the net loss to the PSP household is the shaded area p^fADp^{da}. Once again a reasonable approximation of this loss is the difference between the household's bill for the hour under the new price and the old price, given the new consumption level; this is the shaded area in the graph, p^fCDp^{da}, and denotes the (negative) bill savings calculation. This value *understates the loss*.

Figure 32. Correcting Bill Savings Estimates to Reflect Changes in Consumption



Source: Navigant analysis

The upshot of this discussion is that the original bill savings calculation overstates participant benefits, because the calculation overstates the benefits when day-ahead prices are low relative to the fixed rate, and understates the loss when day-ahead prices are high. These errors arise because the original bill savings estimates do not account for the shifting of energy consumption behavior under the PSP program compared to the standard fixed-rate billing regime. With reference to the figures, this overstatement is approximated by the set of triangles of area $\Delta p \cdot \Delta q/2$, where Δp is the difference

[33] As discussed in the previous section, the bill savings calculations done by CNT Energy include differences in monthly fixed charges, which are not relevant to the current exposition.

between the day-ahead and fixed-rate price for the hour, and Δq is the change in consumption associated with the price difference. When the demand curve is linear, these triangles are exact measures of the overestimate of program benefits; otherwise they are good first-order approximations of the overestimates.

These triangles can't be calculated directly because the counterfactual behavior—the amount of energy participating households would have consumed under the fixed rate alternative—is not observed. Nonetheless, a good approximation of their value for a given hour of the season is $N \cdot \Delta p_t \cdot \Delta \bar{q}/2$, where N is the number of PSP participants, Δp_t is the difference between the day-ahead price and the fixed-rate price for the hour, and $\Delta \bar{q}$ is the average difference in load as obtained via estimates of the elasticity of demand. Based on our analysis that demand is virtually inelastic –at least in the range of observed prices—in winter, spring and fall, we conclude that bill savings in winter, spring, and fall are a very good approximation of consumer surplus. Based on our analysis of medium-run elasticities for summer, we adjust bill savings in summer to better approximate consumer surplus using the estimated demand elasticities shown previously in Table 5.

Table 40 shows the associated adjustment in bill savings necessary to correctly approximate annual consumer surplus. As indicated, the reductions are small.

Table 40. Adjustment to Original Total Bill Savings to Estimate Consumer Surplus

Year	Original Total Bill Savings per Participant	Annual Adjustment per Participant	Consumer Surplus per Participant
2008	$119.70	-$11.11	$108.59
2009	$332.00	-$16.75	$315.25
2010	$215.30	-$4.25	$211.05

Source: Navigant analysis

During discussions on the bill savings estimates shown in the 2009 PSP evaluation report, some members of the ICC staff expressed interest in understanding the components contributing to the overall estimate of consumer surplus. In response to that interest, Navigant estimated three major components of the consumer surplus:

1. Avoidance of the **hedging premium**
2. Savings related to **shifts** in consumption
3. Remaining consumer surplus, primarily due to the **forecast error** between the expected energy component of the flat rate and the actual market rate

Hedging Premium. As stated previously, the hedging premium is unknown; therefore, Navigant estimated its share of total consumer surplus for three different scenarios (see Table 40). All forecast years have the same value because the price forecast and the participant load shape stay constant over the forecast period.

Table 41. Annual Consumer Surplus per PSP Participant from Avoidance of the Hedging Premium

Year	Hedging Premium 5%	Hedging Premium 10%	Hedging Premium 15%
2008	$35.66	$71.33	$107.00
2009	$32.48	$64.96	$97.43
2010	$35.14	$70.29	$105.40
2011–2020	$33.16	$66.32	$99.48

Source: Navigant analysis

Savings Related to Shifts in Usage. The amount of consumer surplus attributable to shifting consumption can be estimated by calculating the triangle portions of the consumer surplus (purple) areas under the demand curves in Figure 32. The methodology for estimating the area within each triangle is the same as the methodology used for estimating the adjustments to the original bill savings. The size of the individual triangles is the same. However, in this case we are not adjusting a previous estimate by reducing benefits under both price conditions (reducing benefits when RTP is low and increasing losses when RTP is high). Instead, we are looking for how the triangles contribute to the total volume of consumer surplus. In this case, when RTP is low the triangle is a consumer surplus benefit, but when RTP is high the triangle is a consumer surplus reduction. The shifting components can offset each other under the different price conditions.

Table 42 shows the component of consumer surplus that can be attributed to changes in consumption in response to price. The relatively high RTP levels in 2008 had the effect of reducing participant consumption and consumer surplus in that year, while lower RTP levels in 2008 and 2009 had the opposite effect. Note that this method is applied to every individual summer hour and implicitly includes the net impact of any conservation or increased usage that occurs. Under this methodology, conservation decreases consumer surplus for the reasons discussed previously.

Table 42. Annual Consumer Surplus per PSP Participant from Shifts in Usage

Year	$ per Participant
2008	-$1.18
2009	$16.75
2010	$2.80
2011–2020	$3.06

Source: Navigant analysis

Remaining Savings. If savings from shifting of use and avoidance of the hedging premium is subtracted from the total consumer surplus, the remaining savings can be considered a good approximation of the benefits PSP participants receive when the actual average annual market price is lower than the expected equivalent energy component of the flat rate. Of course, this method for estimation of savings due to forecast error is highly contingent on the assumed hedging premium, which is unknown.

Table 43. Annual Consumer Surplus per PSP Participant from Forecast Error

Year	Hedging Premium 5%	Hedging Premium 10%	Hedging Premium 15%
2008	$74.06	$38.40	$2.73
2009	$266.00	$233.50	$201.10
2010	$173.11	$138.00	$102.80
2011–2020	$0	$0	$0

Source: Navigant analysis

Table 43 shows the estimate of consumer surplus from the forecast error for the three different hedging premium scenarios. As expected, in 2008 when market prices were high compared to the flat rate and the forecast error was lower, the consumer surplus from the forecast error was much lower. In fact, if the hedging premium is actually 15 percent of the energy charge, there was almost no consumer surplus from forecast error in 2008. Consumer surplus from the forecast error was much higher in 2009 and 2010 when market prices dropped and the forecast error went up.

Given the current unbalance between these two prices, it seems unlikely that the flat rate energy component will stay at its current value throughout the forecast period. In an ideal world, we would expect the flat rate energy component to come in alignment with market prices so that the forecast error is zero over the long run.

For this reason, Navigant uses a value of zero for the annual consumer surplus that comes from forecast error in future years. In other words, in future years the total consumer surplus is the sum of the bill savings from avoidance of the hedging premium and from shifting consumption; however, there are no future bill savings from the difference between market prices and the equivalent energy component of the flat rate. The three components of consumer surplus are shown for the historical years and forecast years in Table 44, assuming a hedging premium of 10% which is the base case.

