ILLINOIS POWER AGENCY

Attachments to the Draft Power Procurement Plan

August 16, 2010

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ATTACHMENT A: Ameren Illinois Utilities Load Forecast for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities
Load Forecast for the period June 1, 2011 – May 31, 2016

Purpose and Summary

The development of the load forecast is an essential step in the development of the Utilities' procurement plan. The load forecast provides the basis for subsequent analysis resulting in a projected system supply requirement. The load forecast process includes a multi-year historical analysis of loads, analysis of switching trends, and competitive retail markets by customer class, known and projected changes affecting load, customer class specific growth forecasts and an impact analysis of statutory programs related to demand response, energy efficiency and renewable energy. The results of this analysis and modeling include a 5 year summary analysis of the projected system supply requirements.

Load Forecast Methodology

Energy Forecast

The models developed for the June 1, 2011 – May 31, 2016 load forecast use both econometric and the statistically adjusted end use (SAE) approaches. The traditional approach to forecasting monthly sales is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. The strength of econometric models is that they are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end use factors that are driving energy use. By incorporating an end-use structure into an econometric model, the statistically adjusted end-use modeling framework exploits the strengths of both approaches. This SAE approach was used for all residential classes, while traditional econometric models were developed for the remaining commercial, industrial and public authority classes. Lighting sales were forecasted by exponential smoothing models. Models were developed using revenue month sales data spanning from January 1995 (data for some models start later than 1995) to September/October 2007. Economic variables were obtained from Moody's Economy.com. Saturation and efficiency data were obtained from EIA. Revenue month weather data was created using billing cycles and weighting daily average temperatures according to the billing cycles. After revenue month sales models were created, the models were simulated with calendar month weather (and calendar month days where applicable) to obtain the calendar month sales forecast.

Since the rate structure changed in 2007 and it was not possible to reclassify the historical data according to the new rates; therefore, modeling was done on each revenue class, i.e., residential, commercial, industrial, public authority and lighting. Next step in the energy forecast was to allocate the sales forecast into the new delivery service rates. DS1 class is equivalent to residential class, and lighting sales are equivalent to DS5. Commercial, industrial and public authority sales were separated into the DS2, DS3A, DS3B and DS4 classes after calculating the shares of each delivery service class within a revenue class.

Residential SAE Model[1]

The SAE modeling framework defines energy use in residential sector (USEy,m) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). The equation for this is as follows:

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives Equation 2,

$$Use_{y,m} = a + b_1 \times XHeat_{y,m} + b_2 \times XCool_{y,m} + b_3 \times XOther_{y,m} + \varepsilon_{y,m} \qquad (2)$$

where $XHeat_{y,m}$, $XCool_{y,m}$, and $XOther_{y,m}$ are explanatory variables constructed from end-use information, weather data, and market data. As shown below, the equations used to construct these X variables are simplified end-use models, and the X variables are the estimated usage levels for each of the major end use based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat- Electric

Energy use by space heating systems depends on heating degree days, heating equipment share levels, heating equipment operating efficiencies, billing days, average household size, household income, and energy price. The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \qquad (3)$$

where $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m), $HeatIndex_y$ is the annual index of heating equipment, and $HeatUse_{y,m}$ is the monthly usage multiplier.

The HeatIndex is defined as a weighted average across equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (Sat) and operating efficiencies (Eff). Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y x \sum_{Type} Weight^{Type} x \frac{\left(Sat_y^{Type} \big/ Efficiency_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Efficiency_{05}^{Type} \right)} \qquad (4)$$

[1] Commercial indices for AmerenIP are constructed using similar approaches; however, non-manufacturing employment and GDP were used instead of households and personal income variables in estimating the indices.

In the above expression, 2005 is used as a base year for normalizing the index. The ratio is equal to 1 in 2005. In other years, it will be greater than 1 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

(5)

$Energy_{05}^{Type}$ is the unit energy consumption of each end-use in 2005 according to EIA data adjusted for each service territory. $HeatShare_{05}^{Type}$ is the saturation levels for each heating end-use in 2005 multiplied by a structural index with base year 2005, which is a function of surface area and building shell efficiency.

$$HeatShare_{05}^{Type} = Saturation_{05}^{Type} \times Structural\ Index_{05} \qquad (6)$$

where

$$Structural\ Index_y = (Building\ Shell\ Efficiency_y \times Surface\ Area_y) / (Building\ Shell\ Efficiency_{05} \times Surface\ Area_{05}) \qquad (7)$$

where

$$Surface\ Area = 892 + 1.44 \times House\ Size \qquad (8)$$

The end-use saturation and efficiency trends are developed from Energy Information Administration (EIA)'s regional projections.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices and billing days. Since the revenue month heating degree days are used in the SAE index, HDD is not used as a separate variable in the model. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{AvgBDays}\right) x \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) x \left(\frac{Income_{y,m}}{Income_{05}}\right)^{0.20} x \left(\frac{HHSize_{y,m}}{HHSize_{05}}\right)^{0.25} x \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}}\right) x \left(\frac{GasPrice_{y,m}}{GasPrice_{05,7}}\right) \qquad (9)$$

where $Price_{y,m}$ is the average residential real price of electricity in year (y) and month (m), $Price_{05}$ is the average residential real price of electricity in 2005, $HHIncome_{y,m}$ is the average real income per household in a year (y) and month (m), $HHIncome_{05}$ is the average real income per household in 2005, $HHSize_{y,m}$ is the average household size in a year (y) and month (m), $HHSize_{05}$ is the average household size in 2005, $HDD_{y,m}$ is the revenue month heating degree days in year (y) and month (m), and HDD_{05} is the annual heating degree days for 2005.

Constructing XCool- Electric

To construct XCool index, the same procedures as in XHeat index are followed; the only difference is that cooling degree days are used instead of heating degree days.

Constructing XOther- Electric

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by appliance and equipment saturation levels, appliance efficiency levels, average household size, real income, real prices, and billing days. The explanatory variable for other uses is defined as follows:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y} \times \mathrm{OtherUse}_{y,m} \qquad (10)$$

The methodology for constructing OtherIndex is the same as heating and cooling indices except for the fact that there is no weather variable used in this index.

Peak Forecast

The peak forecast for the Utilities' eligible customer retail load was performed at the operating company level. For each company (AmerenIP, AmerenCIPS, and AmerenCILCO), historical hourly data was collected. The data for each company was gathered for the longest period of time available that was consistent with the current load. This ranged by company from about 5 to 6 years. From this hourly data, daily peak loads were determined. The daily peak loads were the basis for the peak load model. The loads were at transmission level and excluded wholesale load.

The Daily Peak Model

Daily peak loads were modeled using regression within the MetrixND software package. Daily peak load was the dependent variable, and the independent variables included temperature based variables, seasonal variables, day-type variables, and energy growth trend variables. Average daily temperature, defined as the arithmetic mean of the day's high and low temperatures, is the basis for all of the weather variable constructions. Temperature splines are then created from the average daily temperature variable to allow load to respond to temperature in a non-linear fashion. These temperature splines are also interacted with seasonal and weekend variables to allow the temperature response of load to change with respect to these variables (i.e. Load will respond more to an 80 degree day in July than in October, and more on a weekday than a weekend).

Lagged weather variables are also employed in the model. Multiple days of lags of each temperature spline are included, as well as a Rolling HDD and CDD variable. This captures the build-up effect observed in peak load. When there are multiple very hot days in a row, buildings tend to hold more heat and require more air conditioning, which in turn results in higher loads.
The daily peak model also includes independent binary variables representing each day of the week, each month of the year, and major holidays. This captures the change in load

that is not due to weather variation, such as load reductions due to industrial customers and businesses that may not operate on weekends.

Finally, each model contains some variables to capture load growth. Where available, weather normalized 12-month rolling average sales were used to capture growth. This modeling technique is based on the assumption that increased energy usage drives the peak load. In essence it assumes that load factor is relatively stable over time. The sales are weather normalized and averaged over 12 months because actual weather and seasonal variation are already accounted for within the model by other independent variables. This specification allows for peak load growth to be driven by true load additions that are experienced because of customer growth or usage per customer increases that are not influenced by weather. Again the actual weather impacts are already accounted for through the weather variables described above.

In the absence of sufficient history of weather normalized sales, a trend variable is used that, in essence, attributes peak load growth to the passage of time. Under positive economic conditions with normal load growth, this is a reasonable approach to capture the normal increases that are known to take place in the peak load.

Statistical tests verify that the models fit the data quite well. The R-Squared statistic, which indicates the amount of variation in the dependent variable (load) that is explained by the model, ranges from 85.6% to 89.7%. The Mean Absolute Percent Error (MAPE) of the models range from 3.94% to 4.54%, indicating that over all of the years of the analysis, the average day has an absolute error within this range.

Forecasting Normal Weather Conditions for the Daily Peak Model

The AmerenIL utilities define normal for a weather element as the arithmetic mean of that weather element computed over the 10 year period from 2000-2009. Because daily average temperature is the weather variable of interest for the peak forecast, the daily average temperature for each date must be averaged over the 10 year period. Unfortunately, averaging temperatures by date (i.e. all January 1st values averaged, then all January 2nd values and so on) creates a series of normal temperatures that is relatively smooth (i.e. no extreme values) and therefore devoid of peak load making weather conditions. To ameliorate this situation, a routine known as the “rank and average” method is used. In this method, all 10 years of historical weather data are collected. For each summer and non-summer of each year, the respective degree day data is sorted from the highest value to the lowest. Then the sorted data is averaged across the 10 years, with all of the hottest days in each summer averaged with each other. Likewise, all of the coldest days in each non-summer season are averaged, while the mild days are averaged together.

After the weather has been averaged by the degree day rank, the days are “mapped” back to the actual weather from each year for the historical period. For the forecast period, an average weather shape is used to map the degree days. This way, the “normal” degree days follow a realistic contour. The normal temperature series is run through the daily peak forecast model to produce a normal peak load forecast.

Final Forecast Steps

The MetrixLT software develops the hourly load by delivery service class by combining the monthly sales forecast by class, hourly load shapes by class from load research, and distribution loss factors. The software calibrates the delivery service classes to the total system peak forecast developed with the daily peak model. The hourly forecast for each company is combined to develop the Ameren Illinois hourly load forecast.

Switching Trends and Competitive Retail Market Analysis

It is important to note in any discussion of retail switching the inherent difficulty in projecting future activity. The Utilities necessarily must make some assumption of such future switching levels given that 16-111.5(b) of the PUA requires a five year analysis of the projected balance of supply and demand. In making these assumptions, the Utilities have utilized an extension of existing trends and their best judgment to arrive at the expected values. This was accomplished by first establishing the current trend line utilizing actual switching data by customer class for the post rate freeze period (January 2007 through June 2010). The Utilities then reviewed these trends and using their qualitative judgment made adjustments such that the end result is a forecast characterized by increasing switching, although at a slowing rate over time. Given the difficulties inherent with projecting switching, it is expected that subsequent switching projections for future planning periods will likely differ substantially, and thus will have a like effect upon the projection of the Utilities' combined power supply requirements for eligible retail customers.

Residential

As of June 1, 2010, there were five Alternative Retail Electric Suppliers (ARES) registered with both the ICC and the Utilities to serve residential customers in the Utilities' territories, as compared to fifteen so registered to serve non-residential customers in the Utilities territories. However, as of the date this plan was prepared, less than 0.1% of residential customers of the Utilities have exercised their right to choose an ARES (switching is approximately 1.2% when RTP is considered) and significant switching is not expected in the near term.

Past retail switching has likely been dampened in part by the rate credits resulting from Public Act 095-481. These credits provide payment to residential customers over several years and are affected if the customer leaves utility service. After these credits expire (starting in 2010), it is reasonable to expect some increase in residential switching and such assumptions have been imbedded in the forecast.

Residential switching could be positively influenced by an increase in the number of ARES willing to serve residential customers, aggressive marketing campaigns or the development of value added products and services. It is worth noting that the amount of ARES approved to serve residential customers has increased from four to five in the last twelve months. More so, significant reductions in market prices or changes in the

regulations regarding switching rules (i.e. “wet” signature requirements) would reasonably be expected to have an impact upon residential switching rates.

In addition to the ARES options, residential customers may opt for real time pricing through a program administered for the Utilities by CNT Energy. Since program inception in 2007, participation in the program has been steadily increasing and now exceeds 1.0% of available customers.

The Utilities estimate that the combination of residential switching to ARES and real time pricing will be slightly greater than 10% by the end of the five year planning period.

0-149 kW Non-Residential

This customer class has seen approximately 40% switching since January 1, 2007 which represents about a 18% increase over the prior year. Future switching patterns are difficult to predict due to uncertain market conditions. However, as long as market prices stay below the Utilities tariff, one could reasonably expect switching to continue its upward trend.

In addition, now that ARES have been successful in gaining significant switching among the larger industrial and commercial customer classes, it is reasonable to assume ARES will focus efforts on the smaller customer classes. Finally, customers in this class also have an option for real time pricing, giving them other alternatives to switch away from tariff.

The Utilities estimate that switching in this class will be approximately 54% by the end of the five year planning period.

150-399 kW Non-Residential

This customer class has seen approximately 69% switching since January 1, 2007 which represents about a 14% increase over the prior year. Future switching patterns are difficult to predict due to uncertain market conditions. However, as long as market prices stay below the Utilities tariff, one could reasonably expect switching to continue its upward trend.

In addition, now that ARES have been successful in gaining significant switching among the larger industrial and commercial classes, it is reasonable to assume ARES will focus efforts on the smaller customer classes. Finally, customers in this class will also have the option for real time pricing, giving them other alternatives to switch away from tariff.

The Utilities estimate that switching in this class will be approximately 83% by the end of the five year planning period.

400-999 kW Non-Residential

Section 16-113 (f) of the PUA declared this class to be competitive on June 1, 2010. As such, all customers are required to take service under an ARES or the Utilities real time pricing tariff. Therefore, this customer class assumes 100% switching and is therefore no longer considered part of the Utilities fixed price load.

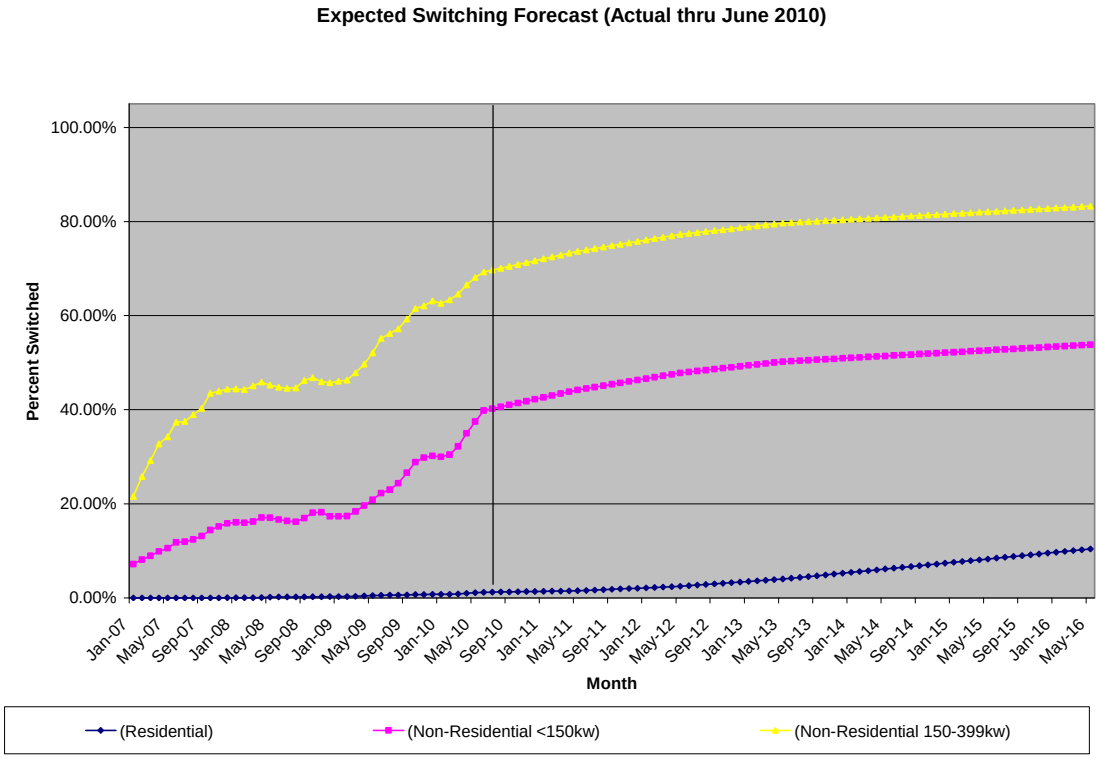
1,000 kW and Greater Non-Residential

This customer class is declared competitive and therefore these customers can no longer take the fixed price service after May 31, 2008 and is therefore not included in the fixed price load.

Switching Patterns

As noted previously, it is reasonable to expect further switching among residential and small commercial customer classes to either real time pricing or ARES as such suppliers increase focus on smaller customer classes, market prices change or switching rules are modified. However, switching will likely at some point approach saturation (the point at which all of those customers willing to switch and acceptable to ARES have done so), thus eventually resulting in a slow down of customer switching rates.

The current assumption within the Plan is that switching will continue, although a decreasing rate over time. Expected values through May 31, 2016 are included in the graph below:



Known or Projected Changes to Future Loads

Known or projected changes to future loads include:

1) Customer Switching behavior, as discussed in Section II.B.(2).
2) Demand Response Program Initiatives, as discussed in Section II.c.(1)
3) Energy Efficiency Initiatives, as discussed in Section II.c.(3)

Growth Forecasts by Customer Class

For the residential customer class, the Utilities currently project a 5-year Compound Annual Growth rate of -0.6%. Commercial growth rates for the Utilities are projected to be 2.4%.

Analysis of the Impact of Any Demand Side Initiatives

Demand Response Programs

Section 12-103 of Public Act 095-0481 establishes specific requirements for Demand Response Programs to reduce peak demand of eligible retail customers. The effective reduction in the Utilities' aggregate supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2011	12 MW
2012	16 MW
2013	20 MW
2014	23 MW
2015	26 MW

The Utilities shall review the cost effectiveness of these programs as specified by statute and shall modify the program design accordingly if needed.

Energy Efficiency Programs

Section 12-103 (b) of Public Act 095-0481 establishes specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers. The effective reduction in the Utilities' supply requirements to be acquired through the RFP process (net of customer switching) is projected to be

2011	106,792 MWh
2012	207,719 MWh
2013	298,197 MWh
2014	386,608 MWh
2015	447,066 MWh

(Please note that the above values only reflect the impact upon the amount of energy that the Utilities have to acquire to serve the eligible retail customer loads, after consideration of switching).

