

Evaluating Residential Real-Time Pricing: Connecting Customer Response to Energy Market Impacts

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ABSTRACT

This paper addresses the importance of evaluation in the emerging field of dynamic pricing. Landmark legislation enacted in the US state of Illinois in 2006 mandated that utilities offer an optional real-time pricing (RTP) program to all residential customers. It was also mandated that after four years the program must be evaluated to gauge its impact on both participants and non-participants. The design of the programs allowed for metering costs to be recovered from both participants and non-participants, which in turn required evaluation of the benefits of RTP to all consumers. Previous evaluations of response to dynamic pricing have consistently shown that customers on average do reduce usage in response to increasing prices. However, the effects of those load reductions on wholesale energy markets have not been as well studied and have been subject to some debate. This paper reviews the development of real-time pricing in Illinois and discusses the proposed methodologies and an initial analysis of market impacts.

Introduction

The evaluation of price based demand response programs is an emerging field of study that is not as mature as the evaluation of traditional energy efficiency programs. While time-of-use pricing has been studied for several decades, the literature on pricing programs that have prices that change by the hour is much more recent and limited. These programs are a subset of demand response programs that use price as the signal to consumers to change their energy use. In contrast, most conventional demand response programs use predetermined payment structures to compensate participants for their reductions. Pricing programs as discussed here do not pay participants to reduce demand, rather participants face a set of variable prices that provide information and incentive to participants to use less during high priced times.

While demand response often uses enabling technologies, ultimately the measurement of demand response focuses on estimating how energy use patterns for a set period of time are different from how they would have been in the absence of the demand response program. This measurement is done in a number of ways, such as establishing a baseline load shape of a non-event day for use as a comparison to the hourly load profile during the event, or more typically for price-based demand response programs, the estimation of the elasticity of demand to price. While economists calculate a variety of types of elasticity of demand, the basic concept is to measure how, as the price of electricity changes, the predicted use of energy changes as well.

The elasticity of demand is an outcome used in evaluating price-based demand response programs, but it focuses on the changes in energy use of the participants rather than how those changes impact the wider electric system and supply/demand equilibrium. While understanding how individual customers could be aggregated up to an estimate in the reduction of the system peak, quantifying and monetizing the value of that reduction remains a topic that has not received significant study. The residential real-time pricing programs currently underway in Illinois will be evaluated in 2011 using criteria that include estimating how participants' changes in energy use impacts overall energy markets and how those changes potentially bring benefits to non-participants.

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The Illinois Mandate

The state of Illinois is unique for its clear legislative mandate for residential real-time pricing. In 2006 legislation to support real-time pricing was enacted to start full scale programs in 2007. This legislation came about as a result of a four year pilot program, the Energy-Smart Pricing PlanSM (ESPP) administered by the CNT Energy², a division of the Chicago-based nonprofit the Center for Neighborhood Technology. It was run in partnership with the Chicago-area utility ComEd. Up to this point all the dynamic hourly pricing programs in the US had been pilot programs of limited length, duration and scope. While there have been full scale time-of-use programs (US Department of Energy 2006), and hourly pricing for commercial and industrial customers (e.g., Georgia Power and Niagara Mohawk), this was new for residential customers.

The ESPP pilot was meant to be a proof of concept pilot. It operated during a period when residential rates were frozen (and in fact reduced 20% from 1997 levels) and ComEd was in the process of joining the organized energy market of the PJM Interconnection. CNT Energy had previously tested community-based approaches to reducing peak demand and aggregating customers in the summers of 2000 and 2001, in response to the challenge of local stress to the distribution infrastructure that was exposed by blackouts in the summers of 1998 and 1999. By 2002 the question of what would be the benefits to residential customers from electricity restructuring emerged as a primary concern for CNT Energy. The California energy crisis, the Enron scandal and the failure of disruptive technologies like residential scale fuel cells had all put a damper on the hopes that the electric industry was changing at its most fundamental level in ways that would benefit small customers. While competition for electric service was emerging at the large commercial and industrial level, it was less clear what would happen for residential customers. In addition, the 2007 rate freeze in Illinois was due to expire and prices were expected to rise.

