lAppendix A

Detailed Documentation of Input Values for Demand Response Net Benefit Estimates

The demand response benefits summarized in the rebuttal testimony of Dr. George were based on a model developed by Freeman, Sullivan & Co. (FSC). A brief overview of the methodology and a detailed summary of the input values underlying the estimates are contained in this appendix.

Demand response benefits emanate from the change in energy use by time of day induced by time-based pricing, incentive programs or other load management strategies. Time-based pricing and incentive options produce demand reductions or load shifting that can be valued at the marginal cost of capacity and energy by rate period over the forecast horizon. The stylistic equations below summarize at a very high level the basic approach to DR benefit estimation:

(1) MW Impact = (Average use per customer during peak period on the current rate) x

(% Drop in peak period use per customer given a change in price) x

(Number of customers in the target population) x

(Customer participation rate)[1]

(2) Total Benefits = [(MW Impact) x (Avoided Capacity Cost)] +

[(MWh Impact by Rate Period) x (Avoided Energy Cost by Rate Period)]

A variety of input data are required to estimate DR benefits, including:

- Estimates of the number of eligible customers by market segment and year
- Average energy use by rate period and customer segment prior to the DR program going into effect
- Explicit or implicit (in the case of a PTR program) prices before and after the DR program goes into effect, by rate period
- Estimates of the elasticity of substitution and daily price elasticity by customer segment
- Assumptions about the number of customers by segment that will select a DR option (or be aware of the option in the case of peak time rebates).

[1] A similar equation is used to predict the change in energy use in each rate period for each year of the forecast horizon.

- The marketing and related costs needed to generate program participation
- The marginal cost of generation capacity by year
- The marginal cost of energy by rate period and year
- Line loss estimates, reserve margins, discount rates, inflation rates and other miscellaneous inputs.

All of the key input values and assumptions are documented in the remainder of this appendix.

A.1 NUMBER OF ELIGIBLE RESIDENTIAL CUSTOMERS

Table A-1 presents ComEd's forecast of the total number of residential customers it will serve for the 2008-2033 period, as well as the annual rate of growth in the residential customer population. As the table indicates, the residential customer growth rate peaks in 2009 at 0.92%, and then steadily declines to approximately 0.15% by 2025, where it remains for the duration of the forecast period. The average annual growth rate over this period is approximately 0.39%. Also presented in Table A-1 is the number of customers that ComEd anticipates will take part in the RTP/Nature First program, which is a separate SMP DR program. For purposes of this analysis, we assumed that customers would not be allowed to participate in both the PTR and Nature First programs. Consequently, the number of projected participants in the Nature First program was subtracted from the total residential customer population for purposes of estimating the total number of ComEd customers who could potentially participate in the PTR program.

Table A-1
Customer Population and Growth Rate Forecast

Year	Total Customers	Customer Growth Rate	Nature First Customers	Total Potential PTR Customers
2008	3,464,988	---	4,000	3,460,988
2009	3,493,401	0.82%	21,000	3,472,401
2010	3,525,540	0.92%	65,000	3,460,540
2011	3,556,918	0.89%	110,000	3,446,918
2012	3,584,306	0.77%	155,000	3,429,306
2013	3,610,471	0.73%	199,000	3,411,471
2014	3,634,661	0.67%	199,000	3,435,661
2015	3,655,379	0.57%	199,000	3,456,379
2016	3,672,925	0.48%	199,000	3,473,925
2017	3,687,249	0.39%	199,000	3,488,249
2018	3,700,155	0.35%	199,000	3,501,155
2019	3,714,215	0.38%	199,000	3,515,215
2020	3,727,958	0.37%	199,000	3,528,958
2021	3,739,887	0.32%	199,000	3,540,887
2022	3,748,863	0.24%	199,000	3,549,863
2023	3,755,611	0.18%	199,000	3,556,611
2024	3,761,995	0.17%	199,000	3,562,995
2025	3,767,262	0.14%	199,000	3,568,262
2026	3,773,290	0.16%	199,000	3,574,290
2027	3,779,327	0.16%	199,000	3,580,327
2028	3,784,996	0.15%	199,000	3,585,996
2029	3,790,295	0.14%	199,000	3,591,295
2030	3,795,602	0.14%	199,000	3,596,602
2031	3,801,295	0.15%	199,000	3,602,295
2032	3,806,617	0.14%	199,000	3,607,617
2033	3,813,088	0.17%	199,000	3,614,088

