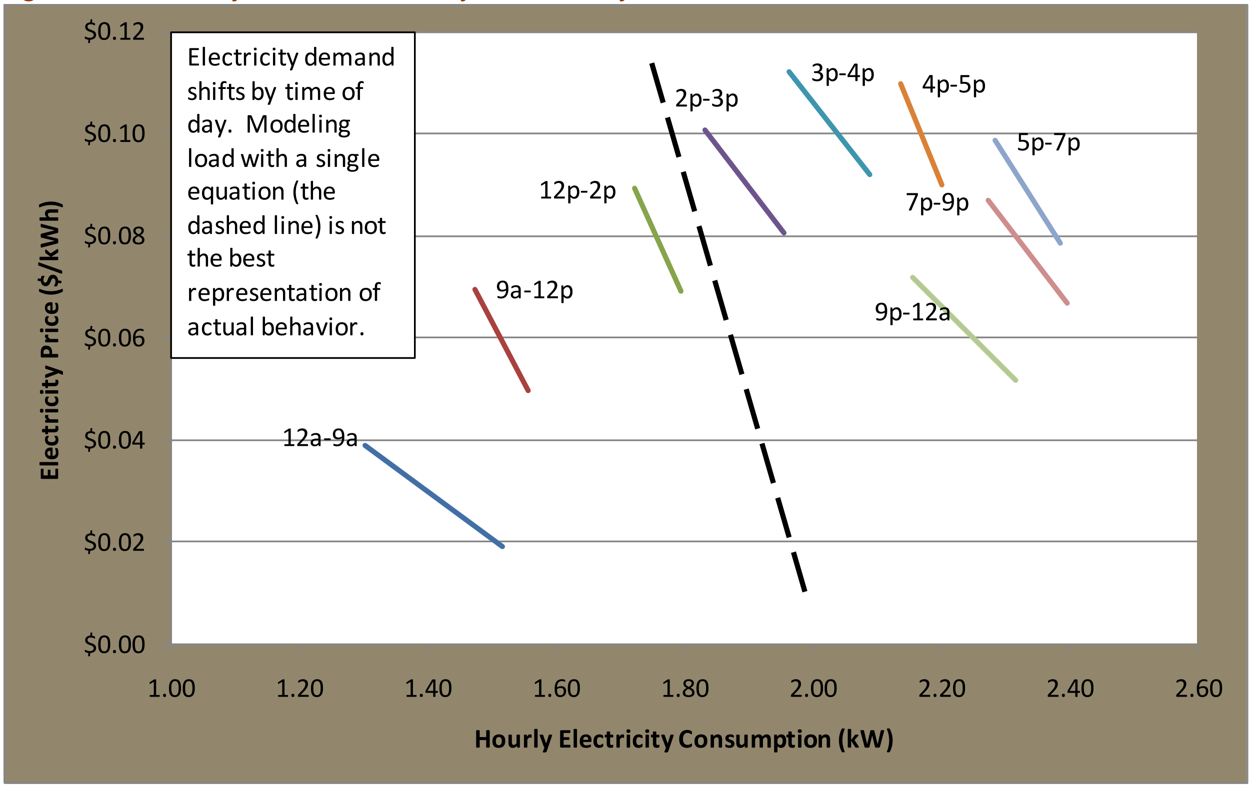
Figure 42. Electricity Demand Shifts by Time of Day



Source: Navigant analysis

The cross-price elasticities, found in the off-diagonal elements of Table 14, have predominately negative (not shaded) signs, with only two positive cross-price elasticities (shaded tan). 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 i causes the participant to consume less electricity in block i, and consume more electricity in block j.

There is little evidence, then, that on HPA days RT-10 households are shifting their load from one period to the next in response to price, *beyond what they already do* in response to differences in *mean* hourly prices, as captured by the medium-run elasticities documented above, and as reflected in the hourly load shapes on non-event days examined in subsection 3.2(see, for instance, Figure 16-Figure 19), and as embedded in a block's pre-committed quantity, s_i . This latter point deserves emphasis: the argument here is not that the RRTP program does not generate price-driven load shifting—it clearly does; the argument is that, after normalizing for temperature, the response to high-price days is not more load-shifting but a general reduction in load. One explanation is that RT-10 households anticipate and respond to high prices by generally reducing activity on high price days. That said, one should not lose sight of the fact that the estimates for cross-price elasticities are generally close to zero and often not significant.

3.4 Bill Savings

In 2010 the aggregate savings for RRTP participants was $1,936,844, which is 13% of the aggregate bill RRTP customers would have faced under the fixed-price rate. The average 2010 bill savings among customers who were in the RRTP program for all of 2010 was $177.

Overall, the RRTP program has generated bill savings of $3,954,882.

3.4.1 Methodology

CNT Energy recalculated the hourly monthly bills for each RRTP participant to determine what the bills would have been under ComEd's standard fixed-price rate. Electricity bills include three broad categories of charges: Electricity Supply Services, Delivery Services, and Taxes/Other. With one exception, all charges in these latter two categories are the same for ComEd's RRTP participants and fixed-price rate customers, and therefore were not changed in the bill recalculation. The exception is the $2.25 per month meter lease charge on RRTP bills. This charge does not apply to fixed price electric bills, and is not included in the recalculation of the fixed-price bill.

The recalculation also took into account the line items in the Electric Supply Services portion of the bill. Within this category of charges, two line items (the Transmission Services Charge and the Purchased Electricity Adjustment charge) use different charge rates in the recalculation because the electricity supply for RRTP customers is procured differently than it is for fixed-rate customers.

The most salient recalculation involves the Electricity Supply Charge. For the standard fixed rate, this charge includes the cost for electricity supply, capacity, and other miscellaneous services and procurement costs. All of these components are purchased together and combined into one Electricity Supply Charge for fixed-price rate customers. In the recalculation, multiplying the monthly kWh by the appropriate summer/non-summer fixed-rate price generates the new Electricity Supply Charge, replacing the Electricity Supply Charge, Capacity Charge and Misc Procurement Component Chg RRTP line items. For RRTP customers, these items are purchased separately and have separate line items.

3.4.2 Results

Table 15 presents a summary of bill savings over the 4-year history of the RRTP program, and Figure 43 and Figure 44 present results of the bill saving analysis for 2010. The 2010 bill savings analysis generated results that are structurally similar to results obtained in previous years. The following conclusions are drawn from these data:

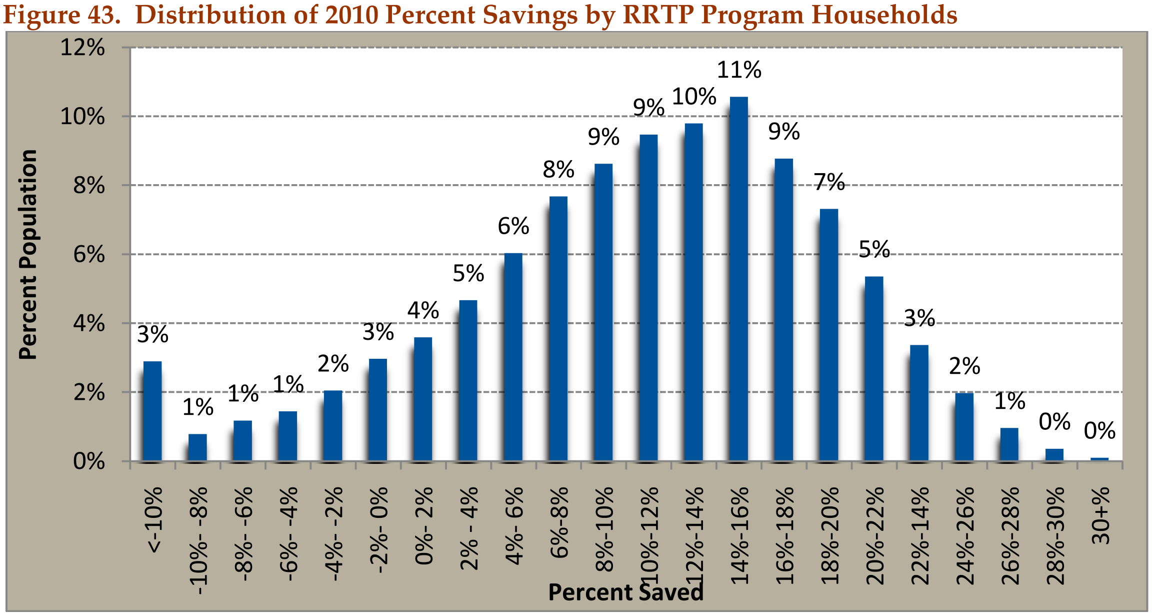
- The vast majority of households enrolled in the RRTP program reap positive savings, with mean savings of $177 in 2010. Figure 43 shows that 89% of RRTP households generated positive bill savings.
- Bill savings were highest in 2009, when energy prices were low.
- As shown in , bill savings increase with the size of the bill.

Table 15. Summary of RRTP Household Bill Savings, 2007-2010.

ComEd RRTP Program Savings Highlights		Overall Program Savings (All Customers)	Overall Program Savings (Customers that participated for full year)	Participants that saved	Individual Average Savings (Yearly)(All Customers)	Individual Average Savings (Yearly)(Customers on program for full year)	Range over which middle majority of customers saved (All Customers	Range over which middle majority of customers saved (Customers on program for full year)
2007	%	13%	9%	95%	13%	9%	6% - 12%	7% - 12%
	$	$165,518	$63,000	n/a	$59	$93	$17 - $18	$37 - $122
2008	%	5%	5%	67%	3%	2%	-2%-8%	-2%-8%
	$	$315,270	$225,185	n/a	$52	$62	-$14 - $82	-$14 - $98
2009	%	19%	19%	95%	15%	15%	11% - 21%	11% - 21%
	$	$1,485,164	$1,191,954	n/a	$185	$205	$64 - $246	$81- $265
2010	%	13%	12%	89%	10%	10%	5%-17%	5%-16%
	$	$1,936,844	$1,289,217	n/a	$168	$177	$43-$237	$53-$246
Program-To-Date	%	13%	11%	90%	11%	9%	6%-17%	6%-14%
	$	$3,954,882	$283,703	n/a	$323	$445	$72 - $440	$174-$577

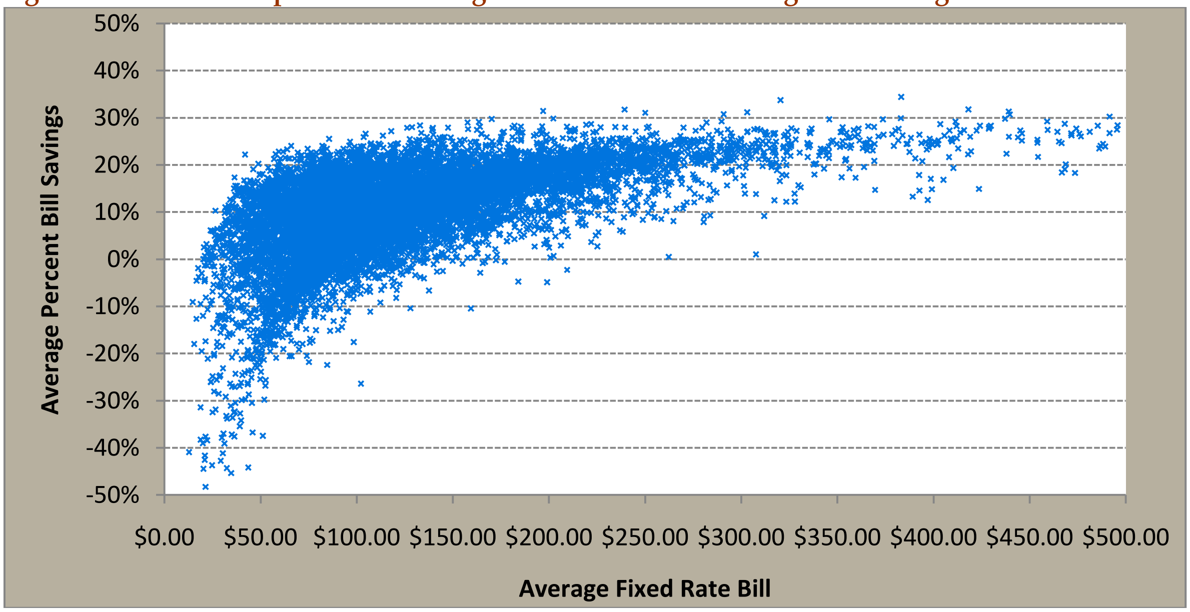
Source: Comverge Analysis

Figure 43. Distribution of 2010 Percent Savings by RRTP Program Households



Source: Comverge Analysis

Figure 44. Relationship between average 2010 Percent Bill Savings and average Fixed-Rate Bill



Source: Comverge Analysis

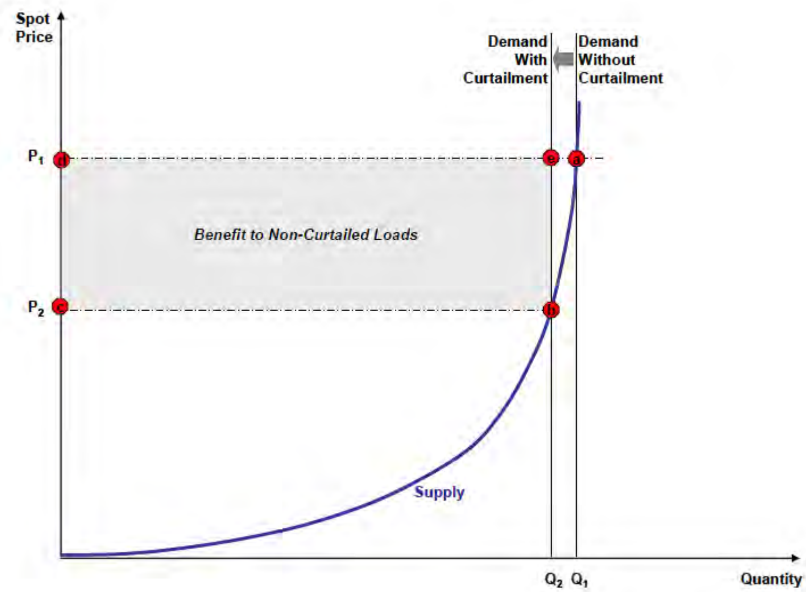
4 Net Benefits Assessment

In this section of the report Navigant addresses the second objective of the evaluation: estimating the consumer net benefits of the RRTP program. Participant benefits are derived from the bill savings due to the behavioral changes induced by the program. These behavioral changes are documented above. Nonparticipant benefits are also derived from the behavioral changes of RRTP customers, but indirectly, mostly via the effect of the aggregate RRTP customer behavioral change on energy prices. To quantify program effects on energy prices it is necessary to develop marginal cost (supply) functions for energy. Subsection 4.1 develops these functions. This is followed in subsection 4.2 by an explanation of the framework of benefits and costs used in the net benefit assessment. Subsection 4.3 presents results of the assessment. This section concludes with a discussion of other benefits not included in the net benefit assessment because of the difficulty of quantifying them.

4.1 Estimating Market Effects

By inducing households to shift their energy consumption pattern, the RRTP program can be expected to generate benefits for other ComEd customers, and more broadly for all PJM customers, in the form of changes in energy prices. This effect is called the market effect. With reference to Figure 45, this benefit arises because a reduction in energy consumption due to the RRTP program serves to reduce the locational marginal price (LMP), and this price reduction applies to all customers in the market.

Figure 45. 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 (MADRI) by The Brattle Group, January 29, 2007, page 20.

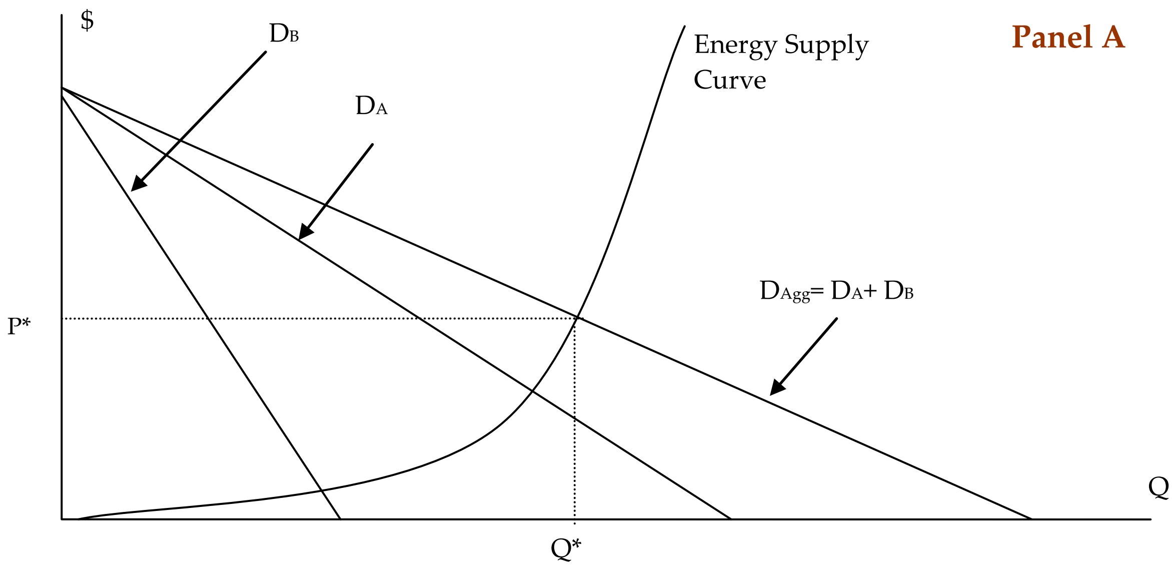
Calculating the effects of the program on price changes requires integration of two analyses: a) the analysis of hourly impacts, from which the change in load due to the program is determined; and b) determination of the response of locational marginal prices (LMPs) to load changes.

The LMPs for the ComEd service area are composed of three components: an energy price component that is the market clearing price of energy in the PJM market; a congestion component reflecting the impact of ComEd loads on the routing of transmission to avoid congestion; and a loss component associated with transmission line losses. In the discussion below we present 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 RRTP program can be determined in the manner illustrated in Figure 45. The energy component of the LMP is conceptually different than the congestion and loss components, because it is a PJM-wide market clearing price, whereas the congestion and loss components are essentially the result of balancing algorithms accounting for location-specific transmission costs. With this in mind we separate 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.

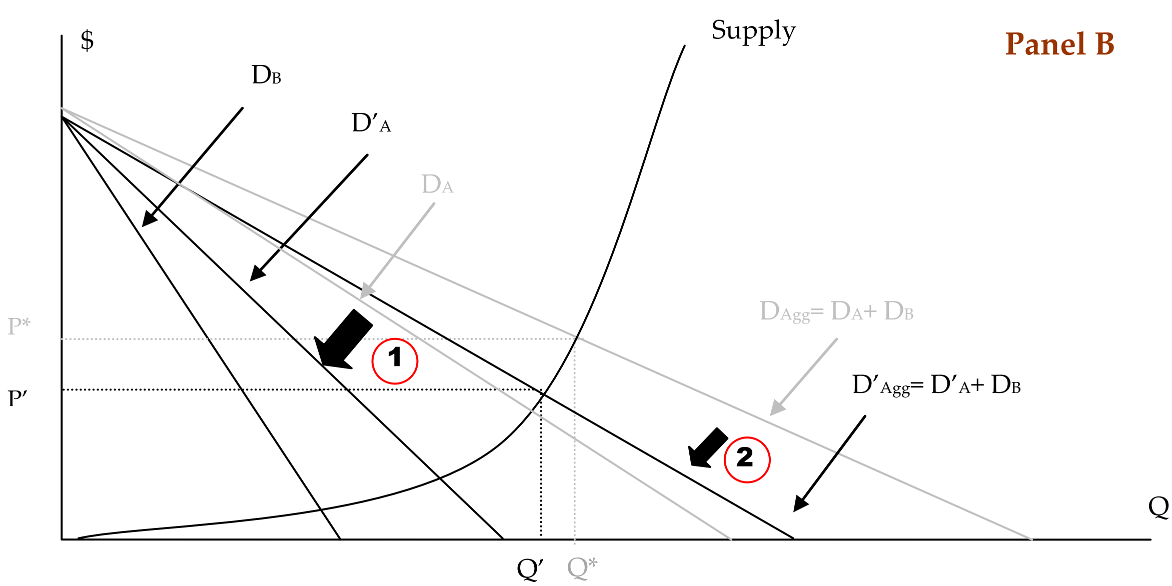
4.1.1 Statistical Derivation of the Energy Supply (Marginal Cost) Curve

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 PJM market, because the energy price is a market clearing price for the entire PJM market. This point is illustrated in the 2-hub market in Figure 46. 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 RRTP 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, but the point remains that a downward shift in a component demand program reduces the energy price.