By modeling typical residential hourly load shapes with hourly market energy prices, and by observing how information and education could help residential customers make changes to their energy use, CNT Energy determined the potential value of real-time pricing. A key component to this analysis was an understanding of the risk premium that is built into flat rates. While a precise number for this remains elusive, some estimates (e.g., ICC 2006) suggest that the typical flat residential rate has a 10 to 15% risk premium embedded in it. This risk premium reflects the uncertainty of weather, fuel, customer switching, etc. that suppliers have to build into their cost structure to offer a stable future price. CNT Energy's analysis of prices from 1999 through 2001 suggested that risk premium was excessive.

By designing a real-time rate that shifted risk to the customer, the potential to change risk into reward and save customers money became possible. This paradigm made real-time pricing in Illinois fundamentally different from the critical peak pricing and other dynamic pricing pilots offered everywhere else. Those pilots (and even some other real-time pricing programs such as the PowerCents DC pilot of 2008/2009) were designed to be revenue neutral for the average customer. Absent of any change in consumption and load profile, the average participant would pay the same as on the flat rate. The Illinois RTP design however was different; by taking on the risk of price volatility, customers could save money (and in fact, this has been the case in all years except 2005). The value to the utility system of this model of RTP would be in proving that participants in fact reduced usage at peak times, while the value to customers would come from capturing the value of the risk premium.

The ESPP pilot ran from 2003 through 2006. It used interval recording meters that stored hourly energy use but were read by meter readers on a monthly basis using hand-held computers, rather than the smart meter technology now being deployed in many jurisdictions. Participation was limited by funding available for the special meters and grew to 1,500 households. Key findings from

² CNT Energy is the successor to the Community Energy Cooperative

third party evaluations reports conducted by Summit Blue Consulting (SBC 2005) and from internal CNT Energy research included:

- Elasticity of demand ranged from -0.043 to -0.08
- Average savings over four years of 10%.³ (But in 2005 averages losses were 6%)
- High participant satisfaction and participants found it easy to participate in the program
- High participant retention: 99% of customers remained in the program in all years except for in 2005 when despite the average losses 87% renewed for the following year

Those results were promising enough to show the potential for wider real-time pricing programs when the rate freeze ended and new rate options went into effect in 2007. Several other factors also gave momentum to this idea. First, residential competition failed to emerge. Competition was one of the key selling points for a restructuring of the electricity industry and while it more or less worked for larger customers, in Illinois by 2006 there were no signs of it for residential customers. Legislators who had supported restructuring were therefore eager to look for alternative ways to give residential customers rate choices once the rate freeze ended. Second, both of the large investor owned utilities in Illinois proposed optional real-time pricing for all customers as part of their distribution rate cases that were filed in 2005 and settled in late 2006. However for residential customers those offers were quite limited. The customer had to pay the full cost (\$5/month) of an appropriate special meter that could record hourly interval data, and there was no support or services available to help them manage their energy use. For residential customers these offers were basically just a tariff hidden in the rate book, not a real program that was easy to understand and participate in.

In the course of the ESPP pilot, five members of the Illinois General Assembly⁴ enrolled in and successfully participated in the program. When legislation to build new real-time pricing program based on the results of ESPP was introduced they were able to gain support for the legislation and it passed unanimously. This legislation served several purposes. It set up a structure for real-time pricing that was designed to support the need of residential customers. This included a third-party program administrator because in Illinois the incumbent utilities were forbidden from marketing any rates or services so as not to impede the (undeveloped) competition. The program administrator was tasked “to develop and implement a program to provide consumer outreach, enrollment, and education concerning real-time pricing and to establish and administer an information system and technical and other customer assistance that is necessary to enable customers to manage electricity use” (Public Act 94-0977). Another component set up a structure for the costs and benefits of the program. Because Illinois had not yet (and still hasn’t) adopted a full smart meter deployment strategy, the incremental cost of metering for supporting real-time pricing is higher because special meters have to be installed at each participating household. The structure that was developed allowed for the costs of metering and program implementation to be split between participants and residential non-participants. The theory behind this was that while participants could benefit through lower bills, non-participants could also benefit if the demand reductions of participants affected overall prices. Arguably there would be benefits for non-residential customers as well, but to ease the debate over cost sharing, their potential benefits and costs were excluded from the analysis.