Table 44. Components of Annual Consumer Surplus per PSP Participant

Year	Hedging Premium 10%	Shifting Consumption	Forecast Error	Total Consumer Surplus
2008	$71.33	-$1.18	$38.44	$108.59
2009	$64.96	$16.75	$233.54	$315.25
2010	$70.29	$2.80	$138.06	$211.05
2011–2020	$66.32	$3.06	$0	$69.38

Source: Navigant analysis

Benefit #3: Non-Participant Benefits

This is the market effects benefit discussed in detail in Section 4.1 of this report. It represents the price reduction benefits that accrue to non-participants because system demand has been lowered by the program. Price reductions come from reduced energy supply costs, reduced congestion prices, and reduced loss prices.

Navigant used the corresponding annual energy supply cost curves by season to estimate non-participant benefits in historical years, and used the average of all years by season for forecast years. For the transmission congestion, and loss marginal cost curves, there was little variance across years or seasons so the average of 2008–2010 was used for modeling non-participant benefits in all historical and forecast years.

The total benefits are calculated for three different populations:

1. All MISO customers
2. All Ameren Illinois customers
3. Ameren Illinois residential customers

The net benefits that accrue to all MISO customers are considered to be the best indicator of overall economic benefits for consumers from the PSP program. However, the subset of benefits that accrue to Ameren Illinois residential customers are also reported based on the specific requirements of Public Act 094-0977 which created PSP, and were incorporated in the order from the Illinois Commerce Commission (ICC) in Docket 06-0961, which implemented that legislation. That docket required an economic evaluation of the RTP program be conducted after the implementation period of 2007–2010, and further required that the net economic benefits to the residential community be specifically identified.

4.2.2 Results

Data was gathered on both historical and forecasted costs and benefits for the PSP program for the years of 2007–2020 following the methodology outlined above. This assessment considers the net benefits of the program looking both at historical program years and at a ten-year projected lifetime (2011 to 2020) for existing PSP participants.

Historical Program Years. Table 45 provides the annual program costs and benefits over the 2007–2010 time frame, which covers the first four years of actual implementation. These results are presented separately for each year since there are dramatic changes from year to year. In the start-up years of the program, net benefits are negative going from -$1,040,000 in 2007 to -$394,000 in 2008. This reflects the significant investment needed to develop the processes and IT systems required for program start-up. In 2009 and 2010 these start-up costs are done and we see regular on-going program implementation costs. Customer enrollments increase each year, meaning benefits also increase. The overall effect is positive net benefits on an annual basis, going from $744,200 in 2009 to $741,800 in 2010. This view is looking strictly at benefits that accrue to the Ameren Illinois Residential customers, as required in Docket 06-

0961. Considering initial start-up costs, the program is close to a break-even point after the first four years of operation. Looking only at the nominal costs presented here without adjustment for the time value of money, total net benefits over the four year period are $51,800.

Table 45. Historical Benefits and Costs for PSP Program 2007-2010

	2007	2008	2009	2010
Participant Benefits: Avoided Capacity Costs	$0	$7,200	$9,800	$14,000
Participant Benefits: Consumer Surplus	$0	$170,800	$1,666,000	$1,872,000
Non-Participant Benefits: Residential Customers	$0	$5,200	$2,100	$14,800
TOTAL BENEFITS	$0	$183,200	$1,677,900	$1,900,800
TOTAL COSTS	$1,040,000	$577,400	$933,700	$1,159,000
NET BENEFITS	**-$1,040,000**	**-$394,200**	**$744,200**	**$741,800**

Program start-up costs and incremental meter costs are included.
Source: Navigant analysis

Ten-Year Projected Lifetime. The historical analysis leads to the question of what program net benefits would be if the program were to be extended over a longer timeframe. Table 46 provides the net present values of the major cost and benefit components that would be related to extending the life of the program another ten years over the 2007–2020 time frame, along with the net present values of the overall net benefits. These results show positive net benefits of $5,913,000 at the MISO level. Net benefits are greatly reduced from the Ameren Illinois view and the Ameren Illinois residential customer view; however, both views still show positive net benefits. From the long-term economic perspective of all consumers and Ameren Illinois residential customers, the PSP program creates net benefits.

Table 46. Net Present Value of Benefits and Costs for Program Inception through 2020

	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Participant Benefits: Avoided Capacity Costs	$3,452,000	$3,452,000	$3,452,000
Participant Benefits: Consumer Surplus	$10,097,000	$10,097,000	$10,097,000
Non-Participant Benefits: Market Effects	$5,844,000	$411,000	$201,000
TOTAL BENEFITS	$19,393,000	$13,960,000	$13,750,000
TOTAL COSTS	$13,480,000	$13,480,000	$13,480,000
NET BENEFITS	**$5,913,000**	**$480,000**	**$270,000**

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The societal discount rate is 1%.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

It is useful to take a look at how these costs and benefits are distributed over time, particularly how forecast values differ from historical values. Table 47 shows annual benefits and costs for each historical year of the program (2007 to 2010), and then forecasted annual values for 2020.

Table 47. Annual Benefits and Costs for PSP Program

	2007	2008	2009	2010	2020
Participant Benefits: Avoided Capacity Costs	$0	$7,200	$9,800	$14,000	$603,300
Participant Benefits: Consumer Surplus	$0	$170,800	$1,666,000	$1,872,000	$716,200
Non-Participant Benefits: Market Effects MISO View	$0	$167,800	-$11,940	$418,300	$581,100
Non-Participant Benefits: Market Effects Ameren Illinois View	$0	$11,780	$729	$29,050	$41,600
Non-Participant Benefits: Market Effects Ameren Illinois Residential View	$0	$5,200	$2,100	$14,800	$20,020
Program Costs	$1,040,000	$577,400	$933,700	$1,159,000	$1,084,000

These costs and benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The societal discount rate is 1%.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Participant benefits from avoided capacity costs increase significantly between historical years and forecast years because the short-term capacity market values are used in 2008 through 2010, while the cost of new entry is used to value avoided capacity for 2011 and beyond. The cost of new entry in real dollars is expected to increase annually throughout the forecast period. These increasing construction costs combined with the increased participant counts and increased summer peak reductions from the program that were already mentioned create the higher forecast benefits for 2020.

Participant benefits from consumer surplus are lowest in 2008 because market prices were relatively high compared to the flat rate. Consumer surplus is substantial in 2009 and 2010 because market prices were lower compared to the flat rate. This created significant bill savings for participants. In future years, it is assumed that the flat rate will come into balance with the market rate over time; therefore, net benefits come primarily from avoidance of paying any hedging premium.