ATTACHMENT B: Ameren Illinois Utilities Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-11	1,009,692	279,200	57,565	27,766	-21,600	1,374,223	1,352,623
July-11	1,335,294	299,359	61,206	27,184	-22,320	1,723,043	1,700,723
August-11	1,333,094	296,921	60,391	27,998	-22,320	1,718,405	1,696,085
September-11	964,978	276,143	55,990	29,988	-21,600	1,327,100	1,305,500
October-11	798,363	267,637	53,874	31,788	-22,320	1,151,662	1,129,342
November-11	835,516	253,917	50,855	33,881	-21,600	1,174,169	1,152,569
December-11	1,107,141	268,221	53,156	36,520	-22,320	1,465,037	1,442,717
January-12	1,207,290	299,658	55,848	38,082	-22,320	1,600,877	1,578,557
February-12	1,042,234	265,476	49,918	34,903	-20,880	1,392,530	1,371,650
March-12	936,023	260,086	48,470	32,241	-22,320	1,276,820	1,254,500
April-12	747,656	231,751	43,955	32,097	-21,600	1,055,460	1,033,860
May-12	776,769	248,105	47,731	28,990	-22,320	1,101,595	1,079,275
June-12	1,001,350	269,369	51,293	27,783	0	1,349,794	1,349,794
July-12	1,324,077	288,594	54,563	27,201	0	1,694,436	1,694,436
August-12	1,324,000	286,842	53,999	28,011	0	1,692,853	1,692,853
September-12	958,055	267,382	50,226	29,993	0	1,305,657	1,305,657
October-12	788,150	259,119	48,387	31,785	0	1,127,441	1,127,441
November-12	825,031	247,193	45,973	33,871	0	1,152,067	1,152,067
December-12	1,088,897	260,785	48,062	36,505	0	1,434,249	1,434,249
January-13	1,178,657	290,830	50,478	38,068	0	1,558,033	1,558,033
February-13	979,421	254,564	44,631	34,891	0	1,313,507	1,313,507
March-13	908,983	252,774	43,972	32,238	0	1,237,967	1,237,967
April-13	729,752	226,718	40,193	32,192	0	1,028,855	1,028,855
May-13	762,154	243,051	43,774	28,999	0	1,077,979	1,077,979
June-13	985,058	262,955	46,985	27,795	0	1,322,793	1,322,793
July-13	1,302,396	281,822	50,112	27,213	0	1,661,542	1,661,542
August-13	1,301,848	280,548	49,780	28,019	0	1,660,195	1,660,195
September-13	939,283	262,176	46,516	29,996	0	1,277,971	1,277,971
October-13	767,549	254,927	45,061	31,781	0	1,099,318	1,099,318
November-13	799,747	243,238	42,914	33,862	0	1,119,762	1,119,762
December-13	1,059,670	257,648	45,161	36,495	0	1,398,975	1,398,975
January-14	1,143,551	287,282	47,537	38,059	0	1,516,429	1,516,429
February-14	949,239	252,041	42,222	34,884	0	1,278,387	1,278,387
March-14	880,321	250,824	41,799	32,237	0	1,205,181	1,205,181
April-14	701,690	223,852	38,103	32,104	0	995,749	995,749
May-14	740,067	242,191	42,010	29,007	0	1,053,276	1,053,276

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-14	962,988	262,218	45,112	27,804	0	1,298,121	1,298,121
July-14	1,271,098	279,848	47,915	27,221	0	1,626,081	1,626,081
August-14	1,270,532	278,529	47,576	28,024	0	1,624,661	1,624,661
September-14	914,825	260,436	44,468	29,996	0	1,249,725	1,249,725
October-14	744,074	253,389	43,091	31,778	0	1,072,331	1,072,331
November-14	769,651	240,692	40,845	33,856	0	1,085,044	1,085,044
December-14	1,021,744	255,390	43,049	36,487	0	1,356,670	1,356,670
January-15	1,083,217	284,295	45,229	38,052	0	1,450,793	1,450,793
February-15	899,820	249,903	40,229	34,881	0	1,224,832	1,224,832
March-15	828,459	246,753	39,504	32,237	0	1,146,953	1,146,953
April-15	664,110	220,995	36,130	32,108	0	953,342	953,342
May-15	706,854	240,069	39,989	29,012	0	1,015,925	1,015,925
June-15	920,582	258,925	42,784	27,811	0	1,250,103	1,250,103
July-15	1,222,520	276,967	45,523	27,226	0	1,572,236	1,572,236
August-15	1,219,573	275,599	45,177	28,027	0	1,568,376	1,568,376
September-15	877,732	257,857	42,237	29,996	0	1,207,822	1,207,822
October-15	709,925	251,079	40,947	31,775	0	1,033,726	1,033,726
November-15	728,834	238,165	38,745	33,851	0	1,039,595	1,039,595
December-15	963,638	252,018	40,718	36,482	0	1,292,855	1,292,855
January-16	1,039,801	279,646	42,628	38,047	0	1,400,121	1,400,121
February-16	902,252	251,275	38,732	34,880	0	1,227,139	1,227,139
March-16	805,144	245,573	37,640	32,236	0	1,120,593	1,120,593
April-16	639,739	217,990	34,105	32,110	0	923,945	923,945
May-16	686,061	237,884	37,909	29,017	0	990,871	990,871

ATTACHMENT C: Ameren Illinois Utilities System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	714,720	637,904	2,030	1,733
July-11	842,292	858,431	2,632	2,025
August-11	936,346	759,739	2,544	2,021
September-11	678,542	626,958	2,019	1,633
October-11	554,176	575,166	1,649	1,410
November-11	581,246	571,323	1,730	1,488
December-11	688,896	753,821	2,050	1,848
January-12	757,415	821,142	2,254	2,013
February-12	690,534	681,116	2,055	1,892
March-12	617,537	636,963	1,754	1,625
April-12	513,687	520,172	1,529	1,355
May-12	552,358	526,917	1,569	1,344
June-12	721,373	628,422	2,147	1,637
July-12	846,581	847,855	2,520	2,078
August-12	934,121	758,732	2,538	2,018
September-12	590,427	715,229	1,942	1,719
October-12	588,677	538,764	1,600	1,433
November-12	569,373	582,694	1,695	1,517
December-12	647,629	786,621	2,024	1,855
January-13	782,227	775,807	2,222	1,979
February-13	660,503	653,004	2,064	1,855
March-13	584,475	653,492	1,740	1,602
April-13	534,127	493,445	1,517	1,341
May-13	550,200	527,779	1,563	1,346
June-13	666,018	656,776	2,081	1,642
July-13	875,822	785,720	2,488	2,004
August-13	884,335	775,860	2,512	1,979
September-13	604,336	673,635	1,889	1,684
October-13	575,499	523,819	1,564	1,393
November-13	523,916	595,846	1,637	1,490
December-13	655,250	743,725	1,950	1,823
January-14	753,440	762,990	2,140	1,946
February-14	645,123	633,263	2,016	1,799
March-14	563,024	642,157	1,676	1,574
April-14	513,469	482,279	1,459	1,311
May-14	508,863	544,413	1,514	1,334

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-14	673,015	625,106	2,003	1,628
July-14	874,495	751,586	2,484	1,917
August-14	820,248	804,413	2,441	1,972
September-14	627,230	622,495	1,867	1,621
October-14	572,087	500,244	1,555	1,330
November-14	476,487	608,557	1,567	1,463
December-14	675,846	680,824	1,920	1,737
January-15	678,828	771,965	2,020	1,892
February-15	611,418	613,414	1,911	1,743
March-15	561,592	585,360	1,595	1,493
April-15	491,677	461,665	1,397	1,255
May-15	465,208	550,717	1,454	1,299
June-15	671,165	578,938	1,907	1,573
July-15	882,955	689,281	2,399	1,833
August-15	780,321	788,055	2,322	1,932
September-15	626,649	581,173	1,865	1,513
October-15	535,815	497,911	1,522	1,270
November-15	486,507	553,087	1,520	1,383
December-15	651,210	641,644	1,850	1,637
January-16	620,555	779,565	1,939	1,839
February-16	615,356	611,783	1,831	1,699
March-16	584,524	536,069	1,588	1,426
April-16	458,246	465,699	1,364	1,213
May-16	478,257	512,614	1,423	1,256

ATTACHMENT D: Ameren Illinois Utilities Contract Volumes to Secure in 2011-2016 Procurement Cycles

Ameren Illinois Utilities Off Peak Contract Volumes to Secure in 2011–2016 Procurement Cycles

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	1,733	1,000	250	483	500	0	0
July-11	2,025	1,000	600	425	400	0	0
August-11	2,021	1,000	550	471	450	0	0
September-11	1,633	1,000	200	433	450	0	0
October-11	1,410	1,000	50	360	350	0	0
November-11	1,488	1,000	150	338	350	0	0
December-11	1,848	1,000	400	448	450	0	0
January-12	2,013	1,000	550	463	450	0	0
February-12	1,892	1,000	400	492	500	0	0
March-12	1,625	1,000	200	425	400	0	0
April-12	1,355	1,000	0	355	350	0	0
May-12	1,344	1,000	0	344	350	0	0
June-12	1,637	1,000	0	637	150	500	0
July-12	2,078	1,000	0	1,078	450	650	0
August-12	2,018	1,000	0	1,018	400	600	0
September-12	1,719	1,000	0	719	200	500	0
October-12	1,433	1,000	0	433	0	450	0
November-12	1,517	1,000	0	517	50	450	0
December-12	1,855	1,000	0	855	300	550	0
January-13	1,979	0	750	1,229	650	600	0
February-13	1,855	0	700	1,155	600	550	0
March-13	1,602	0	600	1,002	500	500	0
April-13	1,341	0	500	841	450	400	0
May-13	1,346	0	500	846	450	400	0
June-13	1,642	0	0	1,642	550	600	500
July-13	2,004	0	0	2,004	700	700	600
August-13	1,979	0	0	1,979	700	700	600
September-13	1,684	0	0	1,684	600	600	500
October-13	1,393	0	0	1,393	500	500	400
November-13	1,490	0	0	1,490	500	550	450
December-13	1,823	0	0	1,823	650	650	500
January-14	1,946	0	0	1,946	700	650	600
February-14	1,799	0	0	1,799	650	600	550
March-14	1,574	0	0	1,574	550	550	450
April-14	1,311	0	0	1,311	450	450	400
May-14	1,334	0	0	1,334	450	500	400

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	1,628	0	0	1,628	0	550	600
July-14	1,917	0	0	1,917	0	650	700
August-14	1,972	0	0	1,972	0	700	700
September-14	1,621	0	0	1,621	0	550	600
October-14	1,330	0	0	1,330	0	450	500
November-14	1,463	0	0	1,463	0	500	500
December-14	1,737	0	0	1,737	0	600	600
January-15	1,892	0	0	1,892	0	650	650
February-15	1,743	0	0	1,743	0	600	600
March-15	1,493	0	0	1,493	0	500	550
April-15	1,255	0	0	1,255	0	450	450
May-15	1,299	0	0	1,299	0	450	450
June-15	1,573	0	0	1,573	0	0	550
July-15	1,833	0	0	1,833	0	0	650
August-15	1,932	0	0	1,932	0	0	700
September-15	1,513	0	0	1,513	0	0	550
October-15	1,270	0	0	1,270	0	0	450
November-15	1,383	0	0	1,383	0	0	500
December-15	1,637	0	0	1,637	0	0	550
January-16	1,839	0	0	1,839	0	0	650
February-16	1,699	0	0	1,699	0	0	600
March-16	1,426	0	0	1,426	0	0	500
April-16	1,213	0	0	1,213	0	0	400
May-16	1,256	0	0	1,256	0	0	450

Ameren Illinois Utilities Peak Contract Volumes to Secure in 2011 – 2016 Procurement Cycles

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	2030	1000	550	480	500	0	0
July-11	2895	1000	1150	745	750	0	0
August-11	2799	1000	1100	699	700	0	0
September-11	2019	1000	500	519	500	0	0
October-11	1649	1000	250	399	400	0	0
November-11	1730	1000	300	430	450	0	0
December-11	2050	1000	600	450	450	0	0
January-12	2254	1000	700	554	550	0	0
February-12	2055	1000	500	555	550	0	0
March-12	1754	1000	300	454	450	0	0
April-12	1529	1000	100	429	450	0	0
May-12	1569	1000	150	419	400	0	0
June-12	2147	1000	0	1147	500	650	0
July-12	2772	1000	0	1772	950	800	0
August-12	2792	1000	0	1792	950	850	0
September-12	1942	1000	0	942	350	600	0
October-12	1600	1000	0	600	100	500	0
November-12	1695	1000	0	695	200	500	0
December-12	2024	1000	0	1024	400	600	0
January-13	2222	0	800	1422	0	400	0
February-13	2064	0	750	1314	700	600	0
March-13	1740	0	650	1090	550	550	0
April-13	1517	0	550	967	500	450	0
May-13	1563	0	550	1013	550	450	0
June-13	2081	0	0	2081	750	700	650
July-13	2737	0	0	2737	950	950	850
August-13	2764	0	0	2764	950	1000	800
September-13	1889	0	0	1889	650	650	600
October-13	1564	0	0	1564	550	550	450
November-13	1637	0	0	1637	550	600	500
December-13	1950	0	0	1950	700	650	600
January-14	2140	0	0	2140	750	750	650
February-14	2016	0	0	2016	700	700	600
March-14	1676	0	0	1676	600	550	550
April-14	1459	0	0	1459	500	500	450
May-14	1514	0	0	1514	550	500	450

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	2003	0	0	2003	0	700	700
July-14	2733	0	0	2733	0	950	950
August-14	2685	0	0	2685	0	950	950
September-14	1867	0	0	1867	0	650	650
October-14	1555	0	0	1555	0	550	550
November-14	1567	0	0	1567	0	550	550
December-14	1920	0	0	1920	0	650	700
January-15	2020	0	0	2020	0	700	700
February-15	1911	0	0	1911	0	650	700
March-15	1595	0	0	1595	0	550	550
April-15	1397	0	0	1397	0	500	500
May-15	1454	0	0	1454	0	500	500
June-15	1907	0	0	1907	0	0	650
July-15	2639	0	0	2639	0	0	900
August-15	2555	0	0	2555	0	0	900
September-15	1865	0	0	1865	0	0	650
October-15	1522	0	0	1522	0	0	550
November-15	1520	0	0	1520	0	0	550
December-15	1850	0	0	1850	0	0	650
January-16	1939	0	0	1939	0	0	700
February-16	1831	0	0	1831	0	0	650
March-16	1588	0	0	1588	0	0	550
April-16	1364	0	0	1364	0	0	500
May-16	1423	0	0	1423	0	0	500

ATTACHMENT E: Commonwealth Edison Load Forecast for Five Year Planning Period, June 2011 through May 2016

COMMONWEALTH EDISON COMPANY

Load Forecast for Five-Year Planning Period
June 2010 – May 2015

July 15, 2009

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I. INTRODUCTION AND SUMMARY

The Public Utilities Act ("PUA") provides that beginning in 2008 electric utilities in Illinois shall provide a range of load forecasts to the Illinois Power Agency ("IPA") by July 15 of each year. The PUA further provides that these load forecasts shall cover the 5-year planning period for the next procurement plan and shall include hourly data representing high-load, low-load and expected-load scenarios for the load of eligible retail customers ("Eligible Retail Customers"). The electric utility is also to provide supporting data and assumptions (220 ILCS 5/16-111.5(d)(2)). This document presents Commonwealth Edison Company's ("ComEd) load forecast for the planning period of June 2010 through May 2015. ComEd will provide the supporting data and assumptions in a separate package of materials.

ComEd's 5-year hourly load forecast ("Forecast") is based on the PUA's definition of Eligible Retail Customers. Eligible Retail Customers include residential and other customers who are entitled to purchase power and energy from ComEd under fixed-price bundled service ("Blended Service") tariffs. Because service to certain classes of non-residential customers has been declared competitive either by statute or by the Illinois Commerce Commission ("ICC"), only those non-residential customers below 100 kW in size are eligible for Blended Service beginning in June 2010.[1] While previous forecasts reflected these known changes in Blended Service eligibility, phase-out provisions within these competitive declarations allowed certain customers to continue to obtain Blended Service through May 31, 2010. That phase-out period will have ended prior to this Forecast period and the net result this year will be to consider the switching opportunities for a smaller group of customers eligible for Blended Service.

Finally, the Forecast includes the effects of energy efficiency and demand response programs, as well as the quantity of renewable energy resources that need to be procured over the period of this Forecast. The Forecast anticipates that these programs will be observed in full compliance with the PUA's requirements, subject to the defined rate impact test.

II. LOAD FORECAST

A. Purpose and Summary

This section of the Forecast provides forecasted energy usage for the Eligible Retail Customers within ComEd's service territory for the 5-year procurement planning period beginning on June 1, 2010. In accordance with Section 16-111.5(b) of the PUA, the Forecast includes a multi- year historical analysis of hourly loads, a review of switching trends and competitive retail market development, a discussion of known and projected changes to future loads and growth forecasts by customer classes. The impacts, if any, of demand response and energy efficiency programs are also addressed.

[1] There is one exception to this statement. The common area accounts for the condominium associations are exempted from this competitive declaration (see Section 16-103.1 of the PUA).

B. Development of the Five-Year Load Forecast (June 1, 2010 – May 31, 2015)

The hourly load analysis provides the means to determine the on -peak and off-peak quantities needed in the procurement process. In presenting the Forecast, this document focuses on average usage or load during the 12 monthly on-peak and off-peak periods during a year. For the purposes of this Forecast, the definitions of the on-peak and off-peak periods are consistent with those commonly used in the wholesale power markets, and on trading platforms such as the New York Mercantile Exchange ("NYMEX") and the Intercontinental Exchange, Inc. ("ICE"). The on-peak period consists of the week day period from 6 a.m. to 10 p.m. CST excluding NERC holidays (this is referred to as the 5X16 peak period). The off-peak period consists of all other hours (this is referred to as the off-peak "wrap"). The Forecast therefore has been summarized as load requirements using the 24 different time periods covered by these standard products. This is the same approach that was presented in past forecasts. The hourly load data is being supplied with the supporting data and assumptions materials.

1. Hourly Load Analysis

a. Multi-year historical analysis of hourly load

The 2009 multi-year historical analysis of hourly load is very similar to the approach used in the 2008 procurement filing. Essentially, the hourly models that were developed last year were updated with another year of customer data and reviewed for fit. The results this year are similar to the previous filing.