A.2 AVERAGE ENERGY USE PER CUSTOMER

Weather normalized average annual energy use for ComEd's residential customers in the base year, 2008, was estimated by ComEd to equal 8,410 kWh. Com Ed projects he annual growth in average energy use per customer to decline from 0.85% to 0.6% between 2008 and 2014 and then to remain constant at 0.5% per year thereafter (for an average annualized growth rate of approximately 0.55% per year over the entire analysis period being considered here. We assume that average energy use during the peak period will grow at the same rate as annual energy use.

The demand response benefit analysis requires estimates of average energy use by rate period. ComEd's 2006 load research data was used to develop estimates of load for each of the 8,760 hours in the year, and these load profiles were applied to the average annual energy use of 8,410 kWh to produce the rate period values shown in Table A-2. The load research sample is segmented into four customer groups: single- and multi-family units, with and without electric space heating. A load weighted average of the four segments profile was used to allocate annual energy use to rate periods shown below.

Table A-2
Average Hourly Demand by Rate Period

	Summer			Non-Summer		
Day Type	Peak	Off-peak	Daily	Peak	Off-peak	Daily
Event Days	2.00	1.50	1.63			
Weekdays	1.24	0.98	1.05	0.88	0.87	0.88
Weekends & Holidays	1.38	1.05	1.14	0.99	0.91	0.93

The peak period used in this analysis is noon to 6 pm, which captures the time of the typical summer PJM system peak. This peak period was selected after an analysis of:

- PJM system load shapes of the 20 highest peak load days for each summer of the years 1993-2007
- ComEd load shapes of the 20 highest peak load days for each summer of the years 2004-2007
- The coincidence of high PJM system load and high ComEd system loads
- The coincidence of the PJM weighted temperatures and ComEd temperatures

Although the estimates of the benefits and costs resulting from the PTR program assume only 12 PTR "event" days per year, we based the impact estimates on average hourly electricity use during peak and off peak periods for the top 20 system load days, which is a more conservative estimate than using only the top 12 system load days.

A.3 PRICES AND INCENTIVES

The change in energy use by time period resulting from the peak time rebate incentive is based on the relationship between the average price paid by customers prior to participating in the PTR program and the opportunity cost of not adjusting their electricity use when the incentive is available. For example, if the incentive payment equals $0.75/kWh and the average electricity price is $0.15/kWh, the opportunity cost of not reducing usage by 1 kWh during the peak period on an event day is $0.90/kWh (the sum of the cost of the electricity used and the rebate payment not received). In this example, the load impacts would be based on the ratio of $0.90/kWh to $0.15/kWh, or six.

Calculating average prices faced by customers required calculating an "all-in" price that combines energy supply, transmission, and distribution fees per kWh of use. However, in calculating the average prices, we did not include the various monthly service charges because they do not influence energy use or demand levels. Because ComEd's residential electric rates vary by customer type (i.e., single- vs. multi-family customers, and customers with and without electric space heating), as well as by season, we calculated seasonal all-in residential rates by weighting the different cost components based on the proportion of the total residential customer population made up by each customer type. The average prices for each customer type and rate block were computed based on ComEd's tariff sheets and its proposed rates in Docket No. 07-0566.