The hitch in this framework is that the concept that peak demand reductions of participating customers would benefit all other customers has been mostly one of theory rather than practice. Some experts have questioned the theory, wondering if in fact short term changes to the demand

³ During the ESPP pilot, the otherwise applicable flat rate was frozen and reduced 20% from 1997 levels. The pilot included adjustments to parts of the real-time pricing rate to level the playing field. Since 2007 when both flat rates and real-time rates have been market-based, savings have been at a comparable or higher level.

⁴ The legislative body of the state of Illinois, composed of elected officials

have any actual longer term impact on prices. For example, one critique of the California pricing experiments noted that,

“[f]irst, price changes in the absence of load changes represent merely financial transfers from one party to another, rather than actual reductions in economic resource costs such as those caused by DR customers’ load reductions. Second, even the immediate cost savings suggested by the price reductions are unlikely to materialize due to LSE’s [load serving entities] common practice of bilateral contracting to control costs and manage price risk. Finally, claims that short-term reductions in wholesale price spikes will automatically result in lower future contract prices ignore the dynamic effects of price expectations on generators’ investment behavior, which in turn affects future market prices.” (Braithwaite 2003)

On the other hand, there is an inherent market inefficiency that comes from incorrect pricing, and a move to real-time pricing creates value through addressing that inefficiency. The Nobel Laureate economist Dr. Vernon Smith has written extensively on how pricing electricity in response to demand will help stabilize the national energy system (Smith 2003). Real-time pricing promotes equity in pricing, as customers who use electricity pay the real costs of that usage. Additionally, Illinois is a restructured state that participates in wholesale energy markets where the dynamics of supply and demand are quite different than in California, and generators do not need to be made whole for losses from reduced demand and consumption. As was noted in the testimony that expanded real-time pricing in Illinois,

“In a competitive market, additional revenues will be passed on to customers as suppliers compete to sell their power. Entities that do not adjust their hedged premiums downward to reflect the new market outlook will find that LSEs, which are the suppliers selected by the auction process to serve flat-rate, default loads, will reduce bilateral purchases. Instead, they will fill their energy supply requirement from the day-ahead or real-time spot market because the risks are now lower due to the presence of price-responsive load.” (Neenan 2006)

To test the theory of how non-participants receive benefits, the legislation established a period of four years after which the Illinois Commerce Commission would review the programs and determine what, if any, benefits were being created from the program. The Commission would then determine if the program should continue, be modified or be cancelled.

The Evaluation of Other Residential Dynamic Pricing Programs

Real-time pricing for large industrial customers has a well documented track record, most notably in New York and Georgia (DOE 2006). Those programs were meant to provide demand response to the local utility, but real-time pricing has also been offered to large customers as a default service in some restructured marketplaces. In those cases it has typically been designed to be an unattractive rate intended to encourage customers to choose a third-part supplier.

For residential customers, time of use rates have been offered since the 1970s in response to Federal legislation, but a new generation of programs began to take hold about a decade ago as the cost of interval metering began to decline. Critical peak pricing programs, which are basically a time of use program with the option by the utility to select a handful of hours during the summer to have a super peak price were the initial design tested.

The most notable critical peak pricing experiment was the California Statewide Pricing Pilot which was launched in the wake of the California energy crisis. This program has been very heavily analyzed, and found clear response to price signals. There were nuances based upon the climate

zone, rate structure, and types of enabling technology deployed (e.g., smart thermostats), but the basic findings included that peak demand could be cut between 1,500 and 3,000 MW, if programs were fully deployed (Levy 2006). Because California did not have a functioning wholesale energy market at the time, that potential for peak demand reduction was not translated into an impact on prices. Rather, the reductions in peak demand were translated into how they would reduce the need for new generation capacity. The potential for those reductions was subsequently utilized as part of the business case for the deployment of smart meters by California utilities. Their business case for smart meters could not quite justify the expenditure on purely operational benefits, so the potential for cost savings from demand response by utilizing those meters for dynamic pricing is what made the cost/benefit analysis come out positively and therefore justify the billions of dollars of investment in new metering systems.

Subsequently many other critical peak pricing pilots have been conducted, as well as tests of a peak time rebate, and one comparison of critical peak pricing peak time rebates and real-time pricing (the PowerCents DC pilot). The findings have been quite consistent in terms of demonstrating that a price signal will influence residential customers to reduce peak demand. Clearly the level of automation will change the results, but even without automation, customers do change usage. The following graph developed by the Brattle Group summarizes the findings from these studies in terms of estimated percentage peak load reductions (Faruqui 2010). The numbers on the horizontal axis represent discrete programs and rate design pilots and demonstrate how these seventy different pilots have consistently found similar results. The magnitude of the demand response is mostly a function of enabling technology and experimental design.