Total non-participant benefits from the reduction in MISO prices are higher in 2008 than in 2009, even though there were half as many customers in 2008. This is because market prices were high in 2008 and the supply curve was steeply sloping at high prices that year. Benefits grow from 2009 to 2010 because of the increase in the number of customers in the program. Benefits are higher in forecast years than in 2010 for several reasons. First, the 2010 participant count is based on an annualized number (8,871), whereas forecast years have a participant count equal to the 2010 end-of-year participant number (10,320). Second, the average supply curve for future years is slightly higher than the 2010 supply curve. Third, it is expected that HPA days will be called in future years on hot weather days, and this will create summer demand reductions higher than what was seen in 2008, which was a cool summer, or in 2009 or 2010, which did not have any HPA days.

It is important to note when looking at all of the historical benefits that there is a trade-off that occurs between non-participant benefits and participant benefits depending on the relationship of market energy prices to the flat rate. In years like 2008 where market prices were relatively high, non-participants gained large benefits when program impacts reduced market prices. Participants received relatively low bill savings in that year. Alternatively, in years like 2009 and 2010 when market prices are low compared to the flat rate, non-participant benefits from the program drop and participant consumer surplus gains soar. In short, when non-participant benefits are high, participant benefits are low, and vice versa. There are always benefits from the program in each year. The relationship between market prices and the flat rate determines whether those benefits go primarily to non-participants or participants.

If market prices do dramatically exceed the flat rate in some future years, it is possible that participants would respond by reducing their load even more than what has been seen in the past three years of relatively low market prices, and supply curves would shift upwards to match or exceed 2008 curves. If this happens, non-participant benefits would be greater than what is currently in the forecast. Likewise, if the market prices continue to stay well above the flat rate, participants will reap more benefits than what is in the current forecast. For these reasons, the current forecast should be considered a conservative estimate of total future benefits. If there are large deviations between the flat rate and market prices in future years, in either direction, program benefits will be greater than what is shown here.

Program costs include significant start-up costs in 2007 when the billing system needed to be modified to handle RTP. After 2007, program administration costs drop significantly even as marketing costs are added. In the forecast years, the meter charges make up 60 percent of the annual program costs. If interval meters were to become standard issue due to a Smart Grid implementation, this meter charge to the program would become zero and significantly reduce future program costs.

We will now learn more about the robustness of the net benefits estimates by looking at results under different scenario conditions.

Growth in Number of Participants

The base scenario results assume no growth in the number of participants in the PSP program after 2010. Two other customer growth scenarios were also considered: reaching 50,000 participants by 2015 and reaching 100,000 participants by 2015.

Table 48 shows that net benefits increase substantially across all views as the participation rates increase. The greatest gains in net benefits occur in the Ameren Illinois and Ameren Illinois Residential views.

Table 48. Impact of Program Participation Rates on Net Benefits

Net Present Value of Net Benefits:	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
No Growth in Participation (rate remains at 1%)	$5,913,000	$480,000	$270,000
Participation Reaches 50,000 by 2015	$31,530,000	$12,080,000	$11,320,000
Participation Reaches 100,000 by 2015	$63,480,000	$26,650,000	$25,220,000

The societal discount rate is 1%.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Societal Discount Rate

The base scenario results assume a societal discount rate of 1 percent. Rates of 2 and 3 percent were also tested in additional scenarios.

What societal discount rates are normally used in net benefits analysis? The U.S. Federal Office of Management and Budget requires a 5 percent discount rate for most studies it reviews, along with sensitivity analysis. The U.S. Environmental Protection Agency typically uses a lower 3 percent discount rate, while the U.S. Congressional Budget Office usually uses a 2 percent discount rate. Navigant recommends use of a discount rate at the lower end of these values, in the 1 to 3 percent range. This is based on the fact that current inflation-protected treasury bonds, which are relatively free of risk and inflation effects, are at 1 percent, 1.5 percent, and 1.85 percent for 10-year, 20-year, and 30-year terms, respectively.[34] These securities typically do a good job of reflecting the social discount rate. Given that Navigant's net benefits assessment is looking at a ten-year forecast period, it uses 1 percent for the base scenario to be in line with these market values. However, Navigant will also look at 2 and 3 percent rates for sensitivity analysis.

Table 49 shows that net benefits decrease slightly as the discount rate increases. Net benefits still remain positive across all customer views under each discount rate scenario.

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[34] http://www.federalreserve.gov/releases/h15/update for March 7–10, 2011.

Table 49. Impact of Societal Discount Rates on Net Benefits

Net Present Value of Net Benefits:	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Societal Discount Rate = 1%	$5,913,000	$480,000	$270,000
Societal Discount Rate = 2%	$5,358,000	$376,100	$183,100
Societal Discount Rate = 3%	$4,861,000	$284,000	$106,800

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020,
but there are no additional participants added to the program.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Program Start-up Costs

The base scenario results include all program costs, including start-up costs. A scenario that excludes start-up costs was also run to evaluate the value of continuing the program forward.

Table 50 shows that, as expected, net benefits increase across all customer views when start-up costs are excluded. The additional net benefits are a significant increase for both all Ameren customers and Ameren residential customers. For these customer views, the net benefits of the program essentially double when the start-up costs are excluded. This verifies that start-up costs are a significant share of the costs for this program.

Table 50. Impact of Start-up Costs on Net Benefits

Net Present Value of Net Benefits	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Base Scenario: Include Program Start-up Costs	$5,913,000	$480,000	$270,000
Exclude Program Start-up Costs	$6,943,000	$1,510,000	$1,299,000

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020,
but there are no additional participants added to the program.
The Societal Discount Rate is 1%.
Incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Incremental Meter Costs

The base scenario results include all incremental meter costs on an amortized basis as a monthly charge per participant. A scenario that excludes meter costs was also run to evaluate the net benefits of the PSP program in a Smart Grid environment where special metering is not needed for participation.

Table 51shows that, as expected, there are additional net benefits across all customer views when incremental meter costs are excluded. The increase in net benefits is greater than $6 million within each view, which is substantial in all views, but particularly for Ameren Illinois and Ameren Illinois Residential.

Table 51. Impact of Incremental Meter Costs on Net Benefits

Net Present Value of Net Benefits	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Base Scenario: Include Incremental Meter Costs	$5,913,000	$480,000	$270,000
Exclude Incremental Meter Costs	$12,460,000	$7,028,000	$6,817,000

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The Societal Discount Rate is 1%.
Program start-up costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Hedging Premium

The base scenario assumes the hedging premium included in the energy cost component of the fixed rate is 10 percent. Scenarios were developed to test net benefits when the hedging premium is less (5 percent) or more (15 percent).

Table 52 shows that the assumption on the hedging premium has a greater influence on net benefits swinging from positive to negative than any of the other sensitivity variables. If the hedging premium is only 5 percent instead of the assumed 10 percent, net benefits from the program are no longer positive from the Ameren or Ameren residential customers' view. This is because a significant portion of the forecasted consumer surplus benefits come from the portion of bill savings that PSP customers derive when they accept the risk of market prices on their own and avoid paying hedging premiums. If the hedging premium is reduced, the amount of consumer surplus they can expect to achieve is also reduced. Net program benefits are still strongly positive at the MISO customer view regardless of the hedging premium assumption.