Figure 46. Illustration of How a Demand Reduction Influences Price in a 2-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 (2007-2010) input prices have shifted and technology may have changed, but we avoid the necessity of fully and properly accounting for these factors by separately estimating supply equations for each of the 16 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,

$$\begin{aligned} \ln P_t &= \alpha_0 + \alpha_1 Q_t + \alpha_2 Q_{t-1} + \varepsilon_t \\ \varepsilon_t &= \rho \varepsilon_{t-1} + \phi_t, \quad \phi_t \ IID \end{aligned} \tag{14}$$

Where Q_t is the PJM load in hour t, measured in gigawatts; $\ln(P_t)$ 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 PJM 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 equation (14), 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 PJM 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 a 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, the hour of the day, the day of the week, etc., and so these shifts essentially "trace out" the supply equation.[21] The logic of this "tracing out" of the supply function requires that the analyst does not include as explanatory

[21] 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, *Kennedy, P. "A Guide to Econometrics, 5th Edition". MIT Press, 634 pages*). 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.

variables those factors expected to have much greater effects on demand than on supply, such as those mentioned above –weather variables, indicator variables for the hour of the day, etc.

4.1.2 Energy Supply Equation Estimation Results

Energy supply equations were estimated for each season of the program period, Winter 2007-Fall 2010. To illustrate the general nature of the results, Table 16 presents estimated energy supply equations for each of the four summers of the program period (June-August, 2007-2010), along with several load statistics to provide context for results. Results for all seasons are reported in Table 17. Results are all strongly statistically significant. Recalling that, with reference to equation (14), the price elasticity of supply is $\frac{1}{\alpha_1 Q_t}$, the load statistics in Table 16 can be used to calculate price elasticity of supply at key loads. At mean loads, the price elasticity of supply was 0.021 in summer 2007, 0.022 in summer 2008, 0.040 in summer 2009, and 0.029 in summer 2010. These values indicate that supply is inelastic. For instance, at the mean load in summer 2008, a 10% increase in price increases supply by approximately 0.22%. At the 95th percentile loads, estimated elasticities fall to 0.016 for summer 2007, 0.016 for summer 2008, 0.030 for summer 2009, and 0.022 for summer 2010.

The negative coefficients on the lagged PJM 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 changes as it would be in the absence of high fixed costs of generation.

Figure 47-Figure 51 display the seasonal energy supply curves for the program period. The supply curves are presented only through the range of the observed price data; so, for instance, the curves for summers and winters are typically longer and higher because prices in these seasons tend to cover a greater range. As shown in Figure 51, a striking feature of the results is that the supply curve was much higher in summer 2008 than in other summers. This likely reflects the spike in natural gas prices in the middle of 2008. Figure 52 presents natural gas prices over since 2002. Prices spiked sharply in summer 2008, and otherwise were, in the time frame of the RRTP program, moderately high in 2007 and lowest in summer-fall 2009. This correlates well with the supply curves presented in Figure 51.

Table 16. PJM Energy Supply Equation Estimation Results, Summers 2008-2010 (dependent variable is the natural log of price)[a]

Variable	2007	2008	2009	2010
	Coefficient Estimate (Standard Error)			
Intercept	1.4556 (0.06466)	1.6190 (0.07454)	1.8946 (0.0435)	1.6858 (0.04748)
PJM Load	0.5160 (0.026756)	0.5192 (0.02889)	0.3029 (0.0198)	0.3704 (0.0199)
Lagged PJM Load	-0.2395 (0.02677)	-0.2213 (0.02890)	-0.1159 (0.0198)	-0.1360 (0.0199)
Lagged error (ε_{t-1})	0.5251 (0.01766)	0.7073 (0.01509)	0.3727 (0.0198)	0.4259 (0.0199)
Load Statistics				
Load Mean/St. Dev. (gWh)	90/18	89/17	83/16	93/18
Load Percentiles 25/50/75/95 (gWh)	76/89/104/121	75/89/102/117	69/82/94/110	78/92/107/12 4
Load Min/Max (gWh):	55/140	57/130	51/127	56/137

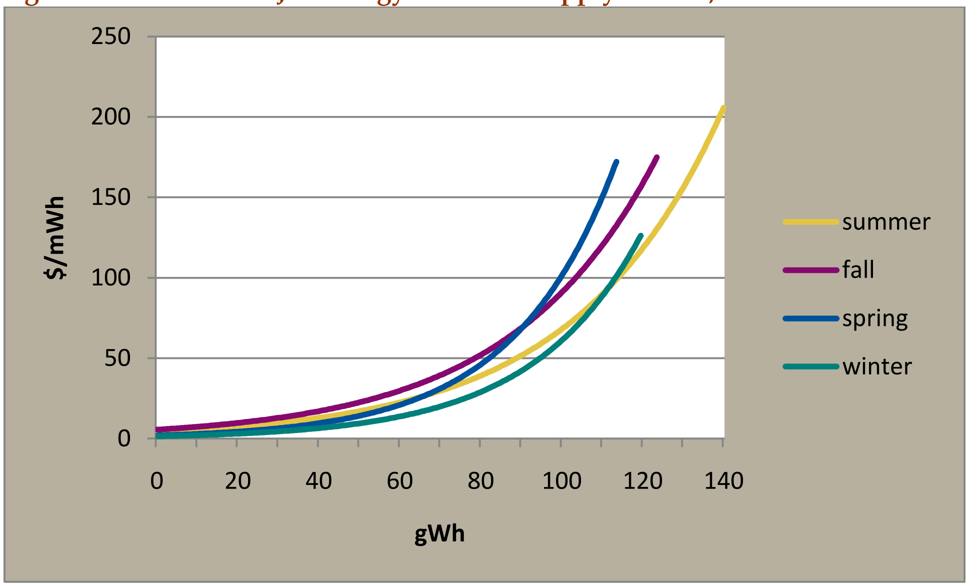
[a]All coefficient estimates are statistically significant at the .01 level. *Source: Navigant analysis*

Table 17. Coefficient Estimates and Standard Errors of Estimated PJM Seasonal Energy Supply Equations (standard errors in parentheses)

	Variable			
Season	Intercept	PJM Load	Lagged PJM Load	Lagged Error
Winter 2007	0.391	0.4647	-0.0926	-0.5482
	(0.1252)	(0.0381)	(0.0381)	(0.0223)
Spring 2007	0.6853	0.581058	-0.1878	0.5643
	(0.1103)	(0.0372)	(0.0372)	(0.0177)
Summer 2007	1.4556	0.5160	-0.2395	0.5251
	(0.0647)	(0.0268)	(0.0268)	(0.0181)
Fall 2007	1.6494	0.6579	-0.3697	-0.60303
	(0.0813)	(0.0293)	(0.0293)	(0.0171)
Winter 2008	0.7045	0.7278	-0.3450	0.6027
	(0.1087)	(0.0285)	(0.0285)	(0.0171)
Spring 2008	0.7756	0.7590	-0.3169	0.6154
	(0.1170)	(0.0353)	(0.0353)	(0.0169)
Summer 2008	1.6190	0.5192	-0.2213	0.7073
	(0.0745)	(0.0289)	(0.0289)	(0.0151)
Fall 2008	1.7480	0.5730	-0.2898	0.3837
	(0.0607)	(0.0255)	(0.0255)	(0.0198)
Winter 2009	1.4188	0.5039	-0.2225	0.3845
	(0.0694)	(0.0200)	(0.0200)	(0.0199)
Spring 2009	1.7078	0.4549	-0.2042	0.4548
	(0.0620)	(0.0249)	(0.0249)	(0.0190)
Summer 2009	1.8946	0.3029	-0.1159	0.3727
	(0.0435)	(0.0198)	(0.0198)	(0.0198)
Fall 2009	1.9702	0.4741	-0.2708	0.5380
	(0.0600)	(0.0213)	(0.0213)	(0.0181)
Winter 2010	1.2248	0.4845	-0.1922	0.5364
	(0.0884)	(0.0200)	(0.0200)	(0.0183)
Spring 2010	1.7474	0.5063	-0.2542	0.5465
	(0.0689)	(0.0258)	(0.0258)	(0.0179)
Summer 2010	1.6858	0.3704	-0.1360	0.4259
	(0.0475)	(0.0199)	(0.0199)	(0.0193)

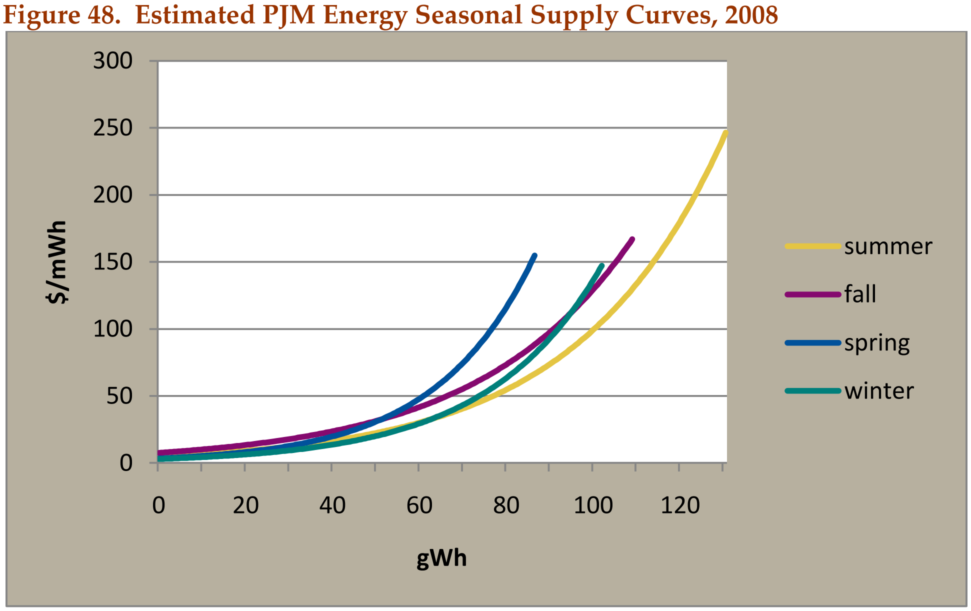
Source: Navigant analysis

Figure 47. Estimated PJM Energy Seasonal Supply Curves, 2007



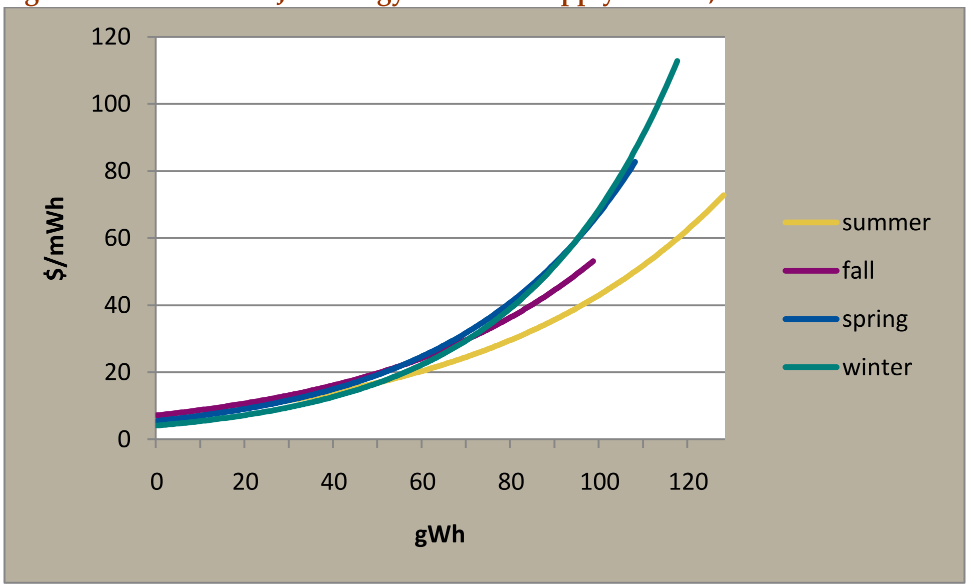
Source: Navigant analysis

Figure 48. Estimated PJM Energy Seasonal Supply Curves, 2008



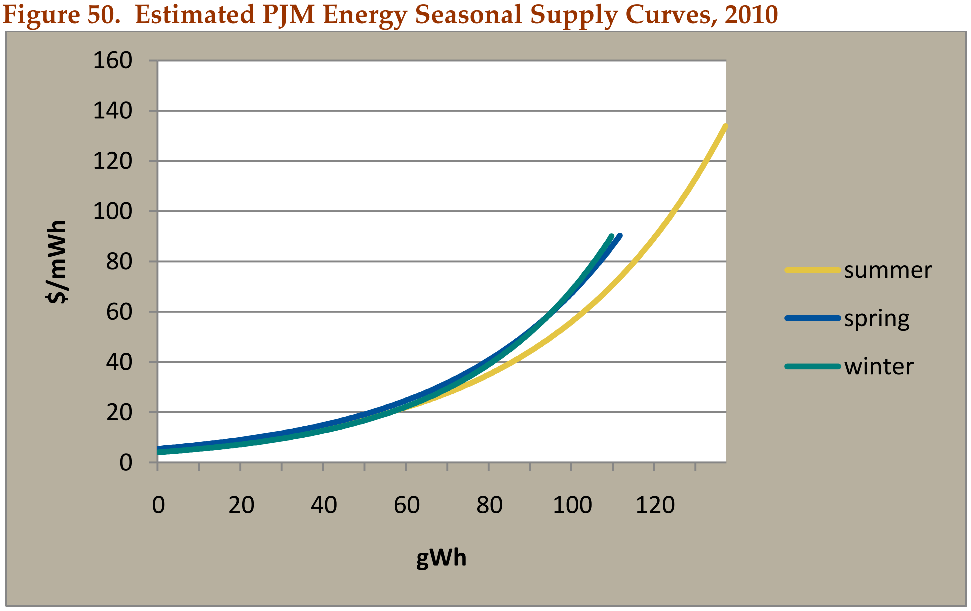
Source: Navigant analysis

Figure 49. Estimated PJM Energy Seasonal Supply Curves, 2009



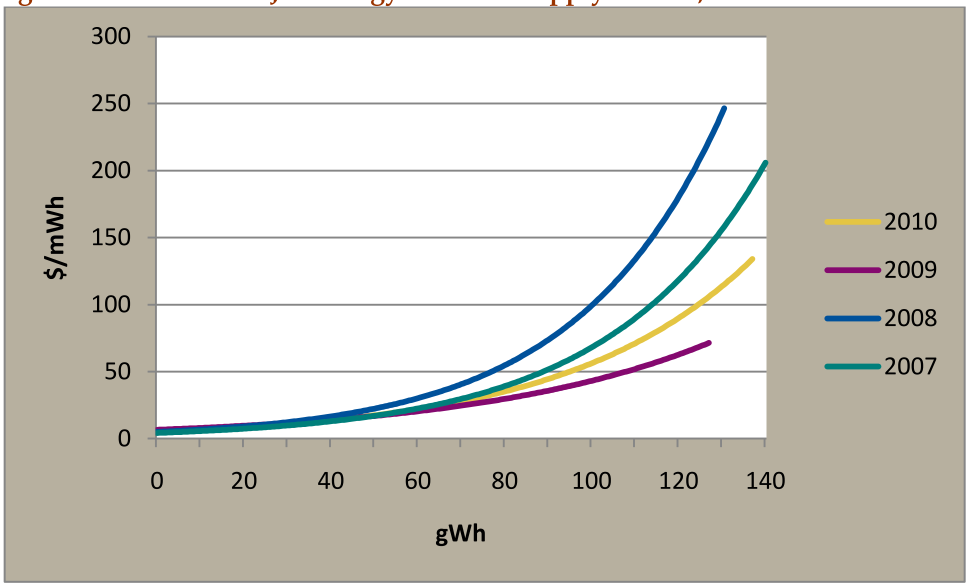
Source: Navigant analysis

Figure 50. Estimated PJM Energy Seasonal Supply Curves, 2010



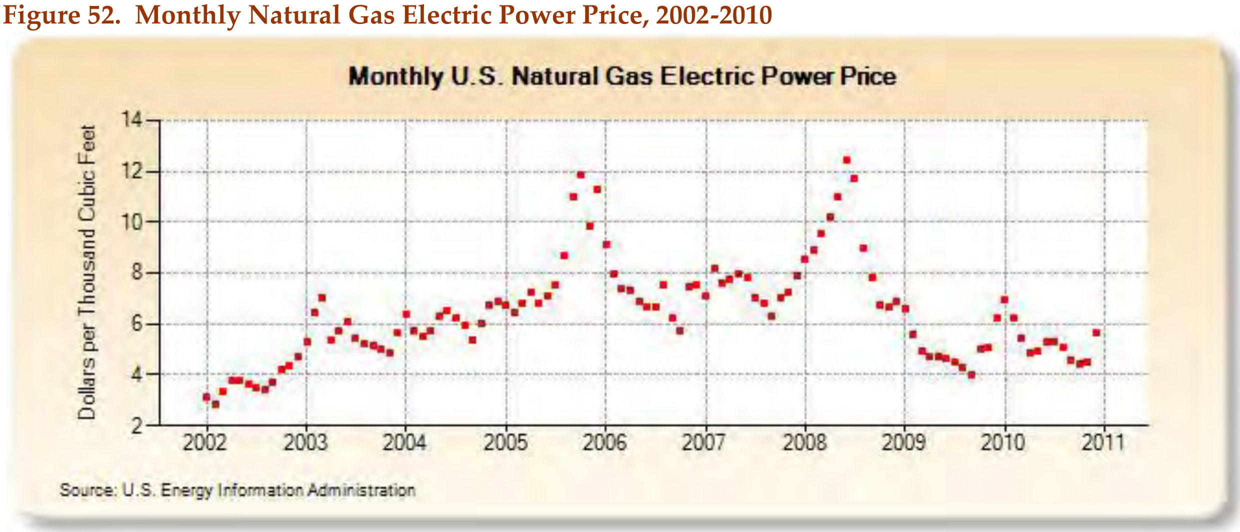
Source: Navigant analysis

Figure 51. Estimated PJM Energy Summer Supply Curves, 2007-2010



Source: Navigant analysis

Figure 52. Monthly Natural Gas Electric Power Price, 2002-2010



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

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

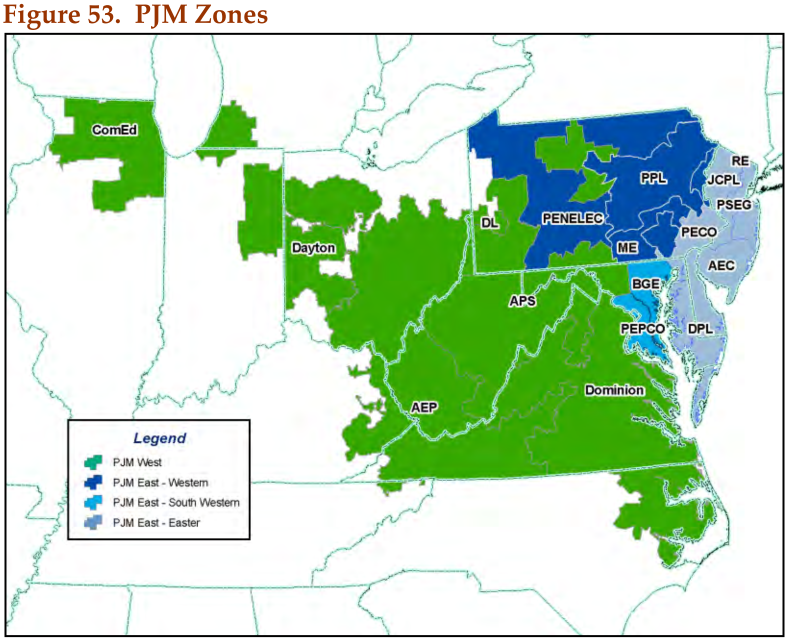
After some experimentation in which we examined the effect of loads at a number of PJM zones on the congestion and loss prices at ComEd, we settled on a quadratic specification of hourly marginal congestion and loss involving three source variables: the load at ComEd, the load at PJM-East, and the load in the rest of PJM ("PJM-Other").[22] These zones are presented in Figure 53, where PJM-East is shaded in various shades of blue, and PJM-Other is the green-shaded area except for the ComEd zone. We use these zones because the analysis indicates that the effect on ComEd congestion and loss prices of PJM-East can differ markedly from the effect of the rest of PJM.