The 2009 multi-year historical analysis of load during the 24 monthly on-peak and off-peak periods is based on hourly profile data for the period from January 2004 to March 2009. The profiles are based on statistically significant samples from ComEd's residential and small commercial and industrial ("C&I") customer population. As noted last year, these samples provide the only basis for an analysis of actual historical hourly usage of Eligible Retail Customers because the standard meters currently used for these customers do not record usage on an hourly basis. Further, as discussed in greater detail below, the profiles show clear and stable weather-related usage patterns that are indicative of how residential and small C&I customers use electricity. Thus, the customer load profiles provide reliable information on the historical hourly usage of customers.

Using the hourly load profiles and actual customer aggregate usage, Table II-1 depicts the historical on-peak and off-peak hourly usage of the major customer groups within the Eligible Retail Customers for the period from January 2006 to December 2008.

Table II-1

Load Forecast Table (Historical Detail 2006-2008)

ComEd Historical Actual Sales

Historical Energy Sales in MWh for Eligible Retail Customers (Line Loss Adjusted)

		Residential Load		Watthour		Small Load (0 to 100kW)		Street Lighting Load		Total Load (MWh)	
Year	Month	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2006	1	1,256,132	1,374,251	84,681	67,709	481,564	391,036	4,463	10,303	1,826,841	1,843,298
2006	2	1,161,366	1,227,567	81,336	62,544	446,830	339,993	3,983	9,865	1,693,515	1,639,969
2006	2	1,246,506	1,170,307	86,979	59,836	511,103	348,217	3,371	10,401	1,847,960	1,588,761
2006	4	883,139	1,049,491	63,376	53,330	442,887	355,126	2,200	9,608	1,391,601	1,467,555
2006	5	1,041,922	1,154,671	74,321	54,697	493,627	354,870	1,249	10,727	1,611,119	1,574,964
2006	6	1,367,943	1,202,345	78,971	52,171	591,188	383,157	1,762	9,911	2,039,863	1,647,583
2006	7	1,849,638	2,187,719	78,633	63,303	570,238	500,836	1,339	10,577	2,499,848	2,762,435
2006	8	1,853,407	1,570,249	79,281	48,641	677,835	441,188	2,189	10,893	2,612,713	2,070,971
2006	9	945,129	1,065,004	73,838	59,665	477,947	389,067	3,073	10,246	1,499,985	1,523,981
2006	10	1,101,961	1,100,271	76,818	55,208	505,606	364,796	3,766	10,832	1,688,151	1,531,107
2006	11	1,163,770	1,205,908	78,308	60,523	474,375	356,398	4,321	10,518	1,720,774	1,633,347
2006	12	1,278,904	1,537,332	54,003	51,049	487,419	446,154	4,835	8,804	1,825,162	2,043,341
Totals		**15,149,818**	**15,845,113**	**910,544**	**688,677**	**6,160,620**	**4,670,838**	**36,550**	**122,683**	**22,257,532**	**21,327,312**
2007	1	1,457,097	1,468,878	56,674	43,742	583,358	443,717	5,636	13,179	2,102,765	1,969,515
2007	2	1,267,467	1,369,362	36,786	29,412	442,442	345,901	2,778	5,567	1,749,474	1,750,242
2007	2	1,057,784	1,134,928	23,570	18,140	418,035	317,973	2,086	5,513	1,501,476	1,476,554
2007	4	909,275	994,657	19,710	14,900	390,199	297,316	5,324	19,813	1,324,507	1,326,685
2007	5	1,104,862	1,072,495	23,298	16,207	474,806	325,316	3,179	8,800	1,606,145	1,422,818
2007	6	1,440,606	1,435,159	20,885	15,367	502,081	375,267	3,236	8,688	1,966,807	1,834,481
2007	7	1,630,033	1,768,442	28,412	21,906	526,360	418,045	3,520	8,725	2,188,325	2,217,117
2007	8	2,011,503	1,691,894	26,597	16,913	598,902	385,432	3,660	9,379	2,640,661	2,103,618
2007	9	1,244,723	1,497,186	20,857	18,610	457,852	392,067	4,430	8,737	1,727,862	1,916,600
2007	10	1,142,776	1,173,411	21,873	14,996	467,438	312,726	5,506	9,616	1,637,593	1,510,749
2007	11	785,173	844,163	14,842	11,558	291,515	222,695	5,428	9,193	1,096,958	1,087,609
2007	12	1,440,058	1,821,833	27,331	26,082	469,111	439,096	6,848	10,309	1,943,347	2,297,320
Totals		**15,491,357**	**16,272,407**	**320,836**	**247,833**	**5,622,099**	**4,275,550**	**51,629**	**117,517**	**21,485,920**	**20,913,307**
2008	1	1,411,279	1,483,772	29,148	23,056	466,843	361,907	6,297	10,557	1,913,567	1,879,292
2008	2	1,318,731	1,342,790	26,989	21,401	443,650	337,946	5,615	9,295	1,794,986	1,711,432
2008	3	1,092,187	1,305,371	23,682	21,257	409,987	350,785	4,030	6,004	1,529,885	1,683,417
2008	4	1,011,328	1,006,047	21,714	16,003	427,661	300,578	4,163	8,288	1,464,865	1,330,916
2008	5	886,256	1,047,507	17,377	14,660	392,652	317,448	2,424	3,392	1,298,709	1,383,007
2008	6	1,319,145	1,400,770	21,381	16,263	481,461	364,433	692	7,997	1,822,679	1,789,463
2008	7	1,832,155	1,649,107	24,545	16,852	553,938	391,569	392	2,338	2,411,030	2,059,866
2008	8	1,489,004	1,620,019	23,926	18,615	507,114	406,990	890	4,645	2,020,934	2,050,269
2008	9	1,088,190	1,166,101	19,823	15,684	457,734	341,009	1,268	4,339	1,567,015	1,527,133
2008	10	1,081,333	1,003,909	23,739	16,888	426,681	295,683	1,773	4,603	1,533,526	1,321,083
2008	11	1,021,535	1,335,393	26,766	25,996	381,408	366,260	1,905	4,363	1,431,614	1,732,012
2008	12	1,504,635	1,541,136	31,715	26,073	469,006	382,791	1,848	3,530	2,007,204	1,953,531
Totals		**15,055,778**	**15,901,921**	**290,805**	**232,748**	**5,418,134**	**4,217,399**	**31,296**	**69,352**	**20,796,014**	**20,421,420**

Table II-2 carries forward the total load in MWhs from Table II-1 and then provides the average load for each period in MWs, which is useful in determining the required volume of standard wholesale energy products.

Table II-2

Load Forecast Table (Historical Summary 2006-2008)

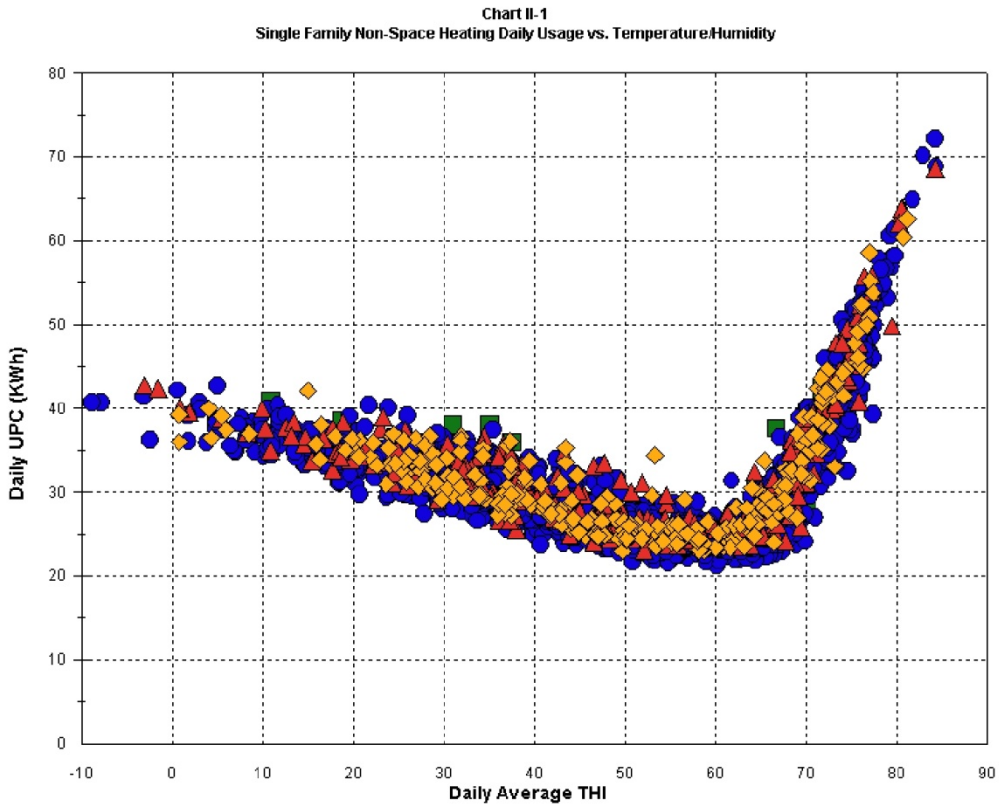
ComEd Historical Actual Sales Historical
Energy Sales for Eligible Retail Customers
(Line Loss Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2006	1	1,826,841	1,843,298	5,437	4,518
2006	2	1,693,515	1,639,969	5,292	4,659
2006	3	1,847,960	1,588,761	5,022	4,225
2006	4	1,391,601	1,467,555	4,349	3,669
2006	5	1,611,119	1,574,964	4,577	4,018
2006	6	2,039,863	1,647,583	5,795	4,477
2006	7	2,499,848	2,762,435	7,812	6,515
2006	8	2,612,713	2,070,971	7,100	5,508
2006	9	1,499,985	1,523,981	4,687	3,810
2006	10	1,688,151	1,531,107	4,796	3,906
2006	11	1,720,774	1,633,347	5,121	4,254
2006	12	1,825,162	2,043,341	5,704	4,819
Total		**22,257,532**	**21,327,312**		
2007	1	2,102,765	1,969,515	5,974	5,024
2007	2	1,749,474	1,750,242	5,467	4,972
2007	3	1,501,476	1,476,554	4,266	3,767
2007	4	1,324,507	1,326,685	3,942	3,455
2007	5	1,606,145	1,422,818	4,563	3,630
2007	6	1,966,807	1,834,481	5,854	4,777
2007	7	2,188,325	2,217,117	6,513	5,434
2007	8	2,640,661	2,103,618	7,176	5,595
2007	9	1,727,862	1,916,600	5,684	4,607
2007	10	1,637,593	1,510,749	4,450	4,018
2007	11	1,096,958	1,087,609	3,265	2,832
2007	12	1,943,347	2,297,320	6,073	5,418
Total		**21,485,920**	**20,913,307**		
2008	1	1,913,567	1,879,292	5,436	4,794
2008	2	1,794,986	1,711,432	5,342	4,754
2008	3	1,529,885	1,683,417	4,553	4,126
2008	4	1,464,865	1,330,916	4,162	3,617
2008	5	1,298,709	1,383,007	3,865	3,390
2008	6	1,822,679	1,789,463	5,425	4,660
2008	7	2,411,030	2,059,866	6,850	5,255
2008	8	2,020,934	2,050,269	6,015	5,025
2008	9	1,567,015	1,527,133	4,664	3,977
2008	10	1,533,526	1,321,083	4,167	3,514
2008	11	1,431,614	1,732,012	4,709	4,163
2008	12	2,007,204	1,953,531	5,702	4,983
Totals		**20,796,014**	**20,421,420**		

ComEd analyzed the hourly load profiles for all the major customer groups within the Eligible Retail Customers. As a result of that analysis, ComEd developed hourly load models for those major customer groups that determined the average percentage of monthly sales that each customer group used in each hour of that month. Those hourly models were then used to develop the monthly on-peak and off-peak usage percentages for the planning periods. These percentages were applied to ComEd's forecasted monthly sales to obtain the forecasted procurement quantities that are presented later in this Forecast (see Chart II-7 and the discussion in section IIB(1)(d), below). In the following section, the hourly analysis of the residential single-family non- space heating customer segment is described. This class represents approximately half of the annual sales of the Eligible Retail Customer segment and provides a good example of how the hourly load profile data were analyzed and modeled.

(i) Residential Single-Family Hourly Load Profile Analysis

One of the most significant, and easily understood, determinants of residential energy usage is weather. The "scatter plot" shown below (Chart II-1) demonstrates the significant relationship that exists between weather and usage for the single-family non-space heating residential customer segment.



A scatter plot shows the relationship between two variables. Each point represents a single observation (a day in this case). In this chart, the values shown on the vertical or Y-axis are daily usage per customer ("UPC"). The values shown on the horizontal or X-axis

are the daily average temperature-humidity index ("THI"). The graph shows daily UPC based on observations from June 2002 to March 2009 and the average THI on those days. THI, rather than temperature alone, is used because residential usage is sensitive to humidity. Different geometric shapes are used to distinguish points representing weekdays from those depicting Saturday, Sunday or holiday usage.

The scatter plot is very useful in understanding the relationship between customer usage and weather. If there were no relationship between the two, points on the graph would not display a clear pattern. However, it is apparent that there is a clear pattern. The right side of the graph at the high end of the horizontal axis shows the days on which THI was the highest. The points at that end of graph indicate that the highest UPC occurred when THI levels were at their peak -- 80 plus degrees. Moving to the left, the points show UPC declining rapidly as the THI decreases until the 60 degree level is reached at which a base usage appears. From that base level, UPC gradually increases as colder temperatures are experienced.[2]

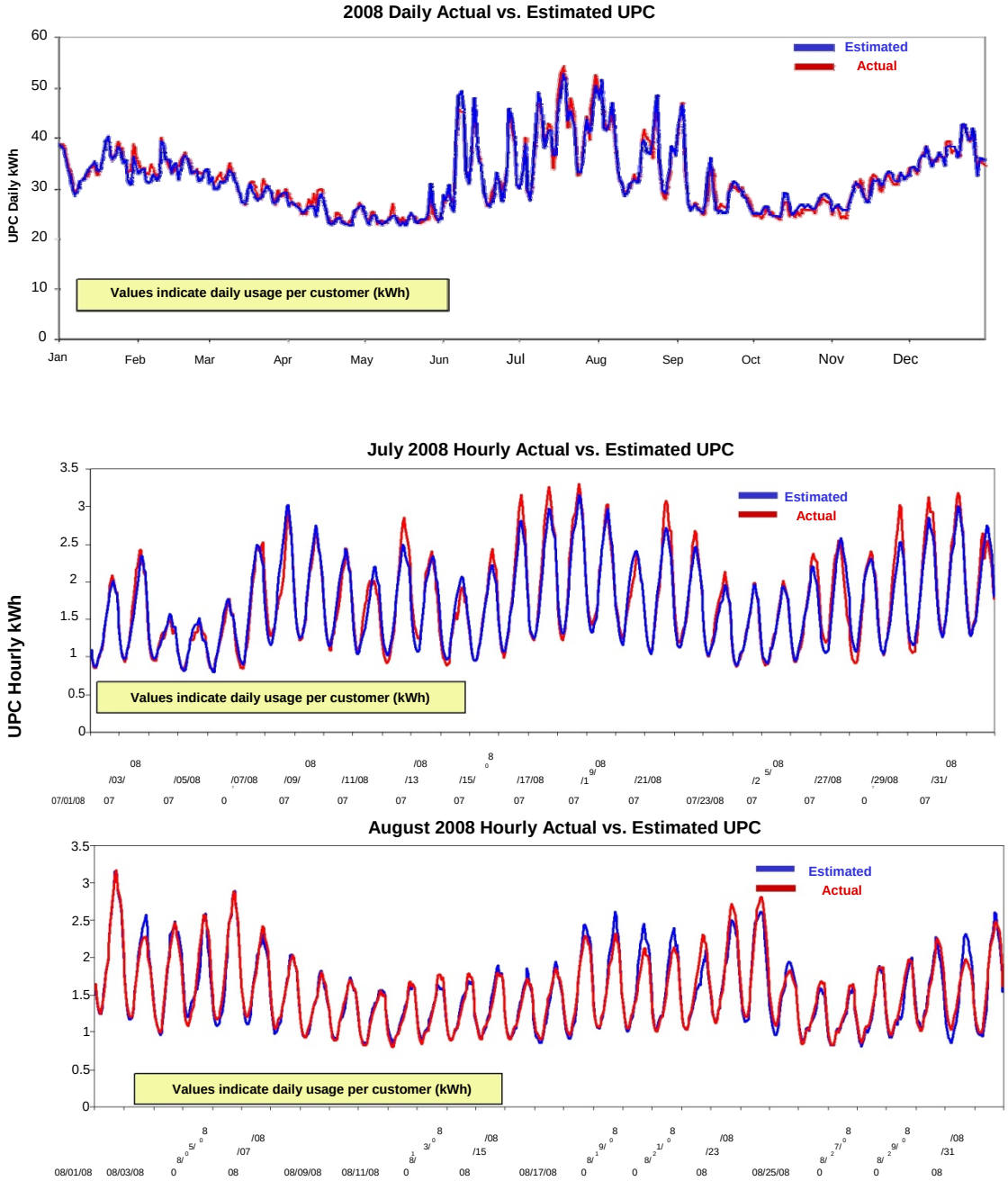
Hourly models were developed to account for the strong weather relationship shown in the graph and to account for numerous other factors that influence residential usage. The models explicitly account for the differing effects of energy use at various temperatures. Variables are included to allow for seasonal usage patterns in water heating, refrigeration and other seasonal uses. Weekend and holiday variables are included to allow for behavioral differences on those days relative to weekdays. The amount of daylight on each day is included to account for seasonal differences in lighting loads. Weather variables for prior days are included in the model to account for the dynamic effects of temperature buildup. The full list of variables included in the residential single-family model is shown in Appendix A-1.

One way to visualize the model's performance is to look at plots of actual and estimated[3] values for the historical estimation period. The following chart demonstrates the performance of the model over the one-year period from January 2008 through December 2008 at the daily level and zooms in to show the hourly performance in July and August of 2008.

[2] Unlike usage for commercial customers, residential daily usage does not vary significantly between weekdays and weekends. In fact, residential usage on weekends and holidays is typically greater than on week days.

[3] The estimated data in Chart II-2 is based on the actual weather experienced over the relevant period.