Table 52. Impact of Hedging Premium on Net Benefits

Net Present Value of Net Benefits:	MISO View	Ameren Illinois View	Ameren Illinois Residential Customers View
Hedging Premium = 5%	$2,798,000	-$2,635,000	-$2,845,000
Base Scenario: Hedging Premium = 10%	$5,913,000	$480,000	$270,000
Hedging Premium = 15%	$9,028,000	$3,595,000	$3,384,000

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The Societal Discount Rate is 1%.
Start-up costs and incremental meter costs are included.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

4.3 *Other Program Benefits*

The PSP program potentially generates a number of additional benefits that are difficult to quantify. Among these are environmental and health benefits due to reduced emissions of pollutants; benefits from mitigation of market power in electricity markets; benefits from reduced price volatility; benefits from increased reliability and power quality; and benefits from reduction in consumption-related deadweight loss.

4.3.1 Environmental and Health Benefits

In principle, demand response programs may generate environmental benefits in either of two ways. First, a reduction in energy consumption could generate a reduction in harmful emissions associated with the production of energy, such as SO_2, NO_x, and CO_2. Second, even in the absence of a reduction in consumption, a shift in consumption can generate environmental benefits or costs depending on the marginal fuel mix at different times of day.

Navigant's finding that PSP conservation effects are basically zero means that any program-induced environmental benefits or costs are due to the effect of the program on load-shifting. Holland and Mansur (2008) use an analysis of emissions within North American Electric Reliability Corporation regions to examine the effect of reduced variance in within-day load due to RTP on regional emissions.[35] Their analysis approach is to statistically estimate the effect of average daily load mean and variance on emissions, and to then estimate the effect of RTP on these distributional parameters. Results of an econometric analysis indicate that for the Mid-America Interconnected Network (MAIN) region, which encompasses Ameren Illinois, a reduction in the within-day load coefficient of variation (COV) would generate slight decreases in the generation of SO_2, NO_x, and CO_2. In particular, a 1 percent reduction in the within-day load COV generates reductions in these pollutants of 0.027 percent, 0.037 percent, and 0.031 percent, respectively.

The observed load-shifting due to the PSP program does indeed reduce load variance by reducing load when it is high and increasing it when it is low. As an example, in summer 2008, within-day variance in load for control customers (load research group customers) was 0.240, whereas that for PSP customers was 0.184, a reduction of approximately 25 percent. Given that load-shifting due to the PSP program was highest in summer 2008, this serves as a reasonable upper bound on the relative effect of the PSP program on average household load variance.

To estimate the effect of this variance reduction on emissions, we must first approximate its effect on the MAIN load COV, and then use this calculation in the econometric model estimated by Holland and Mansur to estimate the consequence for emissions. In particular:

1. The share of the total annual load of the MAIN region attributable to PSP households, given the program includes 10,000 households generating 13 mWh each, is approximately 0.0004.[36]
2. Assuming that PSP households' share of the load COV is also 0.0004—a reasonable assumption—the PSP program reduces the MAIN load COV by $(0.25)\cdot(0.0004) = 0.0001$, or 0.01 percent.
3. In light of the results obtained by Holland and Mansur reported above, it follows that the PSP program reduces SO_2, NO_x, and CO_2 emissions by 0.00027 percent, 0.00037 percent, and 0.00031 percent, respectively.
4. Holland and Mansur approximate SO_2, NO_x, and CO_2 emissions in MAIN to be about 1.3 million tons, 350,000 tons, and 220 million tons, respectively.

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[35] Holland, S.P. and E.T. Mansur. 2008. "Is Real-Time Pricing Green? The Environmental Impacts of Electricity Demand Variance". *The Review of Economics and Statistics* 90(3): 550-561.

[36] The annual load for PSP customers is approximately 130 gWh: 13 mWh per household, multiplied by 10,000 households. The annual load for the MAIN region is 294,155 gWh (from Holland and Mansur, using EPA data from 2000). 130/294,155=.0004.

5. Applying the results in (3) to the loads in (4), we obtain rough estimates of annual emissions reductions due to the PSP program: 3.5 tons of SO_2, 1.3 tons of NO_x, and 682 tons of CO_2.

We now consider the dollar value of these reductions. Based on an analysis of Title IV of the 1990 Clean Air Act, Chestnut and Mills (2005) estimate that the *average* social environmental and health benefit of a combined reduction of 1 ton of SO_2 and 0.3 tons of NOx—a ratio close to that estimated above for the PSP program—is approximately $15,000.[37] Given the above-estimated annual reductions in SO_2 and NO_x, we obtain PSP program benefits associated with these emissions of approximately $52,000.

Whereas the estimate from Chestnut and Mills pertains to the *average* value of emission reductions under Title IV, the PSP program reductions are at the margin, suggesting that $52,000 is an overestimate. On the other hand, Chestnut and Mills observe that the history of studies of the health and environmental costs of emissions is that estimates of such costs are rising over time.

Estimates of the benefits from a reduction in CO_2 vary widely. The median estimate across a number of studies is $14/ton (Toll 2004).[38] At this value, the annual PSP program benefit that arises from CO_2 emissions reductions is $9,500.

Overall, then, Navigant's best estimate of the benefits due to the PSP program arising from reductions in emissions of SO_2, NO_x, and CO_2 is about $62,000 annually.

4.3.2 Benefits Due to Reductions in Market Power

As shown by Borenstein and Holland (2005), the long-run effect of RTP adoption is an increase in demand elasticity, which serves to reduce the market power of generators. One can expect, therefore, that the PSP program further reduces electricity prices for all Ameren Illinois customers beyond that calculated previously, by reducing generator market power. The magnitude of this benefit depends on the degree of market power in MISO. The MISO IMM finds that although there is evidence of *local* market power in MISO, there is little evidence that market power was exercised in 2008 or 2009. (The State of the Market Report for 2010 is not yet available.)[39]

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[37] L.G. Chestnut and D.M. Mills, "A Fresh Look at the Benefits and Costs of the U.S. Acid Rain Program," *Journal of Environmental Economics and Management*, 2005, 77: 252-266.
[38] R.S.J. Tol, "The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties," *Energy Policy*, 2004, 33: 2064-2074.
[39] 2008 and 2009 State of the Market Reports for MISO, prepared by Potomac Economics (Independent Market Monitor for the Midwest Independent System Operator) are available at
http://www.potomaceconomics.com/uploads/midwest_documents/2008_State_of_the_Market_-_Final.pdf
http://www.potomaceconomics.com/uploads/midwest_documents/2009_State_of_the_Market_Report.pdf