Formally, we estimate the equation,

$$\begin{aligned} P_t^{ComEd} &= a_0 + a_1 Q_t^{ComEd} + \alpha_2 \left(Q_t^{ComEd}\right)^2 + a_3 Q_t^{PJM\_East} + \alpha_4 \left(Q_t^{PJM\_East}\right)^2 \\ &\quad + a_5 Q_t^{PJM\_Other} + \alpha_6 \left(Q_t^{PJM\_Other}\right)^2 + \varepsilon_t \qquad , \\ \varepsilon_t &= \rho_0 + \rho_1 \varepsilon_{t-1} \end{aligned} \tag{15}$$

where P_t is either the congestion or loss price, the Q's denote loads at the three sets of zones, and as with the energy supply equation the error structure is AR(1).

Figure 53. PJM Zones



Source: PJM, at www.pjm.com.

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, and so for our analysis we used the equations estimated on data for all four years of the program period, 2007-2010. These

[22] Due to the high prevalence of negative prices, the semi-log form used to model energy supply was not practical in the estimation of the marginal congestion and loss functions.

equations are presented in Table 18 and graphed in Figure 54. The figure illustrates that increases in loads in the non-ComEd zones *reduces* the congestion price at the ComEd zone, with this negative effect more pronounced for PJM-Other than PJM-East. This is not surprising because these prices reflect differentials in energy demand across zones. In summary:

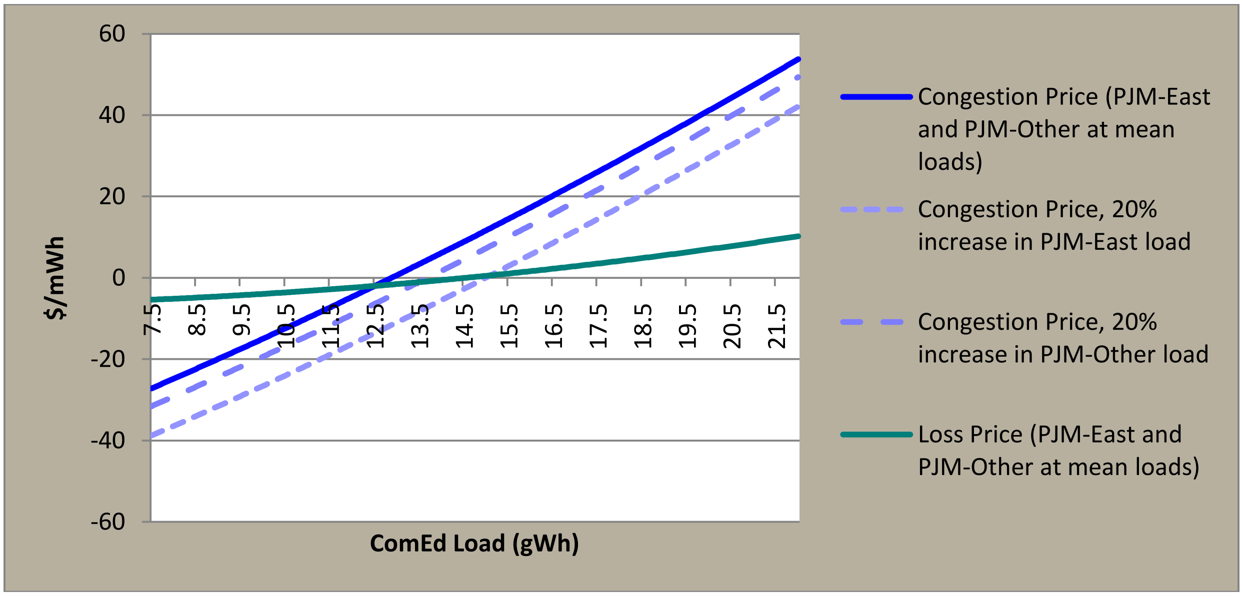
1. All coefficients are highly statistically significant;
2. An increase in ComEd load increases both congestion and loss prices; at low loads both prices are typically negative;
3. The congestion marginal cost curve is steeper than the loss marginal cost curve;
4. An increase in PJM-East load *lowers* ComEd congestion and loss prices;
5. An increase in the PJM-West load also *lowers* ComEd congestion and loss prices, but the effect is much less than for *PJM*-East (about 20-50% the impact of *PJM*-East).

Table 18. ComEd Marginal Cost Curves for Transmission Congestion and Loss, 2007-2010 (dependent variable is price; standard errors in parentheses)

Variable	Coefficient (Standard Error)	
	Congestion Equation	Loss Equation
Intercept	-72.0113	-2.181
	(4.2735)	(0.4385)
ComEd Load (gWh)	38.742	-1.6551
	(7.566)	(0.7776)
Squared ComEd Load (gWh^2)	5.7867	4.2123
	(2.8287)	(0.2937)
PJM_East Load (gWh)	17.316	1.2175
	(4.2372)	(0.4478)
Squared PJM-East Load (gWh^2)	-4.9162	-0.6227
	(0.5573)	(0.0589)
PJM-Other Load (gWh)	9.4027	0.4007
	(4.9797)	(0.5119)
Squared PJM-Other Load (gWh^2)	-1.9675	-0.2405
	(0.6281)	(0.0642)
Lagged error (ε_{t-1})	-0.58466	-0.73126
	(0.005003)	(0.004207)

Source: Navigant analysis

Figure 54. Estimated ComEd Marginal Cost Curves, Transmission Congestion and Loss, 2007-2010.



Source: Navigant analysis

4.2 Framework of the Net Benefit Assessment

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 costs and benefits that could be considered, this section of the report focuses on those that are most important and quantifiable. Section 4.4 of this report discusses other program benefits that are potentially important but difficult to quantify.

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. In this report net benefits are calculated both for the historical period 2007-2010, and for a 10-year forecast period.

The assessment of net benefits for the historical period is required by Public Act 094-0977, which created RRTP and led to the order from the Illinois Commerce Commission (ICC) in Docket 06-0617, 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."*

Extending the calculation of net benefits to a forecast period of 2011-2020 provides the basis for anticipating the future of the program if it were to be extended. In this report Navigant presents such a calculation not only for a "base case" scenario that represents its best judgment about future net benefits, but also for several alternative forecast scenarios that serve to provide perspective on the sensitivity of forecasted future net benefits to important modeling assumptions.

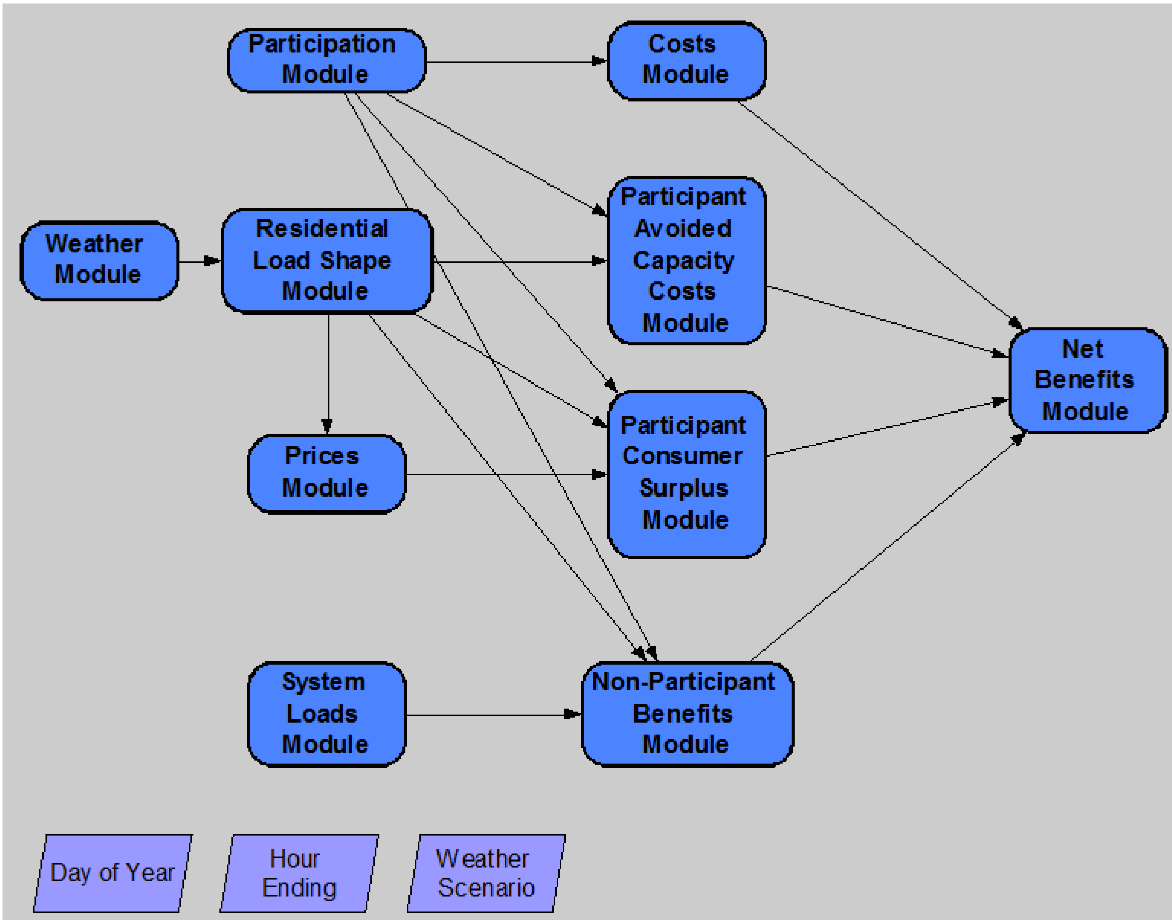
Figure 55 shows the basic components of RTPsim, the net benefits assessment model used for this study.[23] Although there is one cost module, there are three benefits modules:

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

The methodology contained within each of these modules is described below. As shown in Figure 55, these benefit/cost modules employ common input modules like participation rates, load shapes, and prices. In the discussion below, the development of each of these shared input modules is presented first, followed by a presentation of the benefit/cost modules.

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

Figure 55. Basic Components of Net Benefits Assessment Model



Source: Navigant analysis

4.2.1 Participation Module

The participation module starts with historical end-of-year participant counts for the RRTP program. These are compared to general estimates of the number of residential customers in the ComEd 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 yields an assessment of costs and benefits related to the current set of customers, assuming they are allowed to continue in the RRTP program through 2020.

In the sensitivity analysis in section 4.3.3, two alternative growth scenarios are examined. In the first (growth scenario), program enrollment reaches 25,000 customers by 2015 and then remains steady. In the second (high-growth scenario), program enrollment reaches 50,000 customers by 2015 and remains steady. Table 19 summarizes these cases. Participation rates are based on the assumption that the number of ComEd resdintial customers does not change over the next 10 years. This simplification does not have a significant impact on the nature of the final net benefits estimates.

Table 19. Historical and Forecasted RRTP Program Participation Rates

Year	Residential Customers	RRTP Participants	Participation Rate
2007	3,286,000	3,334	0.10%
2008	3,300,000	5,838	0.18%
2009	3,317,000	8,007	0.24%
2010	3,345,000	11,530	0.34%
2015-2020 Base Scenario	3,345,000	11,530	0.34%
2015-2020 RRTP Moderate-Growth Scenario	3,345,000	25,000	0.75%
2015-2020 RRTP High-Growth Scenario	3,345,000	50,000	1.50%

Source: Navigant analysis

4.2.2 Residential Load Shape Module

The Residential Load Shape Module creates annual hourly load shapes for RRTP households with and without the RRTP program. RRTP household consumption in the absence of the program is based on the hourly impact analysis of section 3.2. The load impacts of the program are the difference between the two curves in every hour of 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 load increases. The basis of these load curves for the historical years of 2007 through 2010 has been detailed in Section 3.2 of this report.

Although the historical load shapes essentially come from metered data, predicting what those load shapes will be in the future is a challenge. It is known, however, that two of the primary influences on load shapes are weather and price. The demand analysis presented in section 3.3 explains how energy price affects hourly electricity consumption. Three different time scales of price response are discussed: long-run, medium-run, and short-run.

In the long run RRTP households respond to real-time energy prices in their decisions concerning capital investments, such as energy efficient appliances and weatherization. Four 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 price response. Consequently, long-run price response is not considered in the forecast models of load shapes.

In the medium run RRTP 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 rate, 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 RRTP customers indicating that shifting energy consumption to overnight hours, when prices are low, reduces energy bills. There is no reason to expect that mean hourly prices will change in the future, and so in the net benefit assessment Navigant expects that the structural adjustment to real-time prices derived in the hourly impact analysis of subsection 3.2 will remain the same in the future. Put succinctly, Navigant models hourly load impacts of the RRTP program as fundamentally a structural adjustment to differences across hours in the mean hourly price and forecasts mean hourly prices to remain constant.

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. It might be expected that the short-run price response is minimal except on high-price alert days. In the context of the hourly load impact regression analysis of section 3.2, the effects of short-run price deviations are captured by variables indicating high price alerts and are otherwise embedded in the regression error terms. It follows that the program hourly load impacts estimated in section 3.2 are sufficient for forecasting unless the volatility of future prices increases or decreases.

The upshot is that Navigant forecasts assume that with regard to forecasting future hourly loads, the distribution of future prices will remain the same as seen in 2010. Navigant has no solid information on which to base changes to that assumption. Under this assumption the hourly load functions estimated for 2010 apply to the future.

Navigant chose to use the 2010 load functions, as opposed to those for other years, for two reasons. First, these load functions apply to the current RRTP population, and our best guess is that this population is closer in its behavior to the future population than is the population from previous years. Second, because 2010 was a hot summer, future impacts from hot summers will be modeled based on real observations within that temperature range. Although 2008 was the year with the highest prices and the most high price alerts, it was also a very cool year (see Figure 5, Figure 8, and Figure 11, beginning on page 16). Participants' ability to respond to these alerts was limited by the fact that their air conditioning use was at a moderate level. The load functions for 2010 provide, in Navigant's view, a more typical example of the effect of high price alerts on load response, because the high price alerts were usually driven by high temperature and humidity.

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.

4.2.3 Weather Module

During the summer season, weather consistently contributed to differences in customer load curves and impacts from the program. Due to the strong influence of weather on summer 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 used in conjunction with the summer 2010 load functions to estimate the effect of weather on program net benefits model. The weather scenarios are restricted to the summer season because peak energy demand is greatest in the summer, and consequently the value of modeling temperature variations can be pronounced.

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.[24] 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 14 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 ComEd service territory was available for 1973 through 2010. The first review of the weather history provided the astonishing result that this four year period included one of the coolest summers in the last 38 years as well as one of the hottest summers. Based on annual cooling degree days, 2009 was the second coolest summer since 1973, and 2010 was the second hottest over the same time period. What we have in our historical program data, then, are two "bookends" for the weather extremes we are likely to face over the forecast period.

[24] 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 RRTP impacts is the response on alert days, the individual hottest days of the summer. Alert days 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 alert days.

The goal is to find a weather threshold that will identify probable alert 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 temperature-humidity index (THI).[25] Assuming that the predominant summer load for RRTP customers on alert days is air-conditioning, the THI was used as a measure for finding probable alert days in the historical weather data. Different THI thresholds were tested, with the goal of being able to identify some alert 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 alert 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 probable alert 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.

In general, lower cooling degree days for a summer correspond to a lower number of probable alert days for the same summer. Looking at a sorted list of the 38 years of weather data, four distinct weather scenarios were distinguished, as presented in Table 20. Weather Scenarios and Probabilities Sixty percent of summers have weather conditions in the low to mid range, with average annual cooling degrees of 845 or less and five or fewer probable alert days. Forty percent of summers are hotter, but here the effect is skewed towards some extremely hot summers. Sixteen percent of summers are expected to be extremely hot with average annual cooling degree days near 1205 and sixteen probable alert days. Note that 2010 was one of these extremely hot summers that would have had 18 alert days based on the weather threshold. However, since prices were relatively low due to economic conditions and other factors, there were only thirteen RTA14 alert days actually called.

[25] THI = (.55 * Dry Bulb Temperature) + (.2 * Dew Point Temperature) – 48.5

Table 20. Weather Scenarios and Probabilities, Based on 1973-2010 Weather Data

Weather Scenario	Average Summer Cooling Degree Days	Average Number of Probable Alert Days	Probability of Occurrence
Low	708	2	21%
Mid	845	5	39%
High	1082	10	24%
Extra High	1205	16	16%

Source: Navigant analysis

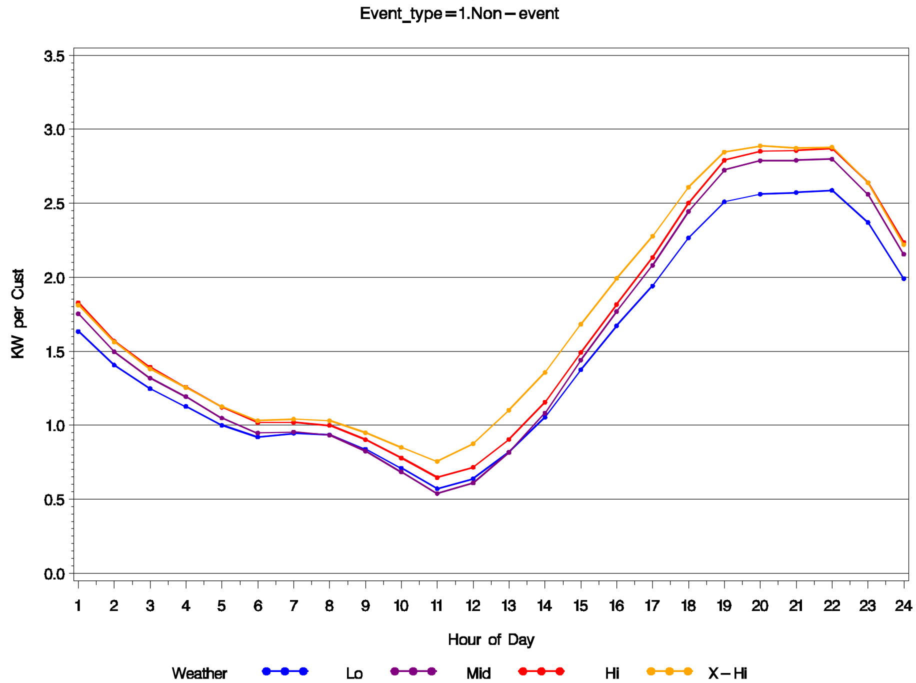
The appropriate weather scenario group was identified for each of the last 38 years. Then average hourly temperatures were calculated for both regular weekdays and probable event weekdays over each weather scenario. The average temperatures were used with the 2010 load shape regression model coefficients to estimate hourly load shapes for each daytype and customer group.

Since it is important to keep hourly load changes aligned with hourly prices within the net benefits model, the 2010 daytype template was used to build all of the weather scenario forecasted load shapes. While most weekdays in each scenario are regular, non-event days, some must be identified and modeled as alert days. The alert days must be aligned with the highest price days. Since 2010 was an example of an Extra High weather scenario year, all alert days (RTA14 and RTA10) in 2010 remained as alert days in the Extra High forecast years. For High weather scenarios, all RTA10 alert days were dropped. This left a total of twelve modeled RTA14 event days which is close to the average of ten probable alert days for this weather scenario. Similarly, for the forecasted Mid weather scenario only the five RTA14 days with the highest prices were kept as modeled alert days, and for the Lo weather scenario this number was reduced to the two highest price RTA14 alert days. This modeling reflects the fact that summers of different average temperatures are expected to have correspondingly different numbers of alert days called, prices being equal.