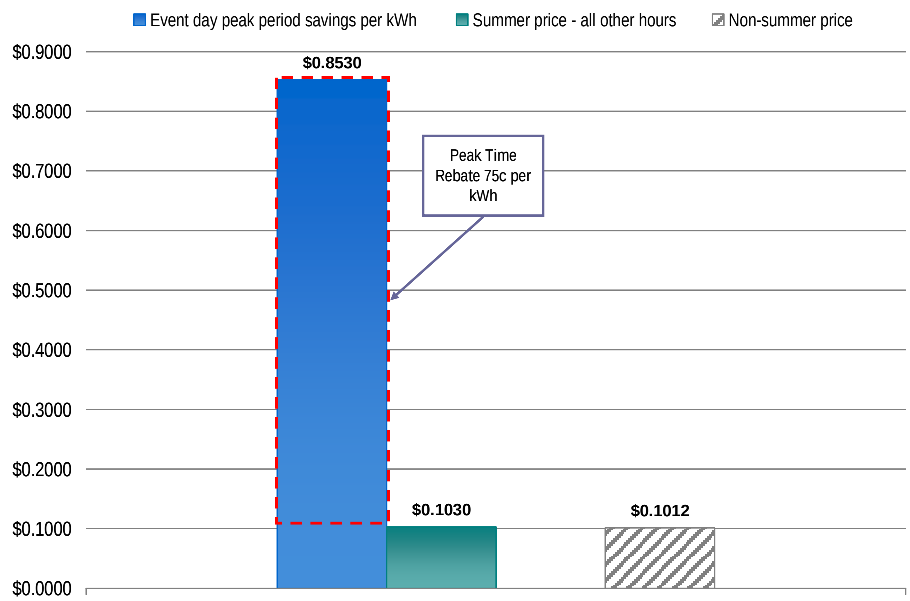
Table A-3 contains the input values used in calculating average all-in residential electric rates for the summer and non-summer seasons, as well as the resulting average rates. Based on these inputs and the population weights for the four residential customer subclasses, we calculated the average residential all-in standard offer rates to equal 10.30 ¢/kWh during the summer months (June through August) and 10.12 ¢/kWh for the non-summer months.

Table A-3
Residential Electric Rate Inputs and Average Rates

Rate Input	Value ($/kWh)	Notes
Energy Supply Charge	0.07320	Summer, no space heat
	0.07149	Non-summer, no space heat
	0.04935	Summer, space heat
	0.04763	Non-summer, space heat
Distribution Facilities Charge	0.02060	Space heating
	0.02508	No space heating
Transmission Services Charge	0.00415	
Supply Administration Charge	0.00012	
Environmental Cost Recovery Adjustment	0.00010	
Franchise Cost Addition	Inflates the transmission services charge (as well as two monthly charges) by 7.87%	
Summer all-in rate:	$0.10302 per kWh	
Non-summer all-in rate:	$0.10121 per kWh	

Figure A-1 illustrates the prices and opportunity costs per kWh underlying the average impact estimates described in this analysis. Note that the PTR event day prices are only shown for the summer season because, in this example, we assume that the PTR events will not be called in non-summer months.

Figure A-1
ComEd Prices and PTR Opportunity Costs



The incentive payment underlying this analysis is $0.75/kWh. Conceptually, this is based on the idea that load serving entities (LSE's) should be willing to pay up to the avoided cost of capacity to reduce electricity use during times when capacity costs are incurred. The $0.75/kWh value is significantly less than the full avoided capacity cost as illustrated in the following analysis.

If no peak time rebates were offered and customers continued their current usage patterns, a LSE would require revenue to meet the installed capacity requirement on critical days. The total revenue associated with capacity costs for residential customers can be calculated by multiplying the average on-peak load for residential customers on the top 20 system load days by the capacity value in the PJM market (line 2 in Table A-4). The analysis in Table A-5 employs the market equilibrium capacity value for the PJM market (see Section A.7 for further explanation). This value, $104.26 per kW-year, is better known as the cost of new entry (CONE) and represents the fixed operating costs and capital costs of a peaking unit (this can be thought of as the cost of having the peaking unit or capacity available). Dividing the revenue associated with capacity by energy use during peak hours provides the capacity costs avoided per kWh reduced (line 5 in Table A-4). Based on this analysis, the maximum cost based peak time rebate is approximately $1.45/kWh.[2] As indicated above, we used a more conservative value of $0.75/kWh for the peak time rebate.

[2] The avoided capacity cost value for 2008 is based on ComEd's forecasted total number of residential customers (including RTP/Nature First customers), 3,464,988, and its forecast for the average annual load for these residential customers (8,410 kWh).