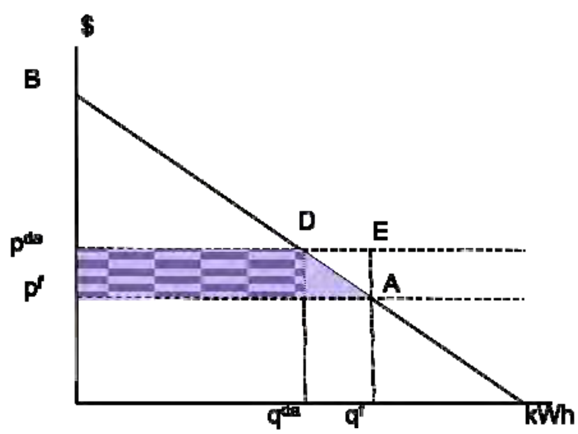
4.3.3 Benefits from Increased Reliability and Power Quality, and Reduced Price Volatility

The higher elasticity of demand associated with the PSP program serves to reduce power outages associated with the failure of supply to meet demand during peak hours, and to reduce price volatility. Boisvert and Neenan (2003) have a good theoretical discussion of the potential benefits of RTP programs for system reliability. Navigant knows of no empirical estimates of these benefits in the peer-reviewed literature.[40]

4.3.4 Benefits from Reduction in Consumption-Related Deadweight Loss

Deadweight loss is a measure of inefficiency in an economic market. Moving to a real-time pricing regime generates a reduction in deadweight loss that does not necessarily accrue directly to customers. This reduction applies to the case when the day-ahead price is higher than the fixed-rate price, and arises because the PSP household consumes less than it would under the fixed-rate price, and thus spares Ameren Illinois the purchase of energy at a higher price than it is worth to the household. This is illustrated in Figure 33. As already noted in reference to Figure 32 on page 95, the shaded area p^fADp^{da} denotes the consumption-related loss to the PSP household from the price increase. On the other hand, the effective cost of providing the initial level of energy q^f at price p^{da} is the area p^fAEp^{da}, and so by facing the true cost of energy, and thereby reducing consumption, the PSP household effectively increases the efficiency of the system, generating an overall gain in economic market efficiency of DEA.

Figure 33. Illustration of Deadweight Losses



Source: Navigant analysis

Our calculations of the reduction in deadweight loss shows these losses to be minor: $6.14 per participant in 2008, $0.00 in 2009, and $0.73 in 2010, and $0.60 in forecast years.

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[40], R.N. Boisvert and B.F. Neenan. "Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets," 2003, Lawrence Berkeley National Laboratory, LBNL-52530. Link available at http://www.osti.gov/bridge/purl.cover.jsp;jsessionid=032CAA47ED710587B6FC23F7D466C9E1?purl=/816220-T0pRMN/native/

5 Conclusions

Navigant has presented a great deal of information in this report regarding the impacts and net benefits of the PSP program, and in this section will highlight the conclusions from each of the previous sections of the report.

Elasticity

Over the past three years of the PSP program, participants have displayed two different types of responses to prices, or elasticities: medium run and short run.

In the medium run, households respond to differences in *average hourly price* with a broad shift in energy consumption behavior as compared to their behavior under the fixed-price regime, forming new habits and modes of operation, such as running dishwashers at night. Such broad shifts in behavior are consistent with the information provided to PSP customers, indicating that shifting energy consumption to overnight hours, when prices are low, reduces energy bills.

Medium-run elasticities are measured based on hourly average differences between participants and a control group, and were found to vary from a low of -0.04 on weekday nighttime hours to a high of -0.29 during late afternoon weekday hours.

Even after shifting their daily energy consumption routine to exploit variation in average hourly prices, households can potentially benefit still more **in the short run**—on an hour-to-hour basis—by responding when prices deviate significantly from their hourly means. The extent of the response depends on both the extent of the price deviation and the cost of short-term behavioral adjustments, including the cost of closely monitoring prices. Programs that provide price information cheaply serve to reduce this cost.

Short-run elasticities were measured using the Generalized Almost Ideal (GAI) demand system. As the medium elasticity model captures the "rules of thumb" behavioral changes in response to seasonal average prices, the GAI demand system focuses on very short-run elasticities: how do participants respond to especially high prices? Frequently checking electricity prices is time consuming; hence, information is costly. Navigant therefore expects customers to respond to high prices only on days when the cost of information is reduced and the potential benefits are high. The HPA serve exactly this purpose. On HPA days, participants are alerted that prices are exceptionally high, creating an opportunity to lower their bill by reducing their load during the high-priced hours. For this analysis, Navigant estimated the GAI demand system using only the 28 HPA days that occurred during summer 2008. The short-run own-price elasticities were found to range from a low of -0.21 in the hour of 3 pm to 4 pm, to a high of -0.89 in the hours of noon to 2 pm. These elasticities are larger than estimates reported elsewhere in other studies of dynamic pricing programs for residential customers; however, this is not unexpected, because the short-run nature of the estimate captures only customer response to very high prices during limited time periods (HPA days).

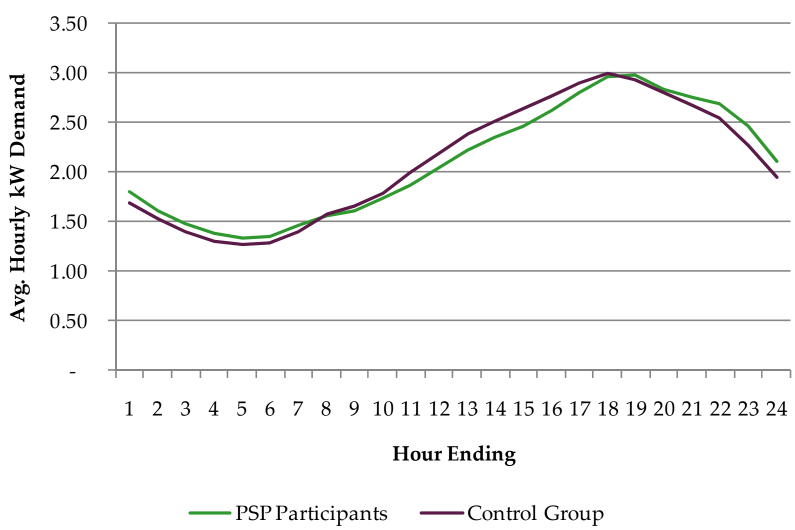
Navigant believes that the use of two separate elasticity estimates, one medium run and one short run, is the best way to characterize residential customers' true response to dynamic prices.

Hourly Demand Impacts

In the spring, winter, and fall seasons there is a general response among PSP participants to use less energy during the day and more in the overnight period compared to a matched control group. This response is slight, but generally persistent over the seasons and the years. This is related to the medium-run elasticity concept that customers learn about general price patterns and establish habits that persistently shift some electric use into known off-peak periods of the day and week.