Chart II-2
ComEd Single Family Profile: Estimated vs. Actual



In all of the three above graphs in Chart II-2, the red line indicates the "actual" load data and the blue line indicates the model's estimated values, based on actual weather. In this case, it is important to understand that the actual data are themselves estimates of population loads based on a statistical sample, and are therefore subject to minor variations that occur in the sample. Despite this statistical variation in the actual values, the charts demonstrate that the model's estimated usage and the actual usage are extremely close. The close alignment of the estimated and actual lines on the charts demonstrates that the model is very effective in determining variations in electrical usage patterns.

b. Switching Trends and Competitive Retail Market Analysis

In determining the expected load requirements for which standard wholesale products will have to be purchased, it is important to provide the best possible forecast of the extent to which Eligible Retail Customers are likely to switch to alternative providers. That issue is considered in the following discussion, which reviews retail development in ComEd's service territory, the entry of alternative suppliers, the rate of customer switching in the past, future trends affecting customer choice and ComEd's 5-year forecast of the percentage of load from various customer segments that will remain to be served with supply procured by ComEd.

(i) Introduction and Brief Overview of Retail Development

There can be no doubt that robust retail markets exist in northern Illinois. In October 1999 the first ComEd customer began taking service from an alternative retail electric supplier ("RES"). In the following ten years there has been a steady movement to RES service. As of May 2009 only 21% of ComEd's entire non-residential sales were being served under Blended Service (the traditional utility fixed rate). By June 2010 that figure is estimated to be below 14% as the over 100 kW customers migrate off of Blended Service and small commercial customers below 100 kW opt for RES service. Thus, the ComEd non- residential market has gone from no retail activity ten years ago to one now approaching 90% of the non-residential sales being served by a RES or Hourly Service.

While customer switching in the commercial and industrial market has been very robust, customer switching in the Residential class has been much slower. There are many factors that contribute to this condition, with acquisition costs, market conditions and modest price changes for residential customers being primary factors. Over the past 12 years the average residential rate is largely unchanged, 11.6 cents/kWh in 2008 versus 11.4 cents/kWh in 1996. Thus, rapid price escalation that might have caused residential customers to seek RES service has not occurred.

In summary, retail choice is a success story in the ComEd service territory. While this phenomena is subject to a variety of factors, especially market conditions, a healthy retail market is anticipated in the near term.

(ii) RES Development

The success of retail market competition is the result of the concerted efforts of ComEd, numerous RESs and policy makers. Today, the retail market development continues in two very meaningful ways. First, RESs continue to enter the ComEd market. Since January 2008 eight new RESs have been certified by the ICC. Five of the eight have been registered by ComEd to serve retail load and the remaining three are in the process. Second, as noted last year, ongoing workshops are occurring related to purchase of receivables ("POR"). The POR topic is addressed in more detail with the "Future Trends" section below.

Just like ComEd's customer base, there is a large and very diverse population of RESs in northern Illinois. These companies differ in many ways. Some have national operations while others operate just regionally. Some are focused on the entire spectrum of customers,

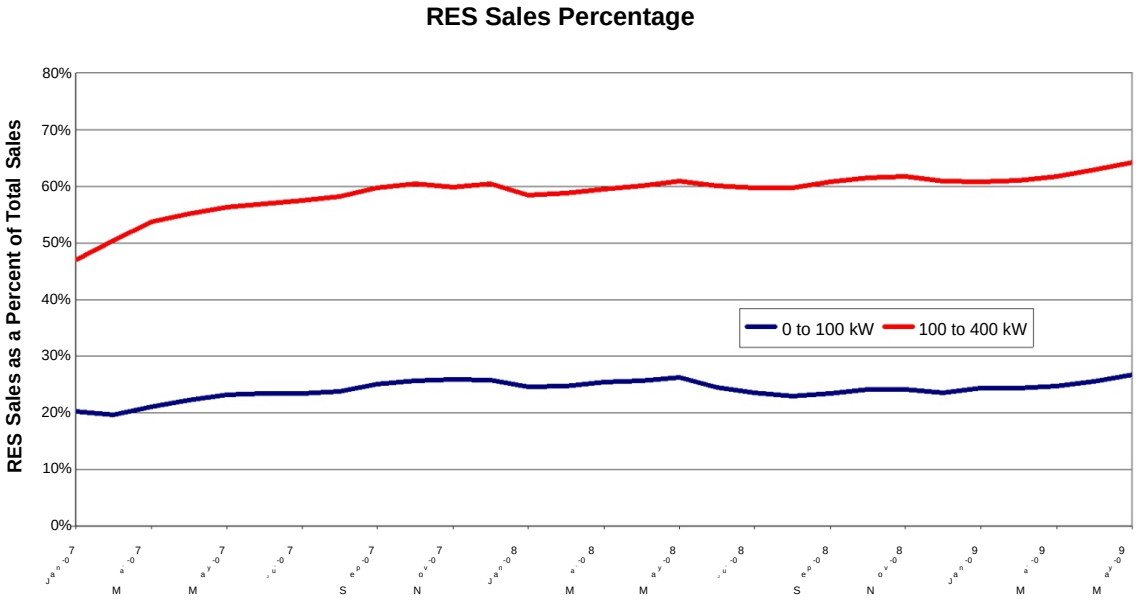
including residential, while others concentrate on just non-residential customers. Some retailers offer other products (e.g., demand response) to assist the customer in managing their electricity usage. This large number of diverse businesses can only be considered a plus to the customers in the ComEd service territory.

It is interesting to note that during one of the most severe recessions in the country's history there has been only one RES that has left the ComEd market in the past year. Another RES surrendered its ARES certification, although they were not registered with ComEd. On the other hand, one RES in our service territory was recently selected by Crain's Chicago Business as the fastest growing small business in the Chicago area.

(iii) Future Trends

RES sales to the 0 to 100 kW customers has been gradually growing over time. Chart II -3 contains monthly RES percentage of sales from January 2007 through May 2009 for the 0 to 100 and 100 to 400 kW customers (though not applicable for this procurement event). The 0 to 100 kW RES sales have been slowly growing over time. RES sales to the 100 to 400 group has been increasing at a faster pace than the 0 to 100 kW group. This is understandable given, among other things, the expiration of Blended Service to this group as of June 2010. The view is that movement by the 100 to 400 kW customers will increase migration by some of the 0 to 100 kW customers. Thus, the outlook is for the 0 to 100 kW customers to continually migrate to RES service, but at a slightly faster pace than in the past few years.

Chart II-3



In assessing future small C&I and residential RES sales, consideration needs to be given to the potential impact of the ongoing discussion concerning POR. A POR program could result in greater participation by RESs in the residential retail market by lowering a RES' costs.

Discussions are currently underway to address implementation issues, and the programs are expected to become operational in the January to March 2011 time frame.

Another development that has some potential to affect the level of Blended Service sales to residential and Small C&I customers is House Bill 722 ("HB722"). That bill passed both houses of the Illinois General Assembly and is awaiting execution by the Governor. HB722 revises Section 17-800 of the PUA by allowing a municipality to adopt an opt-out aggregation program. These revisions have some potential to lessen Blended Service sales to the residential and small C&I customers, but their effect is too uncertain to be taken into account for purposes of this Forecast.

(iv) Forecasted Retail Sales

The forecast percentages of Blended Service sales are shown below, along with some historical perspective.

Table II-3
Percentage of Blended Service Sales[4]

Month	Residential	Watthour	0-100 kW
Jun-04	100.0%	99.4%	87.8%
Jul-05	100.0%	99.4%	87.3%
Jul-06	100.0%	99.6%	90.7%
Jul-07	100.0%	97.4%	76.5%
Jun-08	99.9%	98.0%	75.2%
May-09	99.8%	98.0%	72.1%
Jun-10	99.5%	96.0%	65.1%
Jun-11	98.3%	96.0%	55.4%
Jun-12	98.3%	96.0%	55.4%
Jun-13	98.2%	96.0%	55.4%
Jun-14	98.2%	96.0%	55.4%
Jun-15	98.2%	96.0%	55.4%

[4] For the 2004 to 2006 data the percentages may include a very minor amount of sales related to customers taking service under ComEd's hourly service tariffs.

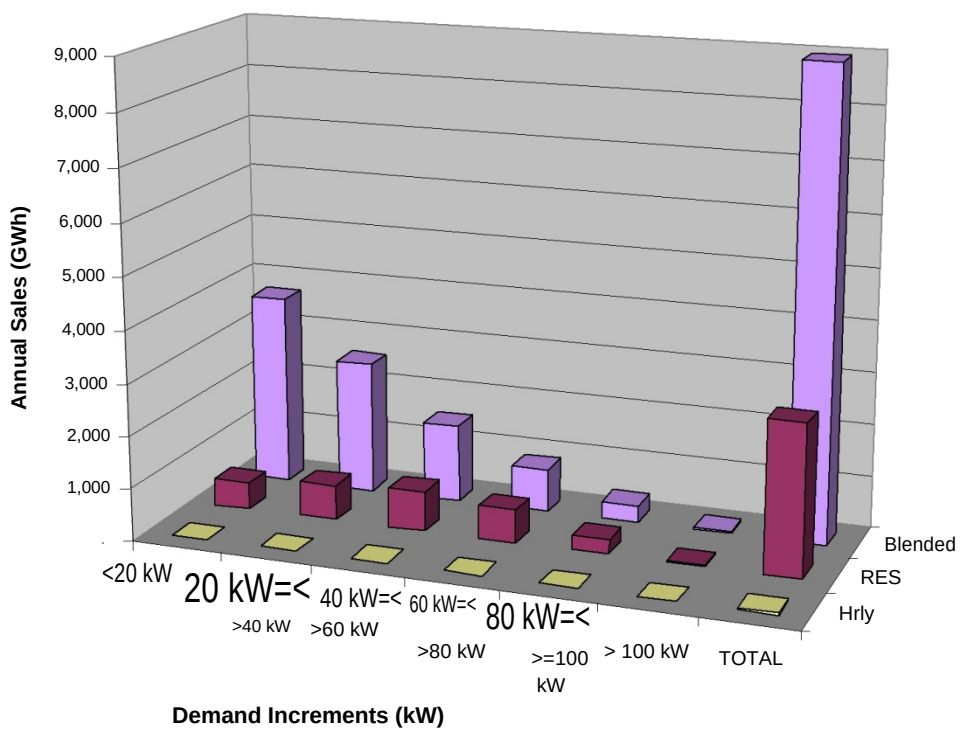
The main drivers of this forecast are:

1. The Blended Service supply cost will reflect certain pre-existing contracts; specifically the financial swap agreement that is in place through May 2013. If market prices continue to be lower than they have been in the last few years, this may produce some "headroom" that provides the opportunity for more RES sales in the 0 to 100 kW customer group or for customers to switch to Hourly Service.

2. In addition, a gradual increase in RES sales to the non-residential customers below 100 kW is assumed as retailers continue to seek new customers. This has been the pattern for the past decade. However, the increase in RES service to the below 100 kW non-residential customers is limited by the fact that many of the customers in this category are rather small in size (i.e., almost "watt-hour like" in size). Below is a chart depicting the allocation of sales (kWh) to the 0 to 100 kW customer group among Blended, RES and Hourly products for the year 2008. The chart breaks down this customer group by 20 kW increments. A large portion of the Blended usage in this class is in the below 40 kW segments. While RES have been able to obtain customers in the below 40 kW segments, their share accounts for only 15% of the total below 40 kW sales. This highlights the difficulty in RESs reaching customers whose electricity bill is relatively small.

Chart II-4

Allocation of 0 to 100 kW Sales by Product



3. Residential switching is not assumed to occur for the next couple of years, but a small amount is expected in later years as a result of the POR initiative.

The effects of those drivers by customer group are as follows:

1. The RES served portion of the 0 to 100 kW customer load will grow from 27% (as of May 2009) to 34% by June 2010. This movement is helped by the current RES marketing efforts related to the 100 to 400 kW customers. POR efforts, potential for headroom and RESs seeking new customers causes this percentage to increase to 44% by June 2011. The percentage holds at this level thereafter given the smaller customer size of the remaining Blended customers.

2. Watthour customers are similar in behavior to residential customers when viewed from a choice perspective and their participation in customer choice is expected to generally mimic the residential movement. Approximately 98% of the total sales to these customers are for Blended Service and that percentage decreases slightly to 96% during the Forecast period.

3. Active residential customer choice is not assumed to occur until 2011 because of the same Blended Service pricing dynamics noted for the small non-residential customers. Beginning in 2011 a small amount (i.e., 0.2-0.4% of total residential sales) is anticipated as POR initiatives are implemented. However, increasing residential hourly sales are anticipated in the Forecast and addressed in the next section.

c. Known or Projected Changes to Future Load

Typically, when ComEd forecasts future loads, it considers whether there are any known major customer decisions, such as the relocation of part or all of a business, that would impact load. For the Eligible Retail Customers, other than the factors we have discussed elsewhere, e.g. switching, energy efficiency measures, growth, etc., there is only one known or projected change that ComEd is aware of that would affect future loads for this group of customers. This is the residential real-time pricing program ("RRTP").

In compliance with Section 16-107(b-5) of the PUA, ComEd received ICC approval to implement an RRTP program.[5] ComEd currently has about 7,000 customers on RRTP and is targeting just over 11,000 by the end of 2009. In addition, ComEd expects about 6,000 additional customers will switch to RRTP in 2010. The program could potentially expand beyond 2010, but is subject to ICC review and approval at the end of the year.

[5] See ICC Order of December 20, 2006, in Docket No. 06-0617.

ComEd is currently seeking approval to implement a smart meter pilot program (ICC Docket no. 09-0263). If approved, ComEd would install 140,000 smart meters by mid-2010. Thus, there is some potential that additional customers could switch to RRTP over the timeframe of this Forecast. However, the number of such customers is small and ComEd does not think it is reasonable to project any additional migration off of Blended Service in this year's Forecast due to the pilot program.

ComEd will also be applying to the Department of Energy ("DOE") for funding under the Smart Grid Investment Grant Program. Under this program, parties can apply for up to $200 million to help cover the costs of deploying smart grid facilities. If ComEd is successful, it plans to deploy additional smart meters in the City of Chicago and also plans to deploy home area network equipment in some of these homes that would permit these customers to have greater control over their energy usage. A decision from DOE is expected in October 2009. While DOE approval is uncertain, to prevent over procurement of energy for Blended customers this forecast assumes 25,000 additional homes do utilize RRTP service beginning in the fourth quarter of 2010. This assumption serves as a placeholder that acknowledges the potential for significant increases in future RRTP customers because of this program while also acknowledging the previously described uncertainties. The timing of DOE decision should permit ComEd to include the effect of this decision in the updated forecast that it intends to submit during the procurement proceeding as it did last year.

The table below shows the combined effect of the RRTP program and of the smart grid program on residential usage over the time period of this Forecast.

Table II-4
RRTP Enrollments and the Amount of Associated Load

End of Year	Incremental Enrollments	Total Enrollments	Annual Usage (GWh)
2009	5,100	11,100	107
2010	31,000	42,100	406
2011	0	42,100	406
2012	0	42,100	406
2013	0	42,100	406
2014	0	42,100	406

Customers that switch to RRTP would no longer be considered in the forecasted load of Eligible Retail Customers. The last column in the above chart depicts the estimated annual usage that would be impacted by this level of RRTP participation using the annual usage of a residential single-family non-space heating customer.

d. Growth Forecast by Customer Class

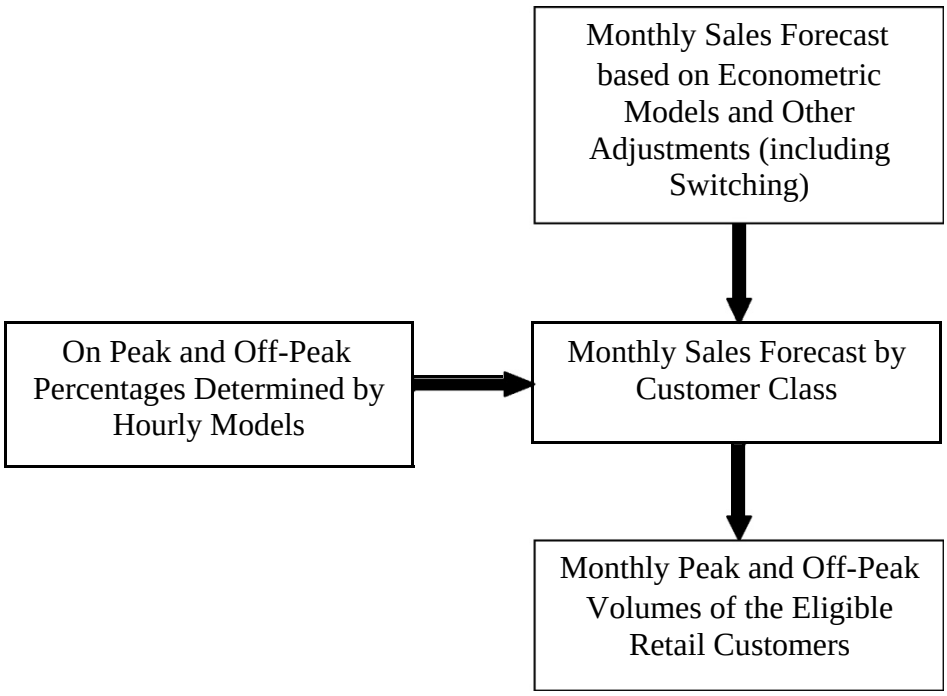
(i) Introduction

This section describes ComEd's growth forecast by customer class for the 5-year procurement planning period beginning on June 1, 2010. Section II(B)(1) discussed the hourly customer load profiles used by ComEd to develop models to present the historical load analysis required by the PUA and to predict average UPC. As indicated in this section, in arriving at a growth forecast by customer class, there are additional models beyond those customer-level hourly models that are used to forecast future customer class sales. These other models play an important role in determining expected load during the 5-year planning period among the Eligible Retail Customer groups.

The following chart illustrates the steps in the ComEd load forecasting process.