Table A-4
2008 Capacity Cost Based Peak Time Rebate Calculations

Line	Description	Units	Value	Notes
1	Average on-peak load during the 20 days with highest system load	MW	6,918.4	Average customer load X number of customers
2	Equilibrium marginal capacity cost	$/kW-year	$104.26	PJM value for cost of new entry for ComEd
3	Marginal Cost Revenues required for capacity	$	$721,311,725	Line 1 X Line 2 x 1,000
4	Energy usage during on-peak critical day periods	kWh	498,124,345	Average customer load X number of customers X event days X peak hours
5	Maximum cost based PTR credit	Cents/kWh	144.8	Line 3 / Line4
6	Illustrative AMI PTR credit	Cents/kWh	75.0	

A.4 PRICE RESPONSIVENESS

The change in energy use during peak periods on PTR days is based on estimates of the elasticity of substitution and daily price elasticities from California's Statewide Pricing Pilot (SPP), after taking into consideration differences in climate and air conditioning saturations between California and the ComEd service area.[3] The SPP was the largest electricity pricing pilot experiment undertaken to date and encompassed a wide range of climate regions. Importantly, the SPP models allow the elasticity values for residential customers to be adjusted based on differences in climate and central air conditioning saturations.

Elasticities are simply measures of customer responsiveness to implicit or explicit electricity prices. The elasticity of substitution reflects load shifting by customers and can be used to estimate the change in the ratio of peak to off-peak energy use as a function of the ratio of peak to off-peak prices. The daily price elasticity reflects load reductions and can be used to estimate the change in daily energy use as a function of the change in average daily prices. In combination, the two values can be used to predict the change in energy use and average demand for each rate period and overall.

Testimony by Dr. Stephen George in SDG&E's AMI application provided evidence in support of using the SPP elasticity estimates, which were derived from an experiment with critical peak pricing tariffs, to predict impacts for PTR incentive programs.[4] As indicated in Dr. George's testimony, the demand models estimated from the SPP

[3] The elasticity estimates are documented in CRA International, *Impact Evaluation of California's Statewide Pricing Pilot.* Final Report, March 16, 2005. Available at: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

[4] Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Dr. Stephen S. George on behalf of SDG&E. *Chapter 6: Demand Response Benefits.* July 14, 2006 Amendment. http://www.sdge.com/ami/docs/chapter_6.pdf

accurately predicted impact estimates for Anaheim Public Utilities' Spare the Power Days program, a peak time rebate program very similar to the example discussed in this testimony.

Equation A-1 shows the SPP regression model specification used to calculate customer load shifting from peak to off-periods in response to a change in price in each rate period.

Equation A-1

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{N} \theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op}) \ln\left(\frac{P_p}{P_{op}}\right)$$
$$+ \phi(CAC) \ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon$$

where:

Q_p = average energy use per hour in the peak period for the average day

Q_{op} = average energy use per hour in the off-peak period for the average day

σ = the elasticity of substitution between peak and off-peak energy use (defined below)

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = cooling degree hours per hour during the peak pricing period[28]

CDH_{op} = cooling degree hours per hour during the off-peak pricing period

θ_i = fixed effect coefficient for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term

Equation A-1 estimates load shifts from peak to off-peak periods as a function of changes in the peak to off-peak price ratio, air conditioning saturation, and cooling degree hours per hour. The price term is interacted with the central air conditioning saturation and weather variables, meaning that the elasticity estimate is a composite of the three terms shown in equation A-2. The model parameters were drawn from Appendix 16-C of the SPP report (p. 147-151).[5] For critical peak days (i.e., event days), the equation coefficients are: σ = -0.03073, λ = -0.00187 and φ = -0.0917.

Equation A-2

[5] Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot Appendices* (March 16, 2005). http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_APPENDICES.PDF .

$$ES = \sigma + \lambda(CDH_p - CDH_{op}) + \phi(CAC)$$

Equation A-3 shows the SPP regression model specification used to calculate the change in daily energy use in response to a change in daily average prices.