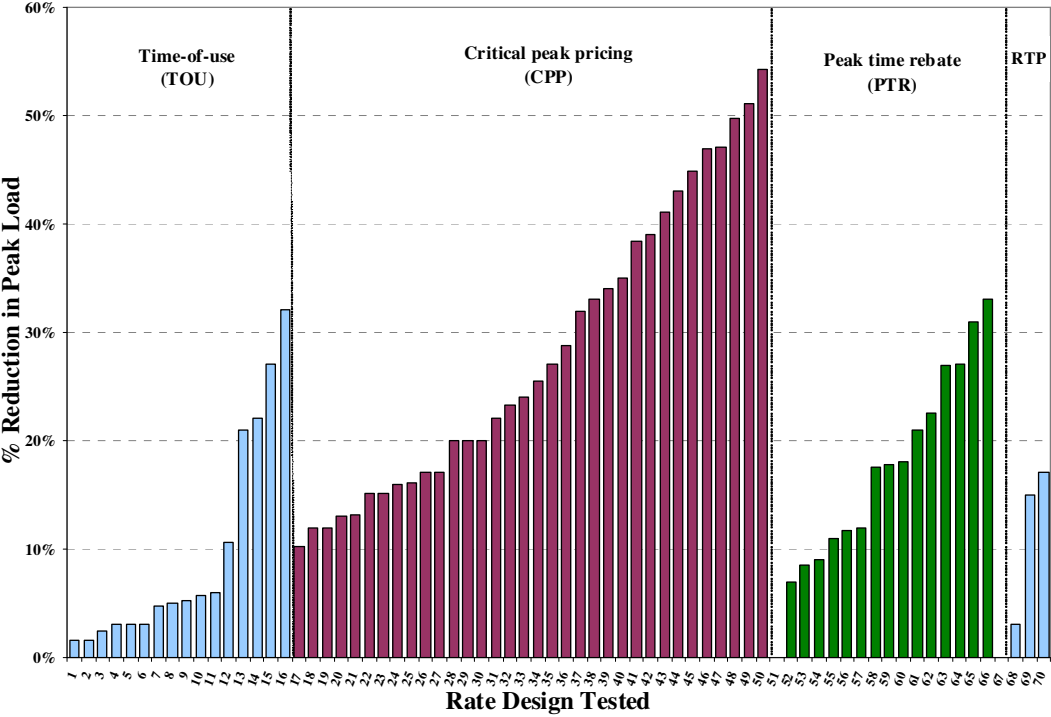


Figure 1: Comparison of Peak Load Reductions across Dynamic Pricing Programs

Participant bill impacts have not been as well studied. Bill savings have largely come from the changes in energy use, not the structural changes of the underlying rate. Most, if not all, of the pilots, with the exception of the programs in Illinois, were designed to be revenue neutral. This means that if the participants did nothing to change their energy use patterns their bills would remain the same (although some programs included various fixed participation incentives). As described

above, only the Illinois programs were designed to fully shift the risk premium embedded in flat rates to the customer, meaning that bill amounts could vary even without changes in usage. It is interesting to note that in the DC pilot the real-time rate offer was designed to be revenue neutral. However, with the collapse of energy prices in 2008, the savings were so high the prices were further adjusted in an attempt to restore revenue neutrality. But even then, prices continued to decline and produced structural savings for participants (PowerCentsDC 2009). In a competitive market structure, removing revenue neutrality shifts risk from competitive generators to customers. The generator's lost revenue does not need to be made whole, which results in a benefit created for consumers that does not have to be balanced with a cost for generators.

Participant savings are important for the individual participant and contribute to the popularity of programs. But in order to justify the greater value of these programs, the following questions need to be answered. How will changes in usage by some customers participating in real-time pricing or other demand response or dynamic pricing programs change the overall demand curve? And then consequently, how will this change the price curve in the wholesale market? Changing that price curve down at peak times could lower prices not just for participants but for all customers. This is the key concept that needs to be proven when the impact of the Illinois real-time pricing programs is evaluated.