Chart II-5

ComEd Energy Sales Forecast Process



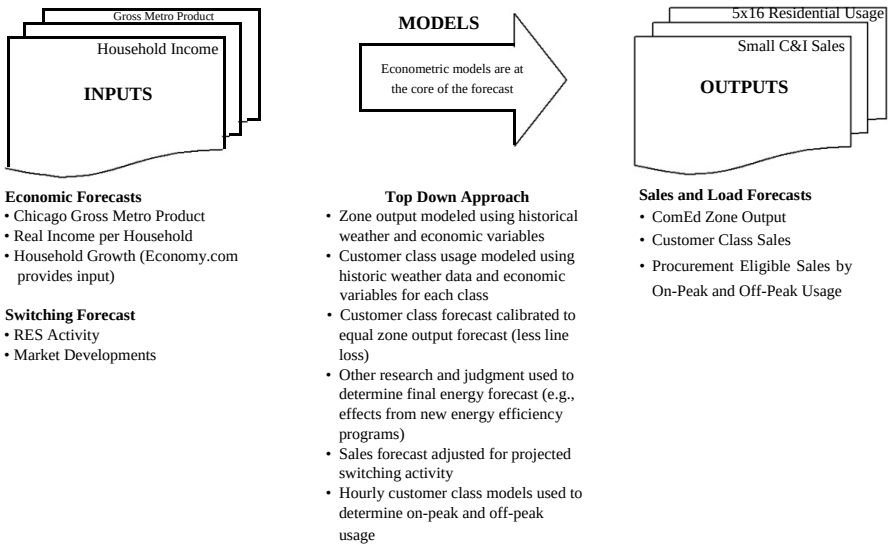
The forecasting process is model based subject to adjustments and judgment. A suite of econometric models is used to produce monthly sales forecasts for ComEd's revenue customer classes. The two major customer classes applicable to this Forecast are Residential and Small C&I. That monthly forecast is adjusted for other considerations (e.g., switching activity) and allocated to more granular delivery service classes (e.g., the residential customer class is

composed of four delivery services classes). The forecast sales are combined with the input from the hourly models to obtain on-peak and off-peak quantities for each month and delivery service class.

The econometric modeling portion of the process is described in the following chart:

Chart II-6

Econometric Modeling Process



As the chart indicates, ComEd's forecasts of sales for its service territory are based on a "top-down" approach. The top-down approach provides a forecast of total sales for the entire service territory and allocates the sales to various customer classes using the models specific to each class. The "zone" forecast model takes into account a number of economic variables that affect electric energy use. For example, the gross metropolitan product ("GMP") for the Chicago and Rockford areas is a good measure of economic activity in ComEd's service territory. As GMP (which is expressed in billions of dollars) increases, use of electric energy rises as well. Similarly, the zone model considers the total number of residential customers in ComEd's service territory. As the number of customers increases, total usage is also affected. Section II (B)(1) describes the significant relationship between weather and energy usage, and the zone model contains sophisticated variables to reflect the effects of temperature and humidity, as well as seasonal usage patterns and other factors. The economic assumptions are contained in Table II-5.

Table II-5

Chicago Area Economic Forecasts - Economy.com (March'09)

Economic Variables	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Gross Metro Product (Billions)	$ 385	$ 391	$ 389	$ 375	$ 381	$ 399	$ 424	$ 438	$ 447	$ 454
Real Disposable Income (Millions)	$ 292,201	$ 298,713	$ 305,962	$ 304,214	$ 304,448	$ 313,277	$ 323,276	$ 336,380	$ 344,531	$ 354,701
# of Households (Thousands)	3,321	3,344	3,368	3,389	3,413	3,444	3,484	3,517	3,545	3,568
Real Income/HH	$ 87,991	$ 89,328	$ 90,851	$ 89,775	$ 89,211	$ 90,953	$ 92,787	$ 95,638	$ 97,199	$ 99,409
Total Employment (Thousands)	4,443	4,480	4,451	4,232	4,222	4,345	4,514	4,639	4,682	4,709
Non-Manufacturing	3,953	3,996	3,980	3,800	3,799	3,915	4,073	4,189	4,234	4,262
Manufacturing	490	484	471	432	423	430	441	449	449	446

Growth Rate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Gross Metro Product	2.5%	1.6%	(0.5%)	(3.5%)	1.7%	4.6%	6.2%	3.5%	1.9%	1.6%
Real Disposable Income	2.4%	2.2%	2.4%	(0.6%)	0.1%	2.9%	3.2%	4.1%	2.4%	3.0%
# of Households	0.6%	0.7%	0.7%	0.6%	0.7%	0.9%	1.2%	1.0%	0.8%	0.7%
Real Income/HH	1.8%	1.5%	1.7%	(1.2%)	(0.6%)	2.0%	2.0%	3.1%	1.6%	2.3%
Total Employment	1.4%	0.8%	(0.7%)	(4.9%)	(0.2%)	2.9%	3.9%	2.8%	0.9%	0.6%
Non-Manufacturing	1.7%	1.1%	(0.4%)	(4.5%)	(0.0%)	3.0%	4.0%	2.9%	1.1%	0.7%
Manufacturing	(1.0%)	(1.1%)	(2.8%)	(8.2%)	(2.0%)	1.5%	2.6%	1.8%	(0.1%)	(0.6%)

Source: Moody's Economy.com

All of the variables used in each of the models in the forecasting process are identified in Appendix A-4.[6]

The remainder of this section will provide a brief description of the models, starting with the ComEd Monthly Zone energy usage model and proceeding to the three customer-level models for Monthly Residential bill-cycle energy usage, Monthly Small C&I bill-cycle energy usage and Monthly Street Lighting bill-cycle energy usage.

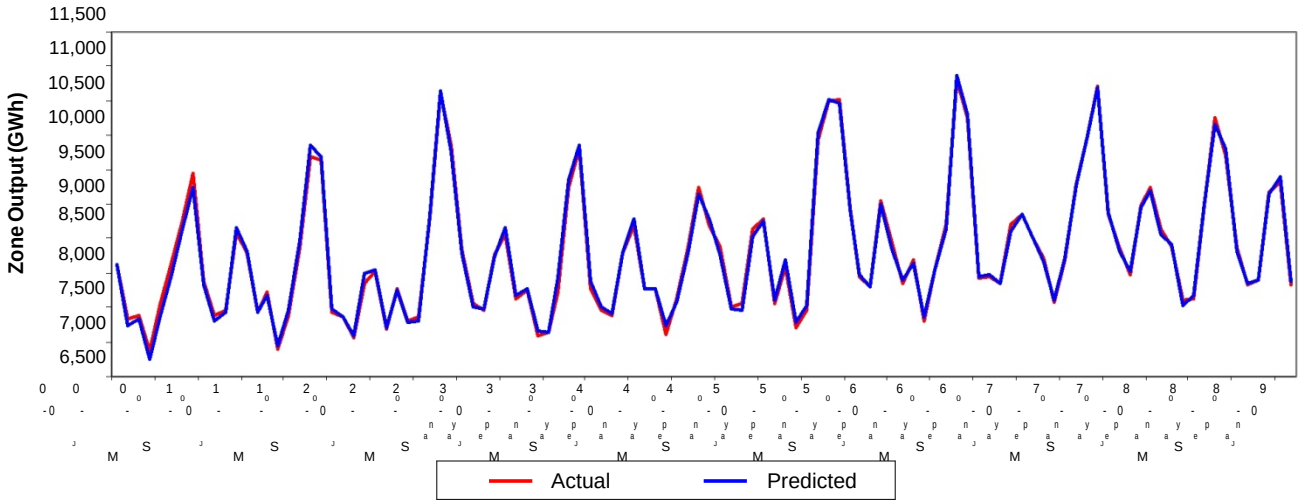
(ii) ComEd Monthly Zone Model

The Monthly Zone model forecasts energy usage in gigawatt hours (GWh) for the entire ComEd service territory. The following chart shows the performance of the ComEd Monthly Zone model by comparing actual zone output to the estimates[7] from the model for each calendar month from 2000 through February 2009.

[6] Technical information about the model coefficients and regression statistics are included in Appendix A-2 and A-3.

[7] Once again, for purposes of this Forecast, the estimates used in Charts II-10, II-11 and II-12 are based on actual weather.

Chart II-7
ComEd Monthly Zone Model: Estimated vs. Actual

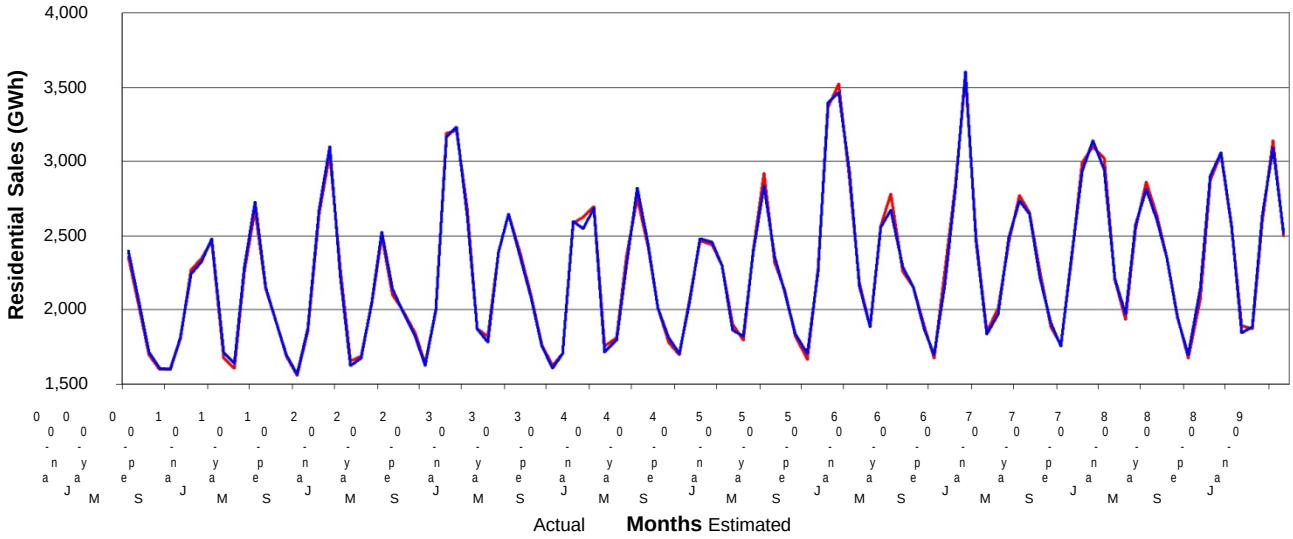


As with customer-level models discussed in Section II(B)(i)(a), the Monthly Zone model is highly useful in understanding energy usage. The graph line depicting the model's estimated usage (based on actual weather) and the line showing actual usage for the period are nearly identical.

(iii) ComEd Monthly Residential Model

The Monthly Residential model forecasts monthly residential bill-cycle sales expressed in kWh per customer per day. The Monthly Residential model is also very useful in understanding energy usage for this customer segment. The following chart compares the monthly energy usage for residential customers estimated by the Monthly Residential model to the actual residential usage for the time period of January 2000 to February 2009.

Chart II-8
ComEd Monthly Residential Model: Estimated vs. Actual

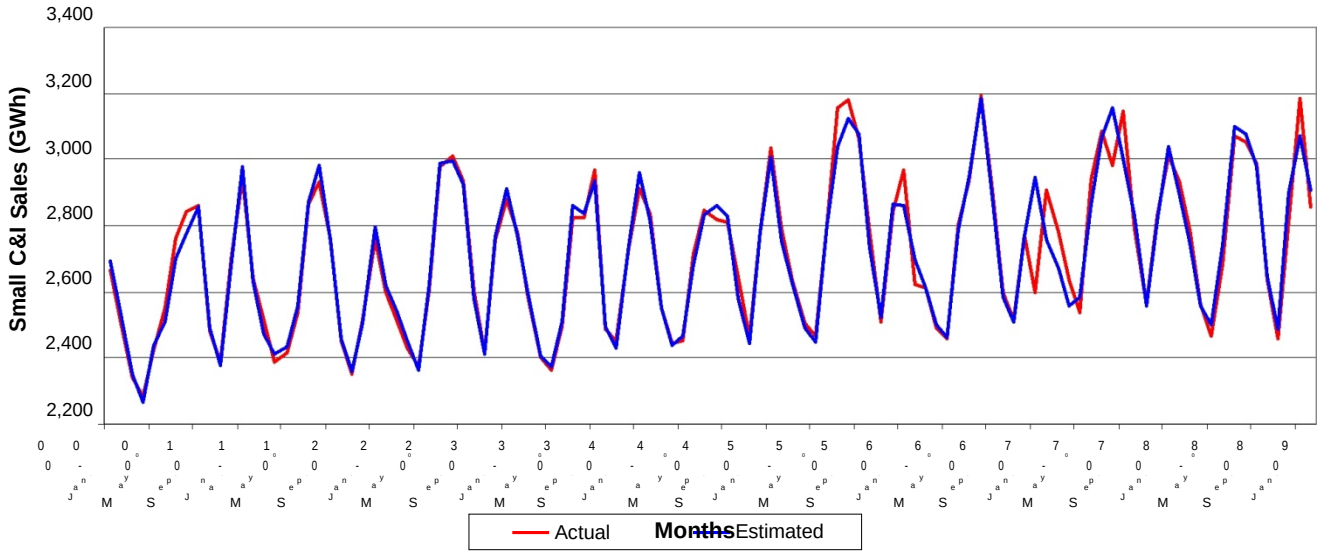


The graph line depicting the model's estimated usage and the line showing actual usage for the period are highly correlated.

(iv) ComEd Monthly Small C&I Model

The Monthly Small C&I model forecasts monthly Small C&I bill-cycle sales. Chart II-9 shows an estimated versus actual comparison demonstrating the model's effectiveness. The larger than normal variance in the period January 2007 to March 2007 is explained by post-2006 billing implementing issues. The transition to the new rates that took effect on January 2, 2007, caused certain retail billing data to lag the actual billing cycle.

Chart II-9
ComEd Monthly Small C&I Model: Estimated vs. Actual



(v) ComEd Monthly Street Light Model

The Monthly Street Lighting model forecasts monthly bill-cycle sales related to street lighting. This final model estimates use per day in GWh.

(vi) Growth Forecast

ComEd's historical and forecasted weather-adjusted energy sales for the residential and small C&I customer classes are shown in Table II-6.

Table II-6

ComEd Weather Adjusted Annual Energy Sales				
	Residential		Small C&I	
Year	Sales (GWh)	Percent Growth	Sales (GWh)	Percent Growth
2002	26,162		31,425	
2003	27,079	3.5%	32,885	4.6%
2004	27,905	3.1%	32,733	(0.5%)
2005	28,290	1.4%	33,057	1.0%
2006	28,516	0.8%	32,958	(0.3%)
2007	28,459	(0.2%)	33,508	1.7%
2008	28,599	0.5%	33,392	(0.3%)
2009	28,373	(0.8%)	33,015	(1.1%)
2010	28,439	0.2%	33,264	0.8%
2011	28,809	1.3%	33,732	1.4%
2012	29,219	1.4%	34,346	1.8%
2013	29,349	0.4%	34,541	0.6%
2014	29,416	0.2%	34,624	0.2%

The forecast is consistent with past experience. Residential sales growth has averaged 1.5% per year from 2002 to 2008. The growth in 2009 is (0.5%), after adjusting for 2008 being a leap year. The annual growth rate is lower in the last few years of this Forecast period as the energy efficiency programs that are required by the PUA are implemented. The same is generally true of the Small C&I growth rates. The 2002 to 2008 average growth rate is 1.0% per year. The 2009 growth rate is (0.8%) after adjusting for leap year. Energy efficiency programs also influence future sales in this customer class.

2. Impact of Demand Side and Energy Efficiency Initiatives

The PUA sets out annual targets for the implementation of cost-effective demand side and energy efficiency measures. ComEd believes these targets are achievable and plans to meet them in planning year 2010. The demand -side and energy efficiency plans for subsequent years have not yet been developed by ComEd or approved by the ICC. For purposes of this forecast, we assume that the statutory targets will be met, except for the planning years 2013 and 2014. In those years, the rate cap may limit the total amount of the energy efficiency programs. For purposes of this Forecast, the impacts in 2013 and 2014 are shown in Table II-9.

a. Impact of demand response programs, current and projected

(i) Background

ComEd is a strong supporter of the use of demand response to actively manage peak demands. Use of demand response resources grew in the mid to late 1990s, and ComEd has maintained a large portfolio of demand response resources, with participation from residential, commercial, and industrial customers. ComEd is a nationally recognized leader in the development and management of demand response resources, and will increase participation in appropriate programs to meet the requirements of the PUA.

The current portfolio of ComEd programs include the following:

Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program (formerly called "Nature First") is a DLC program with over 60,000 customers with a load reduction potential of 105 MW (ComEd Rider AC7).

Voluntary Load Reduction ("VLR") Program: VLR is an energy based demand response program, providing compensation based on the value of energy as determined by the real -time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation, based on the local conditions of the T&D network. This portion of the portfolio has roughly 799 MW of potential load reduction (ComEd Rider VLR7).

Capacity Market Program: Under this program, customers reduce load to a pre-determined level with compensation based on capacity market values from PJM's capacity markets. This program has roughly 432 MW of load reduction potential (ComEd Rider CLR7).

Time-base pricing: All ComEd's customers have an option to elect an hourly, market-based rate. The RRTP Program has operated in the past as ComEd Rate RHEP. This program had roughly 2.9 MW of price response potential.

(ii) Legislative Requirement

Section 12-103(c) of the PUA establishes a goal to implement demand response measures, providing that:

> (c) Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this PUA. This requirement commences June 1, 2008 and continues for 10 years.

Table II-9 shows the estimated annual MWs of demand response measures that will need to be implemented over the Five-year planning period to meet the goals set forth in the PUA:

Table II-7
Estimated Annual Level of Demand Response Measures

Year	Peak Load at Meter (MW)	Annual Goal (MW)	Cumulative Goal (MW)
2010	10,597	10.0	32.8
2011	10,482	10.5	43.3
2012	10,661	10.7	53.9
2013	10,810	10.8	64.8
2014	10,955	11.0	75.7

The cumulative goal includes 11.7 MW for the year 2008 and 11.1 MW for 2009. The 2010 annual goal of 10.0 MW is from the original ICC filing.

The Illinois General Assembly recently passed Senate Bill 2150 ("SB2150"), and that bill is currently waiting to be signed by the Governor. SB2150 revises section 12-103(c) of the PUA to include "customers that elect hourly service from the utility pursuant to Section 16-107 of the PUA, provided those customers have not been declared competitive." Assuming that bill is signed by the Governor, the actual response measures that would need to be implemented to comply with that law would be determined in the next energy efficiency and demand-response plan, covering the planning years 2011-3, that ComEd would file for approval with the ICC pursuant to Section 12-103(f) of the PUA. Thus, this bill will not impact the level of demand response measures that need to be implemented until 2011. If the bill is signed by the Governor, the numbers in the table above for the 2011-4 planning years would be slightly increased.

(iii) Implementation of Demand Response Measures

As required by the PUA (220 ILCS 5/16-103), ComEd filed and received approval for its proposed demand response program for the three-year planning period covering June 2008 through May 2011.[8] The details of that program are provided in the plan that ComEd filed in that docket. ComEd anticipates filing a new plan for the next three-year planning period (i.e., June 2011 through May 2014) sometime in late 2010, as required by the PUA. For purposes of this forecast, ComEd assumes that the statutory targets for demand response programs will be met during the next planning period.