The summer season is when most hourly demand impacts occur from the PSP program. Figure 34 shows that in the 2010 summer season, PSP participants continued their characteristic response of lowering use between 10 am and 5 pm by an average of -0.15 kW. This compares to an average load reduction of -0.21 kW in 2008 and -0.13 kW in 2009 for the same period of the day. Again, this consistency from year to year is representative of the medium-run elasticity response as practiced on all weekdays during the summer season.

Figure 34. Indexed Summer Weekday Load Shapes for 2010



Source: Navigant analysis

2008 was the only year with HPA days. In that year, customers increased their daytime load reductions from an average of -0.21 kW/customer on weekdays to an average of -0.26 kW/customer on HPA days. Looking at weather data for 1990 through 2010, 2008 stood out as one of the coolest summers in that twenty-one year period, and 2010 was the hottest. There was an average difference of 0.7 kW in use during the daytime hours when comparing 2008 summer use to 2010 summer use for the control group. The weather was cool in 2008 and usage was low, but HPAs were called because market prices for electricity were high. This means that when participants responded by turning down their air-conditioning, there often wasn't much air-conditioning in use. Consequently, Navigant modeled HPA day response related to weather and predicts that if HPAs were called during summers of normal temperatures, expected load reductions on HPA days would be closer to -0.45 kW per customer than -0.26 as observed in 2008.

Conservation Effects

Monthly billing data from January 2007 through January 2011 was used to estimate the conservation effect from the PSP program. Billing data was available for 953 control group residential customers and more than 11,000 current or past participants in the PSP program. Although the 2008 and 2009 PSP evaluation studies reported some net annual conservation savings from the program, those previous estimates were based on single-year analyses of the data. The current multiyear data set was used to measure conservation effects over the entire program period. These are considered to be much more robust estimates of conservation effects from the program.

Table 53. Annual Change in kWh Consumption for PSP Participants

Season	Annual kWh Change	Percentage Change
Spring	-47	-1.8%
Summer	-139	-3.2%
Fall	-94	-3.4%
Winter	309	9.2%
Total Year	29	0.2%

Source: Navigant analysis

As Table 53 shows, the PSP program encourages conservation effects among participants in the spring, summer, and fall seasons. Over these three seasons, an average of 280 kWh per year is saved per participant. However, the situation changes in the winter season when participants face relatively low winter market prices. Their use increases by 309 kWh per participant, and this negates the savings from the rest of the year to create an overall net increase of 29 kWh per participant. Given the results of this multiyear study, Navigant recommends that the conservation effect be considered zero on average for the PSP program. However, if in the future winters were to become milder and summers warmer and more humid, the PSP program could induce a mild conservation effect.

Bill Savings

In 2010 the aggregate savings for PSP participants was $1,724,959.78, which represents a 12.35% total savings compared to what the same bills would have been under the standard rate. Average customer savings were slightly negative in the months of July and August, primarily due to a very hot summer and moderate hourly electricity prices, which did not encourage extraordinary efforts to shift air-conditioning loads.

During discussions on the bill savings estimates shown in the 2009 PSP evaluation report, some members of the ICC staff expressed interest in understanding the components contributing to the overall estimate of bill savings. In response to that interest, Navigant estimated three major components of the bill savings:

1. Avoidance of the hedging premium
2. Savings related to shifts in usage

3. Remaining savings, primarily due to the difference between the flat rate and the market rate

The hedging premium can be thought of as the insurance premium that must be paid so regular residential customers can pay a predictable flat rate every month and be protected from both high and low price swings in the electric energy market. Although this hedging premium is known to exist as a portion of the flat rate, there are no straightforward methods for estimating exactly what the value of this premium is. General consensus is that it is likely to be in the 5 percent to 15 percent range when estimated as a percentage of the energy charge. Given the uncertainty around this variable, it was treated as a sensitivity variable and tested at the 5 percent, 10 percent, and 15 percent levels.

The ability to **shift usage** from high price hours to lower price hours is an important component of bill savings in a RTP program. The amount of bill savings attributable to this kind of shifting can be estimated by comparing the PSP participants' actual bills to what their bills would have been if they had not shifted any use but had been billed on day-ahead prices. The control group load shape is our best estimate of what PSP participants would have consumed if they were not in the program. By billing control group consumption on day-ahead prices and then comparing that to PSP participant consumption on day-ahead prices, an estimate is made of how much annual bill savings comes strictly from shifting behavior. The estimated annual bill savings per participant from shifting behavior ranged between $2.05 and $12.99 over the historical period.

If savings from shifting of use and avoidance of the hedging premium is subtracted from the total annual bill savings, the **remaining savings** can be considered a good approximation of the benefits PSP participants receive when the average annual market price is lower than the equivalent energy component of the flat rate. Of course, this estimate of remaining savings due to the price differential is highly contingent on the assumed hedging premium, which is uncertain.

In an ideal world, the flat rate energy component is expected to be in alignment with market prices so that the price differential will be zero over the long run. When looking at bill savings in forecast years, Navigant recommends using a value of zero for the annual bill savings that come from the price differential. In other words, in future years the total bill savings should be modeled as the sum of the bill savings from avoidance of the hedging premium and load shifting; however, there should be no future bill savings from the difference between market prices and the equivalent component of the flat rate.

Relationship Between Day-Ahead Prices, Real-Time Prices, and System Peak Hours

The results for 2010 will be summarized here, and these results are fairly consistent from year to year:

1. The top 20 DAP days can correctly predict 40 percent of the top 20 RTP days.
2. The top 20 DAP days can correctly predict 65 percent of the top 20 system peak days.
3. The top 20 RTP days can correctly predict 35 percent of the top 20 system peak days.