Figure 56 gives an illustration of the load curve results from this method for summer non-event weekdays for the RRTP participants. One load curve is for each of the four different weather scenarios. Differences in load predictions are based on the hourly average temperatures seen for non-event days in each of the different weather scenario groups in the historical weather data. It shows that during the coolest summers, average evening hourly loads run about 0.3 kW below what is seen in the hottest summers. This difference is due strictly to temperature.

NAVIGANT

Figure 56. Participant Summer Weekday Non-Event Load Curves for each Weather Scenario



Source: Navigant analysis

Table 21 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 39 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 set of hourly summer loads for RRTP participants, and a set of loads for the matched control group. Both of these curves are aligned to the same average cooling degree days and number of alert days for the given weather scenario.

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 21. Example of Weather Forecast Random Iterations

Forecast Year	Iteration 1 Weather Scenario	Iteration 1 No. of RTA14 Days	Iteration 1 Average Annual CDD	Iteration 2 Weather Scenario	Iteration 2 No. of RTA14 Days	Iteration 2 Average Annual CDD
2011	Mid	5	845	Hi	12	1082
2012	Lo	5	708	Hi	12	1082
2013	XHi	12+	1205	Mid	5	845
2014	Hi	12	1082	Hi	12	1082
2015	Lo	2	708	Lo	2	708
2016	Mid	5	845	Mid	5	845
2017	Mid	5	845	Mid	5	845
2018	Mid	5	845	Lo	2	708
2019	Mid	5	845	Mid	5	845
2020	Mid	5	845	XHi	12+	1205

Note: The XHi weather scenario has twelve RTA14 days and additional RTA10 days, like 2010.

Source: Navigant analysis

4.2.4 Price Module

As stated previously, for this net benefits model, it will be assumed that future hourly real-time 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 real-time prices in the net benefits model, there is also the need to compare future RRTP customer bills to the portion of the flat rate that is equivalent to the energy charges covered by the real-time 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 22 show the equivalent average energy charge component that would explain the overall estimated bill savings reported for previous years.

Table 22. Estimated Energy Charge Component within the Residential Flat Rate

Year	Cents per kWh
2007	6.34
2008	6.28
2009	5.52
2010	5.67
All Forecast Years (Average of 2009 and 2010)	5.60

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 23 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 23. Scenario Values for Hedging Premium

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

Source: Navigant analysis

4.2.5 System Loads Module

The system loads module is the collection of historical data on hourly PJM and ComEd system loads for 2008 through 2010. Total PJM loads are separated into three pieces: PJM East loads, ComEd loads, and all other PJM loads. Lagged PJM loads are also calculated within this module from the total PJM load series. This is data that will be needed in the estimation of non-participant benefits from market effects.

4.2.6 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 (incremental costs related to purchasing, installing/exchanging, reading and testing/maintaining an interval 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, Comverge is responsible for administration and marketing of the RRTP program. It provides 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. CNT Energy has also provided some additional administrative and marketing services over the historical program period and those costs are also included.

ComEd handles meter acquisition and installation as well as billing for the RRTP 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.[26]

Navigant prefers to account for total incremental meter costs on an amortized basis, so there are ongoing monthly charges related to meter costs for all active RRTP participants, rather than a single full-price equipment and installation cost for each new RRTP participant in addition to incremental monthly meter reading and maintenance charges. This practice is based on the assumption that interval meters removed from the RRTP program could be put to use within other customer groups and there is no need to charge the RRTP 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 RRTP program standard issue for all customers. If this happens, the incremental meter costs for the RRTP program would drop to zero. A scenario which excludes all meter costs was added to the net benefits assessment to allow for consideration of the net benefits impact of this possibility.

[26] Some program evaluation costs were part of Comverge expenses in 2010.

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.

4.2.7 Benefit #1: Participant Avoided Capacity Costs Module

Demand reductions caused by the RRTP program reduce ComEd 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 real-time LMP prices that RRTP 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, multiplied by the annual cost per kW to provide that capacity.

Publicly available information from PJM was used as the source of avoided costs. For historical years and near-term forecast years, the market clearing prices from the Reliability Pricing Model (RPM) Base Residual Auction (BRA) are considered the best estimate of actual capacity costs. For the long-term forecast, when RPM clearing prices are not available, the PJM Cost of New Entry (CONE) estimate for CONE Area 3 is considered the best estimate of capacity costs for ComEd, escalated at an annual 5% rate for real cost increases. The combination of RPM market clearing values for 2007 through 2014 and CONE values for the forecast years of 2015 through 2020 is shown in Table 24, along with the translation of the $/MW-day values into $/kW-year values. The $/kW-year values are the avoided capacity costs used in the net benefits model.

Table 24. Avoided Capacity Costs for RRTP Net Benefits Assessment

Year	$/MW-day	$/KW-day	$/KW-year	Source
2007	$40.80	$0.04	$14.89	RPM
2008	$111.92	$0.11	$40.85	RPM
2009	$102.04	$0.10	$37.24	RPM
2010	$174.29	$0.17	$63.62	RPM
2011	$110.00	$0.11	$40.15	RPM
2012	$16.46	$0.02	$6.01	RPM
2013	$27.73	$0.03	$10.12	RPM
2014	$125.99	$0.13	$45.99	RPM
2015	$379.43	$0.38	$138.49	CONE
2016	$398.40	$0.40	$145.42	CONE
2017	$418.32	$0.42	$152.69	CONE
2018	$439.24	$0.44	$160.32	CONE
2019	$461.20	$0.46	$168.34	CONE
2020	$484.26	$0.48	$176.75	CONE

Source for RPM: "2014/2015 RPM Base Residual Auction Results", PJM DOCS #645284, Table 1, p. 4
Source for CONE: "rpm-bra-planning-parameters-2014-2015(1).xls", sheet 'Net CONE', CONE Area 3[27]

Note that the RPM market clearing price is very low for 2012 and 2013. This occurs because there is a significant increase in new capacity offerings from demand resources and energy efficiency resources at the same time that there is a reduction in the peak load forecast due to slow economic growth. Avoided capacity costs start to grow again in 2014 based on the RPM market, followed by a steep increase in costs between 2014 and 2015 as we switch from a short-term market valuation method to a long-term cost-based peaker replacement method. While this discontinuity between the two price series is acknowledged, it is accepted as the best publicly-available information to be used for this evaluation. The RPM market is a short-term capacity market compared to CONE which is a long-term capacity valuation method.

The expected summer peak reductions from the program are estimated as the average demand reductions from the program at hour ending 15 on alert 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 RRTP Participant load curve when looking at summer afternoons. Hourly distribution loss factors are applied to each of these impacts at the customer meter to create the kW change per RRTP participant at the distribution system level, as shown in Table 25. The distribution losses during these peak hours are close to 7 percent.

[27] An explanation of the methodology used for estimating CONE can be found in "2014/2015 RPM Base Residual Auction Planning Period Parameters", PJM DOCS #631095, p. 7.

Table 25. Summer System Peak kW Change per RRTP Participant

Year	kW per Participant	kW per Participant at Distribution System Level	Program Peak kW
2007	-0.5407	-0.5785	-1149
2008	-0.6906	-0.7389	-3389
2009	-0.6788	-0.7263	-5028
2010	-0.5306	-0.5677	-5544
2011–2020	-0.4768	-0.5102	-5881

Source: Navigant analysis

As a reminder, historical peak responses reflect a changing participant population at the same time that prices and weather were volatile from year to year. In general, 2007 and 2008 had high prices while 2009 and 2010 had low prices, and 2008 and 2009 had cool weather while 2007 and 2010 had hot weather. And even though 2009 was a cool summer overall with no RTA14 events, it did have four days of very high temperatures when RTA10 and Load Guard10 events were called which created a high peak hour reduction.

Also of interest, forecasted peak responses are slightly lower than observed peak responses in 2010 even though the participant composition is the same. This is because 2010 was one of the hottest summers on record, and forecasted summers are expected to have slightly cooler peak day temperatures on average.

4.2.8 Benefit #2: Participant Consumer Surplus

In the design of the RRTP 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 RRTP 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 real-time prices are relatively low *and* the costs to participants when real-time prices are relatively high. As presented graphically below (Figure 57, to be discussed), 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 real-time price causes the RRTP household to reduce consumption below what it would have consumed under the fixed-rate price, thereby reducing its bill but at the cost of consuming less energy.

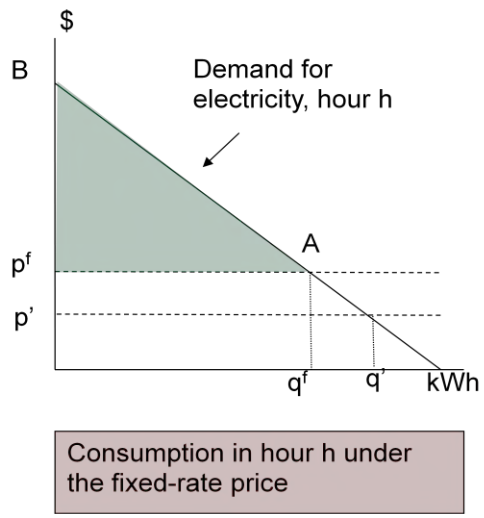
Bill savings are presented in section 3.4 of this report. That bill savings are only an approximation of consumption-related benefits is due to two factors: first, bills associated with the RRTP program include a participant charge. Second, even after accounting for the participant charge, bill savings 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 RRTP total bills to the same kWh usage billed on the standard rate tariff. The RRTP bills include a $2.25 charge per month to cover approximately half of the anticipated 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 incremental cost of the interval 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 RRTP households. Navigant argues that this provides a reasonably good approximation of the "true" benefits of the RRTP program to participants. The deviation between the original calculation of bill savings and the true benefit of the program to RRTP participants arises because the bill savings calculation effectively assumes that energy consumption patterns under the RRTP program are the same as under the alternative fixed-rate plan. In reality, RRTP customers change their behavior compared to that exhibited under the fixed-rate plan to avoid high real-time prices and take advantage of low real-time prices.

To clarify the issue, consider the three graphs shown below. The first graph, in Figure 57, 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 57. The General Case of RRTP Customer Response to Price Differences



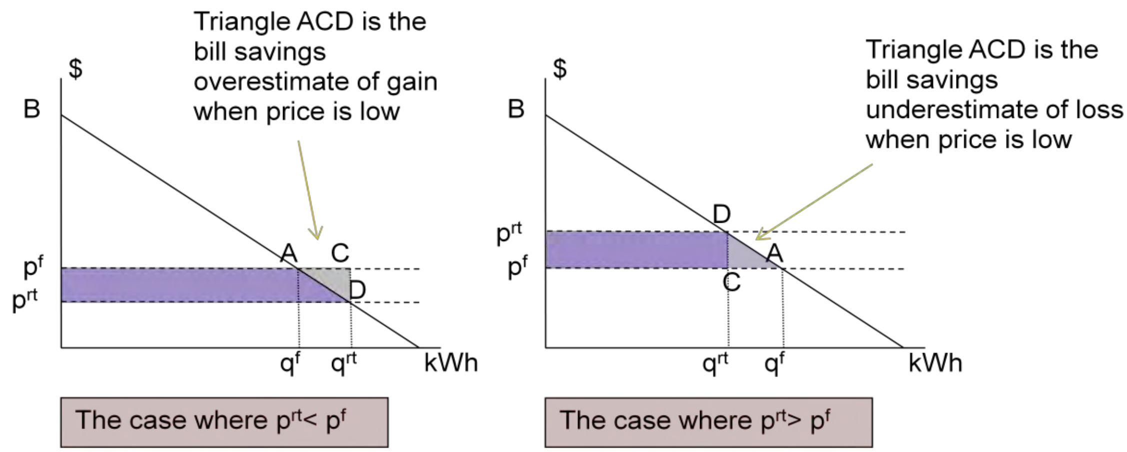
Source: Navigant analysis

Now suppose that under the RRTP program the price of energy faced by the household is the relatively low real-time price p^{rt}, as shown in the first graph of Figure 58**.** Consumption increases to q^{rt} and the net benefit to the consumer from the price difference is the shaded area p^fADp^{rt}. In other words, this is the net benefit to the RRTP 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^{rt}; this is the cross-hatched rectangle, p^fCDp^{rt}.[28] This value somewhat *overstates the benefit* of the RRTP 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^{rt} approaches the true net benefit p^fADp^{rt}.

Moving to the second graph of Figure 58, if the RRTP real-time price is *higher* than the fixed-rate price, household consumption falls, and the net loss to the RRTP household is the shaded area p^fADp^{rt}. 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^{rt}, and denotes the (negative) bill savings calculation. This value *understates the loss*.

[28] 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.

Figure 58. 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 real-time prices are low relative to the fixed-rate price, and understates the loss when real-time prices are high. These errors arise because the original bill savings estimates do not account for the shifting of energy consumption behavior under the RRTP 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 between the real-time 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 RRTP participants, Δp_t is the difference between the real-time 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 13.

Table 26 shows the associated adjustment in bill savings necessary to correctly approximate annual consumer surplus. The table corrects original bill savings calculations to reflect the add-back of the participation charge, as discussed on page 99. As indicated, the consumer surplus reductions are small.

Table 26. Adjustment to Original Total Bill Savings to Estimate Consumer Surplus

Year	Overall Program Savings (All Customers)	Annualized Number of Program Participants used in Net Benefits Model	Annualized Overall Program Savings per Participant	Add Back Annual Participant Charge	Adjusted Total Savings per Participant	Annual Adjustment per Participant	Consumer Surplus per Participant
2007	$165,518	1,667	$99	$27	$126	($2.69)	$123.31
2008	$315,270	4,586	$69	$27	$96	($3.41)	$92.59
2009	$1,485,164	6,923	$215	$27	$242	($5.23)	$236.77
2010	$1,936,844	9,767	$198	$27	$225	($2.79)	$222.21

Source: Navigant analysis

We will now turn our attention to understanding the components contributing to the overall estimate of consumer surplus. Navigant estimates there are three major components:

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 27). All forecast years have the same value because the price forecast and the participant load shape stay constant over the forecast period.

Table 27. Annual Consumer Surplus per RRTP Participant from Avoidance of the Hedging Premium

Year	Hedging Premium 5%	Hedging Premium 10%	Hedging Premium 15%
2007	$28.23	$56.45	$84.68
2008	$31.92	$63.84	$95.76
2009	$27.17	$54.34	$81.51
2010	$32.89	$65.78	$98.67
2011–2020	$31.50	$62.99	$94.49

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   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 the real-time price is low the triangle is a consumer surplus benefit, but when real-time price is high the triangle is a consumer surplus reduction. The shifting components can offset each other under the different price conditions.

Table 28 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 28. Annual Consumer Surplus per RRTP Participant from Shifts in Usage

Year	$ per Participant
2007	$1.92
2008	$0.43
2009	$5.23
2010	$2.28
2011–2020	$1.41

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 RRTP 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 29 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.

Table 29. Annual Consumer Surplus per RRTP Participant from Forecast Error

Year	Hedging Premium 5%	Hedging Premium 10%	Hedging Premium 15%
2007	$93.17	$64.94	$36.72
2008	$60.24	$28.31	$-3.61
2009	$204.40	$177.20	$150.00
2010	$187.00	$154.20	$121.30
2011–2020	$0	$0	$0

Source: Navigant analysis

Given the current imbalance 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. However, this assumption plays a critical role in the outcome of the net benefits calculation, as will be discussed further in a subsequent section.

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 30, assuming a hedging premium of 10% which is the base case.

Table 30. Components of Annual Consumer Surplus per RRTP Participant

Year	Hedging Premium 10%	Shifting Consumption	Forecast Error	Total Consumer Surplus
2007	$56.45	$1.92	$64.94	$123.31
2008	$63.84	$0.43	$28.31	$92.58
2009	$54.34	$5.23	$177.20	$236.77
2010	$65.78	$2.28	$154.20	$222.26
2011–2020	$62.99	$1.41	$0	$64.40

Source: Navigant analysis

4.2.9 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.

For estimating changes in energy supply costs, 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 2007–2010 was used for modeling non-participant benefits in all historical and forecast years.

The total benefits are calculated for three different populations:

1. All PJM customers
2. All ComEd customers
3. ComEd residential customers

The net benefits that accrue to all PJM customers are considered to be the best indicator of overall economic benefits for consumers from the RRTP program. However, the subset of benefits that accrue to ComEd residential customers are also reported based on the specific requirements of Public Act 094-0977 which created RRTP, and were incorporated in the order from the Illinois Commerce Commission (ICC) in Docket 06-0617, which implemented that legislation. That docket required required an economic evaluation of the RRTP program after the implementation period of 2007–2010, and specifically required estimation of the net economic benefits to ComEd's residential customers.

4.3 Results

Data was gathered on both historical and forecasted costs and benefits for the RRTP 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 RRTP participants.

4.3.1 RRTP Program Net Benefits, 2007-2010

Table 31 provides the annual program costs, and annual program benefits *to residential ComEd customers*, over the first four years of the program, 2007–2010. There are dramatic changes from year to year. In the start-up years of the program, net benefits are negative: -$1,933,000 in 2007 and -$1,701,000 in 2008. This reflects the significant investment needed to develop the processes and IT systems required for program start-up, and the cost of recruiting new customers into a new program. In 2009 and 2010 these start-up costs dissipate and therefore net benefits increase substantially as more customers join the program. The overall effect is the achievement of positive net benefits of $24,000 in 2010. It deserves emphasis that this net benefit assessment of the first four years of the program applies to ComEd residential customers only, as required in Docket 06-0617. After three years of strong investment in program start-up costs and experimentation with different marketing methods, the program shows positive net benefits in the fourth year.

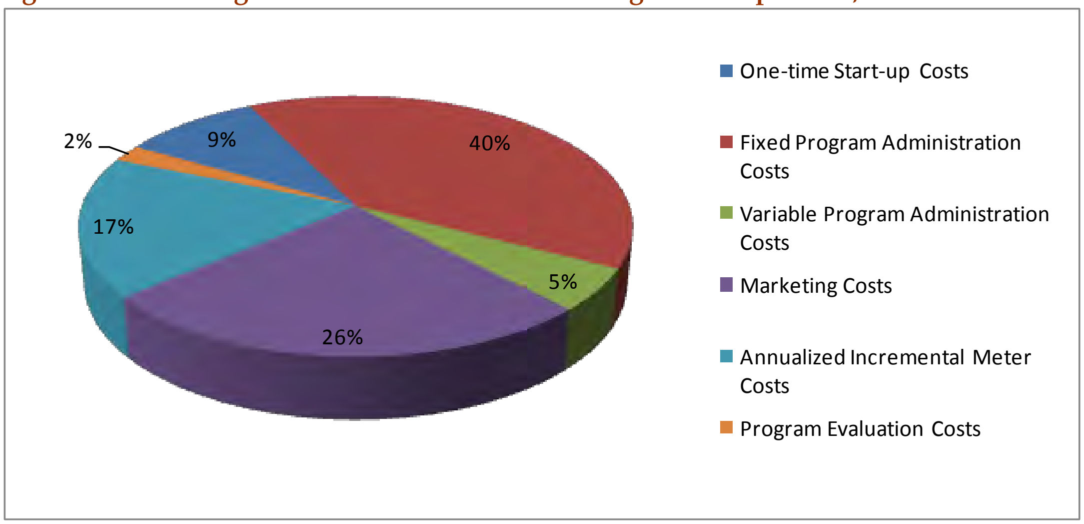
Table 31. Historical Benefits and Costs of RRTP Program 2007-2010

	2007	2008	2009	2010
Participant Benefits: Avoided Capacity Costs	$17,000	$138,000	$187,000	$353,000
Participant Benefits: Consumer Surplus	$245,000	$425,000	$1,639,000	$2,170,000
Non-Participant Benefits: Residential Customers	$34,000	$73,000	$86,000	$83,000
TOTAL BENEFITS	$296,000	$636,000	$1,912,000	$2,606,000
TOTAL COSTS	$2,229,000	$2,337,000	$2,696,000	$2,582,000
NET BENEFITS	**-$1,933,000**	**-$1,701,000**	**-$784,000**	**$24,000**

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

Figure 59 presents the percentage allocation of costs across program components for the four years of the program. The one-time start-up cost comprises initial IT costs to establish the billing system, and the development of the new program process. Fixed program administrative costs include IT, the program call center, billing, operations, web site maintenance, and program management. Variable program administrative costs include incremental call center costs, mailings, and other per-participant costs. Marketing costs are the fixed costs of acquiring and enrolling new participants. Annualized incremental meter costs pertain to the costs associated with purchasing, installing/exchanging, reading, and maintaining interval meters above such costs for a standard residential meter. Program evaluation costs pertain to the cost of producing this report.