(iv) Impact of Demand Response Programs

Demand response programs do not impact ComEd's load forecasts. Load forecasts are made on a weather normalized, unrestricted basis. Since demand response measures are called on days when the temperature is hotter than "normal", the avoided capacity and energy associated with these resources is incremental to the weather normal forecast, and thus is not factored into the load forecasts. In fact, when developing forecasts, any impact on

[8] See Order of February 6, 2008 in docket No. 07-0540.

energy usage from actually implementing a demand response measure in a prior year is added back into that prior year's usage data and then weather normalized before being used to assist in the forecasting process. This assures that the forecast represents a complete picture of the unrestricted demands on the system.

b. Impact of Energy Efficiency Programs

The PUA requires ComEd to implement cost-effective energy efficiency measures beginning June 1st, 2008. The PUA provides annual kWh targets based on a projection of the upcoming years' energy usage for all delivery service customers. Additionally, there is a spending cap that limits the amount of expenditures on energy efficiency measures in any year. For purposes of the PUA, the energy efficiency year is defined as June through May.

(i) kWh Targets

The kWh target for energy efficiency is based on a projection of the amount of energy to be delivered by ComEd to all of its delivery service customers in the upcoming planning year. This percentage increases annually through the year 2015, subject to specified rate impact criteria. The table below shows the target percentages.

Table II-8
Target Incremental Percentages to Meet Energy Efficiency Goals

Year	Annual Percent Reduction in Energy Delivered
2008	0.2%
2009	0.4%
2010	0.6%
2011	0.8%
2012	1.0%
2013	1.4%
2014	1.8%
2015	2.0%

(ii) Projected Overall Goals

The annual energy efficiency goals were determined based on the kWh targets and the rate impact criteria, as discussed above. As discussed in greater detail in the energy efficiency/demand response plan filed in Docket No. 07-0540, the rate impact criteria are not expected to impact the energy efficiency targets through the 2010 planning year. The energy efficiency/demand response plan addressed only the 2008-2010 planning years, as required by the PUA. Thereafter, for purposes of this Forecast, it is assumed that the rate impact criteria will not affect the achievement of the targets, except, as noted above, for planning year 2013 and

2014. Also, for purposes of this Forecast only,[9] the allocation of the energy (kWh) targets to the various customer classes (as shown in Table II-6) was based on several years of historical data and judgment.

The above numbers represent the incremental goal to be achieved by the end of each planning year for all delivery services customers. Since the various energy efficiency measures will be implemented and phased in over the course of each planning year and since Eligible Retail Customers are only a subset of delivery services customers, the actual amount of GWh for Eligible Retail Customers that is impacted in each planning year will be somewhat less (as shown in Table II-9, below).

(iii) Impact on Forecasts

Energy efficiency measures directly impact the amount of energy used by customers throughout the year. As such, they will directly impact the forecasts of future load. The following chart depicts the cumulative impacts of these measures on the Forecast:

Table II-9
Cumulative Impacts of EE on Load Forecast by Customer Type

Planning Year	Residential Allocation (GWh)	Watt-Hour Allocation (GWh)	0-100 kW Allocation (GWh)
2010	302.1	3.1	42.2
2011	521.9	5.9	72.5
2012	806.7	9.5	116.8
2013	1,128.9	13.5	167.1
2014	1,452.2	17.6	217.4

[9] The PUA does not prescribe how the kWh targets are to be apportioned among the customer classes, and the energy efficiency plan did not set goals on a customer class basis.

C. Impact of Renewable Energy Resources

Section 1-75(c) of the IPA Act (20 ILCS 3855/1-75(c)) establishes the following goals and cost thresholds for cost effective renewable energy resources:

Table II-10

Renewable Energy Resource Requirements

Delivery Period	Minimum Percentage	Maximum Cost
2010-2011	5% of June 1, 2008 through May 31, 2009 Eligible Retail Customer load	The greater of an additional 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007.
2011-2012	6% of June 1, 2009 through May 31, 2010 Eligible Retail Customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007.
2012-2013	7% of June 1, 2010 through May 31, 2011 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2013-2014	8% of June 1, 2011 through May 31, 2012 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2014-2015	9% of June 1, 2012 through May 31, 2013 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.

Based on the above, Table II-11 shows the amount of renewable energy resources that need to be procured over the upcoming procurement period and the maximum amount that may be spent acquiring such resources:

Table II-11

Delivery Period	Targeted REC Purchases (MWh)	REC Budget ($M)	Maximum ACP Rate ($/MWh)
2010-2011	1,887,014	58.2	1.598

Since renewable energy resources do not affect demand or consumption, these targets will have no impact on the Forecast.

SB2150, discussed above, also revised the renewable energy provisions of the IPA Act. If enacted into law, beginning June 1, 2010, ComEd must begin collecting from its Hourly Service customers certain Alternative Compliance Payments ("ACP") that are described in that bill. Beginning in 2011, ComEd must include in its Forecast the amounts collected in the prior year ending May 31. The IPA is then to increase it's spending for renewable energy resources for the next plan by the amount collected. These changes will also have no impact on this Forecast.

3. Five-Year Monthly Load Forecast

Based on all of the factors discussed in this section, ComEd has developed the following forecast of projected energy sales to Eligible Retail Customers for the period from June 1, 2010 through May 31, 2011:

Table II-12

ComEd Procurement Period Load Forecast (Expected Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Weather Normal, Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,896,921	1,624,045	5,389	4,413
2010	7	2,231,242	2,197,192	6,641	5,385
2010	8	2,169,255	1,969,226	6,163	5,024
2010	9	1,588,361	1,512,634	4,727	3,939
2010	10	1,357,368	1,415,482	4,040	3,469
2010	11	1,501,640	1,500,691	4,469	3,908
2010	12	1,916,427	1,695,654	5,208	4,510
2011	1	1,752,398	1,886,938	5,215	4,625
2011	2	1,557,990	1,522,786	4,869	4,326
2011	3	1,599,912	1,451,093	4,348	3,859
2011	4	1,301,326	1,311,732	3,873	3,416
2011	5	1,330,118	1,399,860	3,959	3,431
Totals		**20,202,958**	**19,487,333**		

The forecast set forth above shows ComEd's expected load for the 2010 planning year. The PUA requires that the forecast cover a 5- year planning period. The forecast for ComEd's expected load for the 5-year planning period is set forth in Appendix B-1. The PUA also requires ComEd to provide low-load and high-load scenarios. That information for the 2010 planning year is set forth in Tables II-13 and II-14. The low-load and high-load scenarios for the 5-year planning period are set forth in Appendix B -2 and Appendix B-3, respectively. In all of the forecasted sales tables, "line loss" refers only to distribution losses.

Table II-13

ComEd Procurement Period Load Forecast (Low Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,584,668	1,555,100	4,502	4,226
2010	7	1,904,731	1,810,785	5,669	4,438
2010	8	1,728,828	1,641,785	4,911	4,188
2010	9	1,466,876	1,452,475	4,366	3,782
2010	10	1,292,208	1,201,703	3,846	2,945
2010	11	1,298,615	1,370,985	3,865	3,570
2010	12	1,650,192	1,649,663	4,484	4,387
2011	1	1,634,563	1,662,034	4,865	4,074
2011	2	1,378,166	1,372,652	4,307	3,900
2011	3	1,305,459	1,314,545	3,547	3,496
2011	4	1,178,497	1,135,714	3,507	2,958
2011	5	1,191,060	1,246,253	3,545	3,055
Totals		**17,613,863**	**17,413,694**		

Table II-14

ComEd Procurement Period Load Forecast (High Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	2,243,061	1,868,006	6,372	5,076
2010	7	2,740,784	2,536,267	8,157	6,216
2010	8	3,042,075	2,598,387	8,642	6,629
2010	9	1,705,314	1,619,059	5,075	4,216
2010	10	1,495,123	1,520,640	4,450	3,727
2010	11	1,753,289	1,751,082	5,218	4,560
2010	12	2,131,819	1,890,020	5,793	5,027
2011	1	1,914,830	2,059,273	5,699	5,047
2011	2	1,765,411	1,762,320	5,517	5,007
2011	3	1,836,725	1,579,487	4,991	4,201
2011	4	1,536,739	1,524,171	4,574	3,969
2011	5	1,483,888	1,518,612	4,416	3,722
Totals		**23,649,058**	**22,227,324**		

The low-load and the high-load scenarios are based upon a change to three of the main variables impacting load: weather, switching and load growth.[10]

The low-load scenario assumes that the summer weather is cooler than normal, that load growth occurs at a rate 2% less than is expected as shown in the load growth forecast in Table II-12, and that Hourly service and RES sales increase relative to the expected forecast shown in Table II-12. In this scenario an additional 25,000 residential customers are assumed to opt for RRTP in January 2011. Plus, residential RES sales increase over time related to favorable market conditions for the RES. For example, January 2014 RES sales reach 6% of total single -family sales in this scenario. Likewise, similar dynamics occur for the 0 to 100 kW customer group. June 2011 Blended sales are 54% of total 0 to 100 kW sales in the Forecast, but only 34% in this scenario.

The high-load scenario assumes that the summer weather is much hotter than normal (the scenario uses data from 1995, which is the warmest summer in the last 30 years), that load growth occurs at a rate 2% more than is expected, and that switching decreases. The low switching scenario reflects a reduction of 25,000 RRTP customers as either the Smart Grid Investment Grant Program is not approved or else it is decided to switch these customers to a different type of tariff and no residential switching therefore occurs. Also, the expected movement of the 0 to 100 kW customers to RES service not only does not occur, but some opt for Blended service. June 2011 RES sales are 45% of total 0 to100 kW customer class sales in the Forecast, but only 20% in this scenario.

The +/- 2% load growth assumption in both scenarios reflects, in part, the economic uncertainty that currently exists. "Despite indications that the worst of the financial crisis and economic downturn is over, conditions remain extraordinary fragile" (Mark Zandi of Moody's Economy.com) [11]. ComEd's intention is too keep the IPA informed of significant changes in its forecast during the proceedings.

III. CONCLUSION

For all of the reasons described here, ComEd believes that its Forecast for the period June 1, 2010 through May 31, 2015 is consistent with the requirements of the PUA and provides an appropriate approach to develop the procurement plan to acquire supply for the applicable retail customers.

[10] In ComEd's initial procurement plan, the low-load and high-load scenarios were not adjusted for weather. Instead, the impacts of weather on load were considered in the risk analysis section of the procurement plan. Because ComEd will not be developing the procurement plan and risk analysis for the upcoming procurement event, ComEd thought it appropriate to include the weather-related load impacts in these scenarios for purposes of this Forecast.

[11] Mark Zandi, "Expand the Housing Tax Credit" June 16, 2009 article from Moody's Economy.com

Appendices

A. Load Forecast Models

1. Residential Single Family Model (Hour 16)
2. ComEd Model Coefficients
3. ComEd Model Regression Statistics
4. Detailed Description of Variables Used In Forecast Models

B. Five-Year Load Forecast

1. Expected load
2. Low Load
3. High Load

Appendix A-1

Residential Single Family Model (Hour 16)			
Variable	**Coefficient**	**T-Stat**	**Notes**
CONSTANT	1.772	13.387	Constant term
Monday Binary	-0.102	-7.175	
Tuesday Binary	-0.123	-8.728	
Wednesday Binary	-0.137	-9.772	
Thursday Binary	-0.150	-10.616	
Friday Binary	-0.131	-9.296	
Saturday Binary	-0.024	-2.073	
MLK Binary	0.028	0.499	Martin Luther King's Day
PresDay Binary	0.073	1.309	President's Day
GoodFri Binary	0.065	1.044	Good Friday
MemDay Binary	0.170	2.698	Memorial Day
July4th Binary	0.012	0.188	July 4th.
LaborDay Binary	0.284	4.515	Labor Day
Thanks Binary	0.110	1.715	Thanksgiving Day
FriAThanks Binary	0.034	0.550	Friday after Thanksgiving Day
XMasWkB4 Binary	0.146	2.166	Week before Christmas
XMasEve Binary	0.357	4.137	Christmas Eve
XMasDay Binary	0.230	2.840	Christmas Day
XMasWk Binary	0.137	1.962	Christmas Week
NYEve Binary	0.112	1.195	New Year's Eve Day
NYDay Binary	0.179	2.644	New Year's Day
XMasLights Binary	-0.0003	-0.186	Christmas Lights
DLSav Binary	-0.406	-3.888	Day-Light Sayings
Sun.FracDark6	0.393	4.995	Fraction of hour 6 am that is dark
Sun.FracDark7	0.185	3.124	Fraction of hour 7 am that is dark
Sun.FracDark8	0.280	3.214	Fraction of hour ending 8 am that is dark
Sun.FracDark17	0.107	1.690	Fraction of hour ending 5 pm that is dark
Sun.FracDark18	-0.130	-1.881	Fraction of hour ending 6 pm that is dark
Sun.FracDark19	-0.195	-3.118	Fraction of hour ending 7 pm that is dark
Sun.FracDark20	-0.238	-3.615	Fraction of hour ending 8 pm that is dark
Sun.FracDark21	-0.636	-6.011	Fraction of hour ending 9 pm that is dark
Binary Feb	-0.035	-0.694	
Binary Mar	0.029	0.531	
Binary Apr	-0.023	-0.382	
Binary May	0.038	0.559	
Binary Jun	0.158	2.173	
Binary Jul	0.275	3.889	
Binary Aug	0.231	3.718	
Binary Sep	0.220	3.747	

Binary Oct	0.166	2.680	
Binary Nov	0.062	1.154	
Binary Dec	0.112	2.283	
Usage Trend	-0.025	-5.118	
Fall HDD Spline	0.004	1.773	HDD Spline for September and October
November HDD Spline	0.005	3.235	HDD Spline for November
December HDD Spline	0.004	3.585	HDD Spline for December
January HDD Spline	0.006	6.324	HDD Spline for January
February HDD Spline	0.008	6.751	HDD Spline for February
March HDD Spline	0.005	3.967	HDD Spline for March
Spring HDD Spline	0.008	4.816	HDD Spline for April and May
Day lag of HDD Spline	-0.001	-0.731	
Two day lag of HDD Spline	0.0002	0.247	
Weekend HDD Spline	0.001	1.100	
Trend HDD Spline	0.001	4.610	
April THI Spline	0.034	1.146	THI (Temperature Humidity Index) Spline for April
May THI Spline	0.140	20.840	THI (Temperature Humidity Index) Spline for May
June THI Spline	0.155	41.771	THI (Temperature Humidity Index) Spline for June
July THI Spline	0.144	37.844	THI (Temperature Humidity Index) Spline for July
August THI Spline	0.160	40.502	THI (Temperature Humidity Index) Spline for August
September THI Spline	0.184	34.926	THI (Temperature Humidity Index) Spline for September
October THI Spline	0.167	20.103	THI (Temperature Humidity Index) Spline for October
Day lag of THI Spline	0.014	4.809	
Two day lag of THI Spline	0.010	4.419	
Weekend THI Spline	0.009	3.213	
THI Spline for Trend	-0.0003	-0.238	
2007 Plus Dummy	0.074	5.714	An End Shift to describe usage for 2007 and beyond

The coefficients provide the effect that each variable has on the hourly usage for a single hour (Hour 16 which includes the load from 3 p.m. to 4 p.m. in the afternoon). The “T-Stat” provides the statistical significance of the variable, with a value generally greater than +/- two (2) indicating that the coefficient is significantly different from zero.

The hourly model for Hour 16 has an adjusted R-squared of 0.93, which means that 93% of the variance in the hourly data is being explained by the model. At the daily level, the mean average percent error (“MAPE”) for the model is 4.0%. The 4.0% daily MAPE means

that the average percentage difference on a daily basis between the usage predicted by the model and the actual usage for that period was very small. In other words, the model can explain usage with almost a 96% accuracy rate. Such a high accuracy rate is particularly noteworthy because the model is dealing with very short time frames in which many factors may come into play. The high accuracy rate, the low MAPE and the high R-squared indicate that the model captures the vast majority of factors that affect electrical usage.