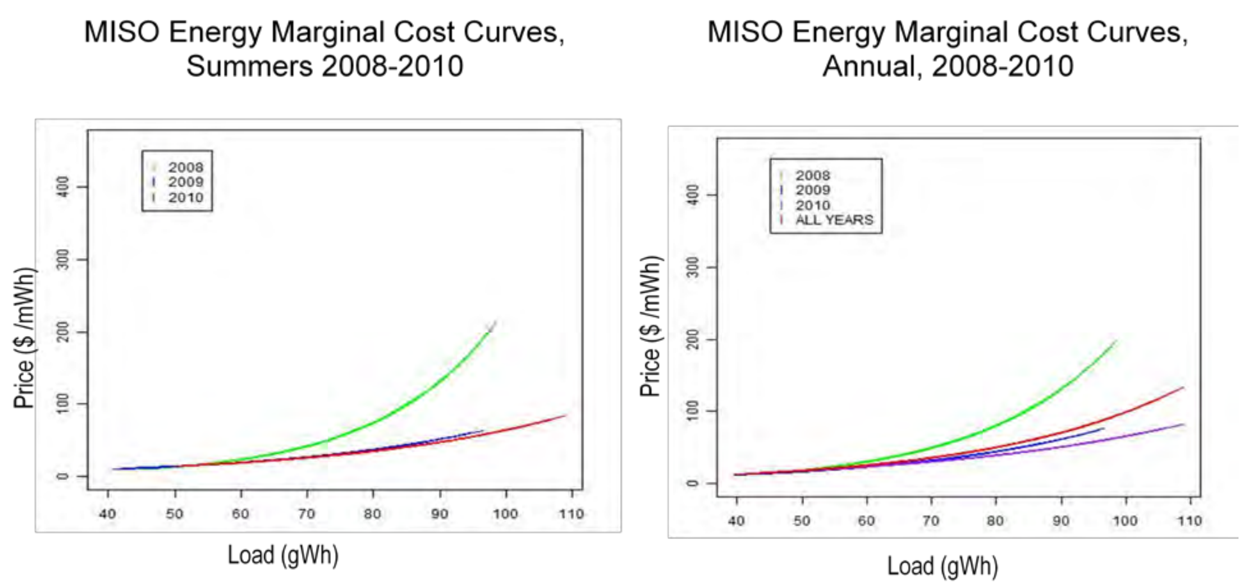
Of most interest here is the finding that DAP is much more reliable than RTP for predicting when system peak days will occur. Because the PSP program uses DAP, customers will be correctly called to action to reduce system peaks more often than would occur using RTP. Because of the high volatility in the RTP compared to the DAP, RTP does not have a predictable relationship with either DAP or system peaks.

Market Effects

Hourly changes in demand that are the result of the PSP program exert influence on MISO prices. This is most significant during peak price periods, such as summer afternoons, when the PSP program causes reductions in demand that contribute to reductions in MISO LMP. These price reductions apply to all customers in the market, not just PSP participants. These non-participant benefits are called the market effect.

The LMPs for the Ameren Illinois service area are composed of three components: an energy price component that is the market clearing price of energy in the MISO market; a congestion price component reflecting the impact of Ameren Illinois loads on the routing of transmission to avoid congestion; and a loss component associated with transmission. Historical price and load data for MISO and the Ameren Illinois system were used to estimate the energy supply curves needed to translate a load reduction into a price reduction on the MISO system.

Figure 35. Estimated MISO Energy Supply Curves

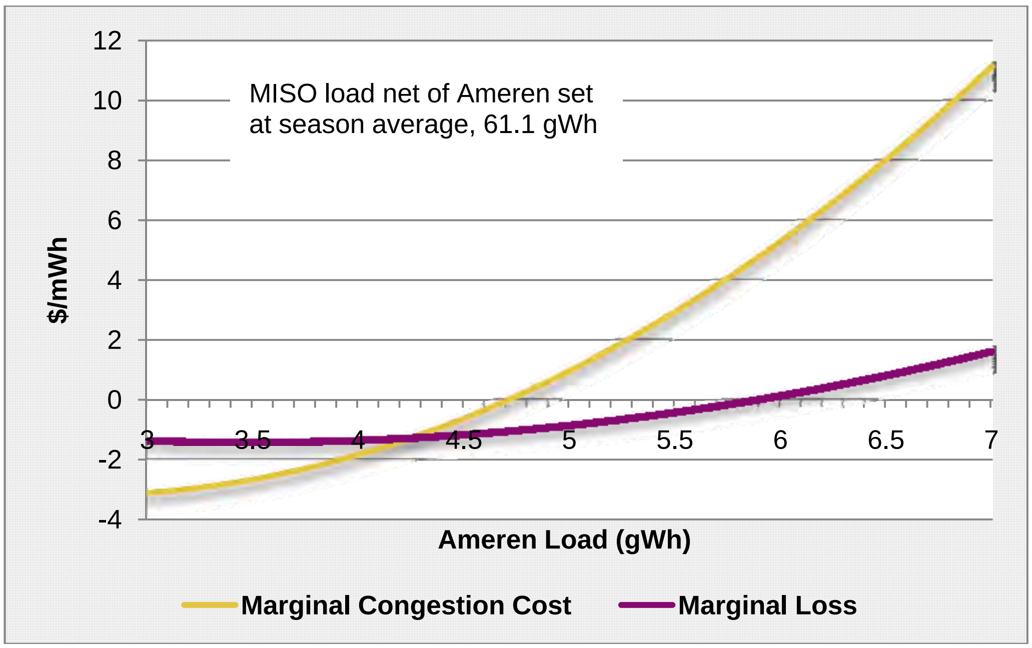


Source: Navigant analysis

Figure 35 displays a set of graphs. The first graph presents the energy supply curves for each summer, 2008–2010, and the second presents annual supply curves, 2008–2010, along with an overall supply curve estimated on all data, 2008–2010. A striking feature of the results is that the supply curve was much higher in summer 2008 than in other seasons. This possibly reflects the spike in gas prices in the middle of 2008. Navigant used the individual historical seasonal supply curves to estimate non-participant benefits in those years, and used the average of all years by season for forecast years.

Figure 36 shows Navigant's estimation of the transmission congestion and loss marginal cost curves. There was little variance across years or seasons for these curves, so the average of 2008–2010 is used for modeling non-participant benefits in all historical and forecast years. There is no variation by season.

Figure 36. Estimated Ameren Illinois Transmission Congestion and Loss Curves



Source: Navigant analysis

Note that all of these marginal cost curves have the traditional "hockey stick" shape (i.e., their slope becomes steeper at higher system loads). It is this characteristic that makes PSP participants' load reductions in summer create overall price reductions for non-participants even as their increased use at non-peak times, such as winter, creates price increases. The price increases during non-peak times are near zero because they tend to occur when the marginal cost curves are flatter.

Net Benefits Assessment

The total net benefits for the PSP program are calculated for three different populations:

4. All MISO customers
5. All Ameren Illinois customers
6. Ameren Illinois residential customers

The net benefits that accrue to all MISO customers are considered to be the best indicator of overall economic benefits for consumers from the PSP program. However, the subset of benefits that accrue to Ameren Illinois residential customers are also reported based on the specific requirements of Public Act 094-0977 which created PSP, and were incorporated in the order from the Illinois Commerce Commission (ICC) in Docket 06-0961, which implemented that legislation. That docket required an economic evaluation of the RTP program be conducted after the implementation period of 2007–2010, and further required that the net economic benefits to the residential community be specifically identified.

This assessment considers the net benefits of the program looking both at historical program years and at a ten-year projected lifetime (2011 to 2020) for existing PSP participants.