Real-Time Pricing in Illinois: From Pilot to Scale

Public Act 94-0977 did not blindly commit Illinois to residential real-time pricing. Rather it first set a burden of proof for the utilities to demonstrate that the programs had the potential to generate net benefits for all residential customers (nonresidential customers were excluded because while they could potentially benefit from reduced market prices, the political challenges of getting them to accept the upfront investment costs in establishing programs was too great). Then after four years of operations, the programs would be evaluated to determine if those benefits were being realized.

The Act provided a clear list of factors to be considered as part of the evaluation of potential benefits and of the full program:

“In examining economic benefits from demand reductions, the Commission shall, at a minimum, consider the following: improvements to system reliability and power quality, reduction in wholesale market prices and price volatility, electric utility cost avoidance and reductions, market power mitigation, and other benefits of demand reductions, but only to the extent that the effects of reduced demand can be demonstrated to lower the cost of electricity delivered to residential customers.”
(Public Act 94-0977)

As part of the short rate case to approve the programs, testimony provided on behalf of the Citizens Utility Board (CUB), helped demonstrate that potential (Neenan 2006). The method used in this testimony developed statistical representations of the supply and demand curves that interact to determine the locational marginal pricing (LMPs) in the ComEd pricing zone. LMPs that would result from existing conditions were compared with the LMPs that would result using a demand curve that reflects the change in electricity usage resulting from an RTP program. Different participation levels were modeled. A 10% participation level in real-time pricing over a seven year time span with periods of high prices and periods of low prices was examined to calculate the gross impact of those demand reductions on energy prices. Using these reductions in wholesale market prices and price volatility, and electric utility cost avoidance and reductions, annual savings were found to range from \$25.6 million in a base case to between \$34.4 and \$41.9 million in scenarios where demand response increased. While this testimony only looked at two of the categories listed in the legislation, the other categories of benefits, while important, are less easily and objectively

measured in monetary terms, since they are not directly associated with market transactions. However, in most cases these benefits are positive and, if it were possible to quantify them, they would increase the benefits.⁵ Additional testimony estimated the annual cost of running a program of that scale to be \$16.9 million, so the modeled market impacts of the program clearly exceed the costs to run it (Thomas 2006).

The next key issue was the split of program costs between participants and non-participants. CUB negotiated a reduction in the cost of the interval metering required for real-time pricing. Both utilities had rate structures that included a \$5/month incremental charge for an interval recording meter that was required. These meters store hourly data but are read by traditional meter readers using a hand-held computer. That cost was reduced to \$2.25 a month, and the balance of metering costs, program administration and internal costs was socialized across the rest of the rate base. For ComEd this was structured as a fixed \$0.14 charge, while Ameren Illinois Utilities (AIU) instituted a Rider that varied month to month. As of March 2010, this charge was \$0.06 cents per month.

The Illinois Commerce Commission found that there was potential for net benefits from real-time pricing programs and programs started in 2007. ComEd's ESPP program was replaced with ComEd's Residential Real-Time Pricing program (administered by a third party demand response provider Converge), and AIU launched Power Smart Pricing Plan (administered by CNT Energy).

However, the increase in flat rates in 2007 (over 20% for ComEd, and over 40% for AIU) sparked a contentious fight over rates that included threats to reinstitute the pre-2007 rates and culminated in the late summer in a rate relief bill that included the establishment of energy efficiency programs. Because of the threat of rolling back rates which would have included getting rid of the new real-time pricing programs, most of 2007 was lost to the marketing efforts for real-time pricing and 2008 was really the first full program year for these RTP programs.

By the spring of 2010 nearly 20,000 households across Illinois were participating in real-time pricing programs. Average bill savings ranged from 6% for the ComEd program in 2007 to 24% for the AIU program in 2009. The very small portion of customers who did not save money tended to be small users for whom the \$2.25 per month meter fee could not be offset by energy savings, and some AIU customers who were otherwise eligible for a special subsidized electric space heat rate.

While ComEd has not yet conducted an evaluation of the elasticity of demand or participants, the AIU Power Smart Pricing program has been evaluated for 2008 and 2009. In 2008, the overall own-price elasticity of demand was -0.043 (Summit Blue 2009) and in 2009, despite low energy prices, -0.023 (Navigant 2010). These levels were consistent with the range found during the ESPP pilot. In a further refinement of the elasticity of demand model Navigant looked more closely at how elasticity of demand changed at various price levels. They found that during the summers of 2008 and 2009 elasticity was low, only -0.01 when prices were below \$0.13 per kWh, but much higher, -0.25, when prices were over \$0.13.