Appendix A-2

ComEd Model Coefficients

ComEd Zone Model			
Variable	**Coefficient**	**StdErr**	**T-Stat**
CONST	1223.349	362.42	3.375
Monthly.GMPDays	7.028	0.724	9.7
Monthly.ResCustDays	1.09	0.167	6.519
CalVars.Jan	-94.384	26.605	-3.548
CalVars.Feb	-240.624	40.01	-6.014
CalVars.Mar	-283.422	31.23	-9.075
CalVars.Apr	-458.748	43.879	-10.46
CalVars.May	-406.946	55.998	-7.267
CalVars.Jun	-265.145	57.203	-4.635
CalVars.Jul	-202.842	67.557	-3.003
CalVars.Aug	-16.883	63.708	-0.265
CalVars.Sep	-127.562	51.94	-2.456
CalVars.Oct	-199.841	49.587	-4.03
CalVars.Nov	-179.604	37.283	-4.817
CalVars.Yr05Plus	152.941	18.81	8.131
CalVars.Apr08Plus	-87.628	21.756	-4.028
CalHDD.HDDSpline	1.895	0.076	24.841
CalHDD.HDDSplineTrend	0.036	0.006	5.656
CalCDD.SpringTDD	12.338	0.982	12.559
CalCDD.SummerTDD	13.973	0.287	48.625
CalCDD.FallTDD	12.762	1.636	7.8
CalCDD.TDDTrend	0.526	0.046	11.325
CalCDD.TDDTrend2000Plus	-0.237	0.091	-2.601
CalCDD.Yr06Plus_TDDShift	-1.275	0.248	-5.142

Residential Customer Class Model			
Variable	**Coefficient**	**StdErr**	**T-Stat**
Monthly.Jan	14.41	1.947	7.402
Monthly.Feb	12.833	1.895	6.774
Monthly.Mar	11.99	1.85	6.479
Monthly.Apr	11.087	1.801	6.156
Monthly.May	10.532	1.788	5.891
Monthly.Jun	11.062	1.892	5.845
Monthly.Jul	12.463	2.068	6.028
Monthly.Aug	12.002	2.085	5.757
Monthly.Sep	11.727	2.019	5.809
Monthly.Oct	11.162	1.813	6.156
Monthly.Nov	11.69	1.803	6.482
Monthly.Dec	13.345	1.885	7.08
Monthly.Yr2004Plus	0.628	0.153	4.096
Monthly.July07Plus	-0.349	0.204	-1.716
CycVars.IncPerHH	0.066	0.018	3.582
CycWthrT.ResHDD	0.195	0.013	15.567
CycWthrT.ResHDDTrend	0.003	0.001	3.105
CycWthrT.ResCDD_Spring	1.346	0.327	4.119
CycWthrT.ResCDD_Jun	2.119	0.143	14.833
CycWthrT.ResCDD_Jul	2.313	0.079	29.386
CycWthrT.ResCDD_Aug	2.507	0.061	41.029
CycWthrT.ResCDD_Sep	2.56	0.105	24.41
CycWthrT.ResCDD_Fall	2.572	0.17	15.099
CycWthrT.ResCDDTrend	0.073	0.006	12.266
CycWthrT.Yr06Plus_ResCDDShift	-0.334	0.054	-6.154
XVars.NewMonthlyBill	-0.028	0.014	-1.986
AR(1)	0.43	0.085	5.074

Small C&I Customer Class Model			
Variable	**Coefficient**	**StdErr**	**T-Stat**
Monthly.Jan	-34.674	7.477	-4.637
Monthly.Feb	-31.392	7.489	-4.192
Monthly.Mar	-32.018	7.429	-4.31
Monthly.Apr	-33.508	7.392	-4.533
Monthly.May	-34.032	7.363	-4.622
Monthly.Jun	-34.41	7.35	-4.682
Monthly.Jul	-34.031	7.355	-4.627
Monthly.Aug	-31.317	7.357	-4.257
Monthly.Sep	-31.509	7.347	-4.289
Monthly.Oct	-30.953	7.353	-4.209
Monthly.Nov	-32.827	7.384	-4.446
Monthly.Dec	-34.646	7.445	-4.653
CycVars.ResCust	0.029	0.003	8.214
Monthly.July06Plus	-1.908	0.569	-3.356
CycWthrT.SCI_HDD	0.424	0.042	10.126
CycWthrT.SCI_HDDTrend	0.008	0.003	2.203
CycWthrT.SCI_CDD	1.967	0.115	17.048
CycWthrT.SCI_CDDTrend	0.041	0.009	4.682
XVars.Emp_NonManuf	0.005	0.002	2.144
AR(1)	0.475	0.071	6.648

StreetLighting Class Model			
Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	-5.84	0.622	-9.387
Monthly.Feb	-5.847	0.623	-9.391
Monthly.Mar	-6.059	0.622	-9.74
Monthly.Apr	-6.163	0.624	-9.878
Monthly.May	-6.302	0.623	-10.11
Monthly.Jun	-6.32	0.623	-10.14
Monthly.Jul	-6.292	0.623	-10.11
Monthly.Aug	-6.236	0.622	-10.02
Monthly.Sep	-6.115	0.623	-9.818
Monthly.Oct	-6.029	0.623	-9.672
Monthly.Nov	-5.933	0.624	-9.502
Monthly.Dec	-5.836	0.623	-9.365
Monthly.Yr2007Plus	-0.076	0.03	-2.513
CycVars.ResCust	0.002	0	12.534

Appendix A-3

ComEd Model Regression Statistics

Regression Statistics	ZONE	Residential	Small C&I	StreetLighting
Iterations	1	17	14	1
Adjusted Observations	169	153	150	91
Deg. of Freedom for Error	145	126	130	77
R-Squared	0.994	0.994	0.981	0.911
Adjusted R-Squared	0.993	0.993	0.979	0.897
Durbin-Watson Statistic	1.127	1.964	2.195	1.163
AIC	8.924	-1.91	0.368	-4.996
BIC	9.369	-1.375	0.769	-4.609
F-Statistic	1063.495	811.409	341.433	56.635
Prob (F-Statistic)	0	0	0	0
Log-Likelihood	-964.16	-43.71	-220.43	110.95
Model Sum of Squares	1.61E+08	2768	8719	5
Sum of Squared Errors	955601	16	166	0
Mean Squared Error	6590.35	0.13	1.28	0.01
Std. Error of Regression	81.18	0.36	1.13	0.08
Mean Abs. Dev. (MAD)	58.95	0.26	0.81	0.05
Mean Abs. % Err. (MAPE)	0.75%	1.21%	0.95%	2.82%
Ljung-Box Statistic	106.38	30.96	20.65	29.57
Prob (Ljung-Box)	0	0.1548	0.6593	0.1994

Appendix A-4
Detailed Description Of Variables
Used In Forecast Models

The econometric models are statistical multi-variant regressions that determine the correlation between electrical usage (dependent variable) and weather, economic and monthly factors (independent variables). Consistent with its recent delivery services rate case filing, ComEd's weather normals are based on the 30-year time period of 1977 to 2006. The following models are used in producing the energy sales forecast (GWh) for the eligible customers:

Monthly Zone energy usage for the ComEd zone
Monthly Residential bill-cycle energy usage
Monthly Small C&I bill-cycle energy usage
Monthly Street Lighting bill-cycle energy usage

ComEd's Load Forecasting group with the input of industry experts developed the models. The following sections describe each model and its specifications. Appendices A-2 and A-3 contain the coefficients and other regression statistics for the models.

ComEd's Monthly Zone Model

The dependent variable in the zone model is monthly zone energy usage for the ComEd service territory. The monthly zone usage is in GWh units. The performance of the model is shown in the Chart II-10 in Section II B 1 d (ii) (estimated[12] vs. actual) for the January 2000 to February 2009 time period.

The independent variables within the model are:

- The monthly binary variables reflect monthly usage patterns. Customer electrical usage is a function of other items besides cooling and heating (e.g., lighting). This other usage is not constant per month and the monthly binary variables are used to account for this variability. December is excluded from the monthly binaries, as the constant term establishes December as the base from which the monthly binary variables are adjusted.

- The GMP variable is the gross metropolitan product for the Chicago metropolitan area and also includes Rockford. This variable measures economic activity for the ComEd service territory. The GMP is adjusted for inflation and is obtained from Moody's Economy.com. Further, the variable is adjusted for the number of weekends (and holidays) and weekdays within a calendar month because overall

[12] As noted in the body of the Forecast, the estimated data used in Charts II-10, II-11 and II-12 is based on actual weather

energy usage for a given month is a function of those daily influences. The variable's units are billions of dollars.

- The Residential Customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the effect of a growing customer base on energy sales and is driven by household formations. This variable is also adjusted for the number of weekends, holidays and weekdays within a calendar month.

- The temperature and humidity degree day ("TDD") variables are weather variables designed to capture the effect on usage from cooling equipment. The TDD variable is similar in design to a cooling degree day ("CDD") variable. A CDD weather variable is often used in energy models. The standard CDD measures the difference in the average daily temperature above a specific threshold (typically 65 degrees as that is a common point at which cooling activity begins). The TDD variable provides several enhancements to the typical CDD variable as delineated below:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  Humidity is included in the TDD variable as humidity does influence electrical usage.

  The TDD variable uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The TDD variable is interacted with seasonal binary variables (i.e., Spring, Summer and Fall) to reflect the seasonal usage pattern related to cooling equipment.

  The TDD variable is in degree-day units.

  The TDD trend variable is a weather variable that captures the changing relationship of cooling equipment over time. Simply put, the effect of a TDD changes over time as customers' usage patterns change over time. For example, as homes have become larger over time the amount of cooling load associated with a change in temperature will also change.

  The TDD trend variable essentially captures the growing influence of cooling equipment over time within the service territory. The TDD trend variable is designed to capture this changing relationship by interacting the TDD variable with a linear time series variable. The TDD trend variable is in degree-day units.

The TDD shift variable is a weather variable akin to the TDD trend variable. This variable is interacted with a binary variable for all years greater than or equal to 2006. The negative sign in the variable's coefficient acknowledges the reduction in long term cooling effect over the past couple of years.

- The HDD Spline variable is a weather variable that measures the relationship on electrical usage from space heating equipment (e.g., natural gas furnace fans and electrical space-heating equipment). The HDD Spline variable is similar in concept to the industry-standard heating degree day ("HDD") weather variable. The HDD Spline provides a couple of enhancements to the HDD weather variable:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  The HDD Spline uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The HDD Spline variable is in degree-day units.

  The HDD Spline trend variable is a weather variable that reflects the changing relationship of heating equipment over time. This variable is conceptually similar to the TDD trend variable. The HDD spline variable is in degree-day units.

- The Year 2005 and April 2008 Shift Plus variables are binary variables designed to capture very recent usage activity within the model. For example, the 2005 Shift Plus variable is a binary variable with the unit one for all months beginning with January 2005 and thereafter. By forcing all of the residuals to sum to zero for the months January 2005 to present, the variable is causing the model to be closely aligned with recent usage activity. This variable is useful for forecasting purposes as it ensures that the forecasted usage is also closely aligned with the most recent pattern of electrical usage.

The coefficient values and the standard measurements of significance within the model (e.g., t-stats) and the overall model performance (e.g., R-squared and MAPE) are contained in Appendices A- 2 and A-3. Chart II-10 contains a plot of the model's estimated monthly usage vs. actual monthly usage from January 2000 to February 2009. The two curves are tightly aligned, which speaks to the accuracy of the model.

ComEd Residential Model

The dependent variable is residential use per customer per day and the units are kWh per customer per day. Chart II-2 shows the model's forecast performance (estimated vs. actual monthly sales from January 2006 to February 2009), which reflects a close fit.

The independent variables are noted below. (Because many of the variables follow the same purpose and logic as in the Monthly Zone model, please see the Monthly Zone model description for additional information.)

- The monthly binary variables reflect monthly usage patterns.
- The Real Income per Household variable is the disposable personal income for the Chicago metropolitan area and Rockford (adjusted for inflation) divided by the number of households for the same area. The data is obtained from Moody's Economy.com. This variable captures the rising household incomes within ComEd's service territory and the correlation it has with consumer purchases of electronic equipment and housing stock. The variable is in dollars per household units.
- The Monthly Bill variable is a typical monthly residential electricity bill assuming historical tariff charges and weather normal customer usage for the year 2002 (adjusted for inflation). Specifically, the historical tariff charges for a single-family and multi-family (both non-space heat) were multiplied by the weather adjusted billing units from the year 2002 for both residential groups. The monthly bills for both residential groups were weighted, based on energy sales, to form a single monthly bill. The monthly bill was also adjusted for the Chicago CPI-U. This variable reflects the influence of electricity charges/prices over time related to consumer behavior.
- Weather variables used in the residential model are similar in concept to the weather variables described in the Monthly Zone model section and will not be repeated here.
- The Year 2004 Plus and July 2007 Plus binary variables are similar in concept to the same variables used in the Monthly Zone model.

ComEd Small C&I Model

The dependent variable is Small C&I use per day and the units are GWh per day. The independent variables within the model are:

- The monthly binary variables, weather variables and shift variables are similar in concept to the Monthly Zone model and will not be repeated here.
- The residential customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the influence

of a growing service territory (i.e., residential customers) on Small C&I energy usage. The units are in thousands of customers.

- The Employment variable is an economic variable that measures the total non-manufacturing employment in the Chicago area. Job growth is correlated to Small C&I development and growth.

- The July 2006 Shift Plus binary variable is similar in concept to the Monthly Zone model.

ComEd Street Light Model

The dependent variable is Street Lighting use per day and the units are GWh per day. The independent variables are:

- Monthly binary variables and a shift variable that are similar in concept to the Monthly Zone model.

- The residential customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the relationship of a growing service territory (measured by the number of residential customers) and street lighting sales.

Appendix B-1

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,896,921	1,624,045	5,389	4,413
2010	7	2,231,242	2,197,192	6,641	5,385
2010	8	2,169,255	1,969,226	6,163	5,024
2010	9	1,588,361	1,512,634	4,727	3,939
2010	10	1,357,368	1,415,482	4,040	3,469
2010	11	1,501,640	1,500,691	4,469	3,908
2010	12	1,916,427	1,695,654	5,208	4,510
2011	1	1,752,398	1,886,938	5,215	4,625
2011	2	1,557,990	1,522,786	4,869	4,326
2011	3	1,599,912	1,451,093	4,348	3,859
2011	4	1,301,326	1,311,732	3,873	3,416
2011	5	1,330,118	1,399,860	3,959	3,431
2011	6	1,852,504	1,584,141	5,263	4,305
2011	7	2,076,846	2,250,683	6,490	5,308
2011	8	2,228,803	1,841,624	6,057	4,898
2011	9	1,539,978	1,492,317	4,583	3,886
2011	10	1,330,406	1,395,685	3,960	3,421
2011	11	1,481,279	1,485,288	4,409	3,868
2011	12	1,730,767	1,854,559	5,151	4,545
2012	1	1,748,566	1,900,359	5,204	4,658
2012	2	1,619,830	1,557,231	4,821	4,326
2012	3	1,524,153	1,524,709	4,330	3,890
2012	4	1,308,312	1,317,586	3,894	3,431
2012	5	1,411,591	1,355,879	4,010	3,459
2012	6	1,790,295	1,684,767	5,328	4,387
2012	7	2,217,563	2,192,986	6,600	5,375
2012	8	2,249,829	1,876,983	6,114	4,992
2012	9	1,403,283	1,636,107	4,616	3,933
2012	10	1,480,948	1,297,937	4,024	3,452
2012	11	1,502,099	1,494,665	4,471	3,892
2012	12	1,659,087	1,950,473	5,185	4,600
2013	1	1,848,540	1,846,176	5,252	4,710
2013	2	1,555,071	1,548,806	4,860	4,400
2013	3	1,460,509	1,597,436	4,347	3,915
2013	4	1,381,178	1,270,897	3,924	3,454
2013	5	1,419,397	1,366,098	4,032	3,485

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	1,706,777	1,780,963	5,334	4,452
2013	7	2,344,057	2,116,293	6,659	5,399
2013	8	2,160,492	1,973,720	6,138	5,035
2013	9	1,487,679	1,568,268	4,649	3,921
2013	10	1,481,418	1,303,568	4,026	3,467
2013	11	1,421,649	1,567,975	4,443	3,920
2013	12	1,745,838	1,887,380	5,196	4,626
2014	1	1,851,420	1,858,493	5,260	4,741
2014	2	1,553,024	1,557,109	4,853	4,424
2014	3	1,456,804	1,606,089	4,336	3,936
2014	4	1,376,102	1,276,207	3,909	3,468
2014	5	1,346,504	1,432,213	4,007	3,510
2014	6	1,799,438	1,717,355	5,355	4,472
2014	7	2,360,789	2,126,231	6,707	5,424
2014	8	2,065,741	2,068,209	6,148	5,069
2014	9	1,568,870	1,496,449	4,669	3,897
2014	10	1,477,930	1,306,305	4,016	3,474
2014	11	1,344,177	1,635,166	4,422	3,931
2014	12	1,834,257	1,824,824	5,211	4,655
2015	1	1,770,149	1,946,892	5,268	4,772
2015	2	1,562,628	1,562,068	4,883	4,438
2015	3	1,536,587	1,553,189	4,365	3,962
2015	4	1,374,992	1,286,587	3,906	3,496
2015	5	1,278,514	1,501,852	3,995	3,542
Totals		99,929,628	98,764,130		

Appendix B-2

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,584,668	1,555,100	4,502	4,226
2010	7	1,904,731	1,810,785	5,669	4,438
2010	8	1,728,828	1,641,785	4,911	4,188
2010	9	1,466,876	1,452,475	4,366	3,782
2010	10	1,292,208	1,201,703	3,846	2,945
2010	11	1,298,615	1,370,985	3,865	3,570
2010	12	1,650,192	1,649,663	4,484	4,387
2011	1	1,634,563	1,662,034	4,865	4,074
2011	2	1,378,166	1,372,652	4,307	3,900
2011	3	1,305,459	1,314,545	3,547	3,496
2011	4	1,178,497	1,135,714	3,507	2,958
2011	5	1,191,060	1,246,253	3,545	3,055
2011	6	1,492,593	1,361,566	4,240	3,700
2011	7	1,813,202	1,600,517	5,666	3,775
2011	8	1,600,160	1,529,717	4,348	4,068
2011	9	1,377,006	1,308,935	4,098	3,409
2011	10	1,188,727	1,109,657	3,538	2,720
2011	11	1,162,567	1,328,861	3,460	3,461
2011	12	1,525,367	1,571,504	4,540	3,852
2012	1	1,509,673	1,632,731	4,493	4,002
2012	2	1,324,249	1,364,761	3,941	3,791
2012	3	1,274,306	1,202,563	3,620	3,068
2012	4	1,121,986	1,072,554	3,339	2,793
2012	5	1,136,425	1,207,014	3,228	3,079
2012	6	1,506,496	1,293,310	4,484	3,368
2012	7	1,707,892	1,653,662	5,083	4,053
2012	8	1,650,858	1,400,077	4,486	3,724
2012	9	1,276,582	1,314,934	4,199	3,161
2012	10	1,143,467	1,128,561	3,107	3,001
2012	11	1,205,340	1,215,337	3,587	3,165
2012	12	1,498,438	1,503,958	4,683	3,547
2013	1	1,511,337	1,608,516	4,294	4,103
2013	2	1,277,561	1,274,191	3,992	3,620
2013	3	1,220,346	1,194,726	3,632	2,928
2013	4	1,090,335	1,070,676	3,098	2,909
2013	5	1,153,362	1,142,270	3,277	2,914

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	1,449,805	1,276,526	4,531	3,191
2013	7	1,656,206	1,650,445	4,705	4,210
2013	8	1,615,558	1,345,411	4,590	3,432
2013	9	1,262,526	1,265,637	3,945	3,164
2013	10	1,105,313	1,103,305	3,004	2,934
2013	11	1,146,890	1,190,707	3,584	2,977
2013	12	1,400,841	1,536,353	4,169	3,766
2014	1	1,477,702	1,556,998	4,198	3,972
2014	2	1,224,975	1,248,087	3,828	3,546
2014	3	1,167,132	1,164,512	3,474	2,854
2014	4	1,024,635	1,071,034	2,911	2,910
2014	5	1,090,035	1,125,262	3,244	2,758
2014	6	1,382,246	1,257,780	4,114	3,275
2014	7	1,555,932	1,661,665	4,420	4,239
2014	8	1,516,179	1,350,945	4,512	3,311
2014	9	1,213,527	1,245,301	3,612	3,243
2014	10	1,103,698	1,025,208	2,999	2,727
2014	11	1,079,263	1,163,694	3,550	2,797
2014	12	1,352,429	1,522,261	3,842	3,883
2015	1	1,434,828	1,489,951	4,270	3,652
2015	2	1,203,316	1,218,107	3,760	3,461
2015	3	1,131,087	1,150,456	3,213	2,935
2015	4	1,017,982	1,019,480	2,892	2,770
2015	5	1,059,403	1,087,997	3,311	2,566
Totals		**81,053,646**	**80,231,414**		