Historical Program Years. Table 54 provides the annual program costs and benefits over the 2007–2010 time frame, which covers the first four years of actual implementation. These results are presented separately for each year since there are dramatic changes from year to year. In the start-up years of the program, net benefits are negative going from -$1,040,000 in 2007 to -$394,000 in 2008. This reflects the significant investment needed to develop the processes and IT systems required for program start-up. In 2009 and 2010 these start-up costs are done and we see regular on-going program implementation costs. Customer enrollments increase each year, meaning benefits also increase. The overall effect is positive net benefits on an annual basis, going from $744,200 in 2009 to $741,800 in 2010. This view is looking strictly at benefits that accrue to the Ameren Illinois Residential customers, as required in Docket 06-0961. Considering initial start-up costs, the program is close to a break-even point after the first four years of operation. Looking only at the nominal costs presented here without adjustment for the time value of money, total net benefits over the four year period are $51,800.

Table 54. Historical Benefits and Costs for PSP Program 2007-2010

	2007	2008	2009	2010
Participant Benefits: Avoided Capacity Costs	$0	$7,200	$9,800	$14,000
Participant Benefits: Consumer Surplus	$0	$170,800	$1,666,000	$1,872,000
Non-Participant Benefits: Residential Customers	$0	$5,200	$2,100	$14,800
TOTAL BENEFITS	$0	$183,200	$1,677,900	$1,900,800
TOTAL COSTS	$1,040,000	$577,400	$933,700	$1,159,000
NET BENEFITS	**-$1,040,000**	**-$394,200**	**$744,200**	**$741,800**

Program start-up costs and incremental meter costs are included.
Source: Navigant analysis

Ten-Year Projected Lifetime. This historical analysis leads to the question of what program net benefits would be if the program were to be extended over a longer timeframe. Table 55 provides the net present values of the major costs and benefits over the 2007–2020 time frame, along with the net present values of the overall net benefits. These results show positive net benefits of $5,913,000 at the MISO level. Net benefits are greatly reduced from the Ameren Illinois view and the Ameren Illinois residential customer view; however, both views still show positive net benefits. From the long-term economic perspective of all consumers and Ameren Illinois residential customers, the PSP program creates net benefits.

Table 55. Net Present Value of Benefits and Costs for Program Inception Through 2020

	MISO View	Ameren Illinois View	Ameren Illinois Residential Customer View
Participant Benefits: Avoided Capacity Costs	$3,452,000	$3,452,000	$3,452,000
Participant Benefits: Consumer Surplus	$10,097,000	$10,097,000	$10,097,000
Non-Participant Benefits: Market Effects	$5,844,000	$411,000	$201,000
TOTAL BENEFITS	$19,393,000	$13,960,000	$13,750,000
TOTAL COSTS	$13,480,000	$13,480,000	$13,480,000
NET BENEFITS	**$5,913,000**	**$480,000**	**$270,000**

These net benefits reflect a base scenario where PSP participants in 2010 continue on the program until 2020, but there are no additional participants added to the program.
The societal discount rate is 1%.
Program start-up costs and incremental meter costs are included.
Hedging Premium is 10%.
NPV are calculated as the mean of 15 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

A series of sensitivity studies were conducted on key assumptions in the net benefits model. Allowing participation to grow increases net benefits substantially. Changing the societal discount rate to 2 or 3 percent creates little difference, because many of the costs of this program are front-loaded. Similarly, excluding start-up costs shows a large increase in net benefits for the Ameren Illinois residential customers for the same reason. Excluding incremental meter costs causes substantial increases in net benefits in all years, both historical and forecasted.

The sensitivity variable with the greatest impact on whether net benefits are positive or negative is the assumption of what the hedging premium is. The hedging premium represents a proportion of bill savings that PSP participants will always receive because they take on the risk of paying market rates. The hedging premium is assumed to be 10 percent in the base scenario presented above. If it is reduced to 5 percent, net benefits become negative from the Ameren Illinois and Ameren Illinois residential views, although the net benefits remain positive from the MISO view. If the hedging premium is actually 15 percent, net benefits from the program increase substantially in the form of additional consumer surplus for PSP participants.

There are two additional important points to make about the net benefit results. First, there is a trade-off that occurs between non-participant benefits and participant benefits, depending on the relationship of market energy prices to the flat rate. In years like 2008 where market prices were relatively high, non-participants gained large benefits when program impacts reduced market prices. Participants received lower bill savings in that year. Alternatively, in years like 2009 and 2010 when market prices are low compared to the flat rate, non-participant benefits from the program drop and participant consumer surplus gains soar. In short, when non-participant benefits are high, participant benefits are low, and vice versa. There are always benefits from the program in each year. The relationship between market prices and the flat rate determines whether those benefits go primarily to non-participants or participants.

Second, if market prices do dramatically exceed the flat rate in some future years, it is possible that participants would respond by reducing their load even more than what has been seen in the past three years of relatively low market prices, and supply curves would shift upwards to match or exceed 2008 curves. If this happens, non-participant benefits would be greater than what is currently in the forecast. Likewise, if the market prices continue to stay well below the flat rate, participants will reap more benefits than what is in the current forecast. For these reasons, the current forecast should be considered a conservative estimate of total future benefits. If there are large deviations between the flat rate and market prices in future years, in either direction, program benefits will be greater than what is shown here.

Other Benefits

The existing published literature makes clear that there are additional benefits associated with RTP that are difficult to quantify. These include benefits associated with improvements in electricity markets—namely, improved power quality and reliability, lower price volatility, and market power mitigation—that could prove significant in certain circumstances, but which are unlikely to be substantial in the case of the PSP program due to current market conditions and the small size of the program. A change in either the size of the program or the conditions of the market—note, for instance, that the MISO Independent Market Monitor states that local market power does exist in MISO, but that currently this market power does not appear to be exercised—could create a situation in which these benefits are substantial and warrant efforts to carefully quantify.

Navigant also considered health and environmental benefits. Using existing peer-reviewed studies, Navigant approximated the benefit of the PSP program in reducing SO_2, NO_x, and CO_2 emissions to be about $62,000 per year. This value reflects recent published estimates indicating that the per-ton health costs of SO_2 and NO_x emissions are quite high—much higher than understood when Title IV of the 1990 Clean Air Act was passed—as well as the conclusion that the PSP program generates only small annual reductions in these pollutants. Importantly, Navigant's estimate pertains to the *overall* social benefit of emissions reduction, not to Ameren Illinois customers in particular; therefore, Navigant did not include it in its net benefit assessment.

A final benefit that was quantified was the reduction in consumption-related deadweight loss. Deadweight loss is a measure of inefficiency in an economic market. Moving to a real-time pricing regime generates a reduction in deadweight loss that does not necessarily accrue directly to customers. This reduction applies to the case when the day-ahead price is higher than the fixed-rate price, and arises because the PSP household consumes less than it would under the fixed-rate price, and thus spares Ameren Illinois the purchase of energy at a higher price than it is worth to the household. The value of the reduction in deadweight loss is calculated to be $6.14 per participant in 2008, $0.00 in 2009, $0.73 in 2010, and $0.60 in forecast years.