Equation A-3

$$\ln(Q_D) = \alpha + \sum_{i=1}^{N} \theta_i D_i + \eta \ln(P_D) + \rho(CDH_D) + \chi(CDH_D)\ln(P_D) + \xi(CAC)\ln(P_D) + \varepsilon$$

where:

Q_D = average daily energy use per hour
η = the daily price elasticity
P_D = average daily price
ρ = measure of weather sensitivity
χ = the change in daily price elasticity due to weather sensitivity
CDH_D = average daily cooling degree hours per hour (base 72 degrees)
ξ = the change in daily price elasticity due to the presence of central air conditioning
CAC = 1 if a household owns a central air conditioner, 0 otherwise
θ_i = fixed effect for customer i
D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.
ε = regression error term.

Equation A-3 estimates the average hourly load during the event day as a function of the average daily price, air conditioning saturation, and average daily cooling degree hours per hour. As with the elasticity of substitution model, the price term is interacted with the central air conditioning saturation and cooling degree hour terms, meaning that the elasticity estimate is a composite of the three terms shown in equation A-4. The model parameters were drawn from Appendix 16-C of the SPP report (p. 147-151) and are as follows: σ = -0.03966, λ = 0.00121 and φ = -0.01573.

Equation A-4

$$\text{Daily} = \eta + \chi(CDH_D) + \xi(CAC)$$

To calculate the elasticity of substitution and daily price elasticities that are representative of ComEd conditions, estimates of the saturation of central air conditioning and cooling degree hours by rate period are required. Recent survey data on ComEd customer appliance holdings was not available. Data from a recent, statewide survey conducted for the Midwest Energy Efficiency Alliance was used.[6] This survey indicated that 90 percent

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[6] Xcel Energy. *Midwest Residential Market Assessment and DSM Potential Study.* Midwest Energy Efficiency Alliance. March 2006. Table 4-15.

of single family households in the state have central air conditioning. This estimate was applied to the entire residential sector.

Table A-5 shows the average cooling degrees per hour at Chicago's O'Hare airport weather station, with a base of 72 degrees, for the rate blocks employed in the analysis. The averages were calculated using National Weather Service temperature data from Chicago's O'Hare airport weather station for the 12-month period from November 2005 to October 2006 (the same period for which ComEd residential load data was analyzed in order to produce an average residential customer load profile).

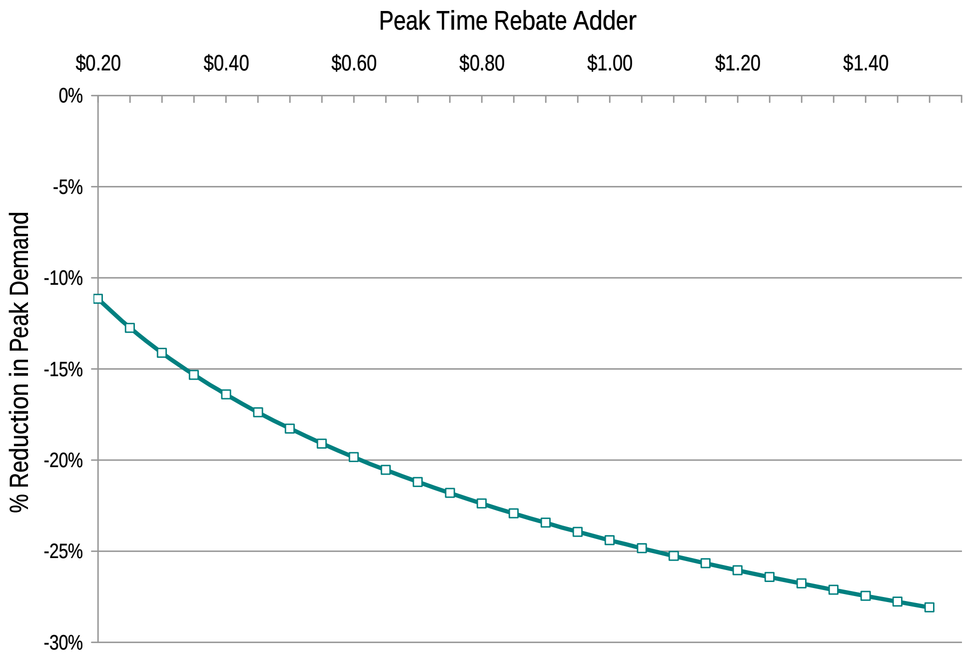
Table A-5
Average Cooling Degree Hours per Hour by Rate Block

	Summer			Non-Summer		
Day Type	Peak	Off-peak	Daily	Peak	Off-peak	Daily
Event Days	13.76	6.18	8.08			
Weekdays	2.16	0.70	1.07	0.49	0.09	0.19
Weekends & Holidays	2.29	0.79	1.17	0.66	0.19	0.30

Using the 90 percent air conditioning saturation estimate and the cooling degree hour estimates in Table A-5 along with the coefficients for Equation A-2 produces an estimate of the elasticity of substitution equal to -0.1271 on event days and -0.1157 on non-event weekdays. Inserting the relevant values into equation A-4 produces estimates of the daily price elasticity equal to -0.0437, -0.0525, and -0.0524 for event days, weekdays, and weekends, respectively.

The elasticity estimates described above can be used to predict the change in energy use by rate period for a wide variety of price levels. Figure A-2 shows the predicted percentage change in peak period energy associated with various PTR incentive levels using the substitution and daily price elasticities reported above. The load reduction for the selected peak time rebate of $0.75/kWh is 21.8%.

Figure A-2
Residential System Load Reduction by Peak Time Rebate Amount



A.5 CUSTOMER PARTICIPATION/AWARENESS

When estimating aggregate impacts for a time-varying price or incentive program, it is necessary to estimate the number of customers that are assumed to be represented by the average response predicted by the price elasticities discussed in the previous section. As discussed in the accompanying testimony, the estimated demand response benefits in this analysis are based on achieving an awareness level for the PTR program of 25% among residential consumers. It should be noted that this awareness level for residential customers is a relatively conservative value; when it approved San Diego Gas and Electric Company's (SDG&E) recent AMI application, the California Public Utilities Commission (CPUC) accepted a 50% awareness level as reasonably achievable.[7] In fact, SDG&E provided testimony indicating that a 70% awareness level was achievable.[8] In recent filings, both Southern California Edison and Central Maine Power assumed awareness levels of 50 percent.

A.6 MARKETING COSTS

Gross estimates of demand response benefits must be reduced by any direct costs of implementing a demand response tariff or incentive program. The primary costs associated with a PTR incentive program are the costs of generating awareness about the

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[7] California Public Utilities Commission. *Opinion Approving Settlement on San Diego Gas & Electric Company's Advanced Metering Infrastructure project.* Application 05-03-015. Decision 07-04-043. April 12, 2007.

[8] Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Mr. Mark F. Gaines on behalf of SDG&E. *Chapter 5: AMI Marketing and Customer Programs.* July 14, 2006 Amendment.

PTR opportunity and how it works, and the cost of notifying consumers about specific PTR events. In this analysis, we based the estimate of marketing and communication costs on testimony provided in SDG&E's AMI application, which included a similar PTR program as a cornerstone of the Company's DR strategy.[9] The SDG&E marketing/communication strategy was based largely on a general awareness campaign followed by a notification strategy for critical events that relied heavily on low or no-cost media such as news announcements, which are commonly used to highlight "Spare the Air Days" for smoggy days in California or "Spare the Power Days" when electricity demand is high. This analysis assumes that the marketing activities required to promote awareness will cost roughly $2 per customer per year in 2010 and 2011 and $1 per customer per year for all subsequent years. The aggregate marketing costs are estimated to grow over time with customer population growth and inflation. In current dollar terms, total marketing costs for ComEd are estimated to equal roughly $7.3 million per year for 2010 and 2011. They drop to $3.8 million in 2012 and then increase based on customer growth and inflation to roughly $6.7 million by 2033.

A.7 MARGINAL GENERATION CAPACITY COSTS

The estimation of marginal generation costs was grounded in the design of PJM's Capacity Market. The total avoided capacity costs are based on expected capacity costs as reflected in PJM's Reliability Pricing Model (RPM) and on the reduction in the installed capacity requirement that can be attributed to the PTR program. The approach takes into consideration:

- The design of the RPM
- The Cost-of-New Entry (CONE) in the Western region, which includes ComEd
- The escalation rate for generation capacity
- Reductions in the installed capacity requirements due to the reserve margin requirements and avoided transmission and distribution losses.