Appendix B-3

ComEd Procurement Period Load Forecast (High Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	2,243,061	1,868,006	6,372	5,076
2010	7	2,740,784	2,536,267	8,157	6,216
2010	8	3,042,075	2,598,387	8,642	6,629
2010	9	1,705,314	1,619,059	5,075	4,216
2010	10	1,495,123	1,520,640	4,450	3,727
2010	11	1,753,289	1,751,082	5,218	4,560
2010	12	2,131,819	1,890,020	5,793	5,027
2011	1	1,914,830	2,059,273	5,699	5,047
2011	2	1,765,411	1,762,320	5,517	5,007
2011	3	1,836,725	1,579,487	4,991	4,201
2011	4	1,536,739	1,524,171	4,574	3,969
2011	5	1,483,888	1,518,612	4,416	3,722
2011	6	2,374,774	1,947,758	6,747	5,293
2011	7	2,751,053	2,764,465	8,597	6,520
2011	8	3,282,281	2,640,419	8,919	7,022
2011	9	1,799,559	1,683,414	5,356	4,384
2011	10	1,557,711	1,601,784	4,636	3,926
2011	11	1,841,899	1,831,063	5,482	4,768
2011	12	2,034,007	2,156,317	6,054	5,285
2012	1	1,994,045	2,159,298	5,935	5,292
2012	2	1,927,623	1,861,103	5,737	5,170
2012	3	1,776,857	1,758,935	5,048	4,487
2012	4	1,593,692	1,579,951	4,743	4,114
2012	5	1,621,335	1,499,462	4,606	3,825
2012	6	2,366,160	2,091,889	7,042	5,448
2012	7	2,946,358	2,786,617	8,769	6,830
2012	8	3,381,944	2,749,375	9,190	7,312
2012	9	1,655,678	1,904,457	5,446	4,578
2012	10	1,758,020	1,526,702	4,777	4,060
2012	11	1,893,831	1,896,808	5,636	4,940
2012	12	1,989,919	2,314,760	6,218	5,459
2013	1	2,169,994	2,122,222	6,165	5,414
2013	2	1,934,539	1,841,183	6,045	5,231
2013	3	1,712,260	1,906,957	5,096	4,674
2013	4	1,724,289	1,552,090	4,899	4,218
2013	5	1,657,633	1,549,732	4,709	3,953

ComEd Procurement Period Load Forecast (High Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	2,308,475	2,263,780	7,214	5,659
2013	7	3,136,294	2,786,984	8,910	7,110
2013	8	3,377,491	2,901,940	9,595	7,403
2013	9	1,827,021	1,829,315	5,709	4,573
2013	10	1,812,624	1,548,872	4,926	4,119
2013	11	1,843,843	2,026,876	5,762	5,067
2013	12	2,142,711	2,284,628	6,377	5,600
2014	1	2,207,278	2,185,376	6,271	5,575
2014	2	1,963,391	1,896,826	6,136	5,389
2014	3	1,740,995	1,954,850	5,182	4,791
2014	4	1,744,254	1,600,887	4,955	4,350
2014	5	1,586,709	1,675,701	4,722	4,107
2014	6	2,450,096	2,252,755	7,292	5,867
2014	7	3,244,753	2,832,204	9,218	7,225
2014	8	3,356,076	3,052,819	9,988	7,482
2014	9	1,924,632	1,816,979	5,728	4,732
2014	10	1,857,384	1,570,439	5,047	4,177
2014	11	1,784,778	2,157,854	5,871	5,187
2014	12	2,283,257	2,265,662	6,487	5,780
2015	1	2,154,300	2,330,210	6,412	5,711
2015	2	1,981,505	1,974,298	6,192	5,609
2015	3	1,900,646	1,898,264	5,400	4,843
2015	4	1,767,369	1,657,983	5,021	4,505
2015	5	1,531,013	1,794,661	4,784	4,233
Totals		**125,321,414**	**120,514,248**		

ATTACHMENT F: Commonwealth Edison Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Commonwealth Edison Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Contract Month	Projected Monthly Volume Requirements									
	SF MW	MF MW	SFSH MW	MFSH MW	WH MW	Small MW	Condo MW	DD MW	GL MW	Total MW
June-11	2,132	442	49	102	44	600	20	15	1	3,405
July-11	2,842	585	50	112	49	662	27	15	1	4,342
August-11	2,615	551	45	102	49	662	30	16	1	4,072
September-11	2,615	395	34	76	43	584	26	16	1	3,791
October-11	1,568	340	41	82	41	552	23	18	1	2,665
November-11	1,712	358	72	131	40	541	22	18	1	2,894
December-11	2,062	408	111	212	44	603	31	19	1	3,491
January-12	2,042	396	126	258	45	618	37	19	1	3,542
February-12	1,718	355	114	235	42	573	34	17	1	3,089
March-12	1,640	344	98	201	42	579	31	17	1	2,955
April-12	1,418	302	70	139	39	524	25	15	1	2,534
May-12	1,545	334	53	106	41	558	23	16	1	2,677
June-12	2,132	443	48	100	44	568	20	15	1	3,372
July-12	2,876	593	50	111	49	631	27	16	1	4,355
August-12	2,629	555	45	101	49	629	30	17	1	4,056
September-12	1,808	391	33	74	43	550	26	17	1	2,942
October-12	1,577	343	41	81	41	531	23	19	1	2,655
November-12	1,706	357	70	128	40	514	22	19	1	2,858
December-12	2,052	407	108	208	44	572	31	20	1	3,443
January-13	2,057	398	125	256	45	593	38	20	1	3,534
February-13	1,659	342	108	224	40	528	33	17	1	2,953
March-13	1,631	341	97	197	42	550	31	17	1	2,908
April-13	1,420	302	69	137	39	503	26	16	1	2,513
May-13	1,540	333	52	104	41	531	24	16	1	2,643
June-13	2,131	443	48	99	44	567	20	16	1	3,368
July-13	2,913	600	50	111	49	634	27	16	1	4,402
August-13	2,633	556	44	100	49	626	30	17	1	4,056
September-13	1,812	392	33	73	43	552	26	17	1	2,949
October-13	1,565	340	40	79	41	532	23	19	1	2,640
November-13	1,690	353	69	125	40	512	22	19	1	2,833
December-13	2,063	408	107	206	44	575	31	20	1	3,456
January-14	2,059	399	123	253	45	593	38	20	1	3,531
February-14	1,658	342	106	220	40	528	33	17	1	2,946
March-14	1,629	341	95	194	42	550	31	18	1	2,902
April-14	1,413	301	68	135	39	502	26	16	1	2,501
May-14	1,533	332	51	102	41	529	24	16	1	2,629

Contract Month	Projected Monthly Volume Requirements									
	SF MW	MF MW	SFSH MW	MFSH MW	WH MW	Small MW	Condo MW	DD MW	GL MW	Total MW
June-14	2,153	448	47	99	44	569	20	16	1	3,398
July-14	2,940	607	50	111	49	633	27	17	1	4,435
August-14	2,639	558	44	99	48	622	30	18	1	4,059
September-14	1,821	395	32	73	43	553	27	18	1	2,962
October-14	1,565	341	39	78	41	532	23	19	1	2,639
November-14	1,681	352	67	123	40	510	22	19	1	2,816
December-14	2,076	411	106	204	44	578	31	21	1	3,474
January-15	2,058	397	121	248	45	592	38	20	1	3,521
February-15	1,662	341	105	217	40	528	33	18	1	2,946
March-15	1,641	342	94	192	42	553	32	18	1	2,916
April-15	1,415	300	67	133	39	502	26	17	1	2,499
May-15	1,531	330	50	100	41	526	23	17	1	2,620
June-15	2,182	453	47	98	44	571	20	17	1	3,433
July-15	2,973	612	50	110	49	632	27	17	1	4,472
August-15	2,659	561	43	98	48	621	30	18	1	4,080
September-15	1,823	394	32	71	43	552	26	18	1	2,961
October-15	1,555	338	38	76	41	529	23	20	1	2,621
November-15	1,690	352	67	121	40	512	22	20	1	2,826
December-15	2,083	411	105	201	44	579	31	21	1	3,477
January-16	2,056	395	119	245	45	590	38	21	1	3,511
February-16	1,729	354	108	223	42	547	35	19	1	3,056
March-16	1,652	343	94	191	43	555	32	19	1	2,930
April-16	1,407	297	66	130	39	498	26	17	1	2,482
May-16	1,543	332	50	100	41	529	24	17	1	2,637

ATTACHMENT G: Commonwealth Edison System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Commonwealth Edison System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	1,851,927	1,553,489	5,261	4,221
July-11	2,101,193	2,241,182	6,566	5,286
August-11	2,248,679	1,823,215	6,111	4,849
September-11	1,538,391	1,466,300	4,579	3,818
October-11	1,314,273	1,350,807	3,912	3,311
November-11	1,457,566	1,436,711	4,338	3,741
December-11	1,699,468	1,791,473	5,058	4,391
January-12	1,712,873	1,829,337	5,098	4,484
February-12	1,589,745	1,499,038	4,731	4,164
March-12	1,492,749	1,461,870	4,241	3,729
April-12	1,276,826	1,257,106	3,800	3,274
May-12	1,382,300	1,294,226	3,927	3,302
June-12	1,754,034	1,617,539	5,220	4,212
July-12	2,209,367	2,145,187	6,575	5,258
August-12	2,231,981	1,823,774	6,065	4,850
September-12	1,370,867	1,571,351	4,509	3,777
October-12	1,431,746	1,223,736	3,891	3,255
November-12	1,446,176	1,411,890	4,304	3,677
December-12	1,597,860	1,844,815	4,993	4,351
January-13	1,785,338	1,748,506	5,072	4,460
February-13	1,494,489	1,458,271	4,670	4,143
March-13	1,404,947	1,503,241	4,181	3,684
April-13	1,323,024	1,186,400	3,759	3,224
May-13	1,364,882	1,277,753	3,878	3,260
June-13	1,667,633	1,700,540	5,211	4,251
July-13	2,338,424	2,063,912	6,643	5,265
August-13	2,143,946	1,912,326	6,091	4,878
September-13	1,452,023	1,496,784	4,538	3,742
October-13	1,423,870	1,216,313	3,869	3,235
November-13	1,362,688	1,469,902	4,258	3,675
December-13	1,679,913	1,776,472	5,000	4,354
January-14	1,782,457	1,748,792	5,064	4,461
February-14	1,488,920	1,457,315	4,653	4,140
March-14	1,399,091	1,502,819	4,164	3,683
April-14	1,316,233	1,184,503	3,739	3,219
May-14	1,294,450	1,334,476	3,853	3,271

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-14	1,851,927	1,553,489	5,512	4,046
July-14	2,101,193	2,241,182	5,969	5,717
August-14	2,248,679	1,823,215	6,692	4,469
September-14	1,538,391	1,466,300	4,579	3,818
October-14	1,314,273	1,350,807	3,571	3,593
November-14	1,457,566	1,436,711	4,795	3,454
December-14	1,699,468	1,791,473	4,828	4,570
January-15	1,712,873	1,829,337	5,098	4,484
February-15	1,589,745	1,499,038	4,968	4,259
March-15	1,492,749	1,461,870	4,241	3,729
April-15	1,276,826	1,257,106	3,627	3,416
May-15	1,382,300	1,294,226	4,320	3,052
June-15	1,754,034	1,617,539	4,983	4,395
July-15	2,209,367	2,145,187	6,004	5,705
August-15	2,231,981	1,823,774	6,643	4,470
September-15	1,370,867	1,571,351	4,080	4,092
October-15	1,431,746	1,223,736	4,067	3,122
November-15	1,446,176	1,411,890	4,519	3,530
December-15	1,597,860	1,844,815	4,539	4,706
January-16	1,785,338	1,748,506	5,579	4,124
February-16	1,494,489	1,458,271	4,448	4,051
March-16	1,404,947	1,503,241	3,818	3,998
April-16	1,323,024	1,186,400	3,938	3,090
May-16	1,364,882	1,277,753	4,062	3,132

ATTACHMENT H: Commonwealth Edison Contract Volumes to Secure in Spring 2011 Procurement Cycle

Commonwealth Edison Off Peak Contract Volumes to Secure in 2011 Procurement Cycle

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	4,221	3,000	0	1,221	1200	0	0
July-11	5,286	3,000	700	1,586	1600	0	0
August-11	4,849	3,000	400	1,449	1450	0	0
September-11	3,818	3,000	0	818	800	0	0
October-11	3,311	3,000	0	311	300	0	0
November-11	3,741	3,000	0	741	750	0	0
December-11	4,391	3,000	100	1,291	1300	0	0
January-12	4,484	3,000	150	1,334	1350	0	0
February-12	4,164	3,000	0	1,164	1150	0	0
March-12	3,729	3,000	0	729	750	0	0
April-12	3,274	3,000	0	274	250	0	0
May-12	3,302	3,000	0	302	300	0	0
June-12	4,212	3,000	0	1,212	0	1200	0
July-12	5,258	3,000	0	2,258	700	1550	0
August-12	4,850	3,000	0	1,850	400	1450	0
September-12	3,777	3,000	0	777	0	800	0
October-12	3,255	3,000	0	255	0	250	0
November-12	3,677	3,000	0	677	0	700	0
December-12	4,351	3,000	0	1,351	0	1350	0
January-13	4,460	3,000	0	1,460	100	1350	0
February-13	4,143	3,000	0	1,143	0	1150	0
March-13	3,684	3,000	0	684	0	700	0
April-13	3,224	3,000	0	224	0	200	0
May-13	3,260	3,000	0	260	0	250	0
June-13	4,251	0	0	4,251	1500	1500	1250
July-13	5,265	0	0	5,265	1850	1850	1550
August-13	4,878	0	0	4,878	1700	1700	1500
September-13	3,742	0	0	3,742	1300	1300	1150
October-13	3,235	0	0	3,235	1150	1100	1000
November-13	3,675	0	0	3,675	1300	1250	1100
December-13	4,354	0	0	4,354	1500	1550	1300
January-14	4,461	0	0	4,461	1550	1550	1350
February-14	4,140	0	0	4,140	1450	1450	1250
March-14	3,683	0	0	3,683	1300	1300	1100
April-14	3,219	0	0	3,219	1150	1100	950
May-14	3,271	0	0	3,271	1150	1150	950

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	4,259	0	0	4,259	0	1500	1500
July-14	5,287	0	0	5,287	0	1850	1850
August-14	4,910	0	0	4,910	0	1700	1750
September-14	3,711	0	0	3,711	0	1300	1300
October-14	3,234	0	0	3,234	0	1150	1100
November-14	3,672	0	0	3,672	0	1300	1250
December-14	4,362	0	0	4,362	0	1550	1500
January-15	4,465	0	0	4,465	0	1550	1600
February-15	4,125	0	0	4,125	0	1450	1450
March-15	3,681	0	0	3,681	0	1300	1300
April-15	3,223	0	0	3,223	0	1150	1100
May-15	3,285	0	0	3,285	0	1150	1150
June-15	4,273	0	0	4,273	0	0	1500
July-15	5,278	0	0	5,278	0	0	1850
August-15	4,943	0	0	4,943	0	0	1750
September-15	3,711	0	0	3,711	0	0	1300
October-15	3,238	0	0	3,238	0	0	1150
November-15	3,674	0	0	3,674	0	0	1300
December-15	4,359	0	0	4,359	0	0	1550
January-16	4,465	0	0	4,465	0	0	1550
February-16	4,115	0	0	4,115	0	0	1450
March-16	3,686	0	0	3,686	0	0	1300
April-16	3,221	0	0	3,221	0	0	1150
May-16	3,278	0	0	3,278	0	0	1150

Commonwealth Edison Peak Contract Volumes to Secure in 2011 Procurement Cycle

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	5261	3000	650	1611	1600	0	0
July-11	7223	3000	2000	2223	2200	0	0
August-11	6722	3000	1650	2072	2050	0	0
September-11	4579	3000	150	1429	1450	0	0
October-11	3912	3000	0	912	900	0	0
November-11	4338	3000	0	1338	1350	0	0
December-11	5058	3000	500	1558	1550	0	0
January-12	5098	3000	550	1548	1550	0	0
February-12	4731	3000	300	1431	1450	0	0
March-12	4241	3000	0	1241	1250	0	0
April-12	3800	3000	0	800	800	0	0
May-12	3927	3000	0	927	950	0	0
June-12	5220	3000	0	2220	650	1550	0
July-12	7233	3000	0	4233	2050	2200	0
August-12	6672	3000	0	3672	1650	2000	0
September-12	4509	3000	0	1509	150	1350	0
October-12	3891	3000	0	891	0	900	0
November-12	4304	3000	0	1304	0	1300	0
December-12	4993	3000	0	1993	500	1500	0
January-13	5072	3000	0	2072	550	1500	0
February-13	4670	3000	0	1670	250	1400	0
March-13	4181	3000	0	1181	0	1200	0
April-13	3759	3000	0	759	0	750	0
May-13	3878	3000	0	878	0	900	0
June-13	5211	0	0	5211	1800	1850	1550
July-13	7308	0	0	7308	2550	2550	2200
August-13	6700	0	0	6700	2350	2350	2000
September-13	4538	0	0	4538	1600	1600	1350
October-13	3869	0	0	3869	1350	1350	1150
November-13	4258	0	0	4258	1500	1500	1250
December-13	5000	0	0	5000	1750	1750	1500
January-14	5064	0	0	5064	1750	1800	1500
February-14	4653	0	0	4653	1650	1600	1400
March-14	4164	0	0	4164	1450	1450	1250
April-14	3739	0	0	3739	1300	1300	1150
May-14	3853	0	0	3853	1350	1350	1150

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	5244	0	0	5244	0	1850	1800
July-14	7382	0	0	7382	0	2600	2550
August-14	6729	0	0	6729	0	2350	2350
September-14	4574	0	0	4574	0	1600	1600
October-14	3868	0	0	3868	0	1350	1350
November-14	4237	0	0	4237	0	1500	1450
December-14	5012	0	0	5012	0	1750	1750
January-15	5057	0	0	5057	0	1750	1800
February-15	4668	0	0	4668	0	1650	1600
March-15	4184	0	0	4184	0	1450	1500
April-15	3729	0	0	3729	0	1300	1300
May-15	3836	0	0	3836	0	1350	1350
June-15	5287	0	0	5287	0	0	1850
July-15	7435	0	0	7435	0	0	2600
August-15	6756	0	0	6756	0	0	2350
September-15	4571	0	0	4571	0	0	1600
October-15	3842	0	0	3842	0	0	1350
November-15	4240	0	0	4240	0	0	1500
December-15	5024	0	0	5024	0	0	1750
January-16	5054	0	0	5054	0	0	1750
February-16	4687	0	0	4687	0	0	1650
March-16	4195	0	0	4195	0	0	1450
April-16	3704	0	0	3704	0	0	1300
May-16	3868	0	0	3868	0	0	1350