Overall annual energy use in kWh for Power Smart Pricing participants also declined, ranging from 1.2% (2009) to 1.5% (2008). In summer months, that reduction in kWh was approximately 5%. Overall the non-summer loadshapes of participants are fairly similar to non-participants. The changes in energy use occur in the summer months and include only very small amount of load shifting. Most of the changes are reductions during peak and shoulder hours.

Defining the Framework for Evaluating Net Benefits

In the evaluation of the 2008 Power Smart Pricing Program, Navigant Consulting⁶ set out a framework for the evaluation of net benefits of real-time pricing. They note that many aspects of the assessment are fairly straightforward: "Participant costs and benefits are relatively straight-forward

⁵ These additional benefits categories are addressed in Violette (2006).

⁶ Summit Blue Consulting who conducted the 2003-2006 evaluations of ESPP and the 2008 evaluation of Power Smart Pricing was acquired by Navigant Consulting in January, 2010.

to calculate. The PSP tariff defines the charges that participants must pay, and their bills can be compared to estimated bills on the alternative flat rates available to them based on similar levels of electric use.” And, “Similarly, tabulating the cost of the PSP program is also relatively straightforward. Budgets and reports are available, which provide information on what it costs to administer the PSP program. The costs that are paid for by participants and those which are paid by non-participants are even known.” The challenge, of course, is determining what are the benefits accrued to non-participants.

Navigant Consulting developed their proposed methodology by studying four general model types for estimating non-participant benefits and then combining the best aspects of each. The models proposed were:

- “1) Summit Blue (2005) report for the International Energy Agency (IEA)
- 2) Brattle report for Mid-Atlantic Demand Response Initiative (MADRI)
- 3) (2006) Testimony in Illinois Commerce Commission (ICC) Docket 06-0691
- 4) Power Systems Engineering Review Council (PSERC) open-source simulation models”

Navigant used these models to:

- Create a MISO (Midwest Independent System Operator)-based regression model to predict 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 (2005) Navigant IEA study; and
- Quantify additional benefits from reduced price volatility, and avoided energy and demand costs using the basic methods outlined in Neenan (2006).

Navigant notes that, “the decision to ignore lost profit to suppliers in the estimation of market benefits deserves additional discussion. If the PSP program serves to reduce overall market prices because it is a more efficient option than the alternative, there is no reason to reimburse profits to a business that loses sales because it could not compete with the best value product in the market.” This concept is important in a state such as Illinois where generation is a deregulated service and power is procured for utilities through requests for proposals issued by the Illinois Power Agency. Making suppliers whole for reduced profits is not required in this regulatory model as it would be in a more traditionally structured state.

An Initial Run at Calculating Net Benefits of RTP

While the full formal net benefits calculation of RTP programs will not occur until 2011, Navigant used the framework described above to perform an initial run of numbers as part of the evaluation of the 2009 Power Smart Pricing Plan. The results of this initial run are promising. While a number of open issues remain, the potential that there will be net economic benefits to non-participants is strong.

Benefits are accrued through three sources, reductions in energy prices, avoided capacity costs and avoided energy costs. Reductions in energy prices were calculated in a manner similar to that in Dr. Nennan’s testimony described above, with Navigant noting that prices, “include an energy price component that is the market clearing price of energy in the MISO market. It follows that a demand reduction at any given hub generates a price reduction *throughout* the MISO market.” These

changes are not long-term changes to the supply/demand equilibrium, rather, “[o]ver periods short enough for little or no change in input prices (coal, natural gas) or technology factors, the [supply] function reduces to a simple relationship between the energy price and the quantity supplied at the price.” In 2008, the 3,000 participants in PSP reduced demand by 0.75 MW during the peak 50 hours, and in the milder summer of 2009, the 7,000 participants reduced demand by 1.05 MW. Peak prices in 2009 were lower than in 2008 so the correlations between the reductions are not linear. The price impact from those reductions, transferred across all megawatt hours totaled \$978,664 in 2008 and \$758,700 in 2009.