Figure 59. Percentage Allocation of Costs across Program Components, 2007-2010



4.3.2 Projected RRTP Net Benefits, 2011-2020.

The historical analysis leads to the question of what program net benefits would be if the program were extended into the future. Table 32 provides the present value of program net benefits that would accrue were the RRTP program extended another ten years, covering the period 2007–2020. Benefits are calculated at three levels: Benefits to all PJM customers, benefits to all ComEd customers, and benefits to all ComEd residential customers. The RRTP program generates positive net benefits of $12,210,000 at the PJM level, but negative net benefits when the population of interest is restricted to ComEd customers. The best measure of the net benefit of the RRTP program to energy consumers, while accounting for costs incurred by ComEd, is the PJM-level measure.

Table 32. Net Present Value of Benefits and Costs for Program, Inception through 2020

	PJM View	ComEd View	ComEd Residential Customer View
Participant Benefits: Avoided Capacity Costs	$6,171,000	$6,171,000	$6,171,000
Participant Benefits: Consumer Surplus	$11,099,000	$11,099,000	$11,099,000
Non-Participant Benefits: Market Effects	$22,650,000	$3,295,000	$1,022,000
TOTAL BENEFITS	$39,920,000	$20,565,000	$18,292,000
TOTAL COSTS	$27,710,000	$27,710,000	$27,710,000
NET BENEFITS	**$12,210,000**	**-$7,145,000**	**-$9,418,000**

These net benefits reflect a base scenario where RRTP 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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 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 33 shows annual benefits and costs for each historical year of the program (2007 to 2010), and then forecasted annual values for 2020.

Table 33. Annual Benefits and Costs for RRTP Program

	2007	2008	2009	2010	2020
Participant Benefits: Avoided Capacity Costs	$17,000	$138,000	$187,000	$353,000	$1,039,000
Participant Benefits: Consumer Surplus	$245,000	$425,000	$1,639,000	$2,170,000	$742,000
Non-Participant Benefits: Market Effects PJM View	$746,800	$1,619,000	$1,940,000	$1,815,000	$1,834,000
Non-Participant Benefits: Market Effects ComEd View	$108,900	$234,900	$277,700	$267,700	$267,000
Non-Participant Benefits: Market Effects ComEd Residential View	$33,750	$72,810	$86,100	$82,980	$82,780
Program Costs	$2,229,000	$2,337,000	$2,696,000	$2,582,000	$1,984,000

These costs and benefits reflect a base scenario where RRTP 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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 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 RPM capacity market values are used in 2007 through 2012, while the cost of new entry is used to value avoided capacity for 2013 and beyond. The cost of new entry in real dollars is expected to increase annually at 5% throughout the forecast period.

Participant benefits from consumer surplus are lowest in 2008 because market prices were relatively high compared to the flat rate and the number of historical participants was lower at that point. 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. The future consumer surplus benefit is expected to be less than what was seen in the historical period when market prices were low.

Total non-participant benefits from the reduction in PJM prices are relatively constant through the 2008 to 2010 period since increasing customer participation is offset by lower market prices. Benefits are higher in forecast years than in 2010 for several reasons. First, the 2010 participant count is based on an annualized number (9,767), whereas forecast years have a participant count equal to the 2010 end-of-year participant number (11,530). Second, the average supply curve for future years is slightly higher than the 2010 supply curve since it is based on the average of 2009 and 2010.

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 when 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 the proportion of those benefits that go to non-participants versus participants.

To demonstrate this effect, we can look at how the non-participant benefits in the base case would change if we use the 2008 supply curve instead of the average of 2009 and 2010 for calculating future year benefits. In 2008, market prices for electricity were relatively high compared to 2009 and 2010. Table 34 shows that if we assume that market prices in future years match the 2008 supply curve, then the net present value of overall program benefits increases by over $3 million for the PJM customer view, by $448,000 for the ComEd customer view, and by $138,000 for the ComEd Residential customer view.

Table 34. Example of Increase in Net Benefits for Non-Participants when Market Prices are High, Inception through 2020

	PJM View	ComEd View	ComEd Residential Customer View
Non-Participant Benefits @ Base Case Forecasted Supply Curve (average of 2009 and 2010 – low market prices)	$22,650,000	$3,295,000	$1,022,000
Non-Participant Benefits @ 2008 Supply Curve for forecast years – high market prices	$25,670,000	$3,743,000	$1,160,000
INCREASE IN NET BENEFITS	**$3,020,000**	**$448,000**	**$138,000**

These net benefits reflect a base scenario where RRTP 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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Total program costs are relatively constant in the historical period. Future program costs are lower since there are no marketing costs included after 2010 in this base case view, and base case fixed program costs are reduced to $810,000 per year compared to a historical annual average of

$1,170,333 over 2008 through 2010. In the forecast years, the meter charges make up 42 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.

4.3.3 Sensitivity Analysis

The remaining discussion focuses on the effect of various model assumptions on the estimated net benefit of the RRTP program.

Persistent Forecast Errors

In the base case, it is assumed that the energy component of the flat rate is always in balance with average real-time prices after adjustments are made for the hedging premium and shifting behavior. This is the desired state from a rate-making perspective. However, the desired state is difficult to achieve because it requires an accurate forecast of what real-time prices will be at the time that the flat rate is set. Because it is not possible to perfectly forecast electric market prices, there will always be some forecast error as discussed previously in this report.

The purpose of the forecast error scenarios is to test how the net benefits of the RRTP program would be affected by different levels of forecast error in the future. Three alternative future forecast error levels are presented. The base case—already presented in Table 32, but reproduced below for the sake of comparison with alternative scenarios—assumes zero forecast error. The second scenario finds the lowest forecast error observed over the four year study period of 2007-2010 and assumes the same level of forecast error would be seen in all future years (2011-2020). The third scenario uses the average forecast error observed over the past four years. The fourth scenario uses the highest forecast error over the past four years. Table 35 illustrates these assumptions and their source years.

Table 35. Assumptions on Future Forecast Error used in Forecast Error Scenarios

Year	Consumer Surplus from Forecast Error per Participant
Actual 2007	$64.94
Actual 2008	$28.31
Actual 2009	$177.20
Actual 2010	$154.20
Base Case Future: Zero Forecast Error	$0
Scenario 1 Future: Lowest Observed	$28.31
Scenario 2 Future : Average Observed	$106.16
Scenario 3 Future: Highest Observed	$177.20

Table 36 shows that the forecast error assumption used for future years has a significant impact on the net benefits of the program. If forecast error in future years is equal to the average forecast error observed over the last four years, then even the ComEd Residential Customer view shows significant positive net benefits of over $1,500,000.

Table 36. Impact of Forecast Error on Net Benefits, Inception through 2020

Net Present Value of Net Benefits	PJM View	ComEd View	ComEd Residential Customer View
Base Scenario: Zero Forecast Error	$12,210,000	-$7,145,000	-$9,418,000
Scenario 1: Lowest Observed Forecast Error	$15,160,000	-$4,196,000	-$6,469,000
Scenario 2: Average Observed Forecast Error	$23,150,000	$3,791,000	$1,518,000
Scenario 3: Highest Observed Forecast Error	$30,290,000	$10,930,000	$8,660,000

These net benefits reflect a base scenario where RRTP 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 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Of course, in the four years of program observation (2007 through 2010), market prices were less than expected. This gave RRTP participants sizeable bill savings compared to what they would have been paying on the flat rate. In all four historical years, RRTP customers benefited from forecast error and, consequently, all of the forecast error scenarios show varying levels of these positive benefits to participants. However, it is possible that the future will hold a different scenario where real-time prices jump up and greatly exceed what is reflected in the flat rate. In this case, participants will experience negative bill savings unless they shift their energy consumption patterns. Estimating how much participants might shift their electric loads on an hourly basis when faced with a substantial overall jump in real-time rates would require significant additional modeling that is beyond the scope of this study. For that reason, we do not show any scenarios for a future where the forecast error is negative.

Growth in the Number of Participants

The base scenario results assume no growth in the number of participants in the RRTP program after 2010. Two other customer growth scenarios were also considered: reaching 25,000 participants by 2015, and reaching 50,000 participants by 2015, with participation then remaining constant through 2020 in both cases. Marketing costs are set at $80 per new participant in the 25,000 participant scenario, but are modeled at $70 per new participant in the 50,000 participant scenario due to slightly declining costs per participant at higher volumes of activity. These forecasted marketing costs are well below the average marketing cost of $235 per new participant that was seen in the historical period of 2007 through 2010. During the historical period several different marketing approaches were tested. Analysis of these results led to the lower marketing costs that are expected to be effective in the forecast period. These forecasted marketing costs are well below the average marketing cost of $235 per new participant that was seen in the historical period of 2007 through 2010. During the historical period several different marketing approaches were tested. In fact, by 2010 annual marketing costs had already dropped to $130 per new participant when 3,500 new participants joined the program. Future marketing costs have been forecast to be in the $50 to $110 range, depending on the marketing approach used and the expected response rate. The values of $80 and $70 used for the net benefits forecast are within this range.

Table 37 shows that net benefits increase substantially from the PJM view as the participation rates increase. This is as expected because new customers generate greater price reduction benefits to PJM energy consumers. One might also expect increases in net benefits to ComEd customers, because fixed costs are spread across a greater number of RRTP participants. However, in both the ComEd and the ComEd Residential views the program net benefits become more negative compared to the no-growth baseline in the growth scenario, and less negative in the high-growth scenario. This is the result of non-linearities in quasi-fixed cost streams across the period, and a truncated period of benefits for participants who join the program from 2012 through 2015. Note that only existing customers and new customers in 2011 get a full ten years of future benefits credited to the program within the time frame of the analysis.

Table 37. Impact of Growth in Program Participation Rates on Net Benefits for 2011 through 2020

Net Present Value of Net Benefits:	PJM View	ComEd View	ComEd Residential Customer View
Baseline: No Growth (participation rate remains at 0.34%)	$10,830,000	-$3,430,000	-$5,107,000
Growth (Participation Reaches 25,000 by 2015)	$22,800,000	-$3,833,000	-$6,963,000
High Growth (Participation Reaches 50,000 by 2015)	$50,340,000	$770,000	-$5,052,000

The societal discount rate is 1%.
Program start-up costs are not included.
Incremental meter costs are included.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

To explain further, in the no-growth scenario annual fixed program costs are $810,000 in every forecast year. In the growth scenarios there are higher annual fixed program costs as the program reaches higher total numbers of participants. This reflects the need to add additional staff to customer support activities in a step-wise fashion. When the program reaches 25,000 total participants, fixed program costs are expected to be $1,311,000 per year. If the program reaches 50,000 total participants, annual fixed program costs are expected to be $1,660,000.

When marketing costs are added to these step-wise increases in fixed program costs, a situation is created where average costs per participant are higher in the two growth scenarios for the years 2011 through 2015 than they are for the no-growth scenario. After 2015, when there are no more marketing costs, per-participant fixed program administration costs reflect the expected pattern: $70.25 for no growth, $52.44 for 25,000 participants, and $33.20 for 50,000 participants.

This nonlinear effect also exists in the PJM view, because ComEd customers are a subset of PJM energy consumers, but it is overwhelmed by the increase in price reduction benefits that accrue to all PJM energy consumers.

As a counterpoint to the results above, Table 38 presents the annual benefit, cost, and net benefit from adding one more participant to the program in 2011. This marginal perspective removes from the calculation of net benefits the effects of fixed costs, because it is assumed that the addition of one more participant does not affect program fixed costs. As shown in the table, adding one more participant increases net benefits by $130 from the perspective of ComEd Residential customers. This is calculated based on a first year marketing (acquisition) cost of $80 and a full ten years of forecasted net benefits. From the ComEd customer view, the net present value of the stream of marginal net benefits is even higher at $281 per participant. So, from both views, adding one more participant increases the program's net benefits if ten years of benefits can be counted. Taken together, Table 37-Table 38 demonstrate the importance to the net benefit of the program to keep fixed costs low.

Table 38. Marginal Net Benefit of Adding One More Participant in 2011

Year	Marginal Cost	Marginal Benefit		Marginal Net Benefit	
		ComEd View	ComEd Residential View	ComEd View	ComEd Residential View
2011	$182	$108	$92	-$74	-$90
2012	$102	$91	$75	-$11	-$27
2013	$102	$93	$77	-$9	-$25
2014	$102	$111	$95	$9	-$7
2015	$102	$158	$142	$56	$40
2016	$102	$162	$146	$60	$44
2017	$102	$165	$149	$63	$47
2018	$102	$169	$153	$67	$51
2019	$102	$173	$157	$71	$55
2020	$102	$178	$162	$76	$60
Net Present Value @ 1%	**$1,044**	**$1,325**	**$1,174**	**$281**	**$130**

These marginal costs and benefits reflect a scenario where one new participant is added in 2011 and they continue on the program until 2020,
Variable program administrative costs, marketing costs and incremental meter costs are included.
Program start-up costs, evaluation costs and fixed program administration costs are not included since their marginal values are zero for one additional customer.
Hedging Premium is 10%.
Values are calculated as the mean of 14 iterations of different weather scenarios for each of the forecasted years.
Source: Navigant analysis

Finally, a useful exercise is to consider how much fixed program administrative costs –the largest share of program costs (see Figure 59)—would need to drop for the program to break even for ComEd customers over the program period 2007-2020. Table 39 presents results from such an exercise. The table shows that for the program to break even from the perspective of ComEd residential customers, fixed program administrative costs would need to drop considerably, even under the high-growth scenario. By contrast, from the perspective of all ComEd customers the break-even point under the high-growth scenario is actually *higher* than current fixed program administrative costs by $80,000 per year.

Table 39. Maximum Annual Fixed Program Administrative Costs to Achieve Positive Net Benefits in Future Years (assuming no other cost changes)

ComEd Customer Population	Growth Scenario	Annual Fixed Program Administrative Costs	
		Base Case	**Cost Required for Program to Break Even**
Residential Customers Only	No Growth	$810,000	$276,000
	Growth: 25,000 by 2015	$1,311,000	$583,000
	High Growth: 50,000 by 2015	$1,660,000	$1,132,000
All Customers	No Growth	$810,000	$451,000
	Growth: 25,000 by 2015	$1,311,000	$910,000
	High Growth: 50,000 by 2015	$1,660,000	$1,740,000

The Societal Discount Rate is 1%.
Incremental meter costs are included.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Discount Rate

What discount rate should be used in a net benefit analysis of a public program? 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.[29] 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.

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

Navigant also ran scenarios with rates of 2 and 3 percent, and the results are presented in Table 40. As expected, increasing the societal discount rate reduces net benefits when they're positive (PJM-level analysis) and increases net benefits when they're negative (both ComEd-level analyses). Perhaps the more significant insight is that, contrary to what is often found in benefit-cost analyses, changes in net benefits due to changes in the discount rate are not dramatic.

Table 40. Impact of Societal Discount Rates on Program Net Benefits, Inception through 2020

Net Present Value of Net Benefits:	PJM View	ComEd View	ComEd Residential Customer View
Societal Discount Rate = 1%	$12,210,000	-$7,145,000	-$9,418,000
Societal Discount Rate = 2%	$11,080,000	-$6,879,000	-$8,989,000
Societal Discount Rate = 3%	$10,080,000	-$6,623,000	-$8,585,800

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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 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 41 shows that, as expected, net benefits increase across all customer views when start-up costs are excluded. However, the additional net benefits do not make a significant difference to the total net benefits results for any of the views, because start-up costs are not significant compared to other program costs.

Table 41. Impact of Start-up Costs on Net Benefits, Inception through 2020

Net Present Value of Net Benefits	PJM View	ComEd View	ComEd Residential Customer View
Base Scenario: Include Program Start-up Costs	$12,210,000	-$7,145,000	-$9,418,000
Exclude Program Start-up Costs	$13,120,000	-$6,235,000	-$8,509,000

These net benefits reflect a base scenario where RRTP 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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 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 RRTP program in a Smart Grid environment where special metering is not needed for participation.

Table 42 shows that meter costs have a significant influence on the net benefits of the program from all three analysis perspectives. In fact, the influence is so great that the ComEd and ComEd Residential views both change from negative to positive net benefits. This shows that the RRTP program could add significant net benefits to the ComEd Residential customer base if it is added as part of a Smart Grid meter deployment.

Table 42. Impact of Incremental Meter Costs on Net Benefits, Inception through 2020

Net Present Value of Net Benefits	PJM View	ComEd View	ComEd Residential Customer View
Base Scenario: Include Incremental Meter Costs	$12,210,000	-$7,145,000	-$9,418,000
Exclude Incremental Meter Costs	$21,740,000	$2,381,000	$107,200

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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

Sensitivity 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 43 shows that the assumption on the hedging premium has a strong influence on net benefits, but it is not strong enough to change negative net benefits to positive net benefits for the ComEd view or the ComEd Residential view.

Table 43. Impact of Hedging Premium on Net Benefits, Inception through 2020

Net Present Value of Net Benefits:	PJM View	ComEd View	ComEd Residential Customers View
Hedging Premium = 5%	$8,896,000	-$10,460,000	-$12,730,000
Base Scenario: Hedging Premium = 10%	$12,210,000	-$7,145,000	-$9,418,000
Hedging Premium = 15%	$15,510,000	-$3,848,000	-$6,122,000

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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

4.4 *Other Program Benefits*

The RRTP 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.

4.4.1 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 SO2, NOx, and CO2. 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 determined that the RRTP program affects emissions both ways. It generates an overall conservation effect of about 4% annually, and it induces load-shifting through the day. An approximation of the emissions benefits of conservation can be determined by first calculating the impact of conservation on emissions, and then estimating the benefit of the reduction. ComEd's 2010 Environmental Disclosure[30] states that for the 12 months ending March 31, 2010, the average emissions generated per mWh were: 750 lbs. of CO^2, 1.13 lbs. of NOx, and 3.60 lbs. of SO^2. Navigant estimates that at current levels, the RRTP program reduces annual energy consumption by 4785 mWh, thereby reducing SO_2 emissions by 8.6 tons, NOx emissions by 2.7 tons per year, and CO_2 emissions CO^2 emissions by 1794 tons per year. The social value of these reductions is discussed momentarily.

Holland and Mansur (2008) use an analysis of emissions within NERC (North American Electricity Reliability Council) regions to examine the effect on regional emissions of reduced variance in within-day load due to real-time pricing.[31] 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 real-time pricing on these distributional parameters. Results of an econometric analysis indicate that for the MAIN (Mid-America Interconnected Network) region, which encompasses ComEd, 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% reduction in the within-day load COV generates reductions in these pollutants of 0.027%, 0.037%, and 0.031%, respectively.

The observed load-shifting due to the RRTP program does indeed reduce load variance by reducing load when it is high and increasing it when it is low. As an example, the hourly consumption analysis for summer 2010 indicated that within-day variance under the baseline scenario was 0.215, whereas it was 0.204 for RT-14 households (7% reduction), 0.139 for RT-10 households (35%

---

[30] https://www.comed.com/Documents/CustomerService_Brochuresandforms/EnvironmentalDisclosureJuly2010.pdf

[31] 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.

reduction), and 0.184 for PA households (14% reduction). In the discussion below we use an enrollment-weighted average reduction in variance of 12%. This applies to summer 2010 but is similar to values obtained in other summers. The variance reduction is generally greatest in summer, so the calculation serves as an upper bound on the effect of load-shifting on emissions reductions.

To estimate the effect of this variance reduction on emissions, we must first approximate its effect on the MAIN load coefficient of variation, 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 RRTP households, given the program includes 11,000 households generating 11 mWh each, is approximately .0004;[32]

2. Assuming that RRTP households' share of the load COV is also 0.0004—a reasonable assumption—the RRTP program reduces the MAIN load COV by (0.12)·(0.0004)=.000048 , or 0.0048%.

3. In light of the results obtained by Holland and Mansur reported above, it follows that the RRTP program reduces SO_2, NO_x, and CO_2 emissions by 0.00013%, 0.00018%, and 0.00015%, 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;

5. Applying the results in (3) to the loads in (4), we obtain rough estimates of annual emissions reductions due to load-shifting attributable to the RRTP program: 1.7 tons of SO_2, 0.6 tons of NO_x, and 330 tons of CO_2.

Combining the effects of conservation and load-shifting, Navigant estimates that at current enrollmenet levels the RRTP program reduces SO_2 emissions by 10.3 tons per year, NOx emissions by 3.3 tons per year, and CO_2 emissions by 2124 tons per year.

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 SO2 and .3 tons of NOx –a ratio close to that estimated above for the RRTP program –is approximately $15,000.[33] Given the above-estimated annual reductions in SO_2 and NO_x, we obtain RRTP program benefits associated with reductions in these emissions of approximately $155,000 per year.

---

[32] The annual load for RRTP customers is approximately 121 gWh: 11 mWh per household, multiplied by 11,000 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.

[33] Chestnut, L.G. and D.M. Mills. 2005. "A Fresh Look at the Benefits and Costs of the U.S. Acid Rain Program". *Journal of Environmental Economics and Management* 77: 252-266.

Whereas the estimate from Chestnut and Mills pertains to the *average* value of emission reductions under Title IV, the RRTP program reductions are at the margin, suggesting that $155,000 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 rise over time.

Estimates of the benefits from a reduction in CO2 vary widely. The median estimate across a number of studies is $14/ton (Toll 2004).[34] At this value, the annual RRTP program benefit that arises from CO2 emissions reductions rounds to $30,000.

Overall, then, Navigant's best estimate of the benefits due to the RRTP program arising from reductions in emissions of SO_2, NO_x, and CO_2 is about $185,000 annually.

4.4.2 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 RRTP program further reduces electricity prices for all ComEd customers beyond that calculated previously, by reducing generator market power. The magnitude of this benefit depends on the degree of market power in PJM. Currently this benefit is likely very small due to the small size of the RRTP program and the lack of evidence of market power in the PJM market. In the 2010 second quarterly report, the PJM independent market monitor (IMM) states,.[35]

> "The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2010." (pg. 29)

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

The higher elasticity of demand associated with the RRTP 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. We know of no empirical estimates of these benefits in the peer-reviewed literature.[36]

---

[34] Tol, R.S.J. 2004. "The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties". *Energy Policy* 33: 2064-2074.

[35] "2010 State of the Market Report for PJM". Monitoring Analytics, LLC. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume1.pdf

[36] Boisvert, R.N. and B.F. Neenan. 2003. "Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets". 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 and Recommendations

In this section we summarize the material presented in this report and provide recommendations going forward. The summary is organized around the evaluation objectives:

- The response of RRTP customers to the program;
- The net benefit of the program to energy consumers.

5.1 Response of RRTP customers to the program

The report examines several aspects of customer response: conservation effects, changes in hourly consumption, price responsiveness, and bill savings.

5.1.1 Conservation effect

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 require that the price of electricity become generally higher, as opposed to the RRTP program in which the price faced by participants is sometimes higher and sometimes lower than that paid by non-participants. Nonetheless, conservation effects are possible. Navigant used fixed effects regression analysis of the monthly bills of RRTP households before and after enrollment, with households in the ComEd Residential Load Study (RLS) serving as controls, to estimate conservation effects.

Results are reported in Table 3. The RRTP program has indeed generated energy conservation in all seasons, with conservation highest in summers and averaging 4% annually. In a statistical analysis of hourly load shapes using very different data and statistical modeling, Navigant found similar levels of energy conservation.

Table 44. Conservation Impact of RRTP Program on RRTP Participants[a]

Season	Overall Percentage Impact	Average daily kWh Impact	Average Seasonal Impact (kWh)
Summer	-5.0%	-1.86	-171
Spring	-2.4%	-0.58	-54
Autumn	-4.8%	-1.28	-117
Winter	-3.2%	-1.04	-94
Annual Impact:	**-4.0%**	**Average Annual Savings (kWh):**	**-435**

[a]These results apply to RRTP households that are not enrolled in ComEd energy efficiency programs. *Source: Navigant analysis*

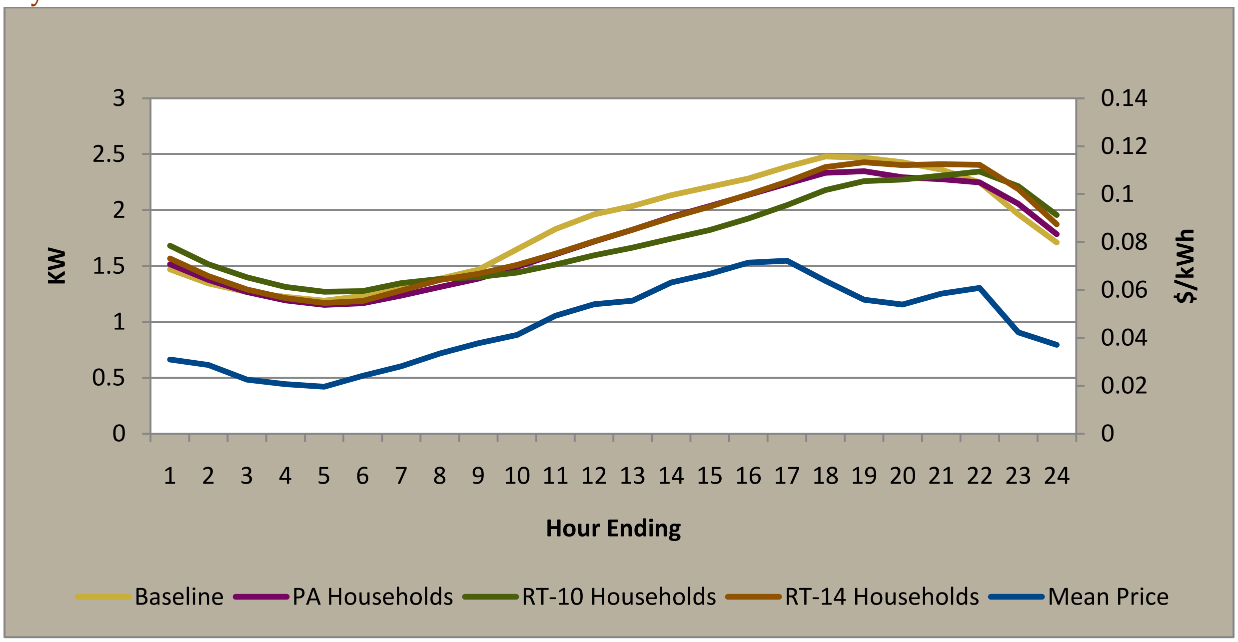
5.1.2 Changes in hourly load shapes

Even in the absence of conservation effects, a dynamic pricing program can generate substantial economic benefits by inducing households to shift consumption from high-priced hours to low-priced hours. Navigant investigated this issue using hourly regression models applied to interval data for both RRTP and RLS households. Unlike the analysis of program conservation effects, the analysis could not use a difference-in-difference approach to isolate the effect of the RRTP program on hourly consumption because interval data for RRTP households is not available for the period before households entered the RRTP program. Instead, Navigant used a propensity score matching method to match each RRTP household to an RLS household, with the matched RLS household thereby serving as a control for the RRTP household. The basic regression model was run separately for all 24 hours of a day, for weekdays vs. weekends, and for each full season of the RRTP program. The model distinguishes the effect on consumption of a household's "membership" in various subgroups of the RRTP program; in particular, whether the household was enrolled to receive, via email or text message, real-time price alerts at the 10-cent threshold (RT-10 household) or the 14-cent threshold (RT-14 household), or not at all (PA household), and whether it was enrolled in ComEd's Load Guard program at the 10-cent threshold or the 14-cent threshold.

Figure 60 presents typical load shapes derived from the analysis, and Figure 61 presents how energy consumption by RRTP households changes from baseline consumption. Each figure includes mean hourly real-time price to show the relationship between loads and prices. Overall, results of the analysis indicate the following:

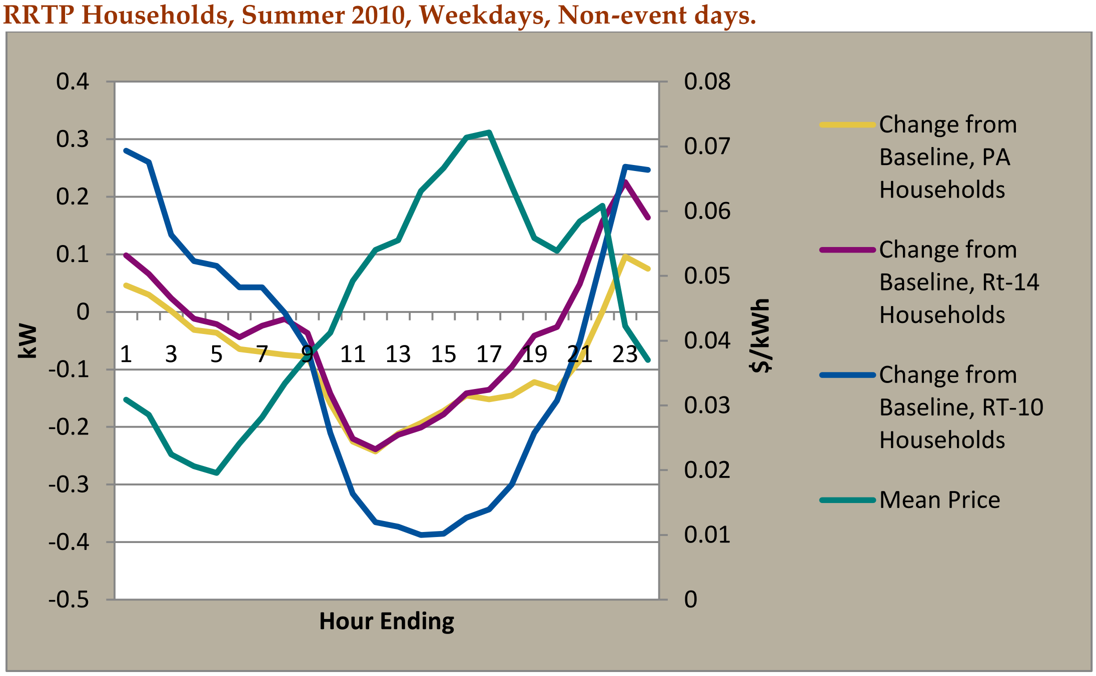
1. Even on days without high price alerts or Load Guard events, RRTP households shift their consumption to avoid high prices.
2. RT-10 households are generally more responsive than RT-14 or PA households; RT-10 households exhibit greater load-shifting on non-event days and a greater response to price alerts. This is not surprising in light of the fact that the default price alert is the 14-cent alert, and RRTP households that desire alerts at the 10-cent level must request the change.
3. In general, RT-14 households are not responsive to RT-14 alerts;
4. In 2008, day-ahead alerts generated at best a slight average hourly reduction in household energy consumption. There have been no day-ahead alerts since 2008.
5. RT-10 alerts generate small hourly savings among RT-10 households, on the order of 0.0-0.08 kW, during mid afternoon to early evening hours. There is no good statistical evidence that the alerts generate savings outside of these hours.
6. There is no convincing evidence that RT-14 alerts generate savings among RT-14 households.
7. Load Guard events at the 10-cent threshold generate small reductions in energy consumption in the event hours. Load Guard events at the 14-cent threshold generally do not generate statistically significant reductions in event hours. The relatively small savings directly attributable to Load Guard events as compared to what is frequently found for DLC programs likely is due to the fact that RRTP customers have already made a substantial shift in energy consumption away from peak hours.

Figure 60. Hourly Load Shapes and Hourly Mean Price, Summer 2010, Weekdays, Non-event days



Source: Navigant analysis

Figure 61. Hourly Mean Price and Mean Change from Baseline Hourly Energy Consumption by RRTP Households, Summer 2010, Weekdays, Non-event days.



Source: Navigant analysis

5.1.3 Price elasticity of demand

Navigant models price responsiveness among RRTP participants as reflecting a medium-run price response and a short-run price response.

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 RRTP 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.

Navigant measured medium-run elasticities for the summer season only, because evidence from the analysis of hourly load shapes indicated little, if any, price-responsiveness by RRTP households in the other seasons. Medium-run elasticities are measured using regression analysis based on the relationship between *average* hourly prices and *average* hourly deviations in consumption from baseline, where baseline consumption is derived from the consumption behavior of RLS matched control households. In general the analysis yielded the result that medium-run elasticities are higher for RT-10 households than for RT-14 households, and are higher on weekdays than on weekends. For RT-10 households, medium-run elasticities averaged about -0.15, indicating that a 1% increase in the average price in an hour reduces consumption by 0.15%, or, to put it another way, an increase in the average price in an hour by 10% reduces average consumption in the hour by 1.5%. For RT-14 households, medium-run elasticities average about -0.05.

The extent of the short-run price 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. Frequently checking electricity prices is time consuming, and the potential gains from doing so are usually quite small. Navigant therefore expects RRTP households to exhibit systematic price responsiveness primarily on days when the cost of price information is low and the potential benefits are high. Such is exactly the case on days with either day-ahead or real-time price alerts. On such high price alert (HPA) days, participants are alerted that prices are high, creating an opportunity to lower their bill by reducing their load during the high-priced hours.

Not all RRTP households make short-run adjustments to prices, even on HPA days. The analysis of hourly load shapes indicated that RT-10 households are responsive to RT-10 alerts, whereas RT-14 are not responsive to RT-14 alerts, and of course PA households are not actively alerted about real-time price spikes. In light of these observations, Navigant limited its analysis of short-run price responsiveness to the consumption behavior of RT-10 households on the 112 HPA days in the summer months of 2007-2010.

Short-run demand for energy was modeled using the Generalized Almost Ideal (GAI) demand system. Estimates of short-run own-price elasticities ranged from a low about -0.16 in the hours of 9 AM -2 PM, and again from 4-5 PM, to a high of -0.31 from 3-4 PM. These elasticities reflect the responsiveness of RT-10 households to real-time prices on high-price days. So, for instance, a 10% increase in price at 3-4 PM of a high-price day reduces energy consumption at 3-4 PM by 3.1%.

5.1.4 Bill savings

The aggregate savings for RRTP participants in 2010 was $1,936,844, which amounts to 13% of the average electric bill, and aggregate savings for the four years of the program were $3,954,862, which also amounts to 13% of the aggregate electric bill. In 2010, 89% of RRTP households enrolled in the RRTP program reaped positive savings, with mean savings of $177.

5.2 *Program Net Benefits*

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

1. All PJM customers
2. All ComEd customers
3. ComEd Residential customers

The net benefits that accrue to all PJM customers are considered to be the best indicator of overall economic benefits for consumers from the RRTP program. However, the subset of benefits that accrue to ComED RRTP customers were also reported based on the specific requirements of the ruling from Illinois Commerce Commission (ICC) Docket 06-0617. That docket required an economic evaluation of the real-time pricing program be conducted after the implementation period of 2007-2010, and further required specific identification of the net economic benefits accruing to ComEd's residential customers.

5.2.1 Market Effects

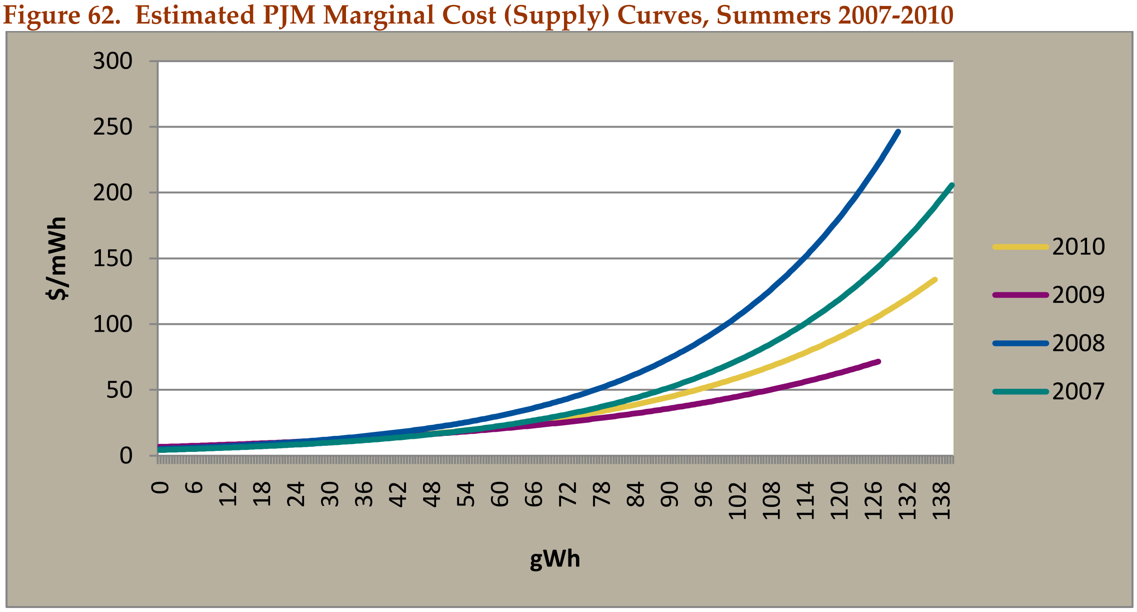
RRTP program benefits accruing to non-participants arise via the effect of the program on energy prices. The energy supply charge faced by RRTP customers is a direct pass-through of the real-time price. By the law of supply and demand, in hours when program participants increase consumption above baseline – the consumption level associated with the fixed rate price, as derived from the analysis of hourly consumption—the locational marginal price (LMP) of energy rises, and all consumers are made worse off. Conversely, when program participants reduce consumption from baseline levels, the LMP price falls, and all consumers are made better off.

The LMP for the ComEd service area is composed of three components: an energy price that is the market clearing price of energy in the PJM market; a transmission congestion price reflecting the impact of ComEd loads on the routing of transmission to avoid congestion; and a transmission loss component associated with energy losses . Historical price and load data for PJM and ComEd were used to estimate the marginal cost (supply) curves for each component. These marginal cost curves were then used to translate load reductions due to the RRTP program into price reductions for all PJM customers and for ComEd customers.

Figure 62 displays energy supply curves for each summer of the program period, 2007-2010. The supply curve is much higher in 2008 than in other years. This likely reflects the spike in gas prices in the middle of 2008. Note that the supply curves are convex – that is, they have the traditional "hockey stick" shape (i.e., their slope becomes steeper at higher system loads). It is this characteristic that makes RRTP 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 supply curves are flatter.

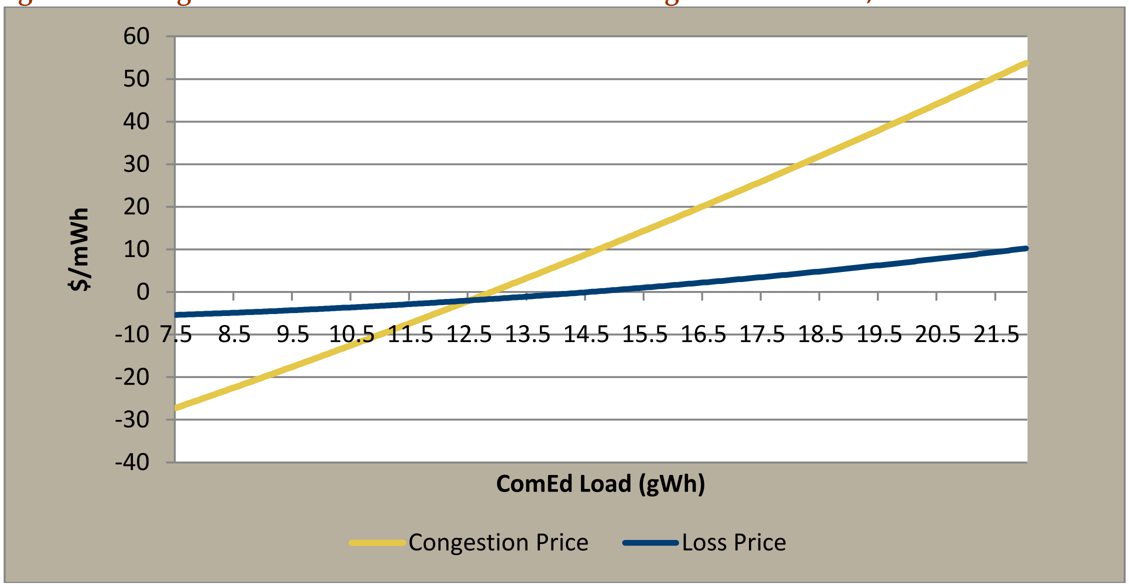
Figure 63 shows marginal cost curves for transmission congestion and loss. The marginal cost functions for congestion and loss varied little over the four years of the program. These curves are conditional on loads in other PJM zones, as discussed in the report. In general marginal cost curves are steeper for transmission congestion than for transmission loss.

Figure 62. Estimated PJM Marginal Cost (Supply) Curves, Summers 2007-2010



Source: Navigant analysis

Figure 63. Marginal Cost Curves for Transmission Congestion and Loss, ComEd Zone



Source: Navigant analysis

5.2.2 RRTP Program Net Benefits, 2007-2010

Table 45 provides the annual program costs, and annual program benefits *to residential ComEd customers*, over the first four years of the program, 2007–2010. There are dramatic changes from year to year. In the start-up years of the program, net benefits are negative: -$1,933,000 in 2007 and -$1,701,000 in 2008. This reflects the significant investment needed to develop the processes and IT systems required for program start-up, and the cost of recruiting new customers into a new program. In 2009 and 2010 these start-up costs dissipate and therefore net benefits increasing substantially as more customers join the program. The overall effect is the achievement of positive net benefits of $24,000 in 2010. It deserves emphasis that this net benefit assessment of the first four years of the program applies to ComEd residential customers only, as required in Docket 06-0617. After three years of strong investment in program start-up costs and experimentation with different marketing methods, the program shows positive net benefits in the fourth year.

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

	2007	2008	2009	2010
Participant Benefits: Avoided Capacity Costs	$17,000	$138,000	$187,000	$353,000
Participant Benefits: Consumer Surplus	$245,000	$425,000	$1,639,000	$2,170,000
Non-Participant Benefits: Residential Customers	$34,000	$73,000	$86,000	$83,000
TOTAL BENEFITS	$296,000	$636,000	$1,912,000	$2,606,000
TOTAL COSTS	$2,229,000	$2,337,000	$2,696,000	$2,582,000
NET BENEFITS	**-$1,933,000**	**-$1,701,000**	**-$784,000**	**$24,000**

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

5.2.3 Projected RRTP Net Benefits, 2011-2020

The historical analysis leads to the question of what program net benefits would be if the program were extended into the future. Table 46 provides the present value of program net benefits that would accrue were the RRTP program extended another ten years, covering the period 2007–2020. Benefits are calculated at three levels: Benefits to all PJM customers, benefits to all ComEd customers, and benefits to all ComEd residential customers. The RRTP program generates positive net benefits of $12,210,000 at the PJM level, but negative net benefits when the population of interest is restricted to ComEd customers. The best measure of the net benefit of the RRTP program to energy consumers, while accounting for costs incurred by ComEd, is the PJM-level measure.

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

	PJM View	ComEd View	ComEd Residential Customer View
Participant Benefits: Avoided Capacity Costs	$6,171,000	$6,171,000	$6,171,000
Participant Benefits: Consumer Surplus	$11,099,000	$11,099,000	$11,099,000
Non-Participant Benefits: Market Effects	$22,650,000	$3,295,000	$1,022,000
TOTAL BENEFITS	$39,920,000	$20,565,000	$18,292,000
TOTAL COSTS	$27,710,000	$27,710,000	$27,710,000
NET BENEFITS	**$12,210,000**	**-$7,145,000**	**-$9,418,000**

These net benefits reflect a base scenario where RRTP 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.
In all future years the energy component of the flat rate is perfectly balanced with hourly prices (zero forecast error).
Hedging Premium is 10%.
NPV are calculated as the mean of 14 iterations of different weather scenarios over the forecasted years.
Source: Navigant analysis

5.2.4 Sensitivity Analysis

A series of sensitivity analyses were conducted on key assumptions in the net benefits model. To summarize:[37]

- If the average forecast error between PJM's real time prices and ComEd's fixed-rate prices that existed during the program period 2007-2010 persists over the 10-year forecast period, the RRTP program would yield positive net benefits to ComEd customers generally and to ComEd *residential* customers in particular. The net benefits for all ComEd customers would be $3.79 million, and the net benefits for ComEd's residential customers would be $1.52 million.
- Allowing RRTP program participation to grow substantially from 2011-2015 increases overall net benefits to PJM customers, but the effect on ComEd customers is mixed, reducing net benefits (making net benefits more negative) for growth to 25,000 participants, and increasing net benefits –in particular, causing net benefits to to increase to +$770,000 over the forecast period 2011-2020—for growth to 50,000 participants. As explained in the body of the report, this nonlinearity in the effect of enrollment growth is due to quasi-fixed costs.
- As expected, increasing the societal discount rate to 3 percent reduces net benefits when they're positive (PJM-level analysis) and increases net benefits when they're negative (both ComEd-level analyses).
- Excluding start-up costs increases net benefits at all levels by about $900,000.
- The value of the hedging premium has a substantial impact on the present value of net benefits. At the PJM level an increase in the hedging premium from 5% to 15% increases net benefits from $8.9 million to $15.5 million. If the assessment is restricted to ComEd residential customers net benefits also increases considerably, but stay negative, increasing from -$12.7 million to -$6.1 million.
- Excluding incremental meter costs causes a substantial increase in net benefits, causing the net benefit to ComEd residential customers to rise from the base case of -$9.4 million over the 2007-2020 program period to +$107,000.

5.2.5 Additional perspective on net benefits

Three additional important points about the net benefit results deserve emphasis. 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[38]. 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 benefits rise. In short, when non-participant benefits are high, participant benefits are low, and vice versa. The relationship between market prices and the flat rate determines whether those benefits go primarily to non-participants or participants.

[37] All results reported here apply to the present value of net benefits over a program period of 2007-2011.

[38] In Table 31, non-participant benefits appear to be slightly *less* than in subsequent years. But this benefit was obtained with a much smaller RRTP enrollment –roughly half of the 2010 level. It follows that if enrollment in 2008 equaled that of 2010, nonparticipant benefits in 2008 would have been roughly twice the value in Table 31.

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 non-participant benefits would be greater than what is currently forecasted. This is especially true in the case where market prices rise due to fuel prices, in which case supply elasticity at a given load. Likewise, if 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 to consumers. 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.

Third, there are a number of program benefits investigated by Navigant not considered in the net benefits assessment because they are too difficult to quantify reliably without considerable resources. 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 RRTP 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 PJM Independent Market Monitor states that local market power does exist in PJM, 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. They also include health and environmental benefits. For instance, using existing peer-reviewed studies, Navigant approximated the benefit of the RRTP program in reducing SO_2, NO_x, and CO_2 emissions to be about $185,000 per year. Navigant has not included this value in its net benefit assessment because the recipients of these benefits are not necessarily ComEd customers or residential customers in the PJM market.

5.3 Recommendations

Based on the evaluation of the RRTP program, Navigant makes the following recommendations.

1) If the RRTP program is extended, Navigant recommends the following activities and changes:
    a) Reduce administration costs. Navigant found the administrative costs for the RRTP program to be much higher than the costs for a similar program of similar size. Table 39 provides an indication of the extent to which administrative costs would need to drop for the program to break even for the period 2007-2020.
    b) Expand the program to increase total net benefits. Current estimates of marketing costs and recruitment results show that spending more on marketing in the future will increase total net benefits.
    c) Consider the development of a survey of households to determine why households do not appear to respond to price in the winter. The results of such a survey would have obvious implications for marketing/education and program net benefits.
    d) Develop a day-ahead alert system in which, if prices on the following day are expected to be higher than at any time in the previous X days (10 days, 14 days, etc.), households are alerted. The hourly impact analysis for 2008, when there were a large number of both day-ahead and real-time alerts, indicates that RRTP households are more responsive to day-ahead alerts. Generating day-ahead alerts based on prices that are high relative to recent

past prices assures that all customers receive program-related messaging that induces timely consideration of energy consumption behavior.

e) Real-time alerts should continue. There is little evidence that real-time alerts generate savings, but because they are automated and therefore inexpensive to generate, they likely provide at least some RRTP households with valuable information.

f) Impose a delay between installing a meter to receive interval data, and the start of program participation. Even a delay between installation and program participation of a few months would prove extremely valuable. A critical issue in future evaluations is identifying program effects. In this evaluation Navigant used the propensity score matching method to identify RLS households with monthly consumption behavior similar to that of RRTP households. Implicit in this approach –or, for that matter, *any* approach that attempts to identify the energy consumption impacts of an RTP program without hourly pre- and post-program consumption data—is that there is no selection bias in program enrollment based on hourly consumption patterns. Having available several months of hourly consumption data *before* the start of the program would address this issue.

2) The RRTP program should be extended for at least another four years. The evaluation presented in this report concludes that in aggregate RRTP program net benefits to ComEd customers over the past four years were either negative or close to break-even, and the baseline forecast of program net benefits to ComEd customers is negative. Nonetheless, several considerations mitigate against the conclusion that the RRTP program should be terminated:
   a) There is considerable uncertainty about program net benefits to ComEd customers, with several reasonable scenarios indicating positive net benefits.
   b) At the PJM level net benefits to consumers are substantial even under the baseline scenario.
   c) Navigant believes that if the recommendations presented above are followed, program net benefits for ComEd customers are likely to be positive in the future even under baseline assumptions. A key issue is the reduction of administrative costs.

Finally, extending the RRTP program serves two other purposes:

a) It increases the opportunities for ComEd customers to choose the pricing regime that best fits their preferences. It is quite possible that even after shifting a larger share of program costs to program participants, many participants would prefer the RRTP program simply because it provides them a greater sense of control over their energy bills. In this case the persistence of the program would be prima facie evidence that the program is economical.

b) It provides ComEd with useful information about how residential customers respond to dynamic pricing, and how to structure dynamic pricing programs in the future. Navigant believes this information will prove valuable in the design and implementation of future programs by both ComEd and other utilities.

Appendix A. Tables of Regression Parameter Estimates

A1. Parameter Estimates: Initial Conservation Effect Model Specification

Below are the parameter estimates and standard errors of the initial model specification for the conservation effect (see equation (1)) . Nonsignificant estimates are highlighted in red. Black cells indicate that that variable could not be included in the estimation due to its being constant in that season (i.e., active RRTP participants also enrolled in an EE program experienced no periods in the winter months in which the temperature exceeded 65 degrees F).

Table 47. Parameter Estimates, Original Model Specification

Season	Parameter Estimates												
	CDD	HDD	RRTP Dummy	RRTP Dummy x CDD	RRTP Dummy x HDD	RRTP Dummy x EE Dummy	RRTP Dummy x CDD x EE Dummy	RRTP Dummy x HDD x EE Dummy	EE Dummy	RRTP Dummy x AC Dummy	RRTP Dummy x CDD x AC Dummy	RRTP Dummy x HDD x AC Dummy	AC Dummy
Summer	0.06159	-0.01814	-0.12557	0.00984	0.00786	0.01489	0.00229	0.00992	-0.07806	0.01870	0.00053	-0.00155	-0.02302
Spring	0.07975	0.01502	-0.02231	0.02336	-0.00115	-0.00399	0.01715	0.00011	-0.05841	0.04029	0.00769	-0.00177	-0.03438
Autumn	0.09599	0.01499	-0.00598	-0.00321	-0.00265	0.03559	-0.00589	-0.00058	-0.06628	0.00571	0.00076	-0.00139	-0.00734
Winter	-1.98734	0.00496	-0.09102	-0.34585	0.00139	-0.16866		0.00366	-0.00860	-0.08853		0.00282	-0.05364

Source: Navigant analysis

Table 48. Standard Errors, Original Model Specification

Season	Standard Errors												
	CDD	HDD	RRTP Dummy	RRTP Dummy x CDD	RRTP Dummy x HDD	RRTP Dummy x EE Dummy	RRTP Dummy x CDD x EE Dummy	RRTP Dummy x HDD x EE Dummy	EE Dummy	RRTP Dummy x AC Dummy	RRTP Dummy x CDD x AC Dummy	RRTP Dummy x HDD x AC Dummy	AC Dummy
Summer	0.00057	0.00091	0.00920	0.00107	0.00160	0.05855	0.00630	0.01038	0.01785	0.03400	0.00309	0.00451	0.02231
Spring	0.00116	0.00013	0.00669	0.00242	0.00026	0.05138	0.01626	0.00199	0.01887	0.03365	0.00770	0.00084	0.02649
Autumn	0.00083	0.00014	0.00615	0.00177	0.00027	0.04470	0.01190	0.00199	0.01969	0.03166	0.00541	0.00082	0.02629
Winter	0.26865	0.00012	0.01492	1.09347	0.00035	0.12606		0.00293	0.01935	0.06048		0.00123	0.02877

Source: Navigant analysis

A2. Parameter Estimates: Propensity Score Matching

Below are the parameter estimates for the propensity score matching regression (see equation (2)and associated discussion).

Table 49. Regression Results for Propensity Score Matching

	Parameter								
	Intercept	Winter_2010	$(\text{Winter\_2010})^2$	Winter_2008	$(\text{Winter\_2008})^2$	Summer_2010	$(\text{Summer\_2010})^2$	Summer_2009	$(\text{Summer\_2009})^2$
Estimate	-1.914000	0.019000	-0.000020	0.012000	-0.000005	-0.057400	0.000195	0.014800	-0.000170
SE	0.090000	0.003760	0.000010	0.003640	0.000009	0.006220	0.000034	0.006740	0.000039

Source: Navigant analysis

A3. Parameter Estimates: Hourly Energy Consumption Model

Table 50 provides an example of parameter estimates with standard errors for the model of hourly energy consumption. Estimation was done with ordinary least squares regression. See equation (3) for a formal statement of the model.

Table 50. Sample of Coefficient Estimates from the Hourly Energy Consumption Model, Summer 2010 weekday.

	Hour Ending							
	2 AM		8 AM		2 PM		8 PM	
Parameter	Coefficient Estimate	Standard Error	Coefficient Estimate	Standard Error	Coefficient Estimate	Standard Error	Coefficient Estimate	Standar d Error
Intercept	-2.4486	0.0167	-2.2612	0.0216	-5.4506	0.0312	-4.8428	0.0300
RRTP	-0.8556	0.0236	-0.1541	0.0305	-0.0978	0.0442	-1.0707	0.0425
Temp	0.0407	0.0002	0.0342	0.0003	0.0712	0.0004	0.0750	0.0004
Preconsumption	0.0234		0.0244	0.0001	0.0402	0.0001	0.0416	0.0001
DA_alert	-	-	-	-	-	-	-	-
RT10_alert	0.1819	0.0087	0.0287	0.0085	0.2247	0.0110	0.1546	0.0083
RT14_alert	-	-	-	-	-0.0548	0.0157	-0.0870	0.0121
LG10	-	-	-0.1131	0.0148	0.0199	0.0168	-0.1344	0.0204
LG14	-	-	-	-	0.0627	0.0224	-	-
ACC_50	-	-	-	-	-0.1695	0.0426	-	-
ACC_100	-	-	-	-	-0.4741	0.0369	-	-
RRTP x Temp	0.0097	0.0003	0.0001	0.0004	-0.0005	0.0005	0.0108	0.0006
RRTP x Preconsumption	0.0052		0.0017	0.0001	-0.0012	0.0001	0.0034	0.0001
RRTP x DA_alert	-	-	-	-	-	-	-	-
RRTP x RT10_alert	-0.0555	0.0177	0.0370	0.0158	0.0049	0.0157	0.0871	0.0119
RRTP x RT14_alert	-	-	-	-	-0.0683	0.0243	-0.0921	0.0211
RRTP x LG10	-	-	-0.0889	0.0212	-0.0730	0.0237	-0.0313	0.0291
RRTP x LG14	-	-	-	-	0.1543	0.0317	-	-
RT10_HH	0.1397	0.0063	0.0729	0.0062	-0.1950	0.0101	-0.0202	0.0104
RT14_HH	0.0360	0.0033	0.0622	0.0033	-0.0081	0.0052	0.1079	0.0053
LG10_HH	0.0906	0.0065	-0.0271	0.0063	-0.1640	0.0101	-0.0608	0.0101
LG14_HH	0.0710	0.0096	0.0174	0.0095	-0.0957	0.0149	0.0409	0.0150
RT10_HH x DA_alert	-	-	-	-	-	-	-	-
RT14_HH x DA_alert	-	-	-	-	-	-	-	-
RT10_HH x RT10_alert	0.1655	0.0343	0.0416	0.0282	-0.0543	0.0236	0.0140	0.0238
RT14_HH x RT14_alert	0.0825	0.0188	0.0091	0.0152	0.0463	0.0164	0.0465	0.0202
LG10_HH x LG10	-	-	0.0004	0.0516	-0.1471	0.0360	-0.0623	0.0802
LG14_HH x LG14	-	-	-0.0806	0.0779	-0.1294	0.0690	-	-

Source: Navigant analysis

NAVIGANT

A4. GAI Demand System Parameter Estimates and Goodness-of-Fit Measures

The parameter estimates, standard errors, and significance levels for the GAI demand system estimated in section 3.3 are shown in Table 51. The reader should note that 97 out of the 102 parameters are statistically significant at the 0.05 level. Table 52 provides performance statistics for the model.

Table 51. Parameter Estimates from the GAI Demand System

Name	Estimate	Std Error	t-stat	Pr > |t|	Name	Estimate	Std Error	t-stat	Pr > |t|
g0101	0.30765	0.0132	23.28	<.0001	a1	-9.71634	0.6665	-14.58	<.0001
g0102	0.020871	0.00272	7.68	<.0001	a2	-1.25896	1.39E-01	-9.06	<.0001
g0103	-0.02983	0.00317	-9.41	<.0001	a3	1.380738	1.55E-01	8.92	<.0001
g0104	-0.03935	0.00248	-15.90	<.0001	a4	1.56752	0.1249	12.55	<.0001
g0105	-0.05474	0.00263	-20.85	<.0001	a5	2.166932	0.1346	16.10	<.0001
g0106	-0.0424	0.00214	-19.78	<.0001	a6	1.970191	0.1113	17.70	<.0001
g0107	-0.12169	0.00641	-18.97	<.0001	a7	5.061075	0.3376	14.99	<.0001
g0108	-0.05194	0.00294	-17.68	<.0001	a8	1.742472	0.1389	12.55	<.0001
g0109	0.011427	0.004	2.86	0.0043	a9	-1.91363	0.2034	-9.41	<.0001
g0202	0.086923	0.0013	67.06	<.0001	a0	514.7225	38.0462	13.53	<.0001
g0203	-0.01375	0.000838	-16.41	<.0001	b2	-0.00269	0.000243	-11.05	<.0001
g0204	-0.00441	0.000615	-7.17	<.0001	b3	0.00252	0.000223	11.29	<.0001
g0205	-0.00578	0.000693	-8.34	<.0001	b4	0.002965	0.000135	21.91	<.0001
g0206	-0.01944	0.000797	-24.38	<.0001	b5	0.004134	0.000152	27.24	<.0001
g0207	-0.02711	0.00172	-15.73	<.0001	b6	0.003733	0.000167	22.32	<.0001
g0208	-0.02089	0.00099	-21.11	<.0001	b7	0.009687	0.00031	31.28	<.0001
g0209	-0.01642	0.00119	-13.79	<.0001	b8	0.003178	0.000223	14.25	<.0001
g0303	0.086948	0.00103	84.59	<.0001	b9	-0.00405	0.000363	-11.14	<.0001
g0304	0.004725	0.000646	7.31	<.0001	s1_0	5.438211	0.7044	7.72	<.0001
g0305	0.00176	0.00074	2.38	0.0173	d1cdh1	0.000905	0.000524	1.73	0.0839
g0306	-0.00576	0.000761	-7.57	<.0001	d1max	-0.03658	0.0084	-4.35	<.0001
g0307	-0.00576	0.00172	-3.36	0.0008	d1ACC50	-0.34737	5.17E-01	-0.67	0.5016
g0308	-0.01161	0.000914	-12.70	<.0001	s2_0	1.585801	0.2037	7.78	<.0001
g0309	-0.02673	0.00125	-21.30	<.0001	d2cdh2	-0.00273	0.000359	-7.61	<.0001
g0404	0.046662	0.000588	79.38	<.0001	d2max	-0.00931	0.00245	-3.80	0.0001
g0405	-0.01637	0.000595	-27.54	<.0001	d2ACC50	-0.05642	2.52E-02	-2.24	0.0254
g0406	0.009006	0.000604	14.92	<.0001	s3_0	1.092287	0.1347	8.11	<.0001

Source: Navigant analysis

NAVIGANT

Name	Estimate	Std Error	t-stat	Pr > |t|	Name	Estimate	Std Error	t-stat	Pr > |t|
g0407	0.011175	0.00123	9.10	<.0001	d3cdh3	-0.00264	0.000361	-7.30	<.0001
g0408	-0.00077	0.000623	-1.24	0.2146	d3max	-0.00713	0.00162	-4.40	<.0001
g0409	-0.01067	0.000894	-11.93	<.0001	d3ACC50	0.002517	9.50E-03	0.26	0.7911
g0505	0.057472	0.000684	84.01	<.0001	d3ACC100	-0.29739	0.1467	-2.03	0.0426
g0506	0.005812	0.000705	8.25	<.0001	s4_0	0.625407	0.0738	8.48	<.0001
g0507	0.021494	0.00125	17.24	<.0001	d4cdh4	-0.00237	0.000341	-6.94	<.0001
g0508	0.004132	0.000745	5.55	<.0001	d4max	-0.00464	0.000883	-5.25	<.0001
g0509	-0.01378	0.00101	-13.62	<.0001	d4ACC50	-0.03171	0.0034	-9.32	<.0001
g0606	0.073594	0.000813	90.53	<.0001	d4ACC100	-0.0802	0.0385	-2.08	0.0374
g0607	0.002215	0.00141	1.57	0.1155	s5_0	0.615181	0.0782	7.86	<.0001
g0608	-0.00891	0.000991	-8.99	<.0001	d5cdh5	-0.00198	0.000334	-5.93	<.0001
g0609	-0.01413	0.00113	-12.56	<.0001	d5max	-0.00458	0.000938	-4.88	<.0001
g0707	0.171172	0.00423	40.45	<.0001	d5ACC50	-0.01265	0.00262	-4.83	<.0001
g0708	-0.00675	0.000946	-7.13	<.0001	d5ACC100	0.029248	0.0405	0.72	0.4699
g0709	-0.04474	0.00245	-18.26	<.0001	s6_0	0.653505	0.0828	7.89	<.0001
g0808	0.109424	0.00151	72.69	<.0001	d6cdh6	0.000826	0.000402	2.05	0.0401
g0809	-0.01269	0.00136	-9.33	<.0001	d6max	-0.00552	0.000989	-5.58	<.0001
g0909	0.12773	0.00244	52.31	<.0001	d6ACC50	-0.00455	0.0032	-1.42	0.1542
s7_0	1.592467	0.1698	9.38	<.0001	d8max	-0.01627	0.00221	-7.37	<.0001
d7cdh7	0.000924	0.000457	2.02	0.043	d8ACC50	0.048216	0.0179	2.70	0.0069
d7max	-0.01424	0.00202	-7.06	<.0001	s9_0	2.911364	0.3144	9.26	<.0001
d7ACC50	-0.00013	0.0106	-0.01	0.99	d9cdh9	0.000664	0.000529	1.25	0.21
s8_0	1.898597	0.186	10.21	<.0001	d9max	-0.02355	0.00376	-6.27	<.0001
d8cdh8	0.000213	0.000462	0.46	0.645	d9ACC50	-0.08461	0.0553	-1.53	0.1258

Source: Navigant analysis

Table 52. GAI Demand System Performance Statistics

Equation	SSE	MSE	Root MSE	R-Square	Adj. R-Sq
w2	58.4517	0.00202	0.045	0.2541	0.2539
w3	53.2838	0.00184	0.0429	0.2341	0.2338
w4	24.7707	0.000857	0.0293	0.253	0.2528
w5	33.2593	0.00115	0.0339	0.3373	0.3371
w6	31.4613	0.00109	0.033	0.3622	0.362
w7	82.9865	0.00287	0.0536	0.2504	0.2501
w8	77.2146	0.00267	0.0517	0.2691	0.2688
w9	141.6	0.0049	0.07	0.2036	0.2033

Source: Navigant analysis

Appendix B. Interpreting coefficient estimates on dummy variables in a semi-log model

Recall, the equation estimated was:

$$\begin{aligned} y_{i,t} &= \alpha_i + \beta_1 CDD_{i,t} + \beta_2 HDD_{i,t} + \beta_3 RRTP_{i,t} + \beta_4 \left(RRTP_{i,t} \times CDD_{i,t}\right) + \beta_5 \left(RRTP_{i,t} \times HDD_{i,t}\right) \\ &+ \beta_6 \left(RRTP_{i,t} \times EE_{i,t}\right) + \beta_7 \left(RRTP_{i,t} \times CDD_{i,t} \times EE_{i,t}\right) + \beta_8 \left(RRTP_{i,t} \times HDD_{i,t} \times EE_{i,t}\right) + \beta_9 EE_{i,t} \\ &+ \beta_{10} \left(RRTP_{i,t} \times AC_{i,t}\right) + \beta_{11} \left(RRTP_{i,t} \times CDD_{i,t} \times AC_{i,t}\right) + \beta_{12} \left(RRTP_{i,t} \times HDD_{i,t} \times AC_{i,t}\right) + \beta_{13} AC_{i,t} + \varepsilon_{i,t} \end{aligned}$$

For concision, let:

$$\mathrm{P} = \beta_6 \left(RRTP_{i,t} \times EE_{i,t}\right) + \beta_7 \left(RRTP_{i,t} \times CDD_{i,t} \times EE_{i,t}\right) + \beta_8 \left(RRTP_{i,t} \times HDD_{i,t} \times EE_{i,t}\right) + \beta_9 EE_{i,t}$$

And let:

$$\mathrm{O} = \beta_{10} \left(RRTP_{i,t} \times AC_{i,t}\right) + \beta_{11} \left(RRTP_{i,t} \times CDD_{i,t} \times AC_{i,t}\right) + \beta_{12} \left(RRTP_{i,t} \times HDD_{i,t} \times AC_{i,t}\right) + \beta_{13} AC_{i,t}$$

Since $y_{i,t}$ 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:

$$z_{i,t} = e^{\alpha_i + \beta_1 CDD_{i,t} + \beta_2 HDD_{i,t} + \beta_3 RRTP_{i,t} + \beta_4 \left(RRTP_{i,t} \times CDD_{i,t}\right) + \beta_5 \left(RRTP_{i,t} \times HDD_{i,t}\right) + \mathrm{P} + \mathrm{O}}$$

Which may itself be transformed to:

$$z_{i,t} = e^{\alpha_i + \beta_1 CDD_{i,t} + \beta_2 HDD_{i,t}} e^{\beta_3 RRTP_{i,t} + \beta_4 \left(RRTP_{i,t} \times CDD_{i,t}\right) + \beta_5 \left(RRTP_{i,t} \times HDD_{i,t}\right) + \mathrm{P} + \mathrm{O}}$$

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

$$z_{i,t} = z_{i,t}^{BASELINE} e^{\beta_3 RRTP_{i,t} + \beta_4 \left(RRTP_{i,t} \times CDD_{i,t}\right) + \beta_5 \left(RRTP_{i,t} \times HDD_{i,t}\right) + \mathrm{P} + \mathrm{O}}$$

Since the principal concern is to estimate savings that are attributable to the RRTP program (and not some other conservation or demand response program) we may drop all variables that interact with the EE variable and their corresponding parameters. The average percentage savings of an RRTP participant *not* participating in either the A/C cycling or either of the energy conservation programs that is attributable to the RRTP program may therefore be written as:

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

With percentage implied consumption reduction is defined as:

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

NAVIGANT

Appendix C. Hourly Price Correlation

Below are the hourly price correlation matrices used in determining the appropriate scheme to group similar hours into blocks, for use in the Generalized Almost Ideal (GAI) demand system. The correlation coefficient is bounded between -1 and 1, where a value of 0 corresponds to no correlation between the two prices, a value of 1 corresponds to perfect positive correlation between the two prices, and a value of -1 corresponds to perfect negative correlation between the two prices. The reader should note that the values found along the diagonal correspond to the price correlation between a given hour and itself, which is by definition equal to 1. The shaded cells represent groups of hours that form a block in the GAI demand system.

Figure 64. Price Correlation Coefficients, Summer High Price Alert Days

1	0.57	0.4	0.31	0.43	0.43	0.38	0.25	0.35	0.29	0.28	0.16	0.14	0.25	0.15	0.11	0.12	0.11	0.1	0.17	0.11	0.12	0.15	0.32
0.57	1	0.46	0.31	0.41	0.49	0.41	0.09	0.11	0.18	0.19	0.06	0.13	0.12	0.17	0.01	0.05	0.01	0.06	0.11	0.11	0.07	0.14	0.26
0.4	0.46	1	0.56	0.47	0.58	0.37	0.16	0.22	0.23	0.13	0.05	0	0.01	0.02	0.12	-0.05	-0.21	-0.11	0.04	0.13	0	0.05	0.25
0.31	0.31	0.56	1	0.47	0.44	0.37	0.23	0.23	0.08	0	-0.03	0.04	0	-0	-0.06	-0.12	-0.27	-0.22	0	0.03	-0.05	-0.13	0.14
0.43	0.41	0.47	0.47	1	0.64	0.51	0.26	0.27	0.22	0.17	0.12	0.09	0.1	0.03	-0.09	-0.06	-0.15	-0.07	0.03	0.17	0.06	0.03	0.23
0.43	0.49	0.58	0.44	0.64	1	0.61	0.34	0.33	0.33	0.27	0.15	0.08	0.14	0.09	-0.01	-0.04	-0.15	-0.05	0.07	0.17	0.06	0.12	0.28
0.38	0.41	0.37	0.37	0.51	0.61	1	0.44	0.47	0.42	0.29	0.22	0.23	0.24	0.18	0.03	0.1	0.01	0.09	0.22	0.27	0.22	0.09	0.32
0.25	0.09	0.16	0.23	0.26	0.34	0.44	1	0.68	0.39	0.35	0.48	0.17	0.19	0.25	0.15	0.12	0.08	0.19	0.25	0.12	0.11	0.16	0.19
0.35	0.11	0.22	0.23	0.27	0.33	0.47	0.68	1	0.65	0.61	0.63	0.28	0.3	0.43	0.32	0.23	0.2	0.25	0.39	0.22	0.21	0.28	0.24
0.29	0.18	0.23	0.08	0.22	0.33	0.42	0.39	0.65	1	0.69	0.56	0.4	0.5	0.44	0.51	0.3	0.35	0.36	0.56	0.41	0.3	0.46	0.41
0.28	0.19	0.13	0	0.17	0.27	0.29	0.35	0.61	0.69	1	0.65	0.48	0.55	0.55	0.41	0.46	0.48	0.44	0.46	0.22	0.29	0.52	0.37
0.16	0.06	0.05	-0.03	0.12	0.15	0.22	0.48	0.63	0.56	0.65	1	0.39	0.38	0.42	0.24	0.29	0.36	0.41	0.47	0.18	0.25	0.54	0.35
0.14	0.13	0	0.04	0.09	0.08	0.23	0.17	0.28	0.4	0.48	0.39	1	0.57	0.38	0.3	0.28	0.35	0.46	0.46	0.46	0.48	0.41	0.29
0.25	0.12	0.01	0	0.1	0.14	0.24	0.19	0.3	0.5	0.55	0.38	0.57	1	0.62	0.42	0.47	0.48	0.48	0.46	0.25	0.29	0.4	0.37
0.15	0.17	0.02	-0.02	0.03	0.09	0.18	0.25	0.43	0.44	0.55	0.42	0.38	0.62	1	0.37	0.54	0.45	0.43	0.35	0.23	0.25	0.29	0.21
0.11	0.01	0.12	-0.06	-0.09	-0.01	0.03	0.15	0.32	0.51	0.41	0.24	0.3	0.42	0.37	1	0.36	0.46	0.35	0.39	0.28	0.27	0.32	0.29
0.12	0.05	-0.05	-0.12	-0.06	-0.04	0.1	0.12	0.23	0.3	0.46	0.29	0.28	0.47	0.54	0.36	1	0.55	0.53	0.45	0.29	0.32	0.34	0.21
0.11	0.01	-0.21	-0.27	-0.15	-0.15	0.01	0.08	0.2	0.35	0.48	0.36	0.35	0.48	0.45	0.46	0.55	1	0.75	0.58	0.43	0.46	0.55	0.36
0.1	0.06	-0.11	-0.22	-0.07	-0.05	0.09	0.19	0.25	0.36	0.44	0.41	0.46	0.48	0.43	0.35	0.53	0.75	1	0.77	0.57	0.57	0.66	0.43
0.17	0.11	0.04	0	0.03	0.07	0.22	0.25	0.39	0.56	0.46	0.47	0.46	0.46	0.35	0.39	0.45	0.58	0.77	1	0.63	0.66	0.76	0.52
0.11	0.11	0.13	0.03	0.17	0.17	0.27	0.12	0.22	0.41	0.22	0.18	0.46	0.25	0.23	0.28	0.29	0.43	0.57	0.63	1	0.75	0.53	0.47
0.12	0.07	0	-0.05	0.06	0.06	0.22	0.11	0.21	0.3	0.29	0.25	0.48	0.29	0.25	0.27	0.32	0.46	0.57	0.66	0.75	1	0.66	0.55
0.15	0.14	0.05	-0.13	0.03	0.12	0.09	0.16	0.28	0.46	0.52	0.54	0.41	0.4	0.29	0.32	0.34	0.55	0.66	0.76	0.53	0.66	1	0.67
0.32	0.26	0.25	0.14	0.23	0.28	0.32	0.19	0.24	0.41	0.37	0.35	0.29	0.37	0.21	0.29	0.21	0.36	0.43	0.52	0.47	0.55	0.67	1

Source: Navigant analysis

Appendix D GAI Demand System Price Elasticity Formulas

The Marshallian price elasticity is given by:

$$\eta_{ij} = -\Delta_{ij} + \frac{1}{w_i x}\left[\Delta_{ij} s_i p_i - s_j p_j \left[\alpha_i + \sum_j \gamma_{ji} \log(p_j) + \beta_i \log\left(\frac{\tilde{x}}{P}\right)\right]\right.$$
$$\left. + (x - \sum s_k p_k)\left[\gamma_{ij} + \beta_i \left(\frac{-s_j p_j}{x - \sum s_k p_k}\right) - \beta_i \left(\alpha_j + \sum_k \gamma_{kj} \log(\mathrm{p_k})\right)\right]\right]$$

where Δ_{ij} is the Kronecker delta, defined by $\Delta_{ij} = \begin{cases} 1 & i = j \\ 0 & i \neq j \end{cases}$.

Given the nonlinear nature of the elasticity formulas, all elasticities were evaluated at the mean of the data unless noted otherwise.

Appendix E Distributions of Summer Hourly Prices

The following tables show the distribution of real-time prices during summers 2007-2010. The tables demonstrate that not only do prices change by time of day, but the variance (or spread) of the prices also changes by time of day. Prices are given in $/kWh. Hours with a larger variance are shaded more deeply.

Table 53. Summer Hourly Price Distributions, by Year

ComEd Mean Hourly Prices Summer 2007					ComEd Mean Hourly Prices Summer 2008				
Hour	Mean	Std Dev	Min	Max	Hour	Mean	Std Dev	Min	Max
1	0.029	0.016	-0.020	0.085	1	0.029	0.022	-0.050	0.090
2	0.027	0.013	-0.003	0.098	2	0.028	0.021	-0.103	0.075
3	0.020	0.014	-0.033	0.066	3	0.016	0.022	-0.074	0.044
4	0.015	0.016	-0.055	0.034	4	0.006	0.035	-0.172	0.042
5	0.017	0.013	-0.030	0.033	5	0.009	0.036	-0.165	0.037
6	0.022	0.012	-0.043	0.057	6	0.013	0.028	-0.092	0.043
7	0.024	0.022	-0.085	0.089	7	0.015	0.040	-0.148	0.072
8	0.027	0.015	-0.026	0.078	8	0.026	0.038	-0.200	0.130
9	0.036	0.014	-0.009	0.080	9	0.042	0.023	-0.102	0.126
10	0.043	0.016	0.016	0.087	10	0.051	0.022	-0.016	0.134
11	0.053	0.019	0.023	0.116	11	0.066	0.031	-0.100	0.137
12	0.059	0.021	0.027	0.117	12	0.074	0.027	0.024	0.135
13	0.063	0.021	0.025	0.132	13	0.080	0.030	0.031	0.156
14	0.065	0.022	0.027	0.134	14	0.089	0.031	0.023	0.160
15	0.074	0.030	0.026	0.233	15	0.095	0.035	-0.020	0.191
16	0.078	0.033	0.028	0.189	16	0.104	0.054	-0.030	0.463
17	0.082	0.035	0.028	0.221	17	0.105	0.040	0.027	0.195
18	0.077	0.029	0.028	0.194	18	0.106	0.037	0.029	0.170
19	0.067	0.027	0.011	0.192	19	0.093	0.040	0.029	0.251
20	0.059	0.022	0.028	0.113	20	0.079	0.035	0.028	0.196
21	0.062	0.031	0.020	0.170	21	0.082	0.042	0.026	0.280
22	0.064	0.025	0.023	0.159	22	0.083	0.037	0.026	0.203
23	0.042	0.014	0.025	0.085	23	0.059	0.026	-0.007	0.138
24	0.036	0.019	-0.007	0.118	24	0.043	0.021	-0.007	0.105

ComEd Mean Hourly Prices				
Summer 2009				
Hour	Mean	Std Dev	Min	Max
1	0.019	0.011	-0.023	0.030
2	0.018	0.013	-0.050	0.028
3	0.016	0.013	-0.030	0.026
4	0.011	0.019	-0.088	0.026
5	0.011	0.023	-0.151	0.026
6	0.012	0.016	-0.045	0.027
7	0.017	0.012	-0.028	0.029
8	0.017	0.022	-0.090	0.034
9	0.024	0.014	-0.079	0.040
10	0.027	0.006	-0.008	0.047
11	0.028	0.009	-0.035	0.052
12	0.032	0.009	-0.003	0.060
13	0.033	0.010	0.007	0.074
14	0.035	0.011	0.013	0.066
15	0.036	0.013	-0.003	0.104
16	0.038	0.019	-0.033	0.110
17	0.037	0.021	-0.087	0.101
18	0.039	0.018	0.011	0.115
19	0.034	0.010	-0.008	0.061
20	0.032	0.011	0.001	0.086
21	0.031	0.011	0.002	0.094
22	0.031	0.009	0.008	0.063
23	0.027	0.004	0.006	0.038
24	0.023	0.007	-0.003	0.031

ComEd Mean Hourly Price				
Summer 2010				
Hour	Mean	Std Dev	Min	Max
1	0.032	0.009	0.008	0.076
2	0.029	0.010	-0.007	0.070
3	0.024	0.012	-0.036	0.041
4	0.021	0.011	-0.026	0.034
5	0.020	0.012	-0.044	0.031
6	0.023	0.008	-0.002	0.037
7	0.026	0.008	0.000	0.043
8	0.030	0.014	-0.009	0.137
9	0.035	0.010	0.017	0.079
10	0.039	0.011	0.024	0.073
11	0.046	0.016	0.027	0.103
12	0.051	0.021	0.027	0.146
13	0.053	0.022	0.026	0.140
14	0.057	0.028	0.029	0.204
15	0.060	0.030	0.027	0.219
16	0.065	0.037	0.026	0.306
17	0.067	0.031	0.030	0.199
18	0.062	0.021	0.029	0.116
19	0.053	0.016	0.031	0.106
20	0.052	0.021	0.028	0.166
21	0.056	0.026	0.031	0.186
22	0.057	0.027	0.029	0.171
23	0.042	0.013	0.026	0.107
24	0.036	0.011	0.020	0.100

Source: Navigant analysis