By design, capacity markets 1) set reliability levels via installed capacity requirements, 2) provide a venue for marginal peaking units to recover their capital and fixed operating costs, and 3) reflect that additional capacity is more valuable when there is a shortage of resources and less valuable when there is an excess of them. PJM's capacity market, as reflected in the RPM, also has a four-year forward procurement requirement and has different installed capacity requirements, CONE's, and demand curves by region.

Importantly, capacity markets are designed to trend toward the equilibrium capacity value. PJM has designed the capacity market around the equilibrium capacity value of $104.26 per kW-year for ComEd, which is also referred to as the cost of new entry (CONE). Using this value is consistent with the approach taken in the capacity market

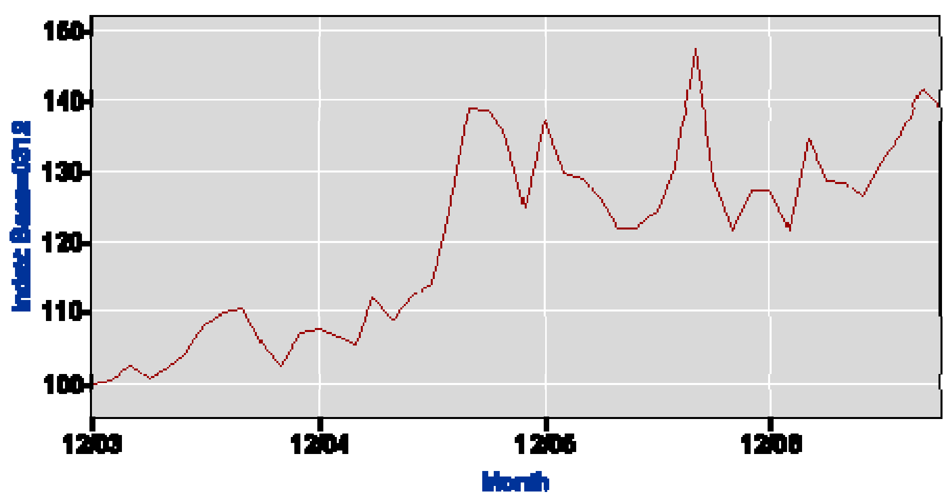
[9] Testimony of Mark F. Gaines cited in previous footnote.

design and implementation. By design, the price of the RPM demand curve equals the price of new entry when the target installed capacity reserves are met and the RPM market is at equilibrium.

Capacity prices for the marginal generation unit were projected to grow at 3.8% per year. The capacity inflation rate is based on the average annual escalation in the construction costs of a combustion turbine (CT) over the last ten years based on the Handy-Withman Index. This is lower than recent PJM adjustments for capacity inflation. In its January 30, 2008 FERC application to update the Costs of New Entry and the demand curves for its Reliability Pricing Model in Docket No. ER 08-516, PJM employed an escalation rate of 10% based on the increase in cost of a CT over the last two years as reflected by the Handy-Whitman Index.

Utility infrastructure costs have been rapidly rising over recent years and are projected to continue to grow due in part to higher domestic and international demand in the utility industry and as well as to high demand for large scale construction and raw products (e.g., steel, cement) in general. The escalation in prices is documented not only by the Handy-Whitman Index, but by the U.S. Department of Labor's Producer Price Indexes. The graph below was drawn from the BLS website and reflects the fact that electric power generation costs over the past three and a half years have increased by roughly 40 percent[10].

Figure A-3
Producer Price Index for Electric Power Generation
U.S. Department of Labor Bureau of Labor Statistics



However, long term price escalation is unlikely to be as high as it has been in the last few years. As detailed in the recent Edison Electric Institute (EEI) report titled "*Rising Utility Construction Costs: Sources and Impacts*" (September 2007), the spike in utility

[10] The BLS website only had data available from Dec 2003, the base date, forward. The underlying data can be accessed at : http://data.bls.gov/PDQ/outside.jsp?survey=pc. Industry code PCU221110221110.

infrastructure costs in the last few years is in part due to a lag between high utility infrastructure demand and manufacturing capacity for large infrastructure components (i.e., turbines, condensers, transformers). Because of these considerations, the average annual escalation rate over the last 10 years for generation capacity was employed in the analysis.

The installed capacity requirement is determined by PJM as the expected peak load plus a resource adequacy margin. By reducing demand, the installed capacity requirement for a LSE is reduced by one plus the resource adequacy margin. Table A-6 reflects the installed capacity requirements for 2008 to 2016 presented by ComEd.[11] The benefit calculations also include adjustments for line losses. The estimate of line losses is documented in Section A.9.

Table A-6
ComEd Installed Capacity Requirements, 2008-2016

Year	Summer Peak Load Forecast	Future Installed Capacity Requirements	Required Reserve Margin
2008	23,950	26,886	12.26%
2009	24,375	27,363	12.26%
2010	24,825	27,869	12.26%
2011	25,275	28,374	12.26%
2012	25,700	28,851	12.26%
2013	26,125	29,328	12.26%
2014	26,525	29,777	12.26%
2015	26,925	30,226	12.26%
2016	27,325	30,675	12.26%

ComEd Illinois Commerce Commission Case 07-0310.
ComEd Summer Peak Load Forecast: 2007 – 2021 (Exhibit 1.2)
http://www.icc.illinois.gov/downloads/public/edocket/199899.pdf

A.8 Marginal Energy Costs

The reduction in wholesale energy costs resulting from load shifting and load reductions was calculated based on the wholesale market data for the ComEd zone for PJM.

For electricity, it is necessary to account for the hourly variation in wholesale prices and weight the prices by the amount consumed/purchased during each specific hour. To

[11] Illinois Commerce Commission. Direct Testimony on Behalf of Commonwealth Edison, Docket No. 07-0310. http://www.icc.illinois.gov/downloads/public/edocket/199899.pdf

better account for avoided wholesale energy costs, the hourly PJM price data was merged with the hourly load shapes for the residential sector.

For each of the rate periods, the total wholesale market cost to purchase energy in the day-ahead market was divided by energy use during those periods, producing a load weighted price. The resulting estimates are contained in Table A-7. These values, combined with the usage data and elasticities, were then used to calculate the electricity supply expenditures before the peak time rebate was in effect and with the peak time rebate in effect. The decrease in the expenditures required to purchase electricity for customers constitutes the wholesale market savings.

Table A-7
Load Weighted Average Wholesale Market Price ($/MWh) by Rate Period

	Summer		Non-Summer	
Day Type	Peak	Off-peak	Peak	Off-peak
Event Days	$121.95	$64.97		
Weekdays	$69.22	$40.38	$51.50	$50.31
Weekends & Holidays	$57.21	$35.13	$39.46	$39.90

A.9 Miscellaneous Input Values

The remaining input values underlying the analysis are summarized below:

- The discount rate used to compute the present value estimates equals ComEd's weighted average cost of capital, 8.55%. proposed in Docket No. 07-0566.

- Demand reductions at the end use level are grossed up by line losses before multiplying them by the marginal capacity and energy costs. Average line losses for ComEd are estimated to equal 9.19%, based on a weighted average of the distribution line losses (7.59%) for the four residential customer subclasses (single- and multi-family customers, with and without electric space heating, plus the transmission line losses (1.6%).[12]

- The annual inflation rate is assumed to equal 2.1%. The GDP deflation value of 2.106% is based on the chained GDP price index for the years 1988-2007, as reported by the US Dept of Commerce's Bureau of Economic Analysis.[13]

[12] Retail Delivery Service Tariff Sheet (No. 378), filed with ICC on 10/17/07 for distribution line losses; PJM's FERC Open Access Transmission Tariff – Attachment H-13, Sheet No. 314A for transmission losses.
[13] See Table 1.1.9: http://www.bea.gov/bea/dn/nipaweb/SelectTable.asp?Selected=Y