In addition to the reduced cost of electricity created by those demand reductions, participants benefited from paying lower capacity costs and paying less for electricity. The table shown below illustrates the total participant and non-participant benefits from this initial analysis as well as an estimation of what the program implementation costs for the program were. In this analysis the program appears to create net benefits.

Table 1: Preview of One-Year Net Benefits Assessment for 2008 and 2009

	2008	2009
Non-Participant Benefits: Reduction in MISO Price	\$978,664	\$758,700
Participant Benefits: Avoided Capacity Costs	\$10,928	\$8,915
Participant Benefits: Avoided Energy Costs	\$207,375	\$1,735,400
TOTAL BENEFITS	\$1,196,967	\$2,503,015
Program Implementation Costs – CNT	\$420,458	\$420,458
Program Implementation Costs – AIU	\$211,418	\$351,689
Evaluation Costs	\$64,000	\$82,000
TOTAL COSTS	\$695,876	\$925,308
NET BENEFITS	\$501,091	\$1,577,707

Navigant notes that, “these are one-year snapshots of net benefits. There is no consideration of the benefits and costs related to continuation of the program in future years. The forecasting of benefits and costs will be added to the 2010 assessment of net benefits along with a consideration of associated probabilities and risks.” Further refinement of the model will be required to more carefully test the assumptions and biases embedded in the model, the appropriate allocation of benefits to non-participants in various areas of MISO, etc. Some of the potential sources of error associated with the supply equation used in this snapshot were already identified. They included: the behavior of the equation as the dependent variable (the MISO load in a given hour) reaches its maximum output, the potential for an autoregressive structure, which may lead to biased parameter estimates and incorrect inferences, and correlations that bias both supply and demand that should be captured in the model. These factors may or may not be significant, but will be given further consideration in the 2010 assessment.

When presented to stakeholders on a teleconference in the spring of 2009, the proposed framework was met with cautious interest. The problem that quickly arose was one of timing. The legislation authorizing residential real-time pricing called on it to be evaluated after four years of operation. The Illinois Commerce Commission would decide if the level of net benefits to residential customers called for the program to be continued, modified or terminated. However, the Commission was required to determine the net benefits of the program within four years of its start. Depending on when the clock started ticking, this could be by the end of 2010. On this timeline, with programs not

really starting until late 2007 (after the summer peak demand season), and with the unusually cool weather and low prices of summer 2009 combined with an economic recession, the data available for analysis would be limited and potentially biased. Given the time required to evaluate a program and conduct a proceeding at a regulatory agency, the summer 2010 data would not inform the results, and therefore the summer of 2008 would be the most significant dataset for analysis. A consensus was reached that the evaluation should rather stretch into 2011 allowing the opportunity for the results of the summer of 2010 to be incorporated. That schedule also began to align the results of this evaluation with other similar efforts underway in Illinois including a smart meter pilot by ComEd that is testing variants of real-time pricing and other rate structures.

The current structure of real-time pricing allocates some of the costs of the program to participants (in the form of a \$2.25 monthly charge) and the rest to residential non-participants (in the form of a rider that currently ranges from \$0.06 a month for AIU to \$0.14 a month for ComEd). If the results of the initial snapshot of net benefits described above holds up, then the logical next question is if the level of support that non-participants pay is appropriate for the level of benefits they receive. An adjustment of the participation fee and the non-participant rider may be required. However, it should be noted that a significant program implementation cost is that of the special meters used for recording hourly interval data. The incremental cost of those meters is currently fully borne by the real-time pricing programs. If and when Illinois utilities seek and receive approval for system wide smart meter deployments the bulk of the cost of metering for real-time pricing would logically shift out of the program and into the more general metering charge which would fundamentally reduce program costs and subsequently alter the allocation of program cost recovery between participants and non-participants.

Conclusion

While studies of dynamic pricing over the past decade have demonstrated consistent and replicable evidence that residential customers will reduce their peak demand in response to price signals, the wider impact of those reductions remains less known. Individual participants clearly benefit by translating their demand reductions into lower bills. However, in order to justify the costs of developing and implementing dynamic pricing programs, finding benefits for non-participants appears to be essential. The upcoming evaluation of real-time pricing programs in Illinois that is scheduled to be conducted in 2011 provides a critical opportunity to explore what those benefits could be. While the initial preview of the net benefits analysis is highly encouraging, not until the full analysis is conducted and subjected to a rigorous critique and review, will the true results be